Amended access arrangement information for the Western Power Network

Response to the Economic Regulation Authority's 29 March 2012 draft decision

May 2012

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Contents

1 Background and context

This document has been prepared in response to the *Draft Decision on Proposed Revisions to Access Arrangement for the Western Power Network*, published by the Economic Regulation Authority (the Authority) on 29 March 2012.

The Authority's draft decision was to not approve Western Power's proposed revisions. The Authority has advised 80 required amendments to the access arrangement that Western Power proposed on 30 September 2011.

This *amended access arrangement information* is to be read in conjunction with the *access arrangement information* submitted by Western Power on 30 September 2011. This document has been prepared in accordance with section 4.15 of the Electricity Networks Access Code (the Access Code) and is provided as part of the Authority's second round public consultation process.

This submission explains Western Power's position on each of the Authority's required amendments and is designed to assist the Authority in making its final decision on the access arrangement for the third regulatory period (1 July 2012 to 30 June 2017)[1].

Where Western Power's view differs from the Authority's, a detailed explanation of the rationale for varying the required amendment is provided, as well as an alternative proposal relating to that particular amendment.

1.1 Access Code objective

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

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

1.1.1 Criteria for approval of proposed revisions

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

> *… when making a draft decision, final decision or further final decision, the Authority must determine whether a proposed access arrangement [to be read as proposed revisions] meets the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) and:*
>
> *a) if the Authority considers that:*
>
> *(i) the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied — it must approve the proposed access arrangement; and*
>
> *(ii) the Code objective or a requirement set out in Chapter 5 (or Chapter 9, if applicable) is not satisfied — it must not approve the proposed access arrangement;*
>
> *and*

[1] Also referred to as 'the AA3 period' or 'AA3'.

b) *to avoid doubt, if the Authority considers that the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied, it must not refuse to approve the proposed access arrangement on the ground that another form of access arrangement might better or more effectively satisfy the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable).*

1.2 Structure of this document

Chapter 2 of this *amended access arrangement information* provides an executive summary of Western Power's overall response to the Authority's draft decision.

Detailed explanation of Western Power's position in response to each of the Authority's required amendments is included in chapters 3 to 16 of this document. For the reader's convenience, the order of the chapters and discussion of required amendments in this document follows the same structure as the Authority's draft decision.

Further supporting information and expert reports are included in the appendices to this document.

Where drafting changes have been made to the proposed access arrangement or its associated policies and contracts, these changes have been incorporated into the *proposed revised access arrangement* that accompanies this submission.

1.3 Explanatory notes

All monetary amounts presented in this document are expressed in real **30 June 2012 dollars** and apply to 1 July to 30 June financial years **unless otherwise stated**. Some tables may not add due to rounding.

2 Executive summary

On March 29 2012, the Economic Regulation Authority (the Authority) released its draft decision[2] on proposed revisions to the access arrangement for the third access arrangement period[3]. The Authority requires 80 amendments to Western Power's proposal that must be accepted or addressed for it to approve the access arrangement.

Western Power notes the significant level of consensus on a range of issues, and accepts or proposes changes that address the majority of the Authority's required amendments. Western Power accepts 35 of the revisions exactly as required and has modified its proposal to address a further 15 required amendments.

Western Power does not accept the remaining 30 required amendments. Western Power considers that accepting these particular amendments would not promote efficient investment in, maintenance, operation and use of the network. Where Western Power proposes that its original position should be maintained, further evidence of how Western Power's revisions satisfy relevant Access Code[4] provisions and the Access Code objective is provided for the Authority's consideration.

2.1 Areas of consensus

There are significant areas of consensus between the Authority's draft decision and Western Power's September 2011 submission. For example, the Authority has determined that the amount of capital investment Western Power proposes to undertake in order to address the highest priority public safety issues is reasonable. The Authority also recognises that investment in wood pole management *may change as Western Power further develops its understanding of what is required*[5].

There are some required amendments that Western Power believes improve the proposal, such as the Authority's recommendation that wood pole management expenditure be subject to the investment adjustment mechanism (IAM). Western Power also supports many of the Authority's amendments to the Applications & Queuing Policy, as they improve clarity and process.

The draft decision also acknowledges aspects of good performance and improvement Western Power has made during the AA2 period (2009-2012). In particular:

- the Authority recognises Western Power's good service standard performance over the second access arrangement period, which was achieved with lower expenditure than initially forecast[6]
- the Authority's technical consultant observes that expenditure governance processes during the second access arrangement period were generally good and that the management of capital expenditure has improved as a result[7]
- the consultant reviewed the demand forecasts and considers the methodology to be consistent with good industry practice[8]

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[2] *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.
[3] 1 July 2012 to 30 June 2017, commonly known as the AA3 period.
[4] *Electricity Networks Access Code 2004*.
[5] Paragraph 34, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, March 2012.
[6] Paragraph 15, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[7] Paragraph 419, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[8] Page 4, *Technical Review of Western Power's Proposed Access Arrangement for 2011-2017, Geoff Brown & Associates*, March 2012.

- the consultant also advises that processes for preparing the capital expenditure forecasts were soundly based and consistent with good electricity industry practice[9]
- the Authority acknowledges the effort that Western Power has made to take account of the interests of users, as well as the considerable work, review and discussion undertaken to date on key issues such as the Applications and Queuing Policy (AQP)[10]

Taking this into consideration, Western Power believes the Authority's draft decision is a solid platform for agreeing an access arrangement that delivers acceptable outcomes for the Western Power Network and the one million customers connected to it.

2.2 Key points of difference

The Access Code requires the Authority to determine whether the proposed revisions meet the Access Code objectives and the requirements set out in Chapter 5 (and Chapter 9 if applicable). If the Authority is satisfied, it must approve the proposed access arrangement and must not refuse to approve the proposed access arrangement on the grounds that another form of access arrangement might better or more effectively satisfy the Access Code objective and the requirements.

The key differences of the form of access arrangement proposed by the Authority compared to Western Power's submission are:

- **a significantly lower weighted average cost of capital (WACC)**

  Western Power considers that the Authority's WACC determination does not provide a reasonable return for the business and compromises its ability to develop the network to meet customer needs.

- **significantly reduced operating expenditure**

  The Authority's draft decision proposes a level of operating expenditure that will impact Western Power's ability to properly maintain and efficiently operate the network to provide services to customers.

- **a lower level of capital expenditure on growth-related programs of work**

  The Authority recommends a 22% reduction in growth-related investment. This is based primarily on the 2011 peak demand forecasts, which were not available at the time of the September 2011 submission. While Western Power agrees that the 2011 demand forecasts indicate less capital expenditure is required for growth-related programs, a 22% reduction may compromise Western Power's ability to connect new customers and maintain security of supply.

Discussion of these and other amendments that Western Power does not accept is included in section 2.4 below.

Western Power considers that the expenditure levels proposed in the Authority's draft decision are not sustainable and would not allow Western Power to provide the service that customers' value at a standard they expect.

The Western Power Network requires significant operating and capital expenditure in the short-to-medium term if it is to remain safe, secure and support growth. This means network tariff increases are unavoidable, particularly for the distribution network.

While price increases are never desirable for customers, Western Power is concerned that delaying expenditure now may lead to even greater price increases in future access arrangement periods.

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[9] Page 3, *Technical Review of Western Power's Proposed Access Arrangement for 2011-2017, Geoff Brown & Associates*, March 2012.
[10] Paragraph 1521, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Western Power respects the Authority's draft decision and has developed a proposed revised access arrangement and expenditure program that reflects many of the Authority's recommendations and results in lower price increases than originally proposed.

To help Western Power and the Authority reach an accord on an access arrangement that balances price increases against the level of expenditure required on the network, Western Power has modelled the impact of the Authority's draft decision on the network outcomes Western Power proposed to achieve in its September 2011 submission.

2.3 Impact of the Authority's draft decision

The Authority's draft decision reduces Western Power's target revenue over the five year access arrangement period by 33% to $6.9 billion[11].

Western Power's September 2011 submission sets out its detailed plans to maintain, operate and invest in the network during the AA3 period, which will enable it to deliver the following outcomes for customers:

- reduce the public safety risk associated with asset failure
- provide sufficient network capacity to facilitate ongoing growth and improve system security to decrease the likelihood of long duration or widespread outages
- prevent deterioration of service, maintaining it at a level consistent with the historical average over the last five years

Western Power defined these proposed outcomes based on feedback from extensive engagement with customers and key stakeholders, who agreed that these were desirable outcomes to be achieved. Balanced against an assessment of what could feasibly be delivered and the impact on prices, the September 2011 submission proposed a level of target revenue needed to deliver these services.

If Western Power was awarded the target revenue determined in the Authority's draft decision, its ability to deliver these outcomes would be significantly compromised.

For example, if the lower level of operating expenditure arising from the draft decision was upheld, Western Power would have to reprioritise its expenditure program. While the major capital investment programs relating to wood pole replacement, electric shocks and bushfire mitigation would still be delivered, maintenance programs such as routine preventative maintenance and vegetation management around overhead lines may need to be scaled back. A maintenance program consistent with the Authority's proposed level of expenditure would increase the life-cycle costs of assets and deteriorate their performance.

A potentially greater impact of the lower target revenue relates to growth and network security. Expenditure consistent with the Authority's draft decision would mean that Western Power would be unable to meet the forecast peak demand of 4619 MW at the end of the AA3 period. Connection of new customers would take longer and be more costly as there will be limited surplus capacity in the network. This would particularly affect high-growth regions such as the Perth metropolitan area (including CBD) and the country north and south regions.

The Authority's draft decision also provides no operating expenditure for network control services, and removes the D-factor adjustment mechanism. By doing this, the Authority's draft decision would impact customers who would have benefitted from the efficient deferral of capital projects, where a non-network solution is viable. It would also mean customers in Ravensthorpe and Bremer Bay will suffer degraded reliability, as there will be no funding to maintain existing generation systems.

Reduced expenditure on network security may also lead to an increased risk of widespread or long duration outages. Specifically:

[11] This includes $906.9 million relating to the Tariff Equalisation Contribution (TEC), which is required to be paid by Western Power but does not fall within the Authority's approval processes.

- an additional 16,000 customers would be at risk due to the deferral of the Mungarra-to-Geraldton and Albany-to-Kojonup lines
- an additional 21,000 customers would be at risk due to capital expenditure reductions in transmission substation capacity
- an additional 111,000 customers would be at risk due to over-utilised metropolitan distribution feeders[12]

With regard to service levels, if the Authority's draft decision was to be upheld, reduced expenditure would lead to deterioration in average reliability in rural areas. It would also increase the risk of Western Power not being able to achieve minimum service standards in most distribution areas.

2.4 Revised AA3 proposal

Western Power has revised its proposed access arrangement to reflect a number of amendments required by the Authority. Western Power has also made revisions where it accepts the Authority's position but proposes an alternative way of achieving the required change.

Western Power's proposed outcomes: to address safety, growth and security risks, while maintaining service levels, remain. However, Western Power has revised its proposal to reflect the most recent demand and expenditure forecasts. It also proposes a reasonable rate of return on investment using the latest relevant market information.

Overall, Western Power's revised proposal requires target revenue of $9.1 billon over the next five years to deliver services to customers. This is 12% less than proposed in its September 2011 submission.

The revised target revenue reflects the most recent view of likely costs, including new requirements and responding to the Authority's amendments. The proposal includes additional expenditure associated with wood pole management, which the Authority has supported in principle. Western Power also accepts the Authority's amendment to recover deferred revenue over ten years rather than five.

The revised proposal reflects a number of new initiatives designed to address the findings of the recent Parliamentary Inquiry[13] into Western Power's wood pole network. The Inquiry highlighted several areas for improvement relating not only to Western Power's wood pole management, but also aspects of its corporate culture and governance. During the AA3 period Western Power will continue to deliver its action plan designed to address issues raised by the Inquiry. This includes dramatically increasing the number of poles replaced and reinforced, enhancing data capture, improving stakeholder relationships and transforming business performance and culture.

Western Power will continue to investigate ways of reducing the cost of transporting electricity over the medium-to-long term in order to control future tariff increases. For example Western Power will investigate more initiatives that reduce the impact of peak demand. As a result, Western Power does not support the Authority's amendment to remove the D-factor scheme.

The D-factor scheme counterbalances incentives under the investment adjustment mechanism. It provides incentive to implement non-capital investments that reduce growth in peak demand and reduce future prices. There is no current mechanism in the Access Code that provides an adequate substitute for the D-factor.

A high level discussion of Western Power's position on other key amendments is summarised below.

[12] Over- utilised feeders means power cannot be re-routed during faults because adjacent parts of the network do not have sufficient capacity.
[13] *Report no.14 of the Standing Committee on Public Administration*, 20 January 2012.

2.4.1 Rate of return on investment

The Authority's draft decision requires the adoption of a real post-tax WACC of 3.87%. In its September 2011 submission, Western Power proposed a real pre-tax WACC of 8.82%.

While Western Power concedes that movements in the market since September 2011 means the WACC would be lower than its original position, Western Power does not believe that the WACC estimate calculated by the Authority is reasonable. This is confirmed by expert advice from SFG[14], which has analysed the outcomes of the Authority's WACC methodology. SFG has found that:

- The Authority's WACC parameters imply that the cost of equity is lower than the cost of debt[15]
- the Authority's methodology produces an allowed return on equity that is materially lower than returns available from comparable firms
- the Authority's methodology produces results in other industries that vary wildly over time. This suggests that the methodology is not robust and should not be relied upon

The Authority's WACC point estimate is the output of several parameters relating to the cost of debt and equity. The Authority's estimates for many of these parameters are either outside or at the lower end of any reasonable range. This includes estimates of the nominal risk free rate (1.09%), the market risk premium (6%), an A- credit rating, a debt risk premium (2.03%), an equity beta (0.65) and expected inflation (2.55%).

Taken together, these estimates result in an overall WACC estimate that is inconsistent with section 6.4 of the Access Code.

Section 6.4 of the Access Code provides that Western Power should be given the opportunity to earn:

> *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.*

Section 6.66 of the Access Code provides that the WACC:

> must represent an effective means of achieving the Code objective and the objectives in section 6.4.

Though the Authority provides arguments for why it considers its calculation of the parameters in isolation is appropriate, it is important that the WACC point estimate, which is an output of these parameters, is considered against section 6.4 of the Access Code.

While the mechanical application of the parameters may result in a certain figure, the Access Code requires that the figure allows the network operator to earn an amount that meets the forward-looking and efficient costs of providing covered services. The Authority's real post-tax WACC point estimate of 3.87% does not allow Western Power to do this.

A return of 3.87% exposes Western Power to the considerable commercial risk that it will be unable to secure sufficient debt to finance its capital investments. More broadly, this exceptionally low WACC estimate provides a disincentive to continue to make the necessary investments in the network required to maintain and improve outcomes for customers.

The proposed rate of return is also the lowest WACC ever determined for a regulated electricity network business in Australia. It is lower than any WACC applied by the Authority to other Western Australian utilities.

Western Power accepts that the calculation of the WACC should be on a real post-tax basis (as distinct from pre-tax). However, Western Power does not believe that the Authority's

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[14] *Estimating beta: Reply to Draft Decision*, SFG Consulting, May 2012.
[15] Based on the Authority's WACC parameters, a 100% equity investment would be less risky than a 60% debt investment in the same firm.

approach to calculating the real post-tax WACC is appropriate and has therefore proposed an alternative approach.

Western Power proposes that the change to the post-tax model for calculating revenue should reflect the tax costs derived from Western Power's tax asset base rather than the regulated asset base. It should also include tax costs associated with receiving gifted assets and capital contributions from customers. This approach is consistent with the method that the Australian Energy Regulator adopts for most other networks businesses and more accurately estimates Western Power's tax costs.

Western Power accepts the Authority's view that it may not be appropriate to compensate Western Power for the additional risks associated with an ex-post review through the equity beta. Western Power has revised the equity beta and will instead claim compensation for the ex-post review risk through the revenue building blocks.

Western Power has reviewed its estimates of the various WACC parameters and has fully considered the Authority's analysis. Further expert evidence[16] confirms that the range used by Western Power is reasonable.

Western Power has revised its proposed real post-tax WACC estimate to be 6.39%. Details of how Western Power determined this point estimate can be found in Chapter 9 of this document.

2.4.2 Operating expenditure

The Authority's draft decision requires Western Power to reduce its forecast operating expenditure by 19.2% ($522 million) over the AA3 period compared to the September 2011 submission.

In determining this reduction, the Authority has:

- rejected expert forecasts of changes in material costs and reduced the forecast costs of labour to levels below the expert advice
- constrained the costs of operating and maintaining the growing network to historical levels, despite acknowledging past underinvestment and supporting future investment requirements
- disallowed the recovery of costs associated with network control services. This has the effect of reducing Western Power's ability to pursue non-network solutions and improve service levels in Albany, Geraldton, Eastern Goldfields, Ravensthorpe and Bremer Bay
- halved the operating expenditure for the field data survey project, limiting Western Power's ability to improve information on the location and condition of assets
- reduced the base costs where historical costs were lower with no corresponding increase where historical costs were higher
- reduced operating costs by *a further 2%* per year with no evidence that this level is efficient or that Western Power can efficiently maintain and operate the network while achieving efficiencies at a rate greater than its peers

The combination of these adjustments results in an expected reduction in operating and maintenance costs of approximately 4% compounding each year.

[16] *Internal consistency of risk free rate and MRP in the CAPM, CEG*, May 2012.
Western Power's proposed debt risk premium, CEG, May 2012.
Estimating equity beta for Australian regulated energy network business, CEG, May 2012
Estimating beta: Reply to Draft Decision, SFG Consulting, May 2012.
Advice on capital asset pricing model for response to ERA Draft Decision, Ernst & Young, May 2012.

Though Western Power appreciates the need to reduce costs, and will endeavour to do so, the Authority's recommended reductions result in unsustainably low levels of operating and maintenance expenditure.

Given that a level of Western Power's operating expenditure is non-discretionary (for example rates, taxes and corrective emergency work), applying the Authority's recommended reduction to discretionary components of Western Power's expenditure (for example planned routine maintenance) leads to a 24.3% reduction in expenditure on these programs. This level of expenditure would not provide for the maintenance activities needed to efficiently manage the network.

Taking the concerns that underpin the Authority's required amendments into consideration, Western Power has reduced its operating expenditure proposal by $58 million (2.1%). This incorporates recent information on costs expected to be incurred in 2011/12 and reductions related to the savings generated by Western Power's Strategic Program of Work (SPOW) that were not already included in the base costs.

Western Power considers that there are no further opportunities to reduce costs through economies of scale than those already incorporated in the base costs. The ability to achieve economies of scale is limited to the extent that activities can be bundled by geographic region. Western Power's activities that are suitable for bundling (such as vegetation management) are already bundled and the reduced costs are incorporated in the base costs.

Further, the age of the Western Power Network impacts opportunities to achieve economies of scale. As discussed in the September 2011 submission, the Western Power Network contains a large number of assets that are nearing the end of their service life. Despite the higher investment proposed for the AA3 period, the rate at which new assets will be added to the network is lower than the rate at which existing assets are reaching the end of their lives. Therefore, operating and maintenance activities are unlikely to reduce with the size of the network.

Figure 1 provides a comparison of Western Power's initial and revised proposal, the Authority's draft decision, and Western Power's historical operating expenditure.

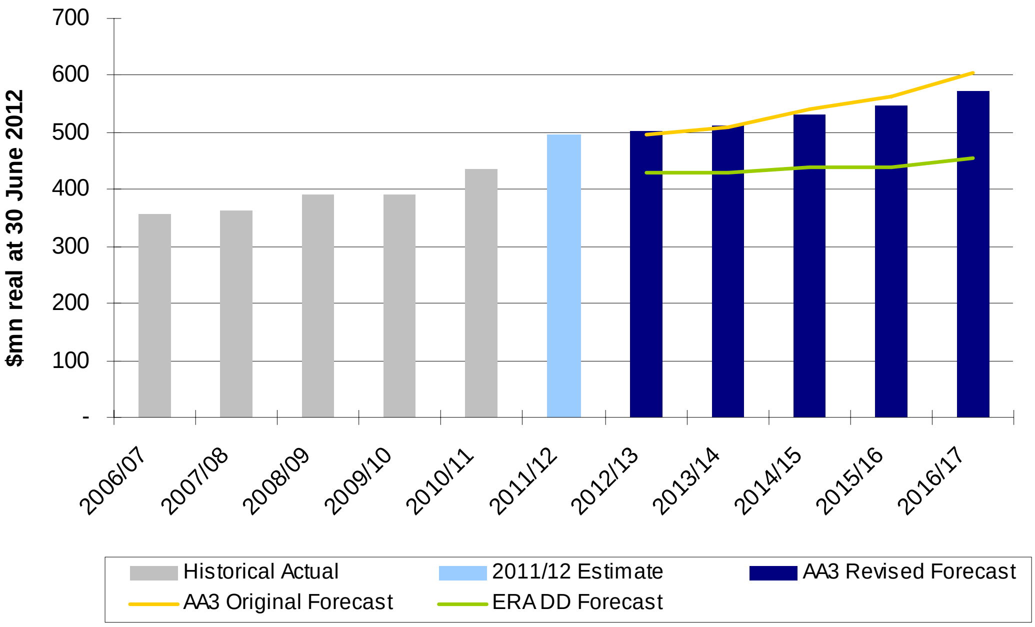


Figure 1: Revised operating expenditure forecast

2.4.3 Capital expenditure forecast

In its draft decision, the Authority accepts Western Power's proposed investment to address high priority public safety issues. In relation to wood pole replacement and reinforcement, it recognises that Western Power's view of the necessary expenditure may change and proposed that wood pole management costs should be subject to the investment adjustment mechanism (IAM).

The Authority also requires a $763 million (22%)[17] reduction in growth-related investment. This reduction is based primarily on the recommendations of its technical consultant, which has applied a broad-brush approach to estimating the reduction in investment that corresponds to the lower peak demand indicated by the 2011 peak demand forecasts.

Western Power accepts the Authority's proposal to apply the IAM to wood pole management. Since the September 2011 submission, Western Power has revised investment in wood pole management in response to the recent Parliamentary Inquiry[18] and further discussions with Energy*Safety.*

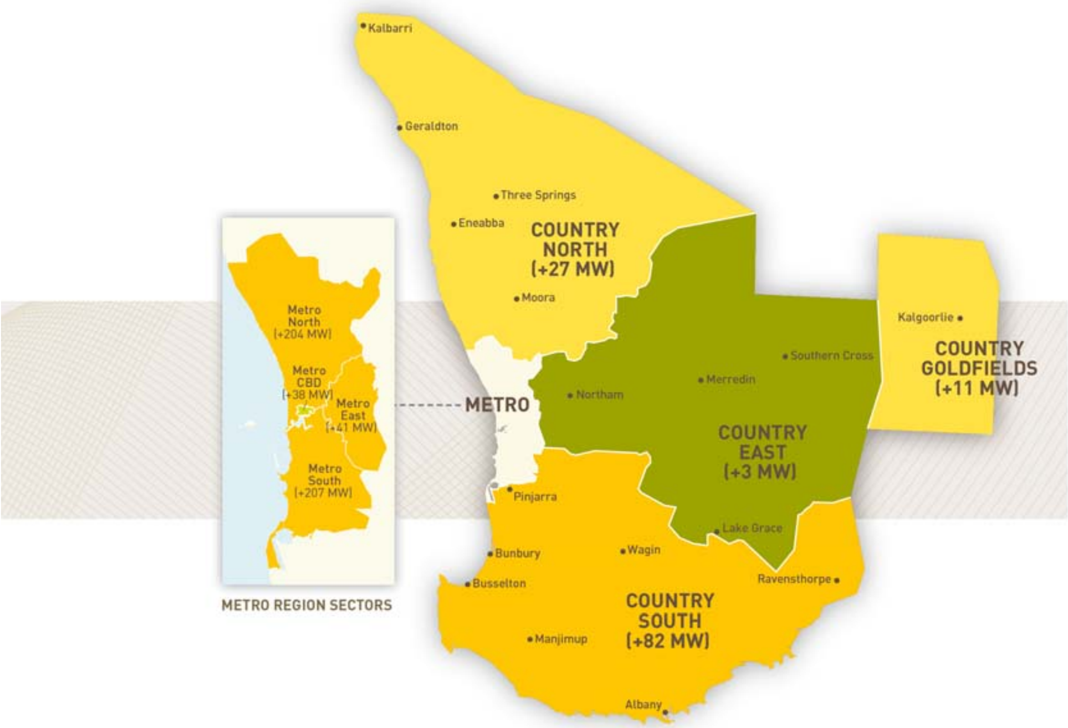
In its November 2011 submission to the Authority[19], Energy*Safety* indicates that additional reinforcement of wood poles would be an acceptable approach to address the safety risk associated with the poles that cannot be replaced during the AA3 period. Western Power has since secured additional capacity to increase the number of wood pole reinforcements by 205,000. Western Power is also investigating options to appoint a second supplier and/or adopt another reinforcement method to increase the number of wood pole reinforcements by up to a further 78,740 during the AA3 period.

Western Power proposes that the cost of the additional 205,000 wood pole reinforcements be included in the AA3 capital expenditure forecast and recovered through the target revenue. The additional cost (resulting from the 205,000 additional reinforcements) to be included in the AA3 capital expenditure forecast is $254.7 million.

Costs associated with the 78,740 extra reinforcements that could potentially be delivered will be recovered via the IAM. This approach provides Western Power with sufficient flexibility to respond to this key safety issue if compliance requirements or delivery capacity changes during the period.

Western Power has also revised the capital expenditure forecasts to reflect the most recent peak demand forecast[20]. This includes consideration of the actual and expected load on the network by substation. Figure 2 illustrates how the reduced demand forecasts affect each region of the South West Interconnected System.

[17] This amount (22%) is the reduction in forecast growth related capital expenditure in Western Power's proposal ($3,525 million) when compared with the ERA's draft decision ($2,762 million) in real dollars as at 30 June 2012.
[18] *Report no.14 of the Standing Committee on Public Administration*, 20 January 2012.
[19] *Letter to ERA regarding Issues Paper on Western Power's AA3 Submission*, EnergySafety, 28 November 2011.
[20] November 2011 demand forecasts, as published in the *Western Power 2011 Annual Planning Report.*



LEGEND

- >15 % decrease
- 10-15 % decrease
- 5-10 % decrease
- 0-5 % decrease
- 0-5 % increase
- 5-10 % increase
- 10-15 % increase
- >15 % increase

REGION	FORECAST 2012 PEAK DEMAND (MW)	FORECAST 2017 PEAK DEMAND (MW)
Metro CBD	383	421
Metro North	1098	1302
Metro South	1361	1568
Metro East	196	237
Country North	240	267
Country South	450	532
Country East	200	203
Country Goldfields	79	90
TOTAL	**4007**	**4619**

Figure 2: Demand increases reflecting the 2011 peak demand forecast

Analysis at the substation level provides a much more accurate forecast of required capacity and associated expenditure than the broad-brush method adopted by the Authority's technical consultant. The consultant incorrectly assumes that there is a direct correlation between the decrease in forecast demand and decrease in forecast expenditure. This assumption is not appropriate as the reduction in costs is not necessarily proportionate to the decrease in demand. For example, a 40% reduction in demand would not equate to a 40% reduction in expenditure.

Western Power has revised down its forecast capital expenditure to reflect the lower demand forecast. However Western Power's reduction is $317 million (9%), substantially less than that estimated by the Authority.

Western Power's forecast investment has also been adjusted to reflect increases in the unit rates of distribution delivery partners. These unit rates have increased as a result of market forces and were negotiated through a comprehensive assessment process.

Minor additional expenditure has also been included to reflect the Commonwealth Government's Clean Energy Future Package. These costs relate to specific initiatives contained in the Clean Energy Future legislation. The additional costs associated with the increased cost of carbon are expected to be captured in the inflation estimates of the Reserve Bank.

Western Power's revised capital expenditure proposal for the AA3 period is $5,997 million (see Figure 3).

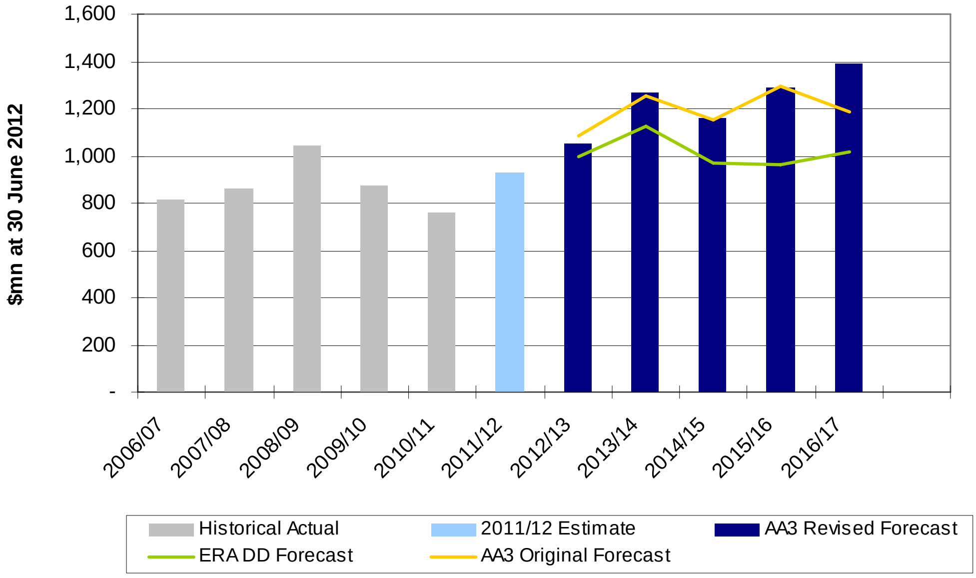


Figure 3: Revised capital expenditure forecast

2.4.4 Investment undertaken in AA2

In its draft decision, the Authority determines that $21 million of projects and programs delivered during AA2 must not be added to Western Power's capital base. On the advice of its technical consultant, the Authority considers that these projects and programs were inefficient and therefore have a value of zero. Western Power does not accept the Authority's view that this investment was inefficient.

Western Power considers that the Authority's application of its requirement to undertake a review of past capital investment results in a high probability that some investment will be valued at zero simply due to a difference of opinion between technical experts rather than because of evidence of inefficiency. Western Power provides further information in section 7.2 of this document to demonstrate that this investment was technically sound and efficient.

The Authority also disallows the addition of planning and environmental costs to Western Power's capital base. This is on the basis that the Authority's technical consultant does not consider these costs were directly related to specific projects or programs and therefore do not meet the new facilities investment test (NFIT). Given that the Authority's consultant accepted that these were genuine business costs, it is appropriate that they should be included as operating expenditure if they are not recovered through the capital base. Western Power has altered its treatment of these costs but maintains that it is appropriate to add these costs to the capital base. Further discussion of this issue can be found in section 7.2.

2.4.5 Service standards and SSAM

The Authority accepts Western Power's proposal to ensure service levels to customers are maintained without reducing the incentives to achieve operating cost efficiencies.

However, the Authority proposes that service targets relating to reliability should be marginally higher than those recommended in the September 2011 submission. This is to account for the impact of investment during AA2. Western Power accepts the Authority's rationale and will use three years of historical data to set the service reliability targets (SAIDI and SAIFI).

The Authority also requires Western Power to reinstate a number of transmission network service standard benchmarks that are not required under the Access Code and are not meaningful to customers. These are:

- system minutes interrupted (for meshed and radial circuits)
- loss of supply event frequency
- average outage duration (measured in minutes)

Typically, these transmission performance measures would be relevant to a distribution network service provider connected to a transmission network. However, Western Power is an integrated distribution and transmission networks service provider, and is accountable for both networks.

Customers connected to Western Power's transmission network are either generators or loads. Western Power considers that the transmission network performance measures listed above do not allow these types of users to determine the value of reference services, as the service level these customers receive is significantly better than the average transmission network performance.

Section 5.6 of the Access Code requires Western Power to provide service standard benchmarks for reference services and that they *must be sufficiently detailed and complete to enable a user to determine the value represented by the reference service*. It does not require pure network performance measures. Therefore it is not appropriate to include them as service standard benchmarks under 5.6 of the Access Code.

It is important that the service standard benchmarks included in the service standard and incentive framework reflect the services received by customers, as it is these benchmarks that drive network investment. Service standard benchmarks that only measure network performance may lead to investment that simply meets a technical target rather than improving the customer's experience.

Western Power will, however, continue to report on these transmission network measures to allow interested stakeholders to monitor overall network performance and compare performance of the Western Power Network to other jurisdictions.

The Authority proposes an amendment to Western Power's proposed call centre service standard benchmark, which excludes phone calls answered by Western Power's automated messaging service. While Western Power understands that the Authority's approach is consistent with the Australian Energy Regulator, unlike many other utilities Western Power's state-of-the-art automated service is directly linked to its network monitoring systems and provides customers real-time information on outages and restoration times in their suburb. Therefore the automated system is a valuable part of the reference service Western Power provides to its customers.

The Authority also requires a change to the service standards adjustment mechanism (SSAM) formula that limits the financial incentive for maintaining or improving service to a level that is below the value of these services to customers. Western Power does not accept this amendment as it means that in some cases the rewards for improving service would be less than the cost of delivering them, resulting in no incentive for Western Power to carry out the work that customers value. The Authority's formula also reduces the penalty to Western Power for not maintaining service levels.

Western Power proposes that the SSAM formula proposed in the September 2011 submission be retained, as it is based on that used by the Australian Energy Regulator, which is considered to be effective for other jurisdictions.

2.5 What it means for customers

Western Power's revised proposal reduces public safety risk associated with asset failure, provides sufficient network capacity to facilitate ongoing growth and improves system security to decrease the likelihood of long duration or widespread outages. It also maintains the network and service performance currently experienced by customers.

Western Power's revised proposal results in average network tariff increases of CPI+ 10.3% per year over the next five years.

Western Power will continue to investigate ways of reducing the cost of transporting electricity over the medium-to-long term, for example incorporating more initiatives that reduce the impact of peak demand. As previously discussed, Western Power will not accept the Authority's required amendment to remove the D-factor as this mechanism is critical to ensure demand side participation opportunities are considered.

Overall, Western Power's revised proposal satisfies the requirements of the Access Code. In accordance with Section 4.52 of the Access Code, the *revised proposed revisions to the access arrangement* are included with this submission for approval by the Authority.

3 Introduction to the access arrangement

3.1 Definition of the access arrangement

Required amendment 1:

Section 1.1.2 of the proposed revised access arrangement must be amended to include the underlined text as follows:

"This access arrangement sets out the terms and conditions under which Western Power will provide users and applicants with access to the Western Power Network…"

Western Power response:

Western Power does not accept this amendment.

The Authority notes that Western Power has proposed to simplify the wording of section 1.1.2 of the access arrangement. The Authority supports simplifying the network description but considered that some other parts of the existing text should be deleted or retained.[21]

Western Power does not accept this amendment as the Authority's proposed wording for section 1.1.2 is inconsistent with the Access Code definition of an access arrangement.

Western Power's original proposed wording is:

> *1.1.2 This access arrangement is an arrangement for access to the Western Power Network from the date specified in section 1.3.1 of this access arrangement. The Western Power Network is a covered network under the Code.*

Western Power's proposed wording for section 1.1.2 incorporates relevant portions of the Access Code definition of access arrangement which states:

> *"access arrangement" means an arrangement for access to a covered network that has been approved by the Authority under this Code.*

The access arrangement is not just the terms and conditions under which Western Power will provide users and applicants with access to the Western Power Network. It deals with a variety of matters as set out in section 5.1 of the Access Code. The terms and conditions under which Western Power will provide access to the Western Power Network are the terms and conditions set out in the Electricity Transfer Access Contract.

Western Power does not propose any further changes to section 1.1.2 of the revised access arrangement.

[21] Paragraph 69, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

3.2 Inclusion of DLVCS in the access arrangement

Required amendment 2:

Section 1.5.1(e) of the proposed revised access arrangement must be deleted and sections 1.5.1 (f) to 1.5.1 (i) renumbered accordingly.

Western Power response:

Western Power does not accept this amendment.

The Distribution Low Voltage Connection Scheme (DLVCS) sets out the proposed charging methodology for distribution low voltage customers. It aims to address customer concerns about the transparency of the existing Contributions Policy and the unpredictability of the required contributions amounts. Customers affected include large residences and small-to-medium commercial or industrial premises. Western Power connects or upgrades between 800 and 1000 such customers per year.

Western Power made a submission to the Authority in January 2012 seeking approval for the introduction of the DLVCS outside of this access arrangement review process. At the time, the Authority indicated it was unable to assess the submission as it was awaiting a change to the Access Code related to the DLVCS.

In its draft decision, published on 29 March, the Authority indicates that it could not approve reference to the DLVCS until an amendment was made to the Access Code to permit such schemes.[22] It required the deletion of section 1.5.1(e) of the proposed access arrangement revisions related to the inclusion of the (DLVCS), and to re-number section 1.5.1 (f) to (i) accordingly.

On 17 April 2012, the necessary Access Code amendment was approved by the Minister for Energy and gazetted. The limit in section 5.17D(b) of the Access Code was also increased from 1% to 4%.

On 18 May 2012 the Authority published a notice[23] seeking public comment on the proposed variations to Western Power's access arrangement for the second access arrangement period Contributions Policy for 2009/10 to 2011/12 that will allow for the DLVCS. It is anticipated that the mid-period submission for the DLVCS may be approved prior to finalisation of this review of Western Power's proposed access arrangement revisions. The Authority noted that it is unlikely the proposed access arrangement revisions will come into effect before November 2012 and, potentially, may be some time after that.

In light of this development Western Power's proposed section 1.5.1(e) should be retained.

[22] Paragraph 70, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[23] *Proposed variations to Western Power's Access Arrangement for 2009/10 to 2011/12: Contributions Policy - Issues paper*, ERA, 18 May 2012, Available from: http://www.erawa.com.au/cproot/10406/2/20120518%20Consultation%20-%20PV%20to%20Western%20Powers%20AA%20for%202009-10%20To%202011-12%20CP%20-%20IP.pdf

4 Reference and non-reference services

4.1 Bi-directional reference tariffs

Required amendment 3:

The proposed revised bi-directional reference tariffs (C1, C2, C3 and C4) must not be extended to battery storage and electrical vehicle systems unless the issues identified in paragraphs 105 to 113 are resolved.

Western Power response:

Western Power does not accept this amendment.

In its draft decision, the Authority requires that the proposed bi-directional reference services (C1, C2, C3 and C4) are not extended to battery storage and electrical vehicle systems unless the issues raised by Synergy are addressed. Synergy's issues are described in paragraphs 105 to 113 of the draft decision.

Western Power does not accept this amendment because it is not appropriate to discriminate against particular electrical appliances unless there is a negative safety, technical or cost impact. No current safety, technical or cost issues that would give rise to the need to prohibit customers on these bi-directional services from using battery storage or electrical vehicle systems have been identified.

If safety, technical or cost issues become apparent over time, Western Power will consider the need to introduce a new reference service and tariff appropriate for these uses. However there are no such issues prohibiting extension of reference services C1 - C4 to electric vehicles and battery storage at this time.

From a network perspective, a bi-directional service (like all other services) does not depend on the source of the electrical energy, whether it be a photovoltaic system, wind turbine, battery or electric vehicle. Western Power's role is to outline the standards that appliances must meet to connect to the network. It is not Western Power's role to determine the type of appliance that can and cannot be connected to the network, or to enforce the use of particular appliances on these reference services.

Many of the issues raised by Synergy are operational in nature and not matters to be resolved through the development of reference services under an access arrangement.

Contractual obligations and application processes are already dealt with under the Electricity Transfer Access Contract (ETAC) and the Applications and Queuing Policy (AQP). This is discussed in section 4.1.2 below.

Similar to the Access Code definitions of entry and exit services, the definition of the bi-directional service is ambivalent to the type of equipment – it is merely concerned with the type of flow of electricity.[24]

The concerns raised by Synergy cover the following issues:

- lack of information regarding electric vehicle systems and battery storage that could impact retailers, customers and government policy due to:
    - increased likelihood for a retailer to breach clause 3 of the ETAC

[24] In Appendix E of the access arrangement a "bi-directional service" means "a covered service provided by Western Power at a connection point under which the user may transfer electricity into and out of the Western Power Network at the connection point". This is essentially identical to the Access Code definition of "entry service" which 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."

  - increased likelihood of customers breaching their supply contract due to Western Power approving the connection of these systems
  - uncertainty regarding the eligibility of customers for feed-in-tariff arrangements for these systems
- commercial and contractual issues associated with the applications and queuing policy, metering process and notification
- the introduction of a reference service that applies more broadly than that requested by Synergy

These concerns are discussed in the following sections.

4.1.1 Lack of information

Areas where Synergy considers information is lacking relate to:

- various connection configurations and their impacts on battery and electric vehicle systems[25]
- Western Power's process for connecting battery and electric vehicle systems to the network and allowing them to operate simultaneously with other systems such as photovoltaic systems, and the impact on system peaks and the costs of network augmentations[26]
- customer, commercial and contractual impacts of connecting and operating battery and electric vehicle systems (especially if these systems are operating simultaneously with photovoltaic systems)[27]
- the cost of connections including the process of approving, connecting and energising battery and electric vehicle systems, including what type of connection configuration is permitted and how the retailer will be notified[28]
- how the location of these systems will be tracked, how meters will differentiate electricity that is exported from a photovoltaic system and electricity that is exported from a battery or how retailers will receive this information under the Metering Code Communications Rules[29]

Western Power has not received specific examples of the issues Synergy claim will arise as a result of this perceived lack on information.

Western Power has considered the possible impacts of battery storage and electric vehicles in terms of the Technical Rules, the AQP, the Contributions Policy, the Access Code and cost impacts. Based on the information currently available and consideration of the issues raised by Synergy, Western Power concludes:

- the cost of connections is adequately addressed in the Contributions Policy and the Price List
- the application process is adequately addressed by the AQP
- the contractual requirements are outlined in the ETAC and
- the technical requirements are set out in standards and the Technical Rules

[25] Paragraph 105, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[26] Paragraph 107, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[27] Paragraph 108, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[28] Paragraph 109, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[29] Paragraph 110, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

As all equipment must comply with relevant standards and the Technical Rules, Western Power considers that there are currently no technical or operational issue with the appliances operating separately or simultaneously. Ongoing review of the Technical Rules will resolve any technical issue as it arises. No adverse affect in terms of impact on safety or equipment has been identified.

Western Power acknowledges that this current assessment is based on limited experience. However, as customers increase their usage of electric vehicles and battery storage, Western Power will monitor the network impact from a technical and safety perspective. If this monitoring suggests that battery storage and electric vehicles cause a sufficiently different impact on the network compared to photo-voltaic systems, then it may be appropriate to develop a different reference service and tariff for these systems.

In the absence of information supporting these impacts, these systems should not be prohibited.

There are no issues related to the network, or to the ETAC, which preclude electric vehicles or battery storage from being included in the bi-directional reference service. Any issues that relate to the end-use customer's relationship with the retailer are operational, and not matters to be resolved through the development of reference services under an access arrangement.

Synergy infers that inclusion of electric vehicles and battery storage in the bi-directional reference service may be contrary to government policy, and, in particular:

> *Synergy … will require clarity from the Office of Energy on whether a customer will be entitled to a feed-in-tariff payment for electricity exported into the network, as recorded on Western Power's meter, from a battery.*[30]

Western Power agrees that this issue will need to be considered by State Government as it will be possible for customers with battery storage and electric vehicle systems to receive payment for this generation under the feed-in tariff. This is a policy issue and it is inappropriate for Western Power to prevent this occurring through the definition of a reference service unless there are safety, technical or cost issues.

Separate metering is not currently required by the Metering Code, the Wholesale Market Rules or the Access Code; all of which do not differentiate between generation sources. Western Power notes that if the Government does wish to distinguish generation from separate sources at a connection point, multiple metering may be required.

4.1.2 Commercial and contractual issues

Western Power's reference services and ETAC require all equipment to comply with relevant standards and the Technical Rules. Western Power has not identified any technical or operational issue with the generation technologies operating separately or simultaneously.

To the extent that issues do arise with the operation of equipment, the ongoing review of the Technical Rules is the appropriate place to resolve them and metering issues are appropriately governed by the Metering Code.

As the reference service relates to a fixed connection point, the connection of battery storage or electric vehicles systems behind the connection point (either on a permanent or intermittent basis) is not relevant to the reference service. A bi-directional service will be required to allow the bi-directional flow of energy regardless of the generation source. Tracking these systems is unnecessary unless there is a safety, technical or cost implication.

The ETAC and the AQP already address the issues associated with appropriate connection. The customer will not be lawfully permitted to export electricity into the network without the appropriate service at the relevant connection point. The service must be a bi-directional service. The retailer would be responsible for applying for this service under the AQP. The process already exists and is clear under the Access Code and access arrangement.

[30] Paragraph 110, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

The AQP expressly provides for the end-use customer to make a connection application. Clause 9.2(a)(ii) of the AQP provides for an end-use customer submitting a connection application for new generating plant (such a photovoltaic system) at a retailer's connection point. Importantly, if end-use customers wish to export energy, the customer must consult with the retailer to apply for a modification of the access service at the connection point from an 'exit service' to a service that permits bidirectional flows of electricity. This is an issue between retailers and their customers. Potential failure of a customer to comply with the AQP or a supply contract is not a sound basis for not including battery storage and electrical vehicles in the bi-directional reference service.

A retailer could impose and enforce a requirement on its customers (under its supply contract with the customers) to advise the retailer of any renewable-energy system that is intended to be connected behind the retailer's connection point. There can only be a breach of the ETAC if the retailer does not lodge an electricity transfer application under the AQP. This may occur if the end-use customer does not notify the retailer of a renewable-energy system connected behind the connection point. Once again, this is an issue between the retailer and its customer and not a matter to be resolved through the development of reference services.

Western Power is working with retailers to refine the detailed process to be applied when an end-use customer submits a connection application for bi-directional equipment. It is not anticipated that changes to the access arrangement or the AQP will be required as a result of these discussions.

4.1.3 Conditions for the introduction of a new reference service

In its draft decision, the Authority noted that:

> *Synergy's submission highlights that it has not requested a bidirectional service for battery and electrical vehicle systems. Synergy notes its request for a bidirectional service in the second access arrangement was intended to meet the requirements of Synergy, its customers and state government policy for photovoltaic systems.*[31]
>
> *…*
>
> *Synergy notes it will make a separate request for a reference service to cover battery and electric vehicle systems once the policy, commercial, connection process and technical requirements have been clarified and there is significant demand from customers to connect battery and electric vehicle systems.*[32]

While Synergy may not have requested a bi-directional service for battery and electrical vehicle systems, it was requested during the consultation.[33] However, whether Synergy has requested a bi-directional service for battery and electric vehicle systems is not criterion for the introduction of a reference service. Under section 5.2 of the Access Code an access arrangement must specify a reference service "for each covered service that is likely to be sought by either or both or ...by a significant number of users and applicants". Western Power believes it is likely that the covered service will be sought by a significant number of users and applicants.

Western Power anticipates that there will be demand from electric vehicle owners for a bi-directional service during the next five years. Figure 4 shows the potential use of electric vehicles (EV) and plug-in hybrid electric vehicle (PHEV) compared to light duty vehicles (LDV) in Western Australia.

[31] Paragraph 111, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[32] Paragraph 113, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[33] Page 20, *Access Arrangement Information Appendix Z – Ernst & Young bi-directional report*, September 2011.

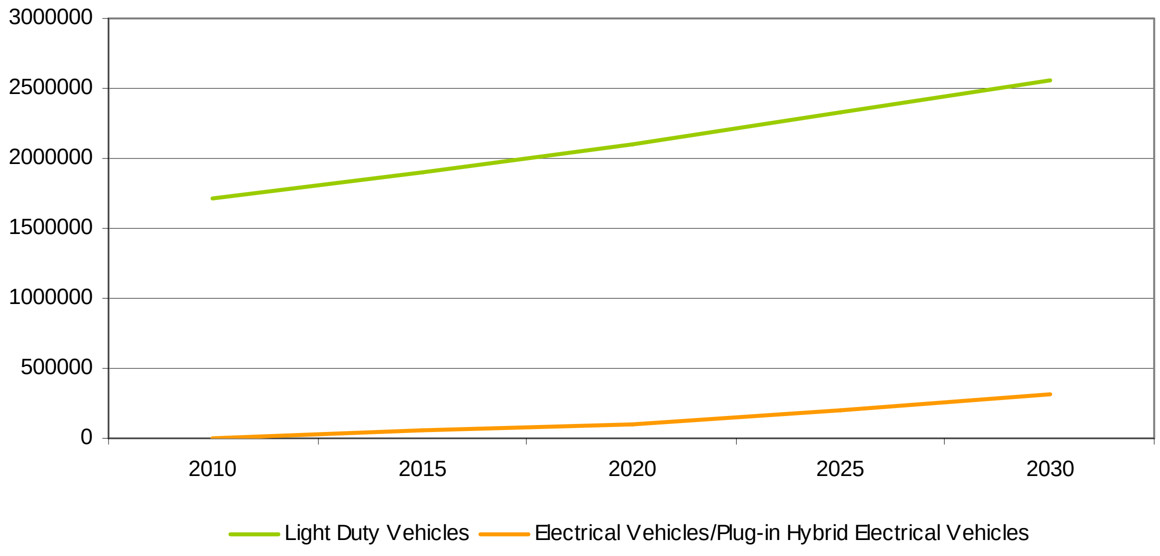


Figure 4: Forecast of numbers of electric vehicles/plug-in hybrid electric vehicles compared with light duty vehicles in Western Australia[34]

If electric vehicles are excluded from the reference service and therefore prohibited from being connected, retailers will need to seek a non-reference service from Western Power. Without such a bi-directional reference service, customers and users will not be entitled to the commercial benefits of a reference service (such as the ERA approved reference tariffs, service standard benchmarks and a standard contract). The additional administrative burden associated with a non-reference service may also prove barrier to these technologies.

In paragraph 112 of the Authority's draft decision, it is noted that:

> *Synergy notes that section 5.2(c) of the Code requires an access arrangement to allow a user to acquire by way of one or more reference services only those elements of a covered service that the user wishes to acquire. On the basis that it is the exclusive service provider to the residential market in the SWIS, Synergy submits the Authority must, in the absence of any other compelling evidence of significant need, give regard to Synergy's concerns associated with battery and electric vehicle systems and the connection issues associated with photovoltaic systems and exclude battery and electric vehicle systems from the proposed revised bidirectional services.*

Synergy's concerns regarding the coverage of the reference services are not relevant to the question of whether these systems, under the test set out in the Access Code, should properly be part of a reference service. The covered service will be a bi-directional service that will allow bidirectional flows of electricity through a connection point (as opposed to the traditional one way flow - either only in or out of the connection point). This is not different from existing reference services, or the definition of "entry service" in the Access Code. Synergy's comments may be based on a misunderstanding of a reference service.

[34] Source: Western Power - extrapolated from Jamison Group, *Fuelling future passenger vehicle use in Australia*, February 2010, Available from: http://www.mynrma.com.au/about/jamison-report.htm.

5 Total revenue requirement

5.1 Performance under adjustment mechanisms

Western Power will return $31 million[35] in revenue in AA3. The adjustments reflect the amounts calculated under various adjustment mechanisms in place during AA2.

The value of the adjustment mechanisms reflects updated *estimated* capital expenditure, operating expenditure, service standard performance and inflation for the year ending 30 June 2012.

Table 1 summarises the financial implications of the adjustment mechanisms on the AA3 target revenue.

Table 1: Performance under adjustment mechanisms during AA2

Adjustment mechanism $ million real at 30 June 2012	Present value adjustment to AA3 transmission revenue	Present value adjustment to AA3 distribution revenue
Gain sharing mechanism	0.0	0.0
Service standards adjustment mechanism	0.6	8.8
Investment adjustment mechanism	-43.6	2.8
Unforeseen events	0.0	0.0
Technical Rules changes	0.0	0.0
D-factor	0.0	0.0
TOTAL	**-43.0**	**11.6**

5.2 Total revenue requirement

Required amendment 4:

The proposed revised access arrangement values for TRt and DRt must be amended to reflect the Authority's amended revenue values for Transmission and Distribution (as shown in last row of Table 4 and Table 5).

Western Power response:

Western Power does not accept this amendment.

The Authority requires Western Power to amend the values for TR_t and DR_t to reflect the Authority's amended revenue values for transmission and distribution.[36]

Western Power does not accept this amendment because it has revised its revenue modelling to reflect the changes outlined in this revised access arrangement submission, which results in different values for TR_t and DR_t to those proposed by the Authority.

Table 2 shows the revised composition of the transmission network revenue for AA3.

35 Present value at 30 June 2012.

36 Paragraph 192, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Table 2: Composition of transmission network target revenue

$ million areal as at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Present value
Operating expenditure	125.5	124.8	129.7	140.6	153.1	558.1
Plus depreciation	87.3	96.3	105.9	113.1	122.6	433.3
Plus redundant assets	0.0	0.0	0.0	0.0	0.0	0.0
Plus return on investment	169.0	182.8	200.2	210.3	228.1	818.1
Plus return on working capital	0.9	3.4	4.0	4.7	4.4	14.0
Plus tax payable	43.9	44.4	42.9	44.1	41.2	180.9
Less value of imputation credits	-11.0	-11.1	-10.7	-11.0	-10.3	-45.2
Forward-looking efficient costs	415.6	440.7	472.1	501.8	539.1	1,959.2
Plus gain sharing mechanism	0.0	0.0	0.0	0.0	0.0	0.0
Plus unforeseen events adjustment	0.0					0.0
Plus Technical Rules change adjustment	0.0					0.0
Plus investment adjustment mechanism amount	-46.4					-43.6
Plus service standards adjustment mechanism amount	0.6					0.6
Plus D-factor amount	0.0					0.0
Plus recovery of AA2 deferred revenue	12.1	12.1	12.1	12.1	12.1	50.6
Adjustments in accordance with previous access arrangement	-33.7	12.1	12.1	12.1	12.1	7.6
Less non-revenue cap services revenue	3.0	3.1	3.3	3.5	3.7	13.7
Transmission target revenue for revenue cap services (unsmoothed)	378.9	449.7	480.9	510.5	547.6	1,953.0

Table 3 shows the revised composition of the distribution network revenue for AA3.

Table 3: Composition of distribution network target revenue

$ million real as at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Present Value
Operating expenditure	386.6	401.1	409.6	415.8	433.0	1,700.1
Plus depreciation	198.2	219.9	244.2	249.6	264.8	972.5
Plus redundant assets	3.4	0.5	0.0	0.0	0.0	3.6
Plus return on investment	252.7	280.3	309.7	338.0	365.3	1,274.2
Plus return on working capital	3.7	8.8	9.8	10.4	10.8	35.4
Plus tax payable	86.0	109.1	143.7	196.7	259.0	640.1
Less value of imputation credits	-21.5	-27.3	-35.9	-49.2	-64.7	-160.0
Forward-looking efficient costs	**909.1**	**992.4**	**1,081.1**	**1,161.4**	**1,268.1**	**4,465.9**
Plus gain sharing mechanism	0.0	0.0	0.0	0.0	0.0	0.0
Plus unforeseen events adjustment	0.0					0.0
Plus Technical Rules change adjustment	0.0					0.0
Plus investment adjustment mechanism amount	2.9					2.8
Plus service standards adjustment mechanism amount	9.4					8.8
Plus D-factor amount	0.0					0.0
Plus recovery of AA2 deferred revenue	91.2	91.2	91.2	91.2	91.2	380.1
Adjustments in accordance with previous access arrangement	**103.5**	**91.2**	**91.2**	**91.2**	**91.2**	**391.7**
Tariff equalisation contribution – TECt	181.2	180.7	180.8	181.7	182.5	755.9
Less non-revenue cap services revenue	14.5	14.9	15.6	16.3	17.0	64.8
Distribution target revenue for revenue cap services (unsmoothed)	**1,179.3**	**1,249.4**	**1,337.5**	**1,418.0**	**1,524.9**	**5,548.6**

5.3 Price path

Western Power's September 2011 submission translated the target revenue for revenue cap services into an average price path and annual revenue cap. The price path was determined by smoothing the revenue over the period whilst retaining the net present value of the total target revenue. The smoothed revenue was based on an increase in average tariffs in the first year similar to the increases seen in the AA2 period (1 July 2009 to 30 June 2012) and constant increases in average tariffs across the remaining years. This was aimed at ensuring that, in present value terms, target revenue over the course of the access arrangement period is equivalent to the sum of the revenue cap allowed in each year.

The Authority's draft decision also translated the target revenue for revenue cap services into an average price path and annual revenue cap, consistent with Western Power's initial proposal. However, it adopted a constant increase in average tariffs in each year.

Since the initial proposal, Western Power has reconsidered whether to use an average tariff for smoothing. Western Power has concluded that the smoothing method can be improved by incorporating the impact of customer numbers and demand as well as energy consumption. This is because Western Power's reference tariffs include fixed and variable components, with some reference tariffs based on energy consumption and other reference tariffs based on demand (metered demand or contract maximum demand).

In this response to the draft decision Western Power has smoothed the revenue based on applying the reference tariffs with forecast customer data for the AA3 period (utilising existing customer data and using energy, demand and customer numbers based on the 2011 growth forecasts).

Reference tariff components across each year of the period have been adjusted to ensure that, in present value terms, target revenue over the course of the access arrangement period is equivalent to the sum of the revenue cap allowed in each year. Western Power has also assumed that all network access services are paying a reference tariff.

Table 4 summarises the expected change in reference tariffs for users of the Western Power Network from one pricing year to the next during the AA3 period.

Table 4: Price path over AA3 – presented in real terms

Pricing year commencing	1 July 2012	1 July 2013	1 July 2014	1 July 2015	1 July 2016
Transmission tariff components	1.6%	1.6%	1.6%	1.6%	1.6%
Distribution tariff components	13.4%	13.4%	13.4%	13.4%	13.4%

Western Power's revised proposal results in average network tariff increases of CPI+ 10.3% per year over the next five years.

Note that actual changes to individual reference tariffs each year may vary by more or less than the tariff changes outlined. Changes to individual reference tariffs during the AA3 period are constrained by a side constraint which is discussed further in section 12.5.

5.4 Annual revenue cap

The revenue to be recovered under the revenue cap for each year of the AA3 period reflects the target revenue and the average price path. The value for each year must be identified when applying the price control formulas, which remain unchanged from the initial submission. The present value of the revenue determined under the price control formula is equivalent to the target revenue detailed in Table 2 and Table 3.

Table 5 details the TR_t annual parameters for AA3:

Table 5: Transmission smoothed annual revenue

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Present Value
Annual revenue cap services revenue – TR_t	435.7	445.6	467.7	492.9	513.4	1,953.0
% change in TR_t		2.3%	5.0%	5.4%	4.1%	

Table 6 details the derivation of the DR_t annual parameters for AA3:

Table 6: Distribution smoothed annual revenue

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Present Value
Annual revenue cap services revenue	989.6	1,138.6	1,313.0	1,538.1	1,801.4	5,548.6
Less TEC_t[37]	181.2	180.7	180.8	181.7	182.5	755.9
Distribution revenue cap formula component – DR_t	808.4	957.9	1,1,32.2	1,356.5	1,618.8	4,792.7
% change in DR_t		18.5%	18.2%	19.8%	19.3%	

[37] The price control formula for the distribution system includes an explicit pass through element for TEC.

6 Operating expenditure

The Authority requires Western Power to reduce its AA3 forecast operating expenditure by 19.2% (or $522 million). The Authority accepts Western Power's method of forecasting recurrent operating expenditure using the network and customer growth parameters but has discounted each of the other elements of proposed operating expenditure. The Authority has rejected the method of determining real labour cost escalation and has outright rejected materials escalation. The Authority then applied a further 2% compounding efficiency dividend on total operating expenditure.

Given that 18.2% of Western Power's costs are non-discretionary (for example rates & taxes, corrective emergency activities), applying these reductions assumes Western Power can achieve a 24.3% (5.4% compounding each year) reduction in its controllable costs during the AA3 period.

While Western Power appreciates the need to reduce costs, and will endeavour to do so during the AA3 period, the Authority's recommended reductions result in a level of operating expenditure below that which is necessary and efficient to operate the Western Power Network.

Taking the Authority's recommendations into consideration, Western Power has reduced its operating expenditure forecast by $156 million. This is offset by additional operating expenditure of $98 million, arising from new obligations, including the increased wood pole replacement program, compliance with Type 1 obligations and the Clean Energy Future package. Table 7 summarises the operating expenditure adjustments.

Table 7: Summary of operating expenditure adjustments

	$ real as at 30 June 2012
INITIAL SUBMISSION OPERATING EXPENDITURE	**$2.714 billion**
Reductions in response to Authority's required amendments	-$77 million
Reduction in indirect costs	-$41 million
Reduction in forecast real costs and inflation	-$15 million
Other reductions	-$16 million
SPOW efficiencies	-$7 million
Total operating cost reductions	**-$156 million**
New activities associated with compliance with Type 1 Obligations in the Code of Conduct for the Supply of Electricity to Small Use Customers	$ 29 million
Increased wood pole management activities	$ 21 million
Requirements in response to the recent Parliamentary Inquiry[38]	$19 million
New activities	$17 million
Negotiated unit rates	$11 million
Clean Energy Future package including the carbon price	$1 million
Total operating cost additions	**$98 million**
TOTAL FORECAST OPERATING EXPENDITURE	**$2.656 billion**

Figure 5 provides a comparison of Western Power's revised proposal with the Authority's draft decision, Western Power's original submission and its historical costs.

[38] *Report no.14 of the Standing Committee on Public Administration*, 20 January 2012.

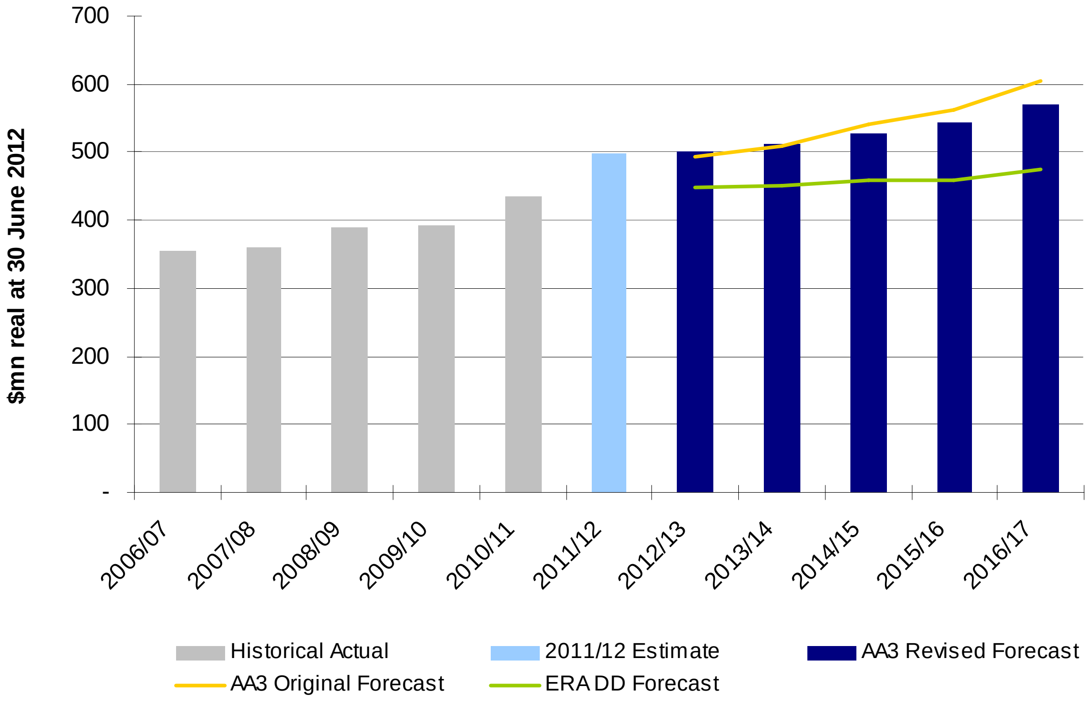


Figure 5: Western Power's revised operating expenditure forecast

6.1 Overview of amendments

The Authority has determined its 19.2%[39] (or $522 million) reduction to forecast operating expenditure by:

- disallowing forecast movements in real materials costs and reducing forecast movements in real labour costs
- constraining costs associated with a growing physical network and growing customer numbers to historical growth with an economies of scale factor
- reducing Western Power's actual base year costs where they are higher than previous years
- removing the costs associated with network control services
- halving expenditure for the field survey data capture project
- constraining Western Power's indirect cost forecast by 13.69%
- applying an additional arbitrary 2% compounding efficiency dividend to Western Power's already reduced operating expenditure forecast

Western Power accepts some of the reductions made by the Authority to its actual base year costs, step changes and indirect costs. These adjustments have been made accordingly for items where Western Power's latest estimate of 2011/12 costs is lower and supports this reduction.

However, the package of reductions that the Authority proposes collectively results in unsustainably low levels of operating and maintenance costs. A maintenance program

[39] 19.2% is the reduction in forecast operating expenditure in Western Power's proposal ($2,714 billion) when compared with the ERA's draft decision ($2,192 billion in real dollars as at 30 June 2012).

consistent with the Authority's proposed level of expenditure would increase the life-cycle costs of assets and deteriorate their performance.

Real cost escalation

One of the key differences between the Authority's draft decision and Western Power's proposal is the method used to calculate real labour and material cost escalation.

The Authority accepts Western Power's application of forecast movements in labour costs. However, it has chosen an alternative forecast method. The Authority's method does not compensate Western Power for compositional changes in its workforce. The Authority has stated that if current labour costs are deemed to be efficient then Western Power should only be compensated for forecast changes in the price of labour and should not be distorted with the addition of compositional changes.

Western Power has experienced compositional changes during AA2 and expects to do so during AA3. The composition of the workforce is influenced by the nature of the work, the relative proportions of capital and operating activities, the technical complexity and the availability of skilled labour, which is a particular challenge in Western Australia due to competition with the mining sector.

The Authority rejects Western Power's estimation of forecast movements in material costs that differ to CPI for two reasons. First, the Authority considers that Western Power did not utilise variations where the forecast growth in material costs was less than CPI and secondly. because the variation was negligible.

This is an incorrect characterisation of Western Power's approach. Western Power did include material cost forecasts that were less than CPI except where this was considered to be double counting. This is shown in Table 33 of the Authority's draft decision. Western Power maintains that it is appropriate to forecast costs separately where the costs are expected to increase at a different rate to CPI. Western Power has updated its forecast material costs, which has resulted in a net decrease over the period.

The Authority's amendments to labour and material escalation are discussed further in section 6.2.

Scale escalation

The Authority's application of scale escalation is significantly different to Western Power's approach. While the Authority accepts the principle of escalating costs for growth in the network and customer base, it has constrained the increases to a level consistent with historical growth in the Western Power Network.[40] The Authority has then reduced the forecast growth in costs even further through implementing an economies of scale factor.

One of the key reasons the Authority has cited for using historical growth rates when applying scale escalation is:

> *historical growth rates act as a proxy for a capex/opex tradeoff , to account for the 'honeymoon' period when new assets are installed, as proposed by Nuttall Consulting.*[41]

Western Power does not accept that network assets are subject to a 'honeymoon period' in relation to operating and maintenance costs.

The 'honeymoon period' assumes there are no operating and maintenance costs incurred during the initial years of service. This is not Western Power's experience or a theory that is supported in electrical engineering or by manufacturers.

Western Power's experience suggests that operating and maintenance costs are incurred during the initial years of an in-service asset's life. Indeed, many asset classes failing early in their lives. This is supported by the findings of the Asset Management Council, which

[40] Paragraph 262, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.
[41] Nuttall Report Reference – Section 1.6.2, Memo – Opex Escalation Review (Victoria Electricity Distribution Revenue Review): Nuttall Consulting, 28 October 2010.

recognises a 'bath tub' curve in operating costs[42] whereby new assets require additional costs in the early years. This is outlined in a report from expert consultants GHD, which was appointed by Western Power to peer review the Authority's technical consultant assumptions.

Further, new assets are included in inspection and maintenance cycles from the time of installation. Section 6.3.3.1 provides references and information supporting the need for operating and maintenance activity during the early years, including an increase in these activities in early years for some assets. This material directly challenges the Authority's assumption that there is a capex/opex trade off and demonstrates that the application of historical growth rates when forecasting growth in operating and maintenance costs is not supported.

The Authority's application of economies of scale reductions to the growth factor is based on its technical consultant's interpretation of Western Power's application of scaling factors. The Authority made a reduction to both the network and customer growth factors stating that:

> *By not including an EOS factor in its scale escalators, Western Power has implicitly assumed that its opex costs are fully variable, an assumption that we do not accept*[43]

Western Power does not accept that that its scale escalation approach assumes full operational expenditure variability. The scale escalation approach seeks to adjust total operating expenditure for the forecast movement required in future years. This means that the resulting escalation only accounts for the required movement in variable cost. The fixed cost elements only move through the application of real cost escalation. Western Power has therefore not incorporated an economy of scale factor, because there is no evidence that this adjustment is appropriate for Western Power.

The application of an additional economy of scale factor is also not supported by Western Power's experience or the advice of technical consultant, GHD. Western Power's network is ageing and the investment to be undertaken during the AA3 period will not reduce the average asset age by the end of the period or the expected number of conditions requiring remediation (see section 6.3.3.2 for further information).

The age of the network has a strong correlation with the condition of the assets which drives the need for operating and maintenance activity. The rate at which new assets are added to the network is lower than the rate at which existing assets are reaching the end of their service life. Therefore, operating and maintenance activities are unlikely to reduce with the size of the network. Western Power sought an expert peer review of the theory that economies of scale can be achieved over the AA3 period. GHD provided this review and stated:

> *GHD does not agree with GBA's assessment and proposes that OPEX is directly related to the number and type of assets within a network. Fixed cost, such as condition and performance inspections are planned activity and the cost is based on the extent of the inspection (time taken for the task) and the frequency that it is required to be performed.*[44]

Further, the ability to achieve economies of scale is limited to the extent to which activities can be bundled by geographic region. Western Power's activities that are suitable for bundling are already bundled and the reduced costs associated with this practice are incorporated in the base costs. Western Power has not included an economy of scale factor in its forecast of operating and maintenance costs as this would reduce the forecast cost to below efficient levels. Application of scale escalation is discussed in section 6.3.3.

[42] *Common Errors in Maintenance Reliability Theory and Practice*, D. Shermin, Asset Management Journal, Issue 1, Volume 3, 2009.

[43] Section 10.4.2, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

[44] Section 3.4, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.

Efficiency dividend

The Authority also imposes a 2% efficiency dividend on Western Power's total operating expenditure. This is based on the Authority's view that Western Power's:

- operating expenditure is high compared to other utilities, underpinned by benchmarking completed by its technical consultant[45]
- recent and continuing investment in IT systems means Western Power has scope to achieve efficiency gains[46]
- corporate operating expenditure is mostly fixed, providing scope for efficiencies to be achieved[47]
- governance is on an improving trajectory[48]

Western Power does not accept the Authority's forecast of operating and maintenance costs and has not included a 2% per year compounding reduction in costs, because to do so would significantly underestimate the required future efficient cost. Western Power considers that the Authority's assumption of expected efficiencies is unsupported in practice and theory and has been applied without considerations of the compounding effects of the other reductions applied by the Authority.

An assessment of potential efficiencies should include an assessment of what can be achieved, including the various components and activities that make up the costs, as well as the extent to which costs are controllable. Western Power has incorporated identified efficiencies from investment in IT systems in its forecasts. Western Power does not expect to achieve efficiencies in business support divisional operating expenditure because it is largely fixed.

Western Power considers that the Authority has adopted its technical consultant's advice in a manner which:

- disregards the advice that the expected efficiencies should not be applied to the first year
- double counts expected efficiencies through the adoption of historical growth rates and economies of scale
- does not take into account the limitations of the analysis underpinning the advice or attempt to adjust for the limitations
- accepts the use of benchmarking as a singular and reliable methodology to forecast efficient costs despite practitioners elsewhere rejecting this approach
- the cumulative efficiency factor of 2% per annum applied to total operating costs is the highest imposed in Australia since the year 2000. Economic consultant Wedgewood White Ltd has advised that *such an adjustment cannot be considered normal or usual practice*[49].
- presents no analysis to determine that the efficiency expected is achievable

This view is supported by independent economic expert, Wedgewood White Ltd.[50]

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[45] Paragraph 309, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[46] Paragraph 310, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[47] Paragraph 314, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[48] Paragraph 315, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[49] Section 2.7, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.
[50] Section 6.4, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.

The impact of the reduction in forecast costs will be a reduction in activities to unsustainable levels, resulting in the continuing deterioration in the performance of assets and an increase in the life cycle costs. Western Power has provided supporting information on the ability to achieve further efficiencies in its major programs of activities (see Appendix I.2). These opportunities are limited. For example, 90% of planned maintenance activities are subject to competitive tendering processes.

Western Power has sought further information on the analysis undertaken by the Authority's technical consultants.[51] Western Power provided its own analysis in its initial submission based on the same data. That analysis showed different results and does not appear to have been reviewed by the Authority or its consultants. Further, when network tariffs are compared across jurisdictions, Western Power's tariffs are within the range of its peers. Western Power considers it is therefore inappropriate to rely on the Authority's analysis to estimate Western Power's forward-looking efficient costs.

The 2% efficiency dividend and the reliability of the Authority's technical consultant's benchmarking analysis are discussed in section 6.3.6.

Non-recurrent programs

The Authority has also reduces the costs of two major projects in the forecast non-recurrent expenditure. The Authority considers that a 50% reduction in the forecast cost of field survey data capture project is appropriate and has reduced the forecast cost for network control services to zero.

The reduction in the costs of the field survey data capture project reflects a view that the costs are too high despite the objectives of the project being appropriate. Western Power has provided additional information to support the cost estimates as has included these costs in its forecasts.

Western Power maintains that it is appropriate to include the costs associated with network control services in the operating and maintenance expenditure forecast, as it can not be recovered through other mechanisms of the Access Code. The impact of not recovering the costs of this project will be significant for the communities affected. Further information has been provided to support the recovery of these costs and the level of these costs in section 6.3.4.2.

6.2 Real labour and material escalation rates

Required amendment 5:

The proposed revised access arrangement should be amended to reflect a forecast of operating expenditure which applies real labour and material escalation rates to the amended values in Table 32 and Table 33.

Western Power response:

Western Power does not accept this amendment

The Authority rejects Western Power's use of real materials escalation forecasts different to CPI. The Authority also reduces real labour cost escalation forecasts to remove the impact of expected compositional changes to Western Power's workforce. This results in a 34.7% ($166 million) reduction in real cost escalation and a 2.20% reduction in total expenditure.[52]

[51] On 30 March 2012, Western Power requested the Authority to "provide a copy of the working spreadsheet or model used by Geoff Brown and Associates that supports the results shown in table 10.2 on page 115 of *the GBA Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*." The Authority declined to provide the data on 3 April 2012 stating that "GBA has provided references to the source data it used which should be adequate to enable Western Power to develop its own view about the benchmarks".

[52] This was a 2.43% reduction to total capital expenditure and a 1.79% reduction to total operating expenditure.

Western Power does not accept this amendment. The Authority's position would prevent the recovery of forward-looking efficient costs as required by section 6.4 and 6.40 of the Access Code. The Authority's amendment also contradicts the findings of independent technical experts, Competition Economists Group (CEG) and Macromonitor.

6.2.1 Labour cost escalation

The key difference between Western Power's expenditure forecast and the Authority's draft decision is the Authority's use of the wage price index (WPI) rather than the average weekly ordinary time earnings (AWOTE) for the purpose of forecasting Western Power's labour costs during AA3.

In summary the Authority has:

- accepted the need to account for growth in real wages by applying real labour cost escalation
- accepted the use of the Western Power Communications Electricity and Plumbing Union Collective Agreement escalation rates until its expiry of that agreement in October 2013
- accepted the use of expert forecasts determined by Macromonitor
- **rejected** the use of AWOTE to forecast labour costs, using WPI instead

As explained in section 3 of Appendix W.1 and section 2.1 of Appendix W.2 of Western Power's September 2011 submission, AWOTE and WPI differ because:

- WPI assumes that the composition of the workforce would not change over the forecast period[53]
- AWOTE includes the effects of compositional changes, including changes in the mix of skill categories and the mix of occupational categories with different pay scales[54]

Western Power expects that the composition of its workforce will change during the AA3 period. Therefore Western Power does not accept that WPI is a better estimate of forward-looking labour efficient labour costs as it does not provide for efficient compositional workforce change.

The Authority cites three reasons for rejecting Western Power's use of AWOTE in favour of WPI:

- the Australian Energy Regulator (AER) uses WPI
- Western Power has previously used WPI in its AA2 forecasts
- current efficient labour costs should not be adjusted for future composition change

These are discussed the following sections.

6.2.1.1 The Australian Energy Regulator (AER) uses the WPI measure

The Authority notes the AER's preference for forecasts based on the labour price index (equivalent to WPI). The AER's preference rests on the assumption that:

> *any increase in total labour costs resulting from promoting existing employees or employing more highly skilled workers is automatically offset by reductions in the number of employees needed.*[55]

[53] Competition Economists Group states that "WPI is only appropriate is the mix of occupational categories is expected to remain constant" Paragraph 61, *Escalation factors: A report for Western Power*, Competition Economists Group September 2011 (Provided as Appendix W.1 of the initial submission).

[54] Paragraph 58, *Escalation factors: A report for Western Power*, Competition Economists Group September 2011 (Provided as Appendix W.1 of the initial submission).

This assumption requires that Western Power only hires or promotes more skilled workers where this displaces workers who are less skilled. This assumption does not hold in practice for Western Power because:

- technological change in scope of works often results in more skilled workers being needed to operate network equipment and systems or design network solutions. For example, the workers required to operate smart grid infrastructure will tend to be more highly skilled than those performing manual meter reading
- competition from the external labour market often requires promotion or recruitment at higher pay scales to attract and retain staff. Western Australia's unemployment rate is at the historically low level of 3.8% (national average is 4.9%) together with the highest workforce participation rate in Australia (68.8% versus 65.2%).[56] Western Power experiences considerable loss of labour to the mining sector

These compositional changes increase Western Power's costs associated with hiring and retaining skilled labour in the Western Australian market. Given that they are market driven, these costs are efficient and should be accepted by the Authority.

6.2.1.2 Western Power has previously used the WPI measure in its AA2 forecasts

The Authority notes Western Power's use of WPI in its AA2 forecasts as another reason for adopting them in the AA3 period.[57] However, Western Power's experience during AA2 showed that this forecast measure inadequately accounted for labour cost growth (see Figure 6).

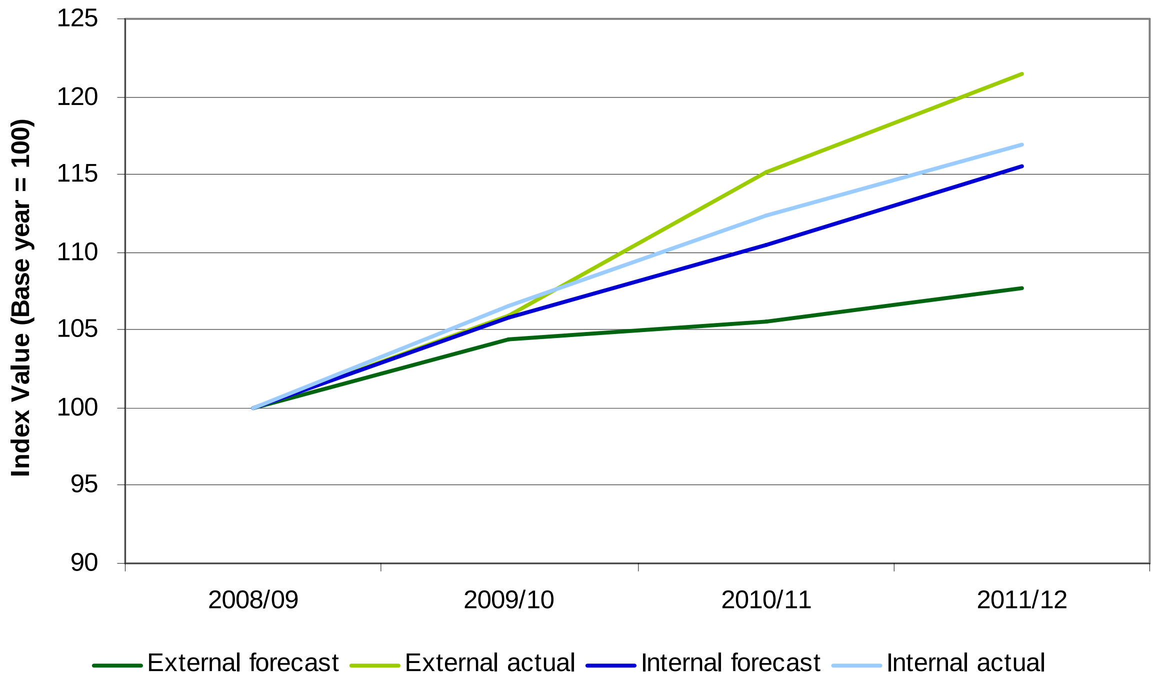

Figure 6: Western Power's AA2 labour escalation forecast vs actual

[55] Paragraph 15, *Updated labour and materials escalation factors*, Competition Economists Group, May 2012.
[56] Paragraph 19, *Updated labour and materials escalation factors*, Competition Economists Group, May 2012.
[57] Paragraph 334, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

In a submission to the Authority in November 2011,[58] Western Power provided evidence that the actual labour cost growth over AA2 outpaced the approved forecast labour escalation rates.

Given the scope of Western Power's proposed AA3 works program, it is reasonable to expect further compositional change in workforce. As a result, Western Power believes that the use of WPI is not appropriate for accurately forecasting movements in labour costs over the AA3 period.

6.2.1.3 Current efficient labour costs should not be adjusted for future composition change

The Authority's draft decision states:

> *The Authority is also of the view that if current labour costs are deemed to be efficient then Western Power should only be compensated for forecast changes in the price of that labour and should not be distorted with the addition of compositional changes.*[59]

This statement indicates that the Authority accepts Western Power's current workforce composition is efficient, but considers that any future changes to this composition that result in higher wages must reflect inefficiencies. This is unfounded and unreasonable.

The composition of the workforce is influenced by the nature of the work the relative proportions of capital and operating activities, the technical complexity and the availability of skilled labour which is a particular challenge in Western Australia due to competition with the mining sector.

Figure 7 shows the changes in the shares of headcount for total internal headcount and for the operational labour category. This demonstrates the material changes in Western Power's labour composition between 30 June 2010 and 31 March 2012.

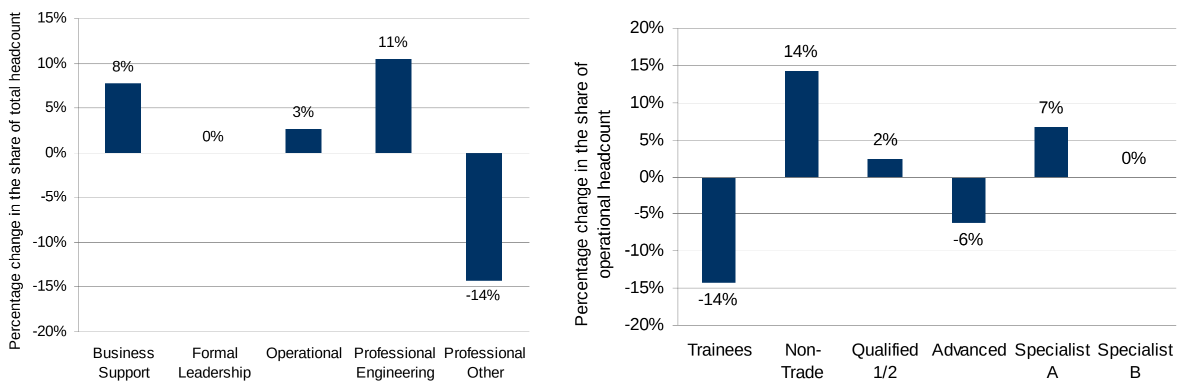

Figure 7: Changes in workforce composition during AA2

It is therefore clear that compositional change to the workforce can reasonably be expected during the AA3 period. Assuming no compositional change in AA3 by adopting WPI will result in Western Power not recovering its forward-looking and efficient costs.

Western Power does not accept the Authority's amendment of labour cost escalation factors and has updated the AWOTE forecast used to escalate the AA3 expenditure forecasts, as foreshadowed in the September 2011 submission (see Table 8).

[58] *Response to Question PN1*, provided to the Authority on the 18 November 2011

[59] Paragraph 336, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Table 8: Western Power's AA3 labour escalation factors

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Initial submission	1.9%	1.5%	3.1%	3.7%	3.1%	3.1%
Authority's Draft Decision	1.9%	1.5%	2.2%	2.4%	2.0%	2.0%
Revised proposal	2.2%	1.6%	2.9%	3.6%	3.1%	3.1%

6.2.2 Materials cost escalation

When considering Western Power's material costs escalation method, the Authority notes that:

> *for the materials escalation costs calculated by Western Power, the negligible amount calculated as a cost escalation would most likely be offset by materials that will increase in cost at below the CPI, which did not form part of the forecast[60].*

The Authority therefore concludes:

> *that the cost escalation factor that should be applied to materials is only the CPI and that Western Power should adjust all material forecasts that have been escalated by recalculating these with a factor of 0 per cent above CPI. [61]*

The Authority has applied a materiality test to Western Power's material cost escalation forecast. The relevant test for the inclusion of operating expenditure in Western Power's target revenue is section 6.4 of the Access Code. Section 6.4(a)(i) states that:

> *The price control in an access arrangement must have the objective of:*
>
> *a) Giving the service provider and opportunity to earn revenue for the access arrangement period from the provision of covered services as follows:*
>
> *ii 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*

This section of the Access Code does not include a test of materiality as applied by the Authority.

Western Power sought independent expert forecasts of movements in materials costs over the AA3 period from the CEG.[62] These forecasts account for real cost increases and decreases during AA3. Contrary to the Authority's statement, Western Power's material escalation forecasts included those materials that were forecast to increase at a rate below CPI. This is evidenced in Table 33 of the Authority's draft decision.[63]

Exclusion of the specific zinc escalation factor forecast by CEG in Western Power's escalation calculation was not an oversight, but a deliberate action to avoid double counting its cost impact. The proportion of zinc related material spend requiring escalation relates to the galvanising on poles. This cost is included in the aluminium and steel prices Western Power incurs and is therefore not included as an individual material escalator in the forecast expenditure.

[60] Paragraph 351, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[61] Paragraph 352, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[62] *Escalation factors: A report for Western Power*, Competition Economists Group, September 2011 (Provided as Appendix W.1 of the initial submission)
[63] Paragraph 352, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Material costs will necessarily differ from CPI. Western Power saw significant differences between CPI and major materials movements in AA2 (see Figure 8) and would expect this to continue for the AA3 period.

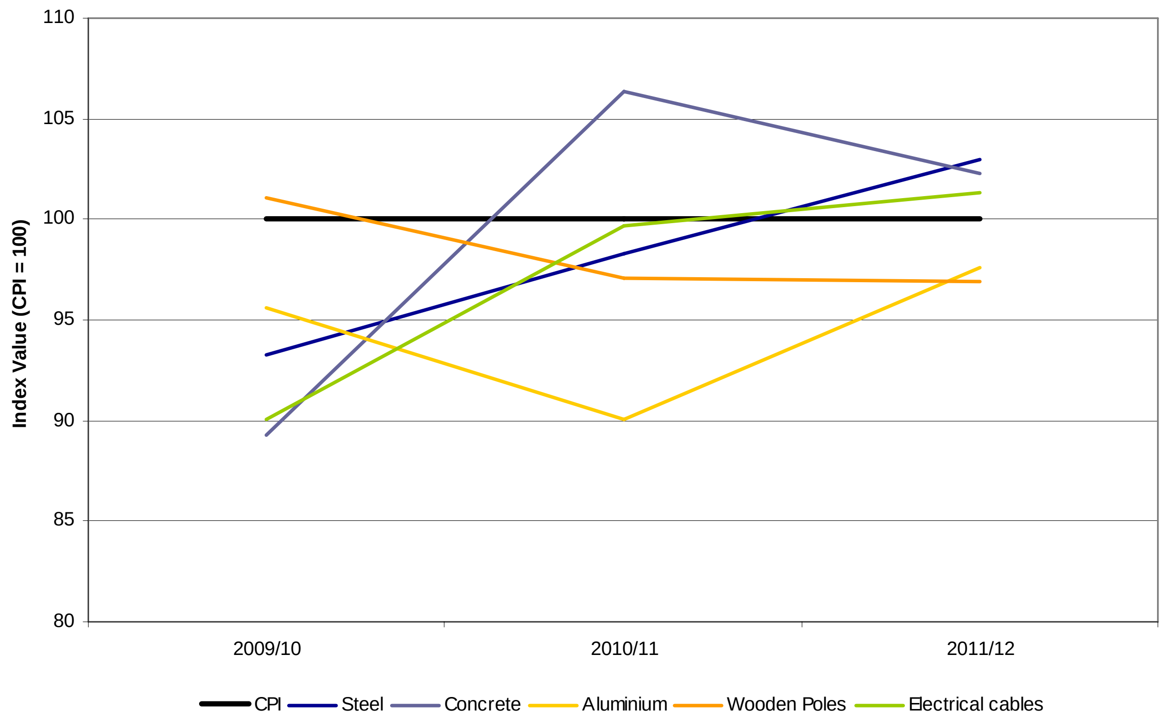

Figure 8: AA2 material costs movement compared with CPI

Given that material prices will inevitably vary from CPI, *substituting an estimate of zero for real escalation factors in place of escalation factors that have been robustly and accurately estimated is likely to give rise to bias.*[64]

Based on Western Power's experience, the experience of its network peers and CEG's expert findings, Western Power maintains that including forecasts of real materials cost escalation is the most robust method to determine forward-looking efficient costs. This method is also consistent with the Authority's determinations for other regulated business, including the AA2 access arrangement decision for Western Power.[65]

As foreshadowed in its September 2011 submission, Western Power has updated its forecasts for AA3 materials escalation and applied them to the revised expenditure forecasts. This results in a materials cost movement reduction of $2.5 million over the AA3 period. Table 9 provides the AA3 materials escalation factors used in Western Power's forecasts.

Table 9: Revised escalation factors used in Western Power's response to the draft decision

AA3 revised escalation factors	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Steel	-6.8%	-4.0%	3.5%	1.8%	0.3%	-0.1%
Copper	-10.4%	1.3%	0.4%	-1.5%	-3.4%	-3.9%
Aluminium	-13.0%	2.6%	5.3%	3.9%	2.9%	2.5%
Oil	2.6%	7.6%	-2.2%	-3.4%	-2.4%	-1.5%

[64] Paragraph 29, *Updated labour and materials escalation factors*, Competition Economists Group, May 2012.
[65] Paragraph 542, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 4 December 2009.

Amended real cost escalation forecasts for labour and materials has resulted in an increase in costs of $16.7 million compared to the September 2011 submission. Table 10 summarises the impact on operating and capital expenditure.

Table 10: Expenditure impact of revised real cost escalation

$ million real at 30 June 2012	Initial submission	Revised proposal	Variance
Operating expenditure			
Materials cost escalation	0.9	0.6	-0.3
Labour cost escalation	148.0	143.5	-4.5
Capital expenditure			
Materials cost escalation	13.0	10.8	-2.1
Labour cost escalation	207.7	228.1	20.4
Total real cost escalation	**369.6**	**386.3**	**16.7**

6.3 Adjustments to operating cost base

Required amendment 6:

The proposed revised access arrangement should be amended to reflect a forecast of operating expenditure as indicated in Table 37 (of the draft decision).

Western Power response:

Western Power does not accept this amendment

In its draft decision, the Authority accepted Western Power's forecasting method for each component of its operating costs:

- recurrent network costs
- non-recurrent network costs
- corporate and indirect costs

However, it requires specific amendments to each component. These are discussed in the following sections.

6.3.1 Recurrent cost adjustments

The Authority accepts that 2010/11 actual costs are the appropriate base year to use to project the AA3 operating expenditure[66]. However, it makes $5.8 million of recurrent cost adjustments, which reduce the forecast costs by $29 million (2.3%) over the period. The Authority:

- accepts Western Power's one-off adjustments of $26.1 million to address previously identified pole maintenance conditions
- adjusts certain line items to what its technical consultant considered was an efficient level resulting in a $5.8 million base year reduction
- removes $0.5 million over the period from the metering step change to account for the expected delay in the introduction of the new obligations associated with the Metering Code amendments
- requires a number of changes in categorisation of recurrent costs including:
  - moving three proposed step change adjustments to the 2011/12 year to be adjustments to the 2010/11 base year[67]
  - moving SCADA and communications licence costs from a step change to a one-off cost to remove the growth component of a fixed cost
  - the separation of the data correction activity into recurrent and one-off costs

Western Power has reviewed the Authority's proposed recurrent cost adjustments and compared the expenditure in these activities to the latest view of the 2011/12 work program and forecast activities for the AA3 period. Based on this analysis, Western Power accepts reductions where expenditure at 2010/11 levels is not expected to continue. Table 11 provides a summary of Western Power's response to each of the Authority's adjustments.

[66] Paragraph 246, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, Economic Regulation Authority, 29 March 2012

[67] Paragraph 251, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, Economic Regulation Authority, 29 March 2012

Table 11: Response to operating expenditure adjustments

$ million real at 30 June 2012	Initial Submission per annum	Draft Decision per annum	Revised submission per annum	Revised submission AA3	Comment
Base year adjustments					
Distribution corrective emergency – primary response assistance	3.0	2.3	2.84	269.1	Do not accept, see section 6.3.1.1
Distribution corrective deferred - data correction	3.3	1.0	1.2	16.9	Do not accept, see section 6.3.1.2
Distribution preventative condition - earthing maintenance	2.3	1.7	1.7	9.9	Accept
Transmission corrective deferred and emergency - substation primary plant maintenance	7.1	5.9	5.9	32.9	Accept
Transmission corrective deferred - environmental cleanup	1.2	0.8	1.2	4.1	Do not accept, see section 6.3.1.3
Transmission preventative condition - plant and building refurbishment	1.4	0.9	0.9	4.9	Accept
Transmission preventative routine - substation battery maintenance and inspections	1.7	1.2	1.7	9.7	Do not accept, see section 6.3.1.4
System management – planning and market operations and control centre administration and management	12.9	2.5	12.9	7.9	Do not accept, see section 6.3.1.5
Step changes					
Distribution corrective emergency – primary response assistance	3.0	N/A	N/A	269.1	Accept
Transmission SCADA and communications- licences	1.0	N/A	N/A	3.3	Accept
Metering – Metering Code amendments	0.5	0.5	0.5	107.4	Accept
One-off adjustments					
Distribution corrective deferred - data correction	N/A	N/A	1.1	16.9	Accept
Transmission SCADA and communications – licences	N/A	N/A	1.0	3.3	Accept

While Western Power accepts a number of adjustments, it is concerned by the approach used by the Authority's technical consultant to determine operating cost changes.

The Authority states:

> *GBA undertook a high level review of individual line items included in the base year operating expenditure to identify base year expenditure line items that appeared to be atypical. GBA focussed on particular base year operating expenditure line items where the increase from 2009/10 was particularly large and sought further information from Western Power on the reasons for the increase.*[68]

Western Power's concern is that this approach results in only downward adjustments to Western Power's cost base. It does not account for activities that have decreased relative to history. Western Power has identified 10 of the 77 recurrent operating expenditure activities that decreased during this period.[69]

Furthermore, the Authority's technical consultant ignores the inherently variable nature of individual operating expenditure line items or activities. Volatility in individual operating and maintenance activities between years is common. This is rare at the regulatory category level and even less frequent at the aggregated operating expenditure level.[70]

The inherent volatility within a regulatory category can be demonstrated by comparing the growth of individual activities and growth of the entire regulatory category. Figure 9 shows an example of this in distribution corrective maintenance categories. While expenditure at the regulatory category level (solid black line) has remained stable since 2006/07, individual activities (various coloured lines) have fluctuated significantly over time because the makeup of work types changes.

[68] Paragraph 237, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[69] As shown in Western Power's response to question *GB1*, provided to the Authority on 27 October 2011.

[70] Regulators often approve base year roll-forward forecasting methods and the operation of gain sharing mechanisms because of the stability in the aggregated level of operating expenditure. For example at AER in its issues paper for developing the efficiency benefit sharing scheme guideline (which is equivalent to the GSM) observed that: *Opex tends to be more consistent over time because the nature of opex is that it is more constant relative to capex and is ongoing*. (AER Issues Paper: Guidelines, models and schemes for electricity distribution network service providers, November 2007, p.23).

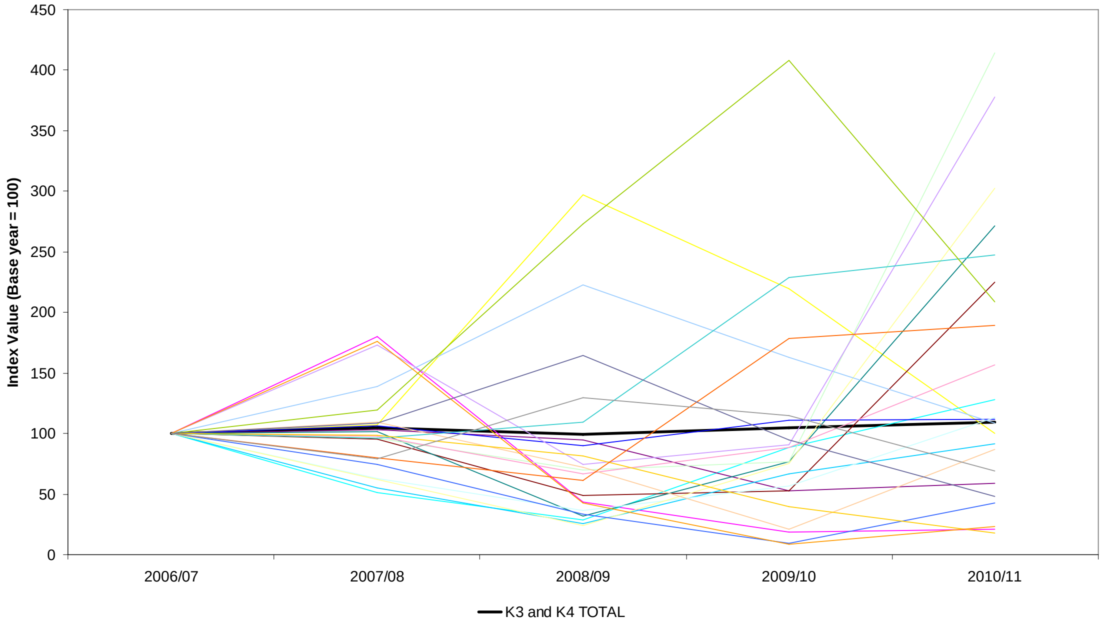

Figure 9: Distribution corrective deferred and corrective emergency expenditure

The roll-forward method for aggregated recurrent operating costs proposed by Western Power and accepted by the Authority will therefore provide the most reliable cost estimate on which to base forecast expenditure. The Authority's approach to amend only the individual activities that have increased from the previous year will downwardly bias forecast costs below sustainable levels (i.e. by removing all the activity variances above the black line and thereby causing the black line to drop).

Further discussion of the adjustments that Western Power does not accept is provided in the following sections.

6.3.1.1 Distribution corrective emergency primary response assistance

The Authority requires Western Power to reduce the step change for distribution corrective expenditure by $0.7 million to $2.3 million to align to its technical consultant's view of an efficient base year.

The Authority forecasts an efficient base year by taking the 2009/10 expenditure for corrective deferred and corrective emergency activities, removing their assumed indirect costs and adding network growth based on historical growth rates with an economies of scale factor applied. However, the Authority's technical consultant has applied the incorrect indirect cost amount. [71]

Western Power has therefore applied the consultant's methodology[72] using the actual proportion of indirect costs in 2010/11.[73] Applying correct data to the Authority's consultant's method results in a required step change of $2.84 million. This value has been incorporated into Western Power's revised forecasts and has been tested against what Western Power is actually experiencing in 2011/12.

[71] Section 10.3.1.3.1, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[72] Section 10.3.1.3.1, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[73] This information was provided to the Authority on 25 November 2011 in column T of tab *scale esc by activity* of Western Power's scale escalation model.

Given corrective emergency work is largely reactive and non-discretionary, a step change value less than this could result in Western Power having to divert funding from preventative maintenance tasks to corrective maintenance activities.

6.3.1.2 Distribution corrective deferred data correction

The Authority's draft decision reduces the 2010/11 base year value for corrective deferred data correction by $2.3 million to $1 million. [74] This is based on Western Power's indication that the activity contained a number of one-off projects that are expected to conclude once Western Power's data is in good condition.[75] The Authority's technical consultant invites Western Power to include these projects as one-off adjustments.[76]

In AA3, Western Power will undertake targeted asset data cleansing projects for switch-wires, conductors and underground assets. While these projects relate to different assets to those addressed in 2010/11 and 2011/12, the nature of the work will not change. This means recent expenditure on these projects is representative of the expected level of expenditure in AA3. Expenditure on these specific projects is expected to conclude once Western Power's asset data has been improved.

Western Power accepts the Authority's approach and has reduced recurrent base year costs by $1.68 million. It has then added project specific costs of $1.1 million for each year of AA3 in the category of 'one-off adjustments'.

6.3.1.3 Transmission corrective deferred environmental cleanup

The Authority's draft decision reduces the 2010/11 base year value for transmission corrective deferred environmental cleanup by $0.4 million[77] to $0.8 million based on its technical consultant's view that expenditure on this line item is volatile.[78] This decision is underpinned by the Authority's technical consultant's understanding of the requirements around polychlorinated biphenyl (PCB) disposal in Australia. The consultant has stated:

> *We are surprised that Western Power still needs to fund PCB disposal. In New Zealand, as in many jurisdictions, PCB was considered such a serious environmental hazard that in the late 1980s and throughout the 1990s PCB contaminated equipment was required to proactively be identified and either be decontaminated or disposed of, in order to reduce the risk of accidental leakage.*[79]

PCB is hazardous and the disposal of contaminated equipment is required to be undertaken. The majority of this was done through the 1980s and 90s. However, in Australia, there was a minimum threshold below which assets contaminated could stay in use until the end-of-life. It is expected that the 2010/11 level of PCB disposal will continue throughout AA3, in line with Western Power's increasing asset replacement program.

Consequently, Western Power will continue to correctly dispose of assets containing hazardous PCBs and has not reduced the 2010/11 recurrent base year value for environmental cleanup costs.

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[74] Paragraph 239, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[75] In 2010/11, Western Power identified a number of programs which had been affected by poor data quality. Western Power subsequently introduced special projects to address these data issues.
[76] Section 10.3.1.3.2, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[77] Paragraph 239, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[78] Paragraph 242, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[79] Section 10.3.1.3.5, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

6.3.1.4 Transmission preventative routine substation battery maintenance and inspections

The Authority reduces the 2010/11 base year value for substation battery maintenance and inspections by $0.5 million to $1.2 million. This is based on its technical consultant's advice that expenditure should reflect the annual average over the current period.[80]

However, the Authority's consultant has reached this figure by adding the wrong expenditure activities together.

Western Power informed the consultants that there had been a change in accounting for substation battery maintenance & inspections and substation primary plant. Western Power advised that this accounting change means that expenditure on substation battery maintenance and inspections should be considered in aggregate with transmission substation inspections.[81] Instead, the Authority's technical consultant has added expenditure for substation battery maintenance and inspections with substation primary plant.[82]

When the correct expenditure types are added together, expenditure on substation battery maintenance and inspections and transmission substation inspections in 2010/11 is in line with historical expenditure. Therefore, Western Power has not amended the 2010/11 recurrent base year value for substation battery maintenance and inspections.

6.3.1.5 Transmission system management categories

The Authority reduces network operations operating expenditure by $10.3 million. This is based on its view that a significant portion of these costs should be attributed to the system management (markets) ring-fenced entity.[83] However, the Authority states*:*

> *'if Western Power considers that it requires more of this expenditure for its operations rather than System Management's operations, then it should provide further information in its response to the draft decision".*[84]

Western Power advises that the September 2011 forecast does not include expenditure required for the system management (markets) ring-fenced entity to carry out market functions. It only included costs that are associated with Western Power's system management division fulfilling its obligations under the transmission and distribution licences.

Western Power therefore rejects the Authority's adjustment to operating costs.

Western Power's system management division performs different roles to those of the system management (markets) ring-fenced entity. Section 8.2.1.3 of this document details the different roles of these two divisions and demonstrates how system management division's functions relate to the provision of reference services.

6.3.2 New adjustments to recurrent expenditure

Since the September 2011 submission, Western Power has revised recurrent operating expenditure forecasts. Additional recurrent operating expenditure of $31 million is required to:

- support Western Power's requirements to address its wood pole management plan
- reflect recently negotiated rates for distribution delivery partners (DDPs)

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[80] Paragraph 244, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[81] *Response to GB53* provided to the Authority on 17 January 2012.
[82] Section 10.3.1.3.7, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[83] Paragraph 357, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.
[84] Paragraph 359, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.

- account for the impact of the Australian Government's Clean Energy Future Package

These are summarised in Table 12 and the following sections.

Table 12: New operating expenditure adjustments

$ million real at 30 June 2012	Initial Submission per annum	Revised submission per annum	Comments
Base year adjustments			
Distribution preventative condition – pole maintenance	12.9	15.0	Revised delivery rates
Distribution preventative routine – power pole bundled inspections	41.1	44.3	Increase in volumes to align with the revised wood pole management plan
Step changes			
Distribution preventative routine – wood pole testing facility	N/A	1.4	Operation of a new wood pole testing facility in Western Australia from 13/14
Transmission preventative routine - SF6 filled switchgear maintenance	N/A	0.02	Impact of the Clean Energy Future Package in 2012/13
Transmission preventative condition - SF6 filled switchgear maintenance	N/A	0.02	Impact of the Clean Energy Future Package in 2012/13
Transmission corrective emergency – SF6 filled switchgear maintenance	N/A	0.06	Impact of the Clean Energy Future Package in 2012/13

6.3.2.1 Distribution preventative condition – pole maintenance

Western Power has revised the delivery rates for the pole maintenance program to reflect the rates experienced in 2011/12 for programs delivered by its distribution delivery partners. The change in delivery rates is efficient as the DDPs were required to submit delivery rates for activities which were compared and tested against market conditions. This is discussed further in section 8.2.2.2.

This is an increase of $2.3 million per annum compared to the September 2011 submission. This activity includes treatment of white ants, pole and pole top maintenance, conductor related maintenance and insulator maintenance.

6.3.2.2 Distribution preventative routine – power pole bundled inspections

Western Power has increased expenditure on the power pole bundled inspection program by $3.8 million to account for an increase in volumes as a result of its new wood pole management plan (see section 8.2.2.2). This activity assesses the serviceability of the assets and is a critical component of Western Power's wood pole management plan.

6.3.2.3 Distribution preventative routine - wood pole testing facility

Western Power has adjusted the 2010/11 recurrent base year by $1.4 million for the operation of a wood pole testing facility in Western Australia.

Western Power currently undertakes desktop analysis of poles that have failed. However, Western Power's experience (supported by findings from the Energy*Safety* Distribution Wood Pole Audit (2008)) indicates that additional and more detailed analysis required to better understand the reasons for unassisted wood pole failure.[85] The need for this detailed analysis is also in line with the findings of the Parliamentary Inquiry.[86]

In early 2012, Western Power engaged Alliance Power and Data to conduct an independent review of the options available for undertaking wood pole testing (see Appendix X). The review recommended that Western Power build, operate and maintain a facility with an objective of testing failed, ex-service and new poles.

The capital cost of establishing the testing facility is $2.4 million (see section 8.2.3.1). The ongoing operation of the testing facility is $1.4 million year.

6.3.2.4 Transmission preventative routine, preventative condition and corrective emergency - Clean Energy Future package

In its September 2011 submission, Western Power advised that it had not yet been able to assess the impact of proposed new legislation and increased costs associated with the Australian Government's Clean Energy Package including the carbon price and associated policies.[87]

Since this time, Western Power has been able to better understand the implications of the Clean Energy Future package and has revised its operating expenditure forecasts accordingly.

The *Ozone Protection and Synthetic Greenhouse Gas (Manufacture Levy) Amendment Act 2011*, which forms part of the Clean Energy Future package, imposes an equivalent carbon price on the manufacturing[88] and importing[89] of sulfur hexafluoride gas (SF6). The prescribed rate per tonne of carbon dioxide equivalent is provided in Table 13.

Table 13: Prescribed rate per tonne of CO2-e[90]

	price per tonne of CO2-e ($)
2012/13	22.28
2013/14	22.83
2014/15	23.41
2015/16	26.08
2016/17	27.14

Consequently, Western Power has revised recurrent operating expenditure forecasts by $0.8 million to account for the impact of increased costs in purchasing and replacing SF6 gas to maintain Western Power's transmission filled switchgear. The Clean Energy Future package will also affect non-recurring operating expenditure (see section 6.3.4.2) and transmission asset replacement capital expenditure (see section 8.2.1.4).

[85] *"Recommendation 16: Western Power should: 1. Establish effective post mortem investigations of all pole failures, including reinforced pole failures"* (p.31, Distribution Wood Pole Audit (2008), Department of Commerce, Energy*Safety*, May 2009).
[86] *Report 14, Standing Committee on Public Administration, Unassisted Failure, Legislative Council*, January 2012.
[87] Page 135, *Access Arrangement Information and AAI Appendix A*, Western Power, September 2011
[88] Section 3A(5).
[89] Section 3A(7).
[90] Australian Government Treasury, *Strong growth, low population: modelling a carbon price,* released on 21 Sep 2011. Note: the legislation provides the price per tonne of carbon equivalent (CO2-e) in nominal dollars. These figures have been adjusted to real $ as at 30 June 2012.

6.3.3 Scale escalation

The Authority accepts Western Power's forecasting method of rolling forward the efficient base year for recurrent costs and escalating costs for growth in the physical network size and customer base. The Authority also and considers that the parameters selected by Western Power (customer numbers and a composite network factor comprising: line length, distribution transformers and substation capacity) are sound.

However, the Authority has adopted historical rather than forecast growth in scale escalation drivers. This approach constrains growth in the costs associated with a growing network and customers base to a level consistent with historical growth.[91] However, the Authority has then reduced forecast costs even further through applying an economies of scale factor.

Western Power does not accept the Authority's amendment to constrain the growth in operating expenditure to the historical rate of growth in the drivers of its operating expenditure or the additional economies of scale adjustment. This is because:

- the forecast cost does not represent an increase in the fixed costs at the same rate as the network grows
- costs will grow at a greater rate in the future than in the past due to the increased investment program and deteriorating condition of the network
- the AER has not generally applied an economies of scale factor in the same manner as the Authority

The Authority has imposed an 'economies of scale' factor on the basis that:

- by not including an economies of scale factor Western Power is assuming that fixed costs will increase at the same rate as the network grows[92]
- the AER has generally required an economies of scale factor to be applied under a scale escalation approach[93]

These issues are discussed further in the following sections.

However, Western Power has modified its scale escalation method and data to address some of the Authority's specific concerns. For example, the Authority notes that the use of an annual average growth rate has distorted the escalation of Western Power's operating expenditure in earlier years, as the majority of the growth is towards the end of the period.[94] Western Power accepts this finding and has sought to improve the accuracy of the scale escalation approach by using an annual growth rate for each year and separately applying the applicable growth rate to specific transmission, distribution and customer factors.

Issues relating to the use of historical scale escalation drivers and the application of an additional economies of scale factor are discussed in the following sections.

6.3.3.1 Growth rate in scale escalation drivers

The Authority has used Western Power's annual average historical network and customer growth rates for the AA2 period to estimate AA3 operating expenditure on the basis that:

- historical growth rates act as a proxy for a capex/opex trade-off[95] to account for the 'honeymoon period'[96] when new assets are installed

[91] Paragraph 262, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[92] Paragraph 263, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[93] Paragraph 264, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[94] Paragraph 260, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[95] The capex/opex trade-off is a mechanism which aims to reduce the operating and maintenance costs in line with increases in replacement capital expenditure.

- the Authority's technical consultant was not able to reconcile the information that Western Power provided to support the forecast network asset quantities includes as drivers of scale escalation[97]
- the difference between the historical average growth rate and forecast average growth rate for customer growth is 'miniscule' and as a result, the Authority does not see any justification to deviate from the historical rate[98]

Western Power maintains its view that forecast growth in the relevant network and customer scale drivers is the appropriate measure of the growth relationship with forward-looking efficient expenditure. This position is accepted in the Australian[99] and UK[100] energy industries. Between 2009 and 2012, the Australian Energy Regulator made 11 electricity transmission, electricity distribution and gas distribution determinations that employed scale escalation using growth driver proxies. All of these relied upon forecast (rather than historical) growth in the relevant proxies.[101] These are discussed below.

Historical growth as a proxy for capital and operating expenditure inter-dependency

The Authority has replaced Western Power's forecast scale drivers with annual average historical rates of growth based on the AA2 period on the basis that *Western Power has not applied a capital expenditure-operating expenditure trade off factor to its scale escalators*. [102]

The Authority's draft decision states:

> *A trade-off arises when new assets require less maintenance than older assets. GBA considers an approach suggested by Nuttall Consulting Ltd in a report for the AER, to account for both the scale escalation of forecast asset growth and capital expenditure-operating expenditure trade-off by using actual growth rates for determining the escalation factor, to be a pragmatic and sound solution. The rationale is that new assets installed have a honeymoon period during which little maintenance is required. This results in a lag between when assets are installed and when they must be inspected or maintained. In other words, the maintenance effort is driven not so much by the new assets installed but by the assets that were installed during the previous regulatory periods. This supports the GBA conclusion that the use of historic growth rates is appropriate.*[103]

[96] The 'honeymoon period' is the theory that new assets installed have a short period during which little maintenance and inspection is required.
[97] Section 10.4.1, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[98] Paragraph 256, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[99] Page 14, *Review of proposed expenditure of ACT & New South Wales electricity DNSPs: Energy Australia's submissions of January and February 2009, a report prepared for the AER*, Wilson Cook, 31 March 2009.
[100] *Electricity Distribution Price Control Review Methodology and Initial Results Paper, Ref: 47a/09,* Ofgem, 8 May 2009.
[101] See AER final determinations for: Vic electricity distribution (2010: CitiPower, Powercor, United Energy, Jemena Electricity Networks, SP AusNet), SA electricity distribution (2010: ETSA), Qld electricity transmission (2011: Powerlink), Tas electricity transmission (2009: Transend), NSW gas distribution (2010: Jemena Gas Networks), Qld gas distribution (2010: Envestra), SA gas distribution (2011: Envestra).
[102] Paragraph 261, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[103] Paragraph 261, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Western Power notes that the cited Nuttall Consulting (Nuttall) advice:

- was not relied upon in the AER's final decision as that decision did not apply a capex/opex tradeoff to the scale escalation and used forecast drivers (rather than historical) to apply scale escalation[104]
- specifically acknowledged the 'bath-tub curve' as an observed counter effect to the 'honeymoon' hypothesis

Advice cited by the Authority's technical consultant was provided to the AER by Nuttall Consulting (Nuttall) during the 2010 Victorian distribution price review.[105] That advice, together with a further Nuttall advice dated 29 October 2010, acknowledges that a counter effect to the 'honeymoon' hypothesis is that of the 'bathtub curve'. Nuttall notes that:

> *The bathtub curve is an accepted theory of asset management and well supported in literature.*
>
> *In addition to opex increasing as an asset ages, this curve recognises an increased level of emergency repair and restoration activity early in the life of an asset.* [106]

Nuttall notes the importance of this curve, but identifies that it was not presented any quantitative data against which to compare its effects on capex/opex tradeoff.

Western Power does not accept that network assets are subject to a 'honeymoon period' in relation to operating and maintenance costs.

The 'honeymoon period' assumes there is no operating and maintenance costs incurred during the initial years of service. This is not Western Power's experience or a theory that is supported in electrical engineering or by manufacturers. Western Power's experience suggests that operating and maintenance costs are incurred during the initial years of in service assets. Indeed, many asset classes suffer from infant mortality, failing early in life. The Asset Management Council recognises a 'bath tub' curve in operating costs[107]. That is, new assets require additional costs in the early years. This experience and explanation outlined in the report from GHD who Western Power sought to peer review the Authority's technical consultant assumptions.

The activities Western Power undertakes that are driven by customer numbers (call centre and metering) move in line with the actual customer base in the year in which they are being considered.

For example, the number of meters that require reading (which accounts for 94% of metering operating expenditure) is a function of the forecast number of customers in the relevant year. Using a historical growth rate as a proxy for the known growth rate cannot be considered a reasonable predictor of the amount of activity (and therefore expenditure) required during the AA3 period. Similarly, transmission and distribution network operating and maintenance costs are driven by the physical size of the network at that time.

Western Power also does not accept that there is a lag or 'honeymoon period' period between the time when new assets are installed and when they must be inspected or maintained. As noted by Nuttall, the bathtub curve theory recognises an increased level of emergency repair and restoration activity early in the life of an asset. Western Power's experience is that equipment fails early in its life (requiring reactive maintenance) or needs monitoring and early maintenance to achieve stable performance (requiring preventative maintenance). The need for maintenance from installation is also outlined in manufacturers'

[104] Appendix J, *Victorian electricity distribution network service providers, Distribution determination 2011-2015, Final decision – appendices,* Australian Energy Regulator, October 2010.
[105] *Opex Escalation Review (Victoria Electricity Distribution Revenue Review):* Nuttall Consulting, 28 October 2010. Cited in footnote 51 of *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[106] Page 5, *Scale Escalation Advice Sought (Nuttall Consulting comments):* Nuttall Consulting, 29 October 2010.
[107] *Common Errors in Maintenance Reliability Theory and Practice*, D. Shermin, Asset Management Journal, Issue 1, Volume 3, 2009.

warranties (see Appendix B). Further, Western Power inspects and maintains assets from their installation.

Western Power tracks replacement rates on transmission and distribution assets, collecting data about the age operating conditions, asset conditions and manufacturing defects. This data is illustrated in Figure 10 and it shows that across different assets, Western Power experiences equipment failing within the first five years. This failure is commonly referred to as 'infant mortality':

> *Newly installed electrical equipment has a relatively high failure rate due to the possibility that the equipment has manufacturing flaws, was damaged during shipping, was damaged during installation, or was installed incorrectly. This period of high failure rate is referred to as the infant mortality.* [108]

Figure 10 shows that 10% of Western Power's total population of reclosers fail within the first five years of their life. Data on Western Power's pole top switch-disconnector failure rates are also presented to demonstrate that there is also some level of infant mortality in these assets. While expenditure may decrease over time, it is inappropriate to assume a 'honeymoon period' where zero or dramatically lower expenditure is required to operate and maintain these assets in their early years.

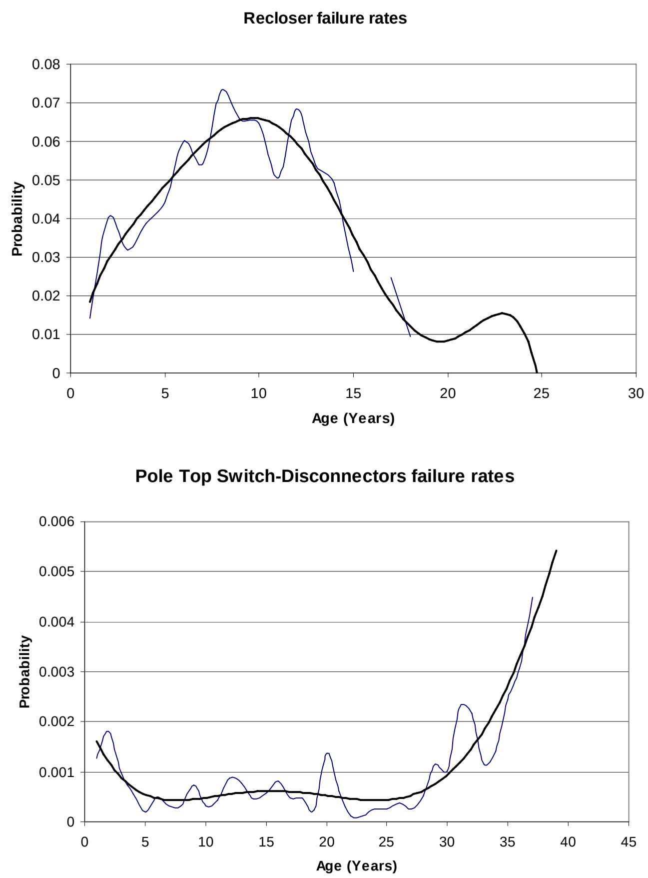

Figure 10: Western Power's asset failure rates (replacement rates)

An expert report from GHD (attached at Appendix G) further explains the bathtub curve and demonstrates its effect on the immediate operating and maintenance activities following installation of new assets with supporting evidence from the Asset Management Council.[109]

[108] Page 165, *Electric Power Distribution Reliability*, Richard E. Brown, 2nd edition.
[109] *Common Errors in Maintenance Reliability Theory and Practice*, D. Shermin, Asset Management Journal, Issue 1, Volume 3, 2009.

GHD discuss further the bath tub curves which show that:

> *…the probability of the failure of asset components is highest during the first third of its life (related to quality issues) and then declines during the second third (random failures) before increasing in the final third (wear out stage)*[110]

This theory is also supported by Western Power's own experience. Figure 11 compares the age of Western Power's distribution assets with the number of faults experienced. The red line provides a trend consistent with the bath tub theory.

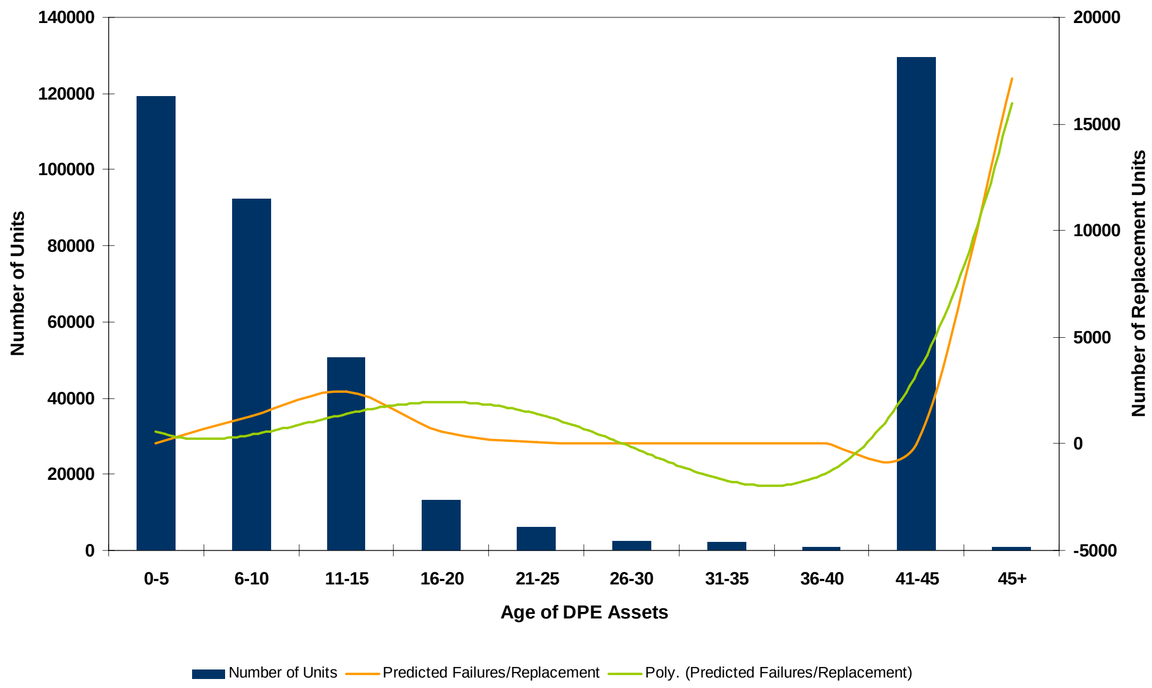

Figure 11: Distribution plant and equipment assets age profile and predicted replacement curve

For the honeymoon hypothesis to affect total operating expenditure, the number of new assets being installed in the period must be greater than the number of existing assets that are expected to transition from 'mid-life' to the end of their useful life in the following period. Asset condition is a significant driver of operating and maintenance activities. The deteriorating condition of assets drives increases in corrective maintenance work. Currently, the deterioration of assets in the Western Power Network is increasing at a faster rate than the physical asset base is growing.

Capital investment in AA3 is ramping up to help slow the overall rate of asset deterioration, but will not achieve a level of renewals that will result in a net reduction in asset deterioration. For example, 32% of Western Power's distribution plant and equipment assets are currently past their design life. Over the AA3 period, Western Power will replace 7.6% of total distribution plant and equipment assets through its reactive and proactive replacement programs. Despite the increasing capital investment program, there will still remain 31% of the population that are past their design life at conclusion of AA3 (see Figure 12).

[110] Section 3.3, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.

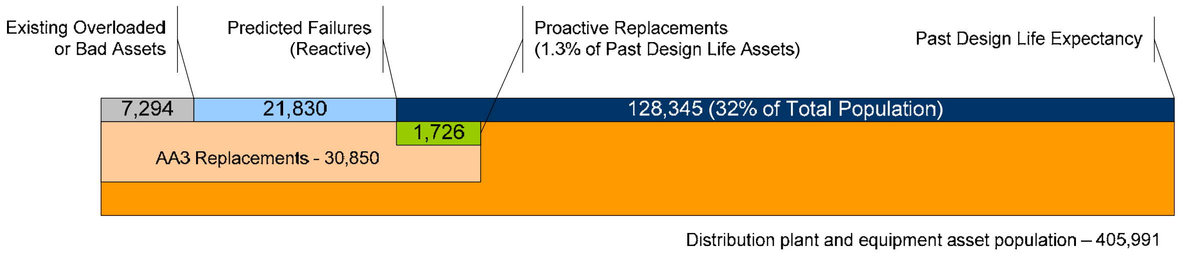

Figure 12: Distribution plant and equipment condition

This means that historical growth rates will underestimate the activities needed to address asset condition compared to using the forecast growth rates that better accounts for the increased activity requirements. Therefore, the Authority's approach will underestimate the efficient operating and maintenance costs required for Western Power during the AA3 period.

GHD supports this conclusion, stating that:

> *Our belief is that, as Western Power's current assets age, the cost of OPEX will increase until that number of assets being renewed balances the age deterioration of existing assets.*
>
> *GHD does not support the GBA report's direct correlation between CAPEX and OPEX for Western Power because it appears to ignore the current condition of the assets and the minimal impact CAPEX over the AA3 period will have on OPEX liabilities.*[111]

Forecast scale drivers

The Authority does not accept the use of forecast network and customer growth rates on the basis that Western Power's forecasts were significantly higher than the actual growth rate from 2007/08 to 2010/11.[112] Furthermore, the Authority states that it is unable to reconcile these forecast quantities to supporting documentation provided by Western Power with particular reference to the Transmission Network Development Plan. The Authority's technical consultant states that:

> *Growth rates for line length and customer numbers are comparable with historic (sic) growth*
>
> *We see no basis for the acceleration in the annual rate of increase in the number of distribution transformers…*
>
> *… are unable to reconcile this [substation capacity] with ...analysis of the transmission network development plan.*[113]

Western Power maintains that the quantities for customer numbers and each elements of the composite network factor comprising: line length, number of distribution transformers and substation capacity that were provided to the Authority in November 2011 were robust. These forecast growth rates for line length, number of transformers, substation capacity and customer numbers were used to determine the capital expenditure requirements for the AA3 period.

Since the initial submission, Western Power has reviewed the growth capital expenditure amendments required by the Authority, coupled with the new demand forecasts and have provided a revised forecast of relevant scale drivers. These are provided in a copy of the scale escalation model[114] and replicated in Table 14.

[111] Section 3.3, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.
[112] Paragraph 256- 259, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[113] Section 10.4.1, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[114] Appendix C.

Table 14: Review of forecast scale escalation factors

Item	2012/13	2012/14	2014/15	2015/16	2016/17
Customer factor	2.59%	2.62%	2.66%	2.69%	2.72%
Distribution line length	1.28%	1.19%	1.25%	1.27%	1.33%
Transmission line length	3.9%	3.11%	0%	0.46%	1.18%
Distribution transformers	2.97%	2.80%	2.86%	2.96%	2.97%
Substation capacity	2.56%	1.25%	7.33%	5.36%	12.51%
Distribution network factor	**2.27%**	**1.75%**	**3.82%**	**3.19%**	**5.60%**
Transmission network factor	**3.14%**	**2.39%**	**3.40%**	**2.92%**	**5.55%**

Western Power has attached the relevant supporting documentation for the growth rates in these drivers to this submission (see Appendix C).

Western Power will report actual data on customer numbers, line length, distribution transformers and substation capacity for each year of the AA3 period.

In its draft decision the Authority and its technical consultant applies individual economies of scale factors to Western Power's network, operations and customer growth rates.[115] The Authority justified this[116] based on:

- its view that Western Power's scale escalation method assumes a one-for-one growth relationship between network growth drivers and operating expenditure (i.e. that operating costs are fully variable)
- Western Power's experience and advice which does not support this theory
- the Australian Energy Regulator having applied economies of scale adjustment in past decisions.

Western Power does not accept that an additional economies of scale adjustment is needed because:

- Western Power's approach does not assume a one-for-one relationship between network growth and expenditure growth as the composite network growth factor accounts for a level of scale economy in fixed operating costs
- The Australian Energy Regulator does not always apply an economies of scale adjustment, and has not applied it in the manner applied by the Authority

The following sections further explain these points.

Growth in the network and economies of scale

In making its decision, the Authority has stated that:

> *The scale escalation …, reflects the increases in operating expenditure as a result of growth in the network. However, growth in the network should result in economies of scale, that is, lower total costs as a proportion of customers or energy demand or energy usage. Western Power has not included any provision for an economy of scale adjustment to modelling scale escalation. An economy of scale adjustment is an acknowledgement that as the network increases, the fixed component of operating expenditure will not increase as fast as the network increases. By not including an economy of scale adjustment, Western Power is assuming that fixed*

[115] Paragraph 265, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.

[116] Paragraphs 263-264, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.

> *costs will increase at same rate as the network grows, which is an assumption that the Authority does not agree with.*[117]
>
> *By not including an EOS factor in its scale escalators, Western Power has implicitly assumed that its opex costs are fully variable, an assumption that we do not accept.*[118]

The Authority's conclusion that Western Power has 'implicitly assumed that its opex costs are fully variable' is incorrect.

For network driven activities, the composite network scale driver comprising average annual growth in line length, distribution transformers and zone substation capacity results in a modelled growth relationship of less than one-for-one which accounts for the manner in which variable operating costs will grow as the network grows. This composite network growth factor assumes neither line length nor distribution transformers nor zone substation capacity has a one-for-one growth relationship with total operating expenditure, but rather something much lesser as a result of applying the composite rather than additive growth rates.[119] Western Power considers this is a reasonable given the nature of network operating and maintenance activities and the condition of the network.

Evidence for economies of scale

The information provided by the Authority and Western Power's experience and advice does not support the theory of economies of scale in practice.

The Authority's approach to economies of scale is internally inconsistent with its benchmarking analysis. If the Authority is to rely on its technical consultant's benchmarking analysis, which assumes linear relationships with costs and each normaliser (RAB, network length and customer numbers), then it is not reasonable to apply an adjustment for economies of scale. The normalisation was undertaken on a linear basis, that is, it implicitly assumes that operating expenditure is linearly related to each of these factors. If the benchmarking holds, and relationships are linear, then there can be no economies of scale.

The Authority's technical consultant's benchmarking also provides no evidence to assume that increased size leads to lower unit costs. Geoff Brown and Associates' analysis suggests that there are no economies of scale that flow from the physical size of the network or customer base. If there was, New South Wales and Queensland would have the two most efficient networks[120], which is not the case as outlined in Table 15, which reproduces the benchmarking relied on by the Authority's technical consultant. Further evidence of the shortcomings of the Authority's benchmarking is provided in section 6.6.1.3

Table 15: Network benchmarking results

	Opex/km line ($ real, 2012)	Opex / customer ($ real, 2012)	Opex / Capital base
Western Power	4,507	433	7.2%
Queensland	**4,053**	**436**	**4.2%**
New South Wales	**4,814**	**409**	**6.0%**
Victoria	3,900	248	6.1%
South Australia	2,724	309	5.7%

[117] Paragraph 263, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.
[118] Section 10.4.2, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[119] To assume a one-for-one relationship, as the Authority and its technical consultant conclude, would have required Western Power to have summed the growth rates in these drivers rather than average them. This would have given a network growth factor of >8%.
[120] Based on publicly available information, New South Wales has a line length of 286,566km and Queensland has a line length of 212,834km.

	Opex/km line ($ real, 2012)	Opex / customer ($ real, 2012)	Opex / Capital base
Tasmania	3,965	407	5.0%

Source: section 10.3.1.2, *Geoff Brown Report Final (Public Version),* 27 March 2012

Western Power considers that using the additional economies of scale adjustment that the Authority proposes is likely to overestimate Western Power's ability to reduce costs over AA3. This is because:

- the current state of the network drives a greater volume of operating and maintenance activity giving rise to diseconomies of scale which is likely to continue until Western Power achieves a sustainable rate of investment and stable asset condition
- a large proportion of operating expenditure is reactive and therefore unable to be grouped in like work types or locations, the dispersed nature means that diseconomies of scale is experienced
- economies of scale achieved through AA1 and AA2 initiatives of grouping planned activities and maintenance is already incorporated into Western Power's base year and therefore has been rolled forward under the scale escalation approach

The network's condition is deteriorating at a faster rate than growth in the size of the network. At the end of the AA3 period the average network asset age will be greater than the average network asset age at the commencement of the AA3 period as demonstrated in Figure 13.

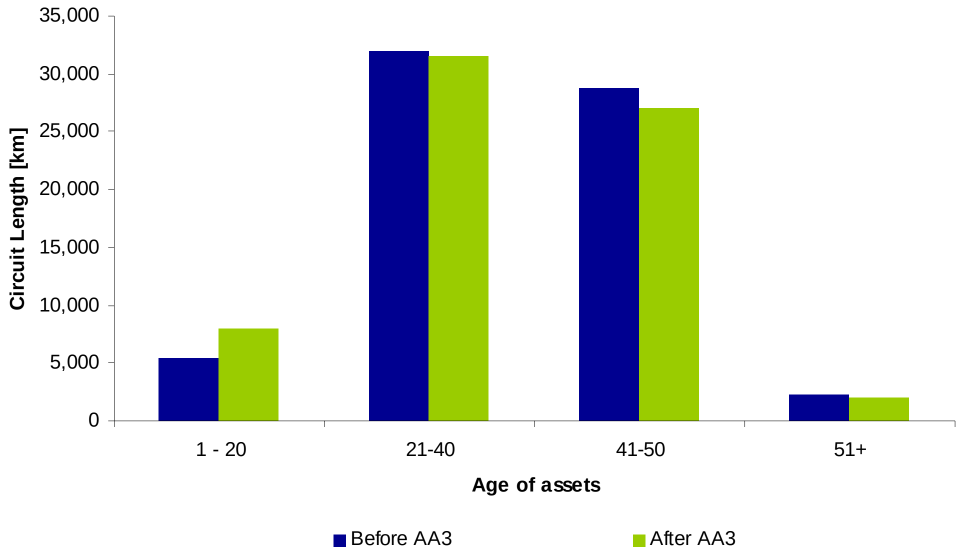

Figure 13: Impact of the AA3 conductor replacement program

Network age is a key contributor to the condition of the network, which drives the quantum of activities required. Asset condition is a key contributor to the ability to achieve economies of scale on the network. Therefore, applying an economies of scale adjustment (as the Authority proposes) will overstate the achievable savings in operating activities.

GHD observed that the application of an economies of scale factor on Western Power by the Authority assumes that the condition of the network is similar to other businesses, which is not the case as acknowledged by the Authority's technical consultant.[121] GHD state that the application of an economies of scale factor *could potentially grow the OPEX backlog in the*

[121] Section 3.4, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.

[network] rather than reduce it as a result of the reduction in funding and reasonably the delivery of associated programs.[122]

Economies of scale cannot be achieved in many categories of expenditure such as the reactive maintenance works. Transmission and distribution corrective emergency and corrective deferred works cannot be bundled, and are likely to suffer from diseconomies of scale, because, as the network grows, the reactive works are spread over a greater distance and become more costly to address.

Efficiencies in the base costs

The specific nature of Western Power's operating activities and operating obligations mean that additional scale economies beyond those already achieved to date (and therefore reflected in Western Power's base costs) are unlikely during AA3 and in many cases, Western Power may, experience diseconomies of scale.

Where economies of scale have been achieved, Western Power has incorporated these in its base forecasts. Western Power has introduced a number of initiatives over the AA1 and AA2 period to optimise planned capital and operating activities, allowing Western Power to realise available economies of scale. These have included: pole inspection bundling, fuse pole bundling, aligning substation asset maintenance cycles, improved works packaging through Western Power's alliance and distribution delivery partner structures, improved contract negotiation including introduction of specific cost savings clauses based on guaranteed work levels (see section 9.2.2.2) and sliding scale price lists linked to variations in volumes. Under the scale escalation approach, these are built into the base year costs.

Western Power has also reduced its expenditure forecasts given identifiable benefits associated with the Strategic Program of Works (SPOW) delivering improved enterprise IT systems. Specific benefits of these technology solutions include improved visibility of available asset data, leading to cost savings associated with an increased ability to package work based on type and location. These are discussed in section 6.6.1.1.

Applying an additional economies of scale factor and reducing available expenditure would severely reduce Western Power's ability to maintain reliability and service standards and result in an increase in the whole of life-cycle asset costs.

Application of economies of scale by the AER

While the Authority cites the AER's application of an economies of scale adjustment in its Powerlink and ETSA Utilities determinations, Western Power notes that:

- economies of scale adjustment has not been universally applied to decisions where scale escalation was applied[123]
- economies of scale adjustment has not been applied in conjunction with an across-the-board efficiency dividend
- the Authority must have due regard to Western Power's specific circumstances including asset condition and operating activities as discussed in section 6.3.3.1.

In assessing the Authority's draft decision on economies of scale, GHD note that:

The underling presumption here, again appears to be that the condition of the SWIN equals the condition of the NEM whereas the GBA report concludes in the case of unassisted asset failures it is deemed to be 4-20 times worse than the NEM. [124]

[122] Section 3.4, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.
[123] See for example, AER final determinations for: Tas electricity transmission (2009: Transend), NSW gas distribution (2010: Jemena Gas Networks), Qld gas distribution (2010: Envestra), SA gas distribution (2011: Envestra).
[124] Section 3.4, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.

6.3.4 Non-recurrent expenditure

The Authority accepts $74 million of Western Power's $224 million non-recurrent operating expenditure, but requires Western Power to adjust the forecast to:

- reduce the field survey data capture project by 50% (-$17 million)
- remove transmission and distribution network control services (-$66 million)
- reduce the extended outage payment scheme (EOPS) and remove planned outage payments (-$7 million)
- reduce transmission line removal (-$4 million)

Western Power accepts the Authority's required amendment to amend the method of calculating EOPS payments and the removal of planned outage payments and has revised the forecast accordingly.

With regard to transmission line removals, Western Power has reduced the forecast expenditure by a similar level to that proposed by the Authority. This reduction is related to a change in scope. This is discussed in section 6.3.4.3.

Western Power does not accept the proposed adjustments to the field survey data capture project and network control services. These programs are discussed in sections 6.3.4.1 and 6.3.4.2.

Western Power has also included non-recurrent operating expenditure related to the following new obligations:

- compliance with 'Type 1 obligations' under the Code of Conduct for the Supply of Electricity to Small Use Customers (see section 6.3.4.4)
- Acceleration and change in capitalisation treatment of the streetlight switchwire program (see section 6.3.4.5)
- the Australian Government's Clean Energy Future package (see section 6.3.4.6)

6.3.4.1 Field survey data capture

In its draft decision, the Authority acknowledges the need for Western Power to improve its asset data. However, it considered that a reduction of 50% to the forecast $17.4 million over the 5 years was appropriate, based on the opinion of the Authority's technical consultants who stated that:

- *Western Power should consider a more targeted approach to fix areas where data is known to be poor*[125]
- *it is the most extensive project of its kind in Australia*[126]
- *there is limited evidence of the forecast expenditure taking into account potential efficiency gains, which should have emerged through the pilot project*[127]

However, the Authority said that Western Power could provide further information to justify the need for a higher cost alternative.[128]

This field survey data project is a critical project for Western Power. It is required to ensure that Western Power is able to manage the network safely, reliably and in a manner that enables Western Power meet legislative and licence requirements including:

[125] Paragraphs 274, 275 and 277, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[126] Paragraph 275, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[127] Paragraph 275, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[128] Paragraph 277, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

- **improve distribution asset data quality** - Poor data quality can cause network design and planning issues, misalignment with external datasets (used for state planning or by other utilities) and inhibit the benefits of improving asset management systems including mobile technologies. It may also mask performance in relation to compliance and public safety.
- **respond to the Energy*Safety* Order 01-2009**[129] - The Order requires Western Power to *'identify and record… the number and location of rural distribution poles; that is all poles not within a town or city boundary'*
- **respond to the recent Parliamentary Inquiry into wood pole management** – The findings of the Inquiry require Western Power to go to every pole in the network *to collate all the remaining attributes and put that into the new database*[130]
- **provide validation of the electrical connectivity model** - the identification of how network assets are connected is critical to ensure safe access to the network and prevent Type 1 breaches of the Code of Conduct for the Supply of Electricity to Small Use Customers (Small Use Customers Code)

Poor data quality can cause network design and planning issues, misalignment with external datasets (used for state planning or by other utilities) and inhibit the benefits of improving asset management systems including mobile technologies. It may also mask performance in relation to compliance and public safety.

In addition, validation of the electrical connectivity model (how network assets are connected) is critical to ensure safe access to the network and prevent Type 1 breaches of the Code of Conduct for the Supply of Electricity to Small Use Customers (Small Use Customers Code).

Western Power believes that the Authority's required adjustment results in insufficient expenditure to conduct this project to achieve its objectives. Western Power also disagrees with the following comments regarding the field survey data capture project made by the Authority's technical consultants:

- *Western Power should consider a more targeted approach to fix areas where data is known to be poor*[131]
- *it is the most extensive project of its kind in Australia*[132]
- *there is limited evidence of the forecast expenditure taking into account potential efficiency gains, which should have emerged through the pilot project*.[133]

Accurate data is vital for Western Power to be able to manage the network safely, reliably and in a manner that enables Western Power meet legislative and licence requirements.

These and other comments are addressed in detail below.

'Western Power should consider a more targeted approach to fix areas where data is known to be poor'

The Authority's technical consultant assumes that Western Power's field survey data capture project involves a complete survey of its transmission and distribution line assets. This is incorrect.

[129] Page 10, *Energy Coordination Act 1994* Order 01-2009.
[130] Page 11, *Standing Committee on Public Administration, Inquiry into Electricity Transmission and Distribution Management by Western Power and Horizon Power*, Transcript of Evidence taken at Perth, Wednesday 9 November 2011.
[131] Paragraphs 274, 275 and 277, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[132] Paragraph 275, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[133] Paragraph 275, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

In developing the business case for the project, Western Power considered the option of surveying all transmission and distribution line assets. However, it did not recommend this option as it was considered to be too expensive.

The scope of the project is to:

- complete a survey of all distribution poles in the Perth metropolitan area concentrating on verification of the pole location
- complete a survey on all distribution poles and associated equipment in rural areas, as this complies with Energy*Safety* Order 01-2009 and Western Power's commitment to the recent Parliamentary Inquiry[134] on wood pole management

Western Power considered a further option that targeted areas where data is known to be poor. It determined that a targeted option is not feasible for identifying missing poles or poles with poor spatial accuracy. A missing pole cannot be identified prior to field survey, as its potential existence and location is not known. The AA2 field survey data capture pilot project has shown that poles with poor spatial accuracy (or inaccurate location information) are spread out evenly across the rural network.

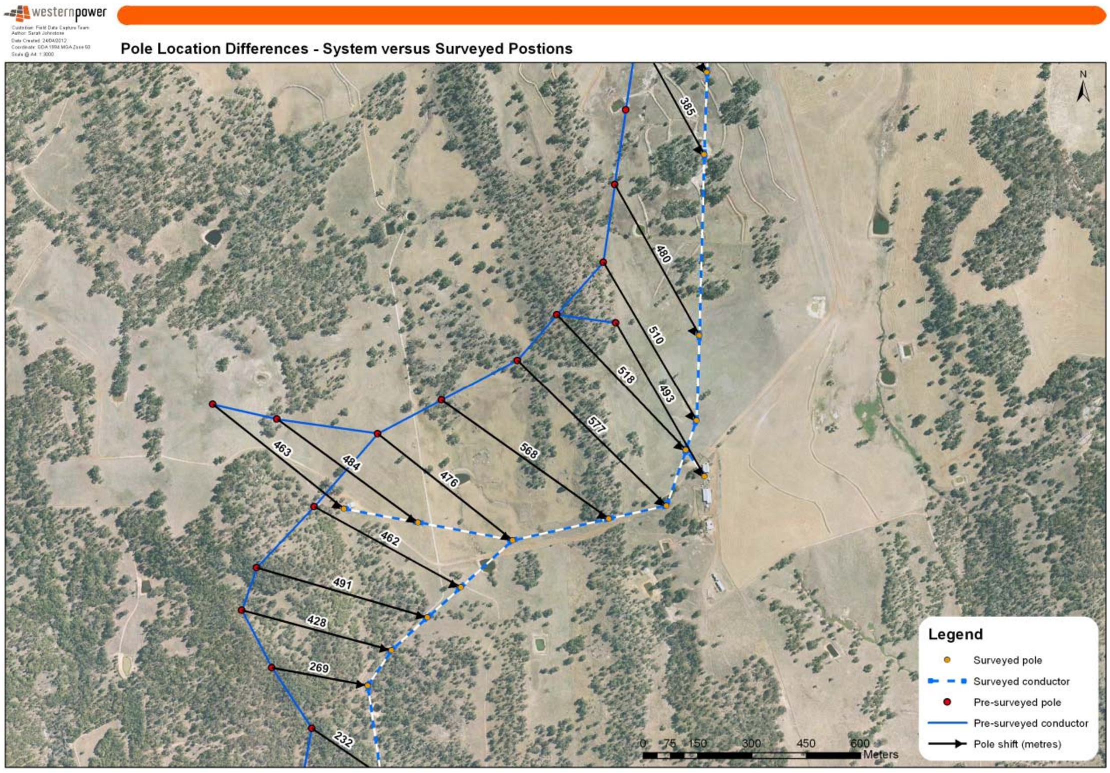

Figure 14: Map illustrating the error in location typical of the area surrounding Northam

The poles shown in Figure 14 would be difficult to locate using GPS and it would be impossible to determine if the inspection results were being recorded against the correct pole. This reinforces the importance of the link between knowing where the asset is and correctly understanding its condition.

The Authority's technical consultant suggested an alternative option whereby existing Western Power staff and contractors working in the field could report all discrepancies to a

[134] Page 11, *Standing Committee on Public Administration, Inquiry into Electricity Transmission and Distribution Management by Western Power and Horizon Power*, Transcript of Evidence taken at Perth, Wednesday 9 November 2011.
Page 19, *Standing Committee on Public Administration, Inquiry into Electricity Transmission and Distribution Management by Western Power and Horizon Power*, Transcript of Evidence taken at Perth, Wednesday 9 November 2011.

specialised data management team for correction. It also suggested that a cultural change is required to ensure discrepancies are recorded.

Western Power has had a 'data corrections' process in place since 2005. This activity corrects errors identified on returned data, and requires Western Power staff and contractors to submit instances of data discrepancies or corrections. The number of field corrections has increased substantially since 2009 as a result of increased training and awareness programs.

However, the data corrections process alone is not sufficient to improve the quality of Western Power's data in an acceptable timeframe and largely fails to address issues of missing assets.

'it is the most extensive project of its kind in Australia

To date, Western Power is the only Australian electricity utility that has not undertaken a large scale data capture project of this nature.

The Authority's technical consultant assumes that Western Power's field survey data capture project is the most extensive project of its kind in Australia. It has based its view on comparing the costs associated with the various projects undertaken by different utilities. But in doing so, it has not:

- compared the project expenditure in similar dollars. The consultant has compared nominal project expenditures incurred in 1998, 2006 and 2007 against Western Power's forecast expenditure in real dollars at 30 June 2012
- accounted for differences in the scale and scope of the projects

The Authority's technical consultant also noted that Western Power had referenced six similar data capture projects.

> *The cost of five of these programs was between $3 million and $6 million whereas one program cost $25 million.*[135]

The $25 million program included the costs associated with field capture, updating systems and project management. Others included only the field capture costs. When the costs of field capture, updating systems and project management were included, and escalated to 2011/12 dollars, the cost of the other five projects increased to between $6 million and $39 million. This excluded indirect costs.

Three of the projects referenced had a lower cost than Western Power's and one had a higher cost, despite having a much smaller geographic area and surveying a much smaller number of assets.

Western Power understands that most eastern states utilities have new large scale data capture activities either planned or currently underway. Western Power has not reflected these additional costs when comparing to the field data survey capture project.

Of the three projects that had a lower cost than Western Power's:

- no information is available on one, which was undertaken over a decade ago
- the other two projects focused only on "significant poles"[136]
  - the number of assets surveyed is unknown for one of the projects
  - the cost of the other project, on a per pole basis, was slightly higher than for Western Power's project.

Comparing projects on a like-for-like basis suggests that Western Power's project is not the most extensive of its kind in Australia. In its review of the GBA report, GHD have concurred with GBA in that *our experience has been that other utilities are implementing economical*

[135] Page B15, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[136] Significant poles are those with equipment attached or where there is a change in direction in the line of greater than 30 degrees.

solutions for the collection of asset management data.[137] GHD do however state that they did not review the business case for the project and therefore do not have the ability to analyse the proposed scope or costs.

A comparison of these projects is provided at Appendix Y.

'there is limited evidence of the forecast expenditure taking into account potential efficiency gains, which should have emerged through the pilot project.'

The Authority's technical consultant stated that:

> *the findings of the pilot project will provide a much more accurate picture of the quality of the data and should be analysed before any ongoing field survey project is finalised.*[138]

Western Power has been monitoring and reporting the results of the AA2 pilot project. These results have been fed directly into the AA3 project planning, and confirm the requirement for the forecast expenditure.

Western Power acknowledges that its legacy asset data records, created at the time of data up-take from paper maps, have a number of issues including missing assets, spatial inaccuracy and incomplete attribute data.

These issues must be addressed to ensure capital investments are targeted to the areas of highest risk, current regulatory obligations are met, and delivery efficiencies can be realised.

The estimated costs for this project are based on assumptions about the activities, materials, labour and volumes required to achieve the program's objectives. Western Power welcomes a review of this documentation as suggested by GHD in its review of GBA's report.[139] The business case attached at Appendix Y outlines the scope and activities so that it can be properly against other program scope and cost estimates.

6.3.4.2 Network control services

The Authority has removed $66 million of costs associated with AA3 network control services as it *is not satisfied that it meets the test in section 6.40 of the Access Code and that Western Power should seek to recover any efficient operating expenditure it incurs on network control services through section 6.76 of the Access Code.*[140] This is on the basis that:

- forecasting the uncertainties involved in forecasting these costs are much higher than other operating cost line items[141]
- the forecasting risk falls entirely on customers, as Western Power can treat any under-expenditure as an efficiency gain and carry it forward[142]
- Western Power has indicated that it will seek to recover these costs under section 6.76 of the Access Code[143]

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[137] Page 6, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.
[138] Page B17, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[139] Page 7, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.
[140] Paragraphs 279-282, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[141] Paragraph 279, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[142] Paragraph 280, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[143] Paragraph 280, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Western Power does not agree with removal of the costs associated with network support in the areas of Bremer Bay, Ravensthorpe, Geraldton, Eastern Goldfields, Pinjar and Albany from the AA3 expenditure forecasts as discussed in the following sections.

Certainty of operating expenditure forecasts

The certainty of costs is not a determining factor in whether Western Power's forecast non-capital costs comply with the Access Code. The relevant information to be taken into account is:

- Western Power has and will continue to efficiently incur costs for procuring network control services[144]
    - distribution network control services at Bremer Bay and Ravensthorpe have been in place over the AA2 period, these existing contracts will continue into AA3
    - transmission network control services will be incurred in AA3, without which, service to customers in the Geraldton, Eastern Goldfields, Pinjar and Albany regions will not be maintained
- the use of these network control services is efficient – Western Power's options analysis has determined the use of a network control services solution to address these specific network constraints provides a higher cost benefit outcome compared to the required capital investment
- the level of costs incurred will be efficient as Western Power has market tested these costs
    - distribution network control services are a continuation of the existing service, Western Power therefore has actual cost data to underpin these forecasts
    - Western Power's September 2011 submission clearly outlined the process and key assumptions which underpinned the forecasts for transmission network controls services[145]

In addition, Western Power has recently completed a competitive tender process to procure network control services at Albany. The tender process confirms the forecast expenditure for transmission network control services included in the September 2011 submission was reasonable.

Western Power has adjusted the expenditure profile over the AA3 period as a result of this more up-to-date information.

Scope for rewards under the GSM

Western Power recognises the Authority's concern that including network control services in the forecast against which the GSM is assessed may result in a windfall gain where it is determined that it is more efficient to reduce or not pursue this option.

Western Power accepts that it would be appropriate to exclude network control services from calculation of the GSM to remove the incentive for any under-expenditure. Network control services are a substitute for capital investment like other demand management activities also excluded from the GSM. Western Power has revised its GSM proposal to incorporate this change (see section 13.1).

[144] In November 2010, the IMO approved a change to clause 5.1.2 of the Wholesale Electricity Market Rules which transferred responsibility for the procurement of network control services from the IMO to Western Power. Available at: http://www.imowa.com.au/f2915,1310692/RC_2010_11_Final_Rule_Change_Report.pdf

[145] This was provided to the Authority in confidential appendix G.1 – AA3 Network Control Services Requirements and included the maximum reserve capacity price, energy price (based on liquid fuel costs) and the prices paid by the Independent Market Operator.

Application of Section 6.76 of the Access Code

The Authority considers that Western Power should seek to recover any efficient operating expenditure for network control services through section 6.76 of the Access Code.[146]

Western Power did not state that it could recover its costs under section 6.76 of the Access Code as it recognises that section 6.76:

- does not provide recovery of forecast network control service costs
- does not allow retrospective recovery of actual network control service costs

Section 6.76 provides for a binding ex-ante assessment of whether forecast non-capital expenditure meets the Access Code requirements for recovery in the next access arrangement period. It does not provide for ex-post recovery of operating costs or in-period variation of an approved access arrangement to provide cost recovery unless these are associated with a trigger event.

In its submission, Western Power advised that:

> *Under clause 6.76 of the Access Code, Western Power may at any time request the ERA to determine whether non-capital costs meet the efficiency tests in the Access Code. The ERA must make and publish a determination within a reasonable time if the non-capital costs are equal to or greater than $1.5 million (CPI adjusted annually). In considering whether to approve non-capital costs, the ERA must follow the public consultation process outlined in the Access Code.*[147]

The purpose of this paragraph was to contrast the regulatory approval process for operating expenditure with the Regulatory Test for capital expenditure. Western Power did not state that clause 6.76 of the Access Code could be used to recover over-expenditure on network control services.

The Access Code treats non-capital costs differently to capital costs. Western Power can add capital expenditure to the regulated capital base at the beginning of the access arrangement period. If the IAM applies, then it is able to recover all costs incurred during the current access arrangement period. If it does not apply and the capital expenditure has not been forecast, Western Power will be able to add the efficient capital expenditure to the asset base but will forgo the financing costs in the current period. GHD has agreed with Western Power's treatment of these costs, stating that: *It is recommended that the principles underpinning the accepted NCS process are stressed, and as a legitimate alternative to conventional network CAPEX expansion, it only needs to pass the New Facilities Investment Test (NFIT) to be accepted and implemented into the network.*[148]

Impact of the Authority not allowing network control services expenditure

Not allowing expenditure for these services may lead to a number of network control services proposed for the AA3 period being withdrawn. This is likely to lead to reduced service performance for customers in areas where network control services are either proposed or currently being employed.

The alternative to procuring the network control services proposed for the AA3 is to begin augmenting the network through major capital investment. It is expected that the network control services currently in operation and those forecast for AA3 are allowing for the deferral of $443 million of capital expenditure.[149] It should be noted that the planning and construction of the capital investment required to address the network constraints will, in some cases take

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[146] Paragraph 281, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[147] Page 1, *Access Arrangement Supplementary for the period 1 July 2012 to 30 June 2017*; Appendix G.1 – AA3 Network Control Services Requirements, Western Power, September 2011
[148] Page 12, *Report for Review of ERA Technical Consultants Report*, GHD, 28 May 2012.
[149] For additional capital investments associated with Eastern Goldfields, Bremer Bay, Ravensthorpe and partial costs for Albany which are not already included in the AA3 capital expenditure forecasts.

up to five years, during which, without network support affected areas will see reduced performance.

Failure by the Authority to provide certainty of cost recovery for network control services will remove any incentive for Western Power to consider alternative options[150] as required under the Access Code requirements (sections 9.3, 9.4 and 6.41). This is inconsistent with the Access Code objective of promoting economically efficient investment in and operation of and use of networks and services of networks and the regulatory test objective to ensure service providers consider alternative options prior to committing to major augmentations.

6.3.4.3 Transmission line removal

The Authority considers that Western Power provided an *excessive estimate of the costs required* for transmission line decommissioning and removal. This conclusion was based on the Authority's technical consultant's benchmarking, which involved comparing the proposed expenditure with the forecast decommissioning and line removal costs associated with the Mid West Energy Project.

Western Power does not consider this benchmarking to be reasonable, as the Mid West Energy Project line decommissioning is not a relevant benchmark for projects that are generally undertaken because:

- the line construct is different
- it is a major project and benefits from synergies with other capital expenditure
- the vegetation costs are much lower due to the sparse and low vegetation types
- environmental mitigation components are excluded

Western Power considers its original unit cost estimates proposed in the September 2011 submission are appropriate for estimating an average decommissioning project.

Western Power initially proposed $6.9 million expenditure to decommission 63 km of transmission line over the AA3 period. This involved the removal of around 400 structures on 7 transmission lines and 44 poles in substations.

However, consideration of new information, including the 2011 peak demand forecast, has led Western Power to update its transmission line decommissioning and removal program.

Western Power will now remove 179 structures on 4 transmission lines and 21 poles at substations at a cost of $2.9 million. This cost estimate has been calculated based on the costs of a recent, average project - the Cannington Marriot Road decommissioning.

6.3.4.4 Compliance with 'Type 1 obligations'

Western Power is required to achieve 100% compliance with 'Type 1 obligations' under the Code of Conduct for the Supply of Electricity to Small Use Customers (Small Use Customers Code). It specifically requires that:

- a distributor must not disconnect a customer's supply address where there is an unresolved complaint relating to the disconnection, after 3pm Monday to Thursday; after 12 noon Friday; on Saturday, Sunday, public holiday or a business day before a public holiday (clause 7.6)
- a distributor must register a customer's supply address as a life support equipment address (clause 7.7(2)(a))
- a distributor must not disconnect a customer's premises listed as a life support equipment address for failure to pay a bill (clause 7.7(2)(b))

[150] Alternative options is defined under the Access Code as: *in relation to a major augmentation, means alternatives to part or all of the major augmentation, including demand-side management and generation solutions (such as distributed generation), either instead of or in combination with network augmentation*.

- distributor must provide 3 days written notice of any planned outage affecting a customer whose premises are listed as a life support equipment address (clause 7.7(2)(c))
- a distributor must create and maintain a Priority Restoration Register (8.3(1))
- a distributor must ensure its Priority Restoration Register complies with any criteria determined by the Minister (clause 8.3 (2))
- if a pre-payment meter customer notifies their retailer that a person residing at the supply address requires life support equipment, a distributor must revert the pre-payment meter to a standard meter within the prescribed timeframes (clause 9.6(3)).

Since September 2011, a number of breaches of Western Power's 'type 1 obligations' have occurred. This has highlighted a number of improvements in current processes and systems that must be achieved in order to prevent further breaches from occurring. There are currently nearly 3,800 customers registered with life support equipment in the Western Power Network.

In the AA3 period, Western Power will spend $29 million to provide improved customer services, network operation and network access including:

- establishing a dedicated team to improve the management of life support equipment customer data and outage notifications. It will establish a field visit processes to validate new life saving equipment at customers' residence to reduce the likelihood of these customers being inadvertently impacted by a planned outage. It will also ensure that each customer with life support equipment is notified in person of planned outages (this impacts approximately 40% of 8400 planned outages annually).
- addressing the planned outage and disconnection requirements through the creation of a dedicated team of seven people to independently review and have control over all distribution access requests. Western Power will introduce of real-time system access for Western Power's switching operators to identify any new life saving equipment customers that may have been added to the register just prior to a planned outage occurring. Recently Western Power has experienced hundreds of changes to the status of customers with registered life support equipment.

  This will require the low voltage network connectivity to be confirmed for each new customer with life support equipment, and for this to be reconfirmed prior to any planned outage. Mapping of the complete SWIN low voltage network connectivity will also be required for input into the low voltage network management system.
- introducing real-time 24x7 central management to allow for improved monitoring and reporting in the low voltage network. This will require the creation of three day control desks and one night control desk requiring 14 controllers and three system support personnel. A process for keeping the low voltage network model up to date for network reconfiguration and extensions will also be introduced.

This program of work is treated as a non-recurrent program for the AA3 period as it is a specific program of work designed to achieve compliance. Once the introduction of the new management arrangements are in place and become business as usual, it is expected that the costs associated with this program of work will become stable and will be captured as a recurrent network cost in subsequent access arrangement periods.

6.3.4.5 Streetlight switchwire program

Western Power has increased its forecast expenditure to accelerate the streetlight switchwire program to address the serious safety risk associated with these assets. The significant risk was highlighted by a fatal incident that occurred in 2011(see section 8.2.2.3).

Western Power has also assessed its capitalisation treatment for this program and determined that a portion of costs for the increased program should be categorised as operating expenditure.

The labour costs associated with the decommissioning and removal of switchwires and control boxes under the program are categorised as operational expenditure. The labour and material costs associated with installation of new LV mains and PE cells are categorised as capital expenditure (see section 8.2.2.3). This treatment is consistent with the Australian Accounting Standards, AASB116 – Property, Plant and Equipment.

This change in accounting treatment has increased operating expenditure by $13 million (where it otherwise would be captured as capital expenditure).

6.3.4.6 Impact of the Clean Energy Future Package

The key legislation of the Australian Government's Clean Energy Package that affects Western Power's fuel costs and subsequently network control services operating expenditure is the:

- Clean Energy (Fuel Tax Legislation Amendment) Act 2011 – which reduces the business fuel tax credit entitlement of non exempted industries to provide an equivalent carbon price applying to the use of liquid and gaseous transport fuel
- Clean Energy (Excise Tariff Legislation Amendment) Act 2011 – which imposes an equivalent carbon price on non-transport gaseous fuels through excise tariffs
- Clean Energy (Customers Tariff Amendment) Act 2011 – which imposes an equivalent carbon price on non-transport gaseous fuels through custom tariffs

Table 16 outlines the prescribed rate per tonne of carbon dioxide equivalent under the legislation. This has been applied to Western Power's forecast generation fuel consumption for the AA3 period.

Table 16: Prescribed rate per tonne of CO2-e[151]

	price per tonne of CO2-e ($ real at 30 June 2012)
2012/13	22.28
2013/14	22.83
2014/15	23.41
2015/16	26.08
2016/17	27.14

The increase in fuel costs associated with the introduction of the Clean Energy Future package will increase Western Power's network control services expenditure by $0.21 million over the AA3 period. The Clean Energy Future Package also affects Western Power's recurring operating expenditure (see section 6.3.2) and transmission asset replacement capital expenditure (see section 8.2.1.4).

[151] *Strong growth, low population: modelling a carbon price.* Australian Government Treasury, September 2011. These values are provided in nominal dollars in the legislation. They have been converted to real $ at 30 June 2012.

6.4 Corporate operating expenditure

The Authority accepts Western Power's business support costs and energy safety levy, and required amendments to insurance costs and rates and taxes. Western Power has amended forecast corporate operating expenditure forecasts to reflect the Authority's draft decision. Western Power has also incorporated expenditure for new initiatives identified since the September 2011 submission and an allocation of shared costs to System Management (Markets).

The revised AA3 corporate operating expenditure forecast is $576 million. This is $8 million less than Western Power's September 2011 submission and $38 million greater than the Authority's draft decision.

These amendments are summarised in Table 17 and discussed in the following sections.

Table 17: New corporate expenditure adjustments

$ million real at 30 June 2012	Initial Submission	Revised submission	Variance	Comments
Business support	383.5	4399.9	16.4	New initiatives and allocation of System Management (Markets) costs
Insurance	137.4	118.9	-18.5	Accept Authority's Draft Decision
Rates and taxes	39.9	36.7	-3.2	Amend
Energy safety levy	23.2	20.6	-2.6	Removal of labour cost escalation
Total	**584.0**	**576.1**	**-7.9**	

6.4.1 Business support

The Authority accepts Western Power's AA3 business support expenditure forecasts but noted that the expenditure, *which is mostly fixed in nature, should provide scope for Western Power to achieve efficiencies.*[152]

Western Power has identified a number of new business support initiatives that are required in response to the recent Parliamentary Inquiry[153] into electricity transmission and distribution management by Western Power. These initiatives are the:

- people and culture plan
- public awareness campaign
- 'Future Energy Alliance' marketing campaign

The business support operating costs associated with these programs are included in revised forecast for the AA3 period.

Western Power has also revised its business support operating expenditure to reflect a revised allocation of costs to the ring-fenced System Management (Markets).

[152] Paragraph 296, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[153] Public Administration Committee – Inquiry into Electricity Transmission and Distribution Management by Western Power and Horizon Power.

6.4.1.1 People and culture plan

Western Power is commencing a two-year, $4.1 million people and culture program in response to the third recommendation of the Parliamentary Inquiry, which requires a further inquiry into the structure, culture and operations of Western Power since disaggregation[154].

The program will engage Western Power's staff through an extensive program of development and training to improve business performance and culture. To progress this initiative, Western Power will develop policies, processes and systems to track and report on progress in workforce capability.

Western Power expects the following benefits to be derived from the people and culture plan:

- improved business preparedness to deliver outcomes through improved culture, learning and development, workforce planning and efficient HR processes
- increased attraction and retention of employees due to improved culture, leadership, learning and development, being a preferred employer
- increased employee morale and job satisfaction due to improved culture, leadership, learning and development
- reduced unplanned absenteeism due to improved culture and learning and development

The costs include changes to business processes and systems, licence fees and both internal and external labour to implement the program (including IT support, technical expertise, project management and change management facilitation).

6.4.1.2 Public awareness campaign

Western Power recognises the need to do more in relation to the potential impact on public safety of its assets. Western Power continues to review its work program to ensure that the maximum reduction in public safety risk is achieved and has increased the programs that have the highest impact in the AA3 period.

To complement the work program and recognise that assets may become a danger to the public as a result of storms or third party damage, Western Power proposes to undertake a public awareness campaign to increase the community's understanding of the potential dangers of Western Power's assets. The program's aim is to ensure the community has the information it needs to stay safe around Western Power's assets.

The $3.1 million initiative will include a 2 year public campaign outlining safe behaviours and actions when coming across or being exposed to assets, as well as being proactive about reporting incidents or conditions that may give rise to public safety incidents.

6.4.1.3 'Future Energy Alliance' marketing campaign

In December 2010, Western Power was directed by the Minister for Energy to establish the Future Energy Alliance, in partnership with Synergy.

The key objectives of the Alliance are to:

- work with the community to build awareness and encourage behavioural change to create an energy efficient WA
- present a coordinated and consistent approach across all GTE's with respect to energy efficiency

A key initiative of the Alliance is its marketing campaign, which is designed to change consumer behaviour to become more energy efficient and reduce growth in peak demand. In

[154] Public Administration Committee – Inquiry into Electricity Transmission and Distribution Management by Western Power and Horizon Power.

the longer term this will reduce the capital expenditure required to meet continuing growth in peak demand.

The continuity of the Alliance is considered by June each year. Forecast expenditure for the Alliance was not included in Western Power's September 2011 submission due to uncertainty of whether the Alliance would continue during the AA3 period.

Western Power has not been advised that the Future Energy Alliance will cease in 2012/13. Western Power has therefore incorporated forecast expenditure of $6 million dollars into its revised expenditure submission, to cover proposed Alliance campaigns and initiatives during the AA3 period.

6.4.1.4 Implementation of Cost Sharing Methodology with System Management (Markets)

Western Power has revised the corporate costs associated with providing services to System Management (Markets). Western Power has estimated, using a cost sharing methodology (see appendix E) that these costs are $4.6 million. Western Power's business support operating expenditure for the AA3 period will be reduced by this amount.

6.4.2 Insurance

Western Power had previously identified an error in the forecast for insurance costs and notified the Authority of this error.[155] The Authority has reduced forecast insurance costs to account for this error but has otherwise noted that the forecast appeared reasonable[156].

Western Power has removed $15 million from the AA3 insurance expenditure forecast to correct the error which consisted of including workers' compensation costs in the insurance line item as well as a payroll on-cost.

6.4.3 Rates and taxes

The Authority has reduced AA3 rates and taxes by $2 million on advice from its technical consultant discounting Western Power's method for forecasting fringe benefits tax and applying a flat 2% growth rate.

Western Power has not accepted this forecasting method but has amended the fringe benefits tax forecast. In addition, Western Power has revised the rates and taxes forecast to correct an error in the September 2011 submission which has previously been notified to the Authority.

6.4.3.1 Fringe benefits tax

Western Power used the approved works program as a proxy for growth in the costs of the fringe benefit tax. The Authority's technical consultant stated Western Power's fringe benefit tax forecast *assumed an increase in headcount of around 30 per cent … which GBA considers unlikely* in particular, it did *not believe that the value of the approved works program is a valid proxy for headcount as much of the program is materials and much of the labour content is outsourced*[157].

Western Power has received its 2011/12 fringe benefit liability statement after the initial submission, indicating that its actual liabilities are $0.3 million more than forecast. Western Power has reset its base year to reflect this actual liability. Western Power does not accept the approach proposed by the Authority's technical consultant of adopting a 2% flat growth

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[155] *Response to GB54: Rates and Taxes and Response to GB56: Insurance*, provided to the Authority on 13 January 2012 and 6 January respectively.
[156] Paragraph 298, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[157] Paragraph 301, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

rate for these costs. Western Power has amended the forecast for fringe benefits tax based on the average annual rate of change in labour costs, mostly offsetting the increase registered in 2011/12. The resulting reforecast represents an increase of $0.5 million over AA3.

6.4.3.2 Correction of errors

Western Power's initial rates and taxes forecast included $29.1 million for land tax, local government rates equivalent, the fire and emergency services levy and water and shire rates.

Western Power previously advised the Authority that this estimate did not reflect the base year expenditure for 2010/11. The forecast for rates and taxes has been revised to reflect the correct base year of 2010/11, which results in a reduction of the land tax forecast of $0.76 million per year.

The revised rates and taxes are included in Table 18.

Table 18: Rates and taxes forecast expenditure

$ million real at June 2012	AA3 Submission	Draft Decision	Proposed Response
Rates & Taxes (excluding fringe benefits tax)	31.8	31.1	28.0
Fringe Benefits Tax	8.2	6.2	8.7
Total rates and taxes expenditure	**40.0**	**37.3**	**36.7**

6.5 Indirect costs

The Authority has reduced Western Power's indirect cost forecasts by 13.7% ($131.7 million) because the Authority's technical consultant has advised that:

- it considers there is an unexplained 17.3% between the base year of 2010/11 and the first year of AA3, 2012/13[158]
- *indirect costs, which should be largely fixed, should not be escalated by more than 0.63 per cent (the network operations net growth escalation factor)*[159]

Western Power does not accept the reduction. However, Western Power has revised forecast indirect costs as follows:

- adopted 2011/12 as the base year for its forecast
- reduced the rate of escalation applied to forward looking costs
- made further reductions to Western Power's forecast costs incorporating anticipated efficiencies to be realised from the Strategic Program of works

The 2011/12 estimate reflects the best forecast of efficient forward looking costs. Western Power has forecast the indirect cost estimate for 2011/12 based on the actual outcomes to March 2012 and adopted 2011/12 as the base year for its forecast. The 2011/12 estimate, including actual year to March costs and forward estimates for April to June are shown in Table 19.

[158] Paragraph 291, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[159] Paragraph 292, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Table 19: 2011/12 indirect costs: year to date and estimates for April to June, $ million real at 30 June 2012

	Actual to March 2012	Apr	May	Jun	Total
Network	20.7	2.2	2.4	2.6	28.0
Operations	41.2	4.5	4.6	4.7	54.9
Corporate	67.8	8.3	9.8	11.3	97.1
Total	129.7	14.9	16.7	18.6	180.0

In applying the reduction, the Authority has cited Geoff Brown & Associates recommendation that indirect costs should be largely fixed. Indirect costs are largely fixed. Western Power has amended the escalated escalation of indirect costs across AA3 to escalate only the variable portion of its indirect forecast with the annual movement in the Approved Works Program.

The revised indirect cost forecast is $881.6 million which is $81.6 million less than the September 2011 submission and $50.2 million more than the Authority's Draft Decision, as shown in Table 20. The amended amount includes efficiencies indentified from the SPOW program. $52.8 million in efficiencies from SPOW were incorporated in the September 2011 submission and an additional $21.1 million has been included in the revised forecast.

Table 20: AA3 indirect costs forecasts, $ million real at 30 June 2012

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Initial submission	187.3	187.4	193.1	199.2	196.2	963.2
Revised proposal	176.7	176.7	175.8	176.3	176.1	881.6

6.6 Efficiency adjustments

The Authority applies an across-the-board compounding efficiency dividend of 2% per year, to Western Power's already reduced operating expenditure. The Authority adopts this approach based on:

- its assumption that Western Power "have made no provision for progressively increasing the efficiency of [its] operating expenditure"[160]
- an expectation that Western Power's investment in modern and enhanced IT systems "should increase efficiencies right across the business"[161]
- its view that Western Power's business support expenditure "which is mostly fixed in nature should provide scope for Western Power to achieve efficiencies"[162]
- benchmarking undertaken by their technical consultants which "indicated that there was scope for Western Power to achieve efficiency gains to improve its performance to the levels of its peers in Australia"[163]
- the Western Australian State Government budget which requires Western Power to "implement an efficiency dividend of 5 per cent each year from 2011/12 to 2014/15"[164]

[160] Paragraph 304, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[161] Paragraph 312, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[162] Paragraph 314, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[163] Paragraph 309, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Western Power accepts that there will be efficiencies gained through the implementation of SPOW and has revised its operating expenditure forecasts accordingly. While these will primarily relate to those costs associated with Western Power's capital investment program and indirect costs associated with managing the works program, Western Power has also incorporated $7 million of efficiencies in operating expenditure over the 5 years.

However, Western Power does not accept the Authority's application of a 2% compounding annual efficiency dividend to total operating expenditure. Western Power considers this adjustment is unreasonable because it will reduce operating costs below those which would be incurred by a service provider efficiently minimising costs and is therefore inconsistent with the Access Code[165]. This position is supported by Western Power's independent technical consultant[166] and economic consultant[167].

An assessment of potential efficiencies should include an assessment of what can be achieved, including the various components and activities that make up the costs as well as the extent to which costs are controllable.

Western Power considers that the Authority has adopted its technical consultant's advice in a manner which:

- disregards the advice that the expected efficiencies should not be applied to the first year
- double counts expected efficiencies through the adoption of historical growth rates and economies of scale
- does not take into account the limitations of the analysis underpinning the advice or attempt to adjust for the limitations
- accepts the use of benchmarking as a singular and reliable methodology to forecast efficient costs despite practitioners elsewhere rejecting this approach
- the cumulative efficiency factor of 2% per annum applied to total operating costs is the highest imposed in Australia since the year 2001
- presents no analysis to determine that the efficiency expected is achievable

These issues are outlined further in the following sections and discussed in detail in Appendix J.

Western Power's response to this adjustment is discussed in the following sections.

6.6.1.1 Efficiencies incorporated in Western Power's forecasts

Western Power's revised forecast is based on efficient costs.

Western Power introduced a number of initiatives over AA1 and AA2 to optimise planned capital and operating activities improving Western Power's efficiency. In the AA2 period, Western Power incurred a level of operating expenditure lower than that determined as efficient in its AA2 final decision.[168].

[164] Paragraph 316, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[165] The Access Code does not require the target revenue to be set at the costs of a service provider at "best industry practice' or at the "efficiency frontier".

[166] GHD note that "a 2% efficiency dividend is predicated on the overall condition of the network being better than it is currently" (Section 3.5, *Report for Review of ERA Technical Consultants Report*, GHD 28 May 2012).

[167] Wedgewood White note that in their opinion "a 9.6% real reduction in total operating costs over a 5-year regulatory period is unlikely to be achievable" and " the ERA has not demonstrated that its proposed efficiency adjustment is consistent with the Code requirements" (Section 6.2, *Review of Operating Expenditure Efficiency Adjustment,* Wedgewood White Ltd, 23 May 2012).

[168] Paragraph 182, *[AA2] Further Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 24 December 2009.

Under the scale escalation approach, the following efficiencies have been built into the base year expenditure:

- competitive market tendering of 90% of planned activities, which is "prima facie efficient (having been subject to competitive tender and therefore include market assessment of both current efficient costs and achievable efficiencies over the contract period); and not controllable by the regulated business in the short term"[169]
- improved works packaging through Western Power's delivery strategy[170] including geographical and work type bundling
- improved contract negotiation including introduction of specific cost savings clauses based on guaranteed work levels and sliding scale price lists linked to variations in volumes

Western Power has provided examples as to how these efficiencies are reflected in the base year for the seven largest programs of expenditure in Appendix I.2.

Furthermore, Western Power has reviewed the Authority's proposed recurrent cost adjustments and compared the expenditure in these activities to the latest view of the 2011/12 work program and forecast activities for the AA3 period. Based on this analysis, Western Power accepts reductions of $29 million ($5.8 million reduction in base costs) where expenditure at 2010/11 levels is not expected to continue (see section 6.3).

6.6.1.2 Expected efficiency gains

Justifying its application of the 2% efficiency on total operating expenditure, the Authority states that "*Western Power's operating expenditure forecasts have made no provision for progressively increasing the efficiency of Western Power's operating expenditure*".[171]

Western Power notes that the Authority applies an assumed rate of efficiency that is well in excess of regulatory precedent. Western Power's economic consultant notes that *to the best of my knowledge, a cumulative efficiency factor of 2% applied to total operating costs is the highest imposed in Australia since the year 2001. In the period from 2000 to 2004 when some regulators did impose efficiency improvements of up to 2% p.a., these efficiencies were generally not achieved.* [172]

Strategic Program of Works

The Authority cites the expected efficiency savings arising from the strategic program of works (SPOW), stating:

> *GBA notes that the significant proposed capital investment by Western Power in modern and enhanced IT under the Strategic Program of Works (SPOW) program was approved by the Western Power Board on the basis of the operating efficiencies it will generate, yet none of the identified efficiencies expected in the third access arrangement period has been captured in Western Power's operating expenditure forecast.*[173]

However, GBA has not provided an analysis of the expected efficiencies attributable to SPOW.

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[169] Section 4.4, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.
[170] Page 65 *Access Arrangement Information for the period 1 July 2012 to 30 June 2017*; AA3 Works Delivery Strategy, Western Power, September 2011.
[171] Paragraph 304, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[172] Section 6.2, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.
[173] Paragraph 310, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.

Western Power does not accept that efficiencies generated by the implementation of SPOW programs were not captured in its operating expenditure forecasts. Western Power included $38.6 million of identified efficiencies that were built into its AA3 forecast. Western Power has reviewed the SPOW business cases again to ensure that all efficiencies have been included and identified a further $39 million which have now been incorporated into the revised AA3 expenditure forecasts. Table 21 details the benefits arising from SPOW projects.

Table 21: Benefits / efficiencies from SPOW projects

$ million real at 30 June 2012	Capex efficiencies	Opex efficiencies	Indirect cost efficiencies	Total
Integrated Solution for Asset Management	22.3	4.8	34.6	61.8
Mobile Workforce Solutions	1.5	-	8.8	10.3
Enhanced Planning and Works Management	18.8	-	14.9	33.7
Equipment and works management data warehouse	4.5	-	3.0	7.5
Ellipse upgrade	-	-	5.9	5.9
NetCIS	-	1.0	0.2	1.2
Ariba	6.9	1.7	6.6	15.3
Total	**54.1**	**7.5**	**74**	**135.6**

Western Power has revised its AA3 forecasts to account for $39.4 million forecast efficiencies derived from its most recent review that were not reflected in the September 2011 submission. Forecast expenditure has been reduced for the regulatory categories that receive the anticipated benefits of the specific SPOW programs.

The efficiencies driven by the SPOW program across AA3 represent 96% of the total AA2 SPOW capital spend, with additional benefits expected to be realised in AA4.

Business support divisional costs

The Authority also refers to the technical consultant's review of Western Power's business support operating expenditure in its application of the 2% efficiency dividend. Geoff Brown and Associates, state that:

> *GBA has noted that the average annual expenditure of $71.6 million for the third access arrangement period is only 2.6 per cent higher than the average annual current access arrangement expenditure of $69.7 million. On this basis, we accept that the AA3 forecast is reasonable, notwithstanding the magnitude of the expenditure in this line item.*[174]

However, the Authority believes that *"this expenditure, which is mostly fixed in nature, should provide scope for Western Power to achieve efficiencies."*[175]

Given that Western Power's business support operating expenditure is largely fixed[176], Western Power would expect that its ability to achieve efficiencies is minimal. Western Power maintains its position in its September submission, that the increase in business support costs over the AA3 period is primarily associated with the forecast increase in labour costs. Without the impact of real cost escalation, Western Power's revised forecasts increase on

[174] Section 10.8.1, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[175] Paragraph 296, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[176] The changes in expenditure are associated with increased staffing to support a higher level of recruitment and increased business planning.

average 1.2% per annum. The majority of this increase is the impact of the new initiatives undertaken in the AA3 period (see section 6.4.1).

Western Power has incorporated identified efficiencies from investment in IT systems in its forecasts. It does not expect to achieve efficiencies in business support divisional operating expenditure because it is largely fixed. All expenditure in this category is as a result of either Western Power's requirement to meet its statutory obligations or the non-discretionary costs of operating the business. As this expenditure is externally driven, Western Power is unable to recognise efficiencies without risking its ability to comply with its obligations under the Access Code.

Given that the new expenditure driving the increase in business support costs is considered reasonable, Western Power considers it unreasonable to use the increase in business support costs to justify a 2% across-the-board annual reduction.

6.6.1.3 The Authority's use of benchmarking analysis

The Authority has indicated that it relied upon benchmarking analysis performed by its technical consultants in deciding to impose the 2% annual compounding efficiency factor on Western Power's already reduced cost operating cost base.[177] The Authority has declined to provide the quantitative data used by their consultant.[178] This has limited Western Power's ability to fully understand the Authority's technical consultant's approach and analysis. Western Power undertook its own analysis in the September 2011 submission which supported that Western Power is in line with its Australian peers.

Western Power sought a technical review of the Authority's benchmarking by an independent economic consultant. The review found states that it does *"not consider GBA's analysis a robust justification for concluding that Western Power could achieve real operating efficiencies of 2% p.a. compounding for 5 years."*[179]

Shortcomings of benchmarking

The comparison of the relative efficiency of cross jurisdictional utilities through benchmarking is widely misused. In its current benchmarking inquiry, the Productivity Commission commented on its application by utility regulators:

> *'Benchmarking' is applied by utility regulators across the world, although there are many complexities in defining what it is, what indicators should be used and how it can be applied in practice.*[180]

It has also cautioned that:

> *It is particularly important in benchmarking to ensure 'like with like' comparisons between network businesses. For example, costs are higher for network businesses with few customers per line length. Ignoring this could lead to such businesses being categorised as inefficient compared with businesses with high customer densities. A network provider under-rewarded using the wrong benchmark would not make efficient investments or other decisions, and could become insolvent, indicating the risks of badly configured benchmarks.*[181]

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[177] Paragraph 309, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[178] Western Power requested this data on the 30 March 2012, the Authority responded on 3 April 2012, noting *GBA has provided references to the source data it used which should be adequate to enable Western Power to develop its own view about the benchmarks*. The sources referenced do not adequately outline how GBA has amended the data which is inconsistent with Western Power's analysis of this same data.

[179] Section 4.2, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.

[180] Page 3, *Electricity Network Regulation*, Productivity Commission, February 2012.

[181] Pages 11-12, *Electricity Network Regulation*, Productivity Commission, February 2012.

> *A potentially important check on any benchmarking exercise— even one that has attempted to control for some variations in the operating environments of distributors — is to distinguish between rival explanations for differences in performance and inefficiency.*[182]

The Australian Energy Regulator (AER) has also identified limitations in the use of benchmarking in assessing an efficient level of expenditure:

> *Benchmarking is not a substitute for rigorous analysis and the exercise of judgment to determine expenditure allowances for a network business and cannot be used in a mechanistic fashion to directly determine expenditure allowances.*[183]
>
> *While benchmarking is a useful tool in distribution determinations, the AER is aware of its limitations which include the sensitivity of results to the adopted methods, errors in assumptions used to normalise the data, and errors in selection of measured inputs or outputs. The AER also pointed out that the weight placed on benchmarking depends on the consistency and quality of input data.*[184]
>
> *Caution should however be used with .. analysis of different jurisdictions as the data used has not been corrected for differences that may exist in the regulatory environment, asset classifications, network maturity and geographical factors.*[185]

Western Power does not accept that the Authority's application of the 2% efficiency dividend is based on sound reasoning. Their technical consultant has not accounted for many of the known problems with cross-jurisdictional benchmarking. This position is supported by Western Power's independent economic consultant who states that *GBA's analysis cannot, by itself, demonstrate that a business is inefficient nor provide guidance regarding the magnitude of potential efficiency gains.*[186] Nevertheless, the Authority has placed substantial weight on this analysis when justifying the application of a 2% efficiency dividend to Western Power's total operating expenditure.

The Authority's benchmarking approach

Geoff Brown and Associates has benchmarked Western Power's 2009/10 operating expenditure with the operating expenditure incurred by the transmission and distribution businesses in Queensland, New South Wales, Victoria, South Australia and Tasmania. It has aggregated operating expenditure "*due to the definitional issues with regards to transmission and distribution expenditure".*[187] It has also has used three normalisers – operating expenditure per km of line length, operating expenditure per customer and operating expenditure as a percentage of the regulated asset base.

GBA has stated that:

> *We acknowledge that our analysis did not use a fully consistent data set and that this means that the results should be treated with caution. Nevertheless, we are confident that the benchmarking is sufficiently accurate to be indicative of the relative efficiency of the electricity network operation in all the states considered.*[188]

Despite recognising the flaws in its approach, the Authority's technical consultant has concluded from the data, as it relates to operating expenditure, that:

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182 Page 18, *Electricity Network Regulation*, Productivity Commission, February 2012.
183 Page 13, *AER submission to the Productivity Commission Inquiry into Electricity Network Regulation*, April 2012.
184 Page 94, *Victorian electricity distribution network service providers, Distribution determination 2011-2015, Final decision – appendices*, Australian Energy Regulator, October 2010.
185 Page 115, *Victorian electricity distribution network service providers, Distribution determination 2011-2015, Final decision – appendices*, Australian Energy Regulator, October 2010.
186 Section 5.2.3, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.
187 Paragraph 229, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
188 Section 10.3.1.2, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

> *Western Power's comparative performance against the other benchmarks is not impressive and does indicate that efficiency gains are available.*[189]
>
> *It is difficult to assess the amount of efficiency gains that could potentially be captured during AA3 but, from what we have seen, an annual efficiency target of around 2% should be readily achieved.*[190]

Western Power does not consider that the Authority's technical consultant has appropriately recognised and corrected for the differences between Western Power and utilities in other jurisdictions.

Furthermore, Western Power's economic consultant, Wedgewood White discusses the bias introduced by the Authority's technical consultant by benchmarking a single year, stating that:

> *GBA's benchmarks are for a single year of expenditure. In many cases operating and maintenance expenses change significantly over the period of a few years. For example, during times of high growth, businesses sometimes transfer resources into customer connection activity and network extensions and out of routine maintenance……. One-off maintenance programs (for example safety related equipment replacement) may also distort expenditures in any given year.*[191]
>
> *… it is necessary to examine several years of expenditure to assess the "normal" level of expenditure before any conclusions can be drawn regarding the efficient level of expenditure.*[192]

The effect of these shortcomings is discussed in the following section.

The Authority's benchmarking outcomes

The Authority's forecast 2% efficiency target together with the other required amendments result in Western Power's 2016/17 operating expenditure being only 5.3% higher in real terms than in 2010/11. This is significantly below the real increases in operating expenditure that are being experienced in other Australian jurisdictions.

Table 22 below summarises the forecast real operating expenditure increases in the most recent revenue determinations for other jurisdictions. It specifically compares the penultimate year in the previous regulatory period to the last year in the following regulatory period, and excludes the impact of appeals, the impact of a carbon price and the Victorian land tax for easements.

Table 22: Comparative analysis of approved increases in operating expenditure

State	Transmission business	Real increase in operating expenditure	Distribution business	Real increase in operating expenditure
Queensland	Powerlink	50.9%	Energex	6.2%
			Ergon Energy	6.7%
New South Wales	Transgrid	30.4%	Ausgrid	17.1%
			Endeavour Energy	24.5%
			Essential Energy	30.7%

[189] Section 10.3.1.2, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[190] Section 10.11, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.
[191] Section 5.2.1, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.
[192] Section 5.2.1, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.

State	Transmission business	Real increase in operating expenditure	Distribution business	Real increase in operating expenditure
Victoria	SP AusNet	40.0%	CitiPower	26.1%
			Powercor	27.4%
			Jemena	27.0%
			United Energy	23.5%
			SP AusNet	51.4%
South Australia	ElectraNet	28.0%	ETSA Utilities	45.6%

Energex and Ergon Energy have forecast the lowest rate of increase in operating expenditure. However, this follows substantial increases in operating expenditure in the preceding period.[193] Their respective benchmarks for operating and capital expenditure as a function of line length and customer numbers were also higher than Western Power's in 2009/10. This analysis suggests that the two per cent efficiency target is not reasonable.

The ratio of capital expenditure to operating expenditure is low in Western Australia compared to the ratio in all but one of the other jurisdictions[194] (but only in that jurisdiction in 2009/10). It is also considerably lower than the ratio compared to the other jurisdictions with government owned network businesses.

For a benchmarking exercise to be informative it should, as far as possible, control for all differences in operating conditions between firms. However, Geoff Brown and Associates' analysis controls only for the regulated asset base, customer numbers and network length. There are many other factors that could, and should, be taken into account. If regulated asset base, customer numbers and network length truly explain how efficient a network service provider should be, then all other things being equal, NSW and Queensland should have the two most efficient networks, yet the data suggests otherwise.

In fact, the data suggests that the larger a network service provider is, the more inefficient it is which is counterintuitive. Western Power is not suggesting that size leads to inefficiency, simply that there a number of factors that impact on the relative operating costs of interstate providers. Geoff Brown and Associates have only used three normalisers where there are a number of other possible factors which will necessarily influence operating expenditure[195] including differences in the:

- actual make up of the network (age profile, technology, past investment etc.)
- environmental factors and their influence on costs
- accuracy of asset valuation
- service quality standards
- past expenditure decisions
- definition of transmission and distribution companies across states
- accounting methodologies of network service providers
- mix between industrial and residential connections
- customer density

[193] Real increases of around 60% and 45% from 2004/05 to 2008/09 for Energex and Ergon, respectively.
[194] The ratio of capital expenditure to operating expenditure in that one jurisdiction was forecast to increase significantly in the following year.
[195] Section 5.2.1, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.

- transformer capacity
- transmission losses
- peak and average demand levels
- labour costs
- proportion of the network that is underground
- climate and terrain
- occurrence natural phenomena that can damage distribution wires such as floods, storms and fires

Western Power has attempted to address these shortcomings by undertaking further analysis that normalises the expenditure for the different capital to operating expenditure ratios by benchmarking the aggregate of capital and operating expenditure. Western Power has adopted the same normalisers used by the Authority's technical consultant, namely line length, customer numbers and regulated asset base.

Western Power compares favourably to the other jurisdictions when the benchmarking is undertaken on this basis, as illustrated in Table 23.

Table 23: Updated benchmarking results

	Opex + Capex /km line ($ nominal)	Opex + Capex /Customer ($ nominal)	Opex + Capex /Capital Base($ nominal)
Western Power	10,941	1,073	18.2%
Queensland	12,863	1,439	15.6%
New South Wales	14.510	1,284	19.0%
Victoria	8,575	551	14.1%
South Australia	5,385	615	11.8%
Tasmania	29,219	3,091	38.9%

Victoria compares more favourably than the other jurisdictions. However, as highlighted by the Productivity Commission, the number of customers per line length in Victoria is much higher than in other jurisdictions and so it will possible to incorrectly conclude that Victorian utilities are more efficient than the other jurisdictions.

South Australia also compares more favourably than the other jurisdictions in 2009/10 but this is largely a timing issue. The capital expenditure is forecast to increase significantly in the following year resulting in a less favourable comparison.

The Victorian and South Australian data also excludes the costs incurred by the Australian Energy Market Operator that are incurred by the network businesses in the other states.

Western Power compares less favourably against the capital base than against line length and customer numbers. This is due to a range of factors, in particular, the way in which the capital base was valued with the commencement of independent economic regulation, the age of the capital base, whether capital contributions are included or excluded in determining the capital base and the extent to which capital expenditure has been disallowed.

Western Power has undertaken benchmarking of network tariff costs for residential and small business customers. Even with the inclusion of the tariff equalisation cost (TEC), Western Power's tariffs (coloured bar in Figure 15) remain similar to other distribution network tariffs.

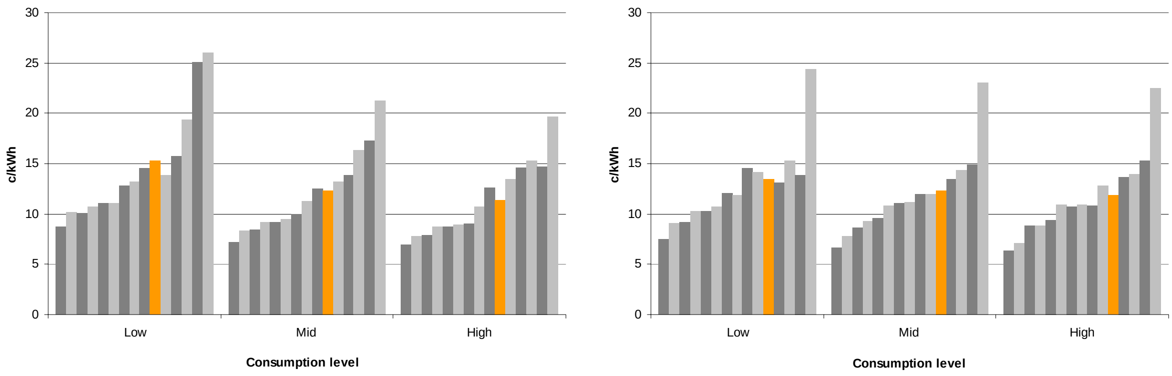

Figure 15: Western Power's tariffs for residential (LHS) and small business customers (RHS) compared to other electricity distributors

6.6.1.4 State Government's required efficiency dividends

The Authority has referred to the Western Australian Government's 2011/12 Budget requiring all government trading enterprises (GTE), including Western Power, to implement an efficiency dividend of 5 per cent in 2011/12 when concluding that a 2 per cent compounding reduction in Western Power's operating costs is reasonable. The Authority states that:

> *a further efficiency dividend for GTEs to be measured as a percentage of the discretionary spending, starting at 2.5 per cent in 2012-13 with an additional 1.5 per cent in 2013-14, 1.5 per cent in 2014-15 and 0.5 per cent in 2015-16. This builds on the existing five per cent efficiency dividend applied to these entities in 2011-12 which has already achieved confirmed savings of $524 million*[196]

The Government's requirements, including the latest announcement about further reductions[197], apply to discretionary spending. This approach recognises that it is unreasonable to expect reductions in non-discretionary spending. Further, the 2012/13 operating costs in the budget estimates for Western Power are above its forward looking efficient operating cost forecast. Western Power is the only Western Australian Government GTE that is subject to independent economic regulation. This means that Western Power is the only GTE that is required to provide a robust methodology and forecast of expenditure requirements sufficient to withstand scrutiny by the Authority, its expert technical consultant and other stakeholders. It is expected that the outcome of the current review process will provide the best guide on the efficient cost.

6.6.1.5 Application of the 2% efficiency dividend

The efficiency factor imposed by the Authority is not supported by evidence that Western Power's operating expenditure is inefficient, but is also applied inappropriately:

- **in addition to an economies of scale factor** – effectively building an efficiency into Western Power's operating expenditure before the 2% dividend is applied
- **from 2012/13** – this is in contrast to the technical consultant report which recommends commencement from 2013/14 effectively increasing the reduction in operating expenditure in the final year from 7.8% to 9.6%[198]

[196] Paragraph 316, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[197] The Government has announced future reductions of 2.5% in 2012/13, 1.5% in 2012/14 and 2014/15 and 0.5% in 2015/16 related to Government Trading Enterprise's discretionary spending. Page 165, *2011-12 Budget: Economic and Fiscal Outlook, Budget Paper 3,* Government of Western Australia, presented to the Legislative Assembly on 19 May 2011.
[198] Western Power's economic consultant notes that "it is unusual, but not unprecedented, for an economic regulator to propose reductions in expenditure greater than that recommended by its

- **to all operating costs including non-discretionary, fixed and competitively tendered costs** – given Western Power does not have scope to achieve efficiencies on these costs, it would require a reduction in controllable costs of around 26% in the final year

Western Power's economic consultant recognises that:

> *a significant proportion of expenditure is already efficient. Moreover, the mechanisms used to ensure that costs are reasonable …. Necessarily limit the subsequent rate of reduction in costs.*[199]

Wedgewood White also points out that:

> *the ERA's prospective 2% efficiencies must be obtained from only internal labour and business support, then by 2016/17, real expenditure in these categories would need to be some 26% lower than the ERA's amended forecast. This is unrealistic in my opinion.*[200]

If Western Power was awarded the target revenue determined in the Authority's draft decision, its ability to deliver these outcomes would be significantly compromised.

For example, if the lower level of operating expenditure arising from the draft decision was upheld, Western Power would have to reprioritise its safety expenditure program. While the major capital investment programs relating to wood pole replacement, electric shocks and bushfires would still be delivered, maintenance programs such as routine preventative maintenance and vegetation management around overhead lines may need to be scaled back. The package of reductions that the Authority proposes collectively results in unsustainably low levels of operating and maintenance costs. A maintenance program consistent with the Authority's proposed level of expenditure would increase the life-cycle costs of assets and deteriorate their performance.

The Authority's draft decision also provides no operating expenditure for network control services, and removes the D-factor adjustment mechanism. By doing this, the Authority's draft decision would impact customers who would have benefitted from the efficient deferral of capital projects, where a non-network solution is viable. It would also mean customers in Ravensthorpe and Bremer Bay will suffer degraded reliability, as there will be no funding to maintain existing generation systems.

This results in Western Power needing to achieve the lowest allowed growth in operating expenditure of any recent electricity network regulatory decision. As previously discussed, Western Power and its independent technical and economic consultants do not believe this to be realistic or achievable.

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engineering consultant." (Section 4.4, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.).

[199] Section 4.4, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.

[200] Section 4.4, *Review of Operating Expenditure Efficiency Adjustment*, Wedgewood White Ltd, 23 May 2012.

7 AA3 opening capital base

7.1 Reporting on actual capital expenditure

Required amendment 7:
The actual capital expenditure for 2009/10 and 2010/11 must be restated to exclude expenditure relating to cancelled or deferred projects and to reverse the statutory inventory adjustments in both years.

Western Power response:

Western Power does not accept this amendment.

7.1.1 Statutory inventory adjustments

The Authority has requested the 2009/10 and 2010/11 capital expenditure figures should be restated to reverse a statutory inventory adjustment that occurred across these two years. While the net effect in nominal terms is neutral, the Authority considers the figures should be restated correctly for each year for the purposes of establishing the opening capital base to ensure the balances are stated correctly in real price terms[201].

Western Power has restated the actual capital expenditure for 2009/10 and 2010/11 to reverse the statutory inventory adjustments in both years. This is attached at Appendix K.

7.1.2 Cancelled / deferred projects

In its draft decision the Authority states that:

> *The Authority does not consider expenditure which relates to cancelled or deferred projects meets the requirements of the new facilities investment test. If such expenditure has been identified for write-down in the statutory accounts, then it should not be added to the capital base.*[202]

Western Power does not agree with the Authority's reasoning that expenditure that is expensed in the statutory accounts should also be expensed for the regulatory accounts.

Western Power prepares its annual *statutory* financial statements in line with the requirements of the International Financial Reporting Standards (IFRS), which requires expenditure that will not result in the creation of an asset (cancelled or deferred projects) to be expensed.

However, Western Power's annual regulatory financial statements are prepared in accordance with the Authority's *Guidelines for Access Arrangement Information* and the requirements of the Access Code. These regulatory accounts have been reviewed by the Office of the Auditor General and by the Authority's financial consultants.

The Authority's *Guidelines for Access Arrangement Information* requires that:

> *a service provider will apply regulatory adjustments to the disaggregated statements to account for …differences in accounting methods and assumptions between the base accounts and regulatory financial statements.*[203]

and that:

[201] Paragraph 389, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[202] Paragraph 388, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[203] Page 7, *Guidelines for Access Arrangement Information*, ERA, 6 December 2010.

> *the capital expenditure: is recorded on an "as incurred" basis, and includes expenditure on capital assets that did not enter into service during the year, but excludes any amount for the interest (or like allowance) incurred during construction.* [204]

Western Power has applied regulatory adjustments and reported the capital expenditure on an as-incurred basis. The test that applies for determining whether expenditure can be added to the capital base, and therefore whether it is reported in the regulatory financial statements, is the satisfaction of the new facilities investment test (NFIT) as per section 6.51A of the Access Code. It is not based on the requirements of the IFRS for the defined construction and creation of an asset.

Capital projects may be cancelled or deferred following investigation of alternative options, or a change in underlying assumptions. This was particularly evident in the AA2 period, when the global downturn and economic uncertainty prompted a more conservative pace of expansion.

The actual peak demand reached during the AA2 period fell well short of that predicted by the forecast on which the AA2 submission was based.[205] A number of projects that began at the end of the AA1 period or early in 2009/10 were stopped as the load growth requirements changed.

Western Power undertakes works on the basis that the expenditure is required to provide covered services. The expenditure must satisfy the NFIT to be added to the capital base. This includes an assessment of whether Western Power was acting efficiently and in accordance with good electricity industry practice, considering the prevailing conditions at the time. Western Power should not be penalised for a change in circumstances where it was efficient to commence the work and the work was reasonably expected to meet the NFIT at the time it was forecast and when it was incurred.

Should the Authority require that Western Power treats the costs associated with cancelled and deferred projects as operating expenditure, there will need to be an increase in the forecast operating expenditure for the AA3 period.

Treating these costs as operating expenditure increases operating expenditure by approximately $18 million over the AA3 period. This would increase tariff revenue to be recovered from customers by the same amount.

7.2 AA2 capital investment satisfying the NFIT

Required amendment 8:

The proposed revised access arrangement should be amended to reflect the values shown in Table 41 above.

Western Power response:

Western Power does not accept this amendment.

The Authority considers that expenditure totalling $21.2 million undertaken in the AA2 period does not meet the NFIT. The Authority's view was based on an assessment by its technical consultants, Geoff Brown and Associates. The consultants reviewed a sample of 19 capital projects undertaken during AA2 and assessed:

- 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 of program approval and the final project or program cost

[204] Page 8, *Guidelines for Access Arrangement Information*, ERA, 6 December 2010.
[205] See Appendix H for further information on changes to forecast demand.

- 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

This approach was predicated on the assumption that if the project or program was implemented in accordance with Western Power's expenditure governance procedures then, assuming these procedures were consistent with good industry practice, it can be assumed that implementation was efficient and wasteful expenditure did not occur.

The Authority's draft decision proposes the following expenditure should not be added to the capital base:

- $5.7 million in relation to a cost overrun on phase 1 of the Mobile Workforce Solution project which forms part of the Strategic Program Of Works (SPOW)
- $102,000 incurred on planning for a second Picton-Busselton 132 kV line which has been deferred indefinitely
- $4.5 million in relation to planning and environmental costs which are not directly related to a specific project or program and the Authority's technical consultant considers do not meet the requirements of the NFIT
- $1.9 million in relation to transmission line relocations which Western Power intends to recover in full from the customers concerned
- $9 million in relation to a cost overrun on elements of SPOW

Western Power does not accept the findings of the Authority and its consultant. Western Power has provided further information at Appendix L and in the following sections to support the inclusion of the following expenditure in the capital base:

- $14.7 million of capital investment related to the Mobile Workforce Solutions project and SPOW projects that satisfies the new facilities investment test
- $102,000 incurred on planning for a second Picton-Busselton 132kV line and $4.5 million in relation to planning and environmental costs
- the revised forecast of capital investment for 2011/12 that satisfies the new facilities investment test, including $6.5 million of early strategic planning costs

7.2.1 SPOW

The Authority has excluded $14.7 million of AA2 capital expenditure for Western Power's SPOW from the capital base, citing that these amounts do not satisfy the NFIT. In making this assessment, the Authority relies on advice from its technical consultant. The Authority's technical consultant highlights two areas of concern:

- a $5.7 million overrun on Phase 1 of the Mobile Workforce Solution
- a $9 million overrun on the program in general, for which the Authority's technical consultant was unable to form an opinion on

Western Power does not accept that an overrun of the initial budget is evidence that these amounts do not satisfy the NFIT. In relation to Phase 1 Mobile Workforce Solution, Western Power considers that the project management and governance of the project was appropriate and that it is reasonable to re-scope these types of projects as they progress to respond to emerging issues and market conditions.

Western Power has provided supplementary information to demonstrate that the SPOW expenditure undertaken in the AA2 period satisfies the NFIT. Summaries of the reasons the program satisfies the NFIT are provided in Appendix L.

7.2.1.1 Mobile Workforce Solution

The Mobile Workforce Solution (MWS) is an ongoing project to procure and implement a solution to streamline the process of inspecting field assets and upload the information directly into Western Power's asset management system. In assessing the MWS project, the Authority's technical consultant considers that Western Power's approach to considering options was inadequate and project management was poor. The consultant speculates that this project may have been initiated so that Western Power could be seen to be doing something to manage problems with its wood pole program. The Authority's consultant also indicated that it considered that proper approval was not provided for the budget overrun.

Western Power does not accept the Authority's technical consultant's conclusions about the intentions of the project, governance or project management.

The project was initiated to address the need to improve the efficiency and reliability of data collection from the field. In 2009, Western Power decided to pilot the program with wood pole inspections. The planning and implementation phases of the MWS project followed Western Power's governance procedures. A business case was prepared and presented to the Managing Director for approval.

The business case was approved for an amount of $3 million to cover the first phase of the project. It identified that a multi-phased approach would be employed to allow for likely changes in scope to address issues arising and market conditions to be managed. This is common practice in large IT projects where new systems are being introduced or must be integrated with existing business infrastructure. Costs are contained where further work can reflect known issues rather than building in risks of unknown issues in a larger package of work.

The scope of the project included the full deployment of the solution for distribution wood pole inspections. It did not include the planning and business case work for the next phase of the program.

The options analysis outlined three options:

1. the impacts to the business of not proceeding with the work
2. returning to the market to source other options
3. the procurement of Mincom Mobile Software Solution

The Mincom solution was identified to be the preferred option as it was expected to efficiently minimise costs in delivering the requirements through:

- increased confidence of delivery and performance
- opportunities to leverage product development opportunities
- achieving economies in implementation

The business case also identified a number of key risks including the potential for scope changes arising form the wood pole program, lack of internal user acceptance and the potential to not achieve the required time frame.

The $5.7 million overspend identified compared to the business case was comprised of the following:

- **a change variation of $2.2 million that was approved by the Managing Director**

  The change variation document highlights that a number of the risks called out in the original business case eventuated. In particular the business requirements significantly changed in response to Energy*Safety* Order 01-2009 and the recent Parliamentary Inquiry[206]. It also changed to accommodate the upgrade in the Ellipse system. $1.8 million reflected the wood pole inspections and $0.4 million was to support other elements of the program.

  This change variation included the $1 million considered by the Authority's technical consultant as being incurred prior to the variation being approved. The project was managed and governed through monthly project reporting which identified in advance the need for further budget.

[206] *Report no.14 of the Standing Committee on Public Administration*, 20 January 2012.

This change variation clearly articulated the need for funding the continuation of wood pole inspections ($1.8 million) and planning for the future phases beyond wood poles ($0.4 million).

- **The approval of an interim business case for funding of $3.4 million**.

  This interim business case was to bridge the gap prior to Board approval in order to maintain the efficient delivery of the program. This business case also funded wood pole inspections ($1.9 million) and other elements of the program ($1.5 million)

  The overspend on wood pole inspections of $3.8 million arose as a result of a number of known and declared risks eventuating, and a number of other unplanned events (e.g. departure of key resources targeted for employment by large mining companies) that have impacted the delivery of the project.

7.2.1.2 SPOW cost over-run

In its draft decision the Authority excludes $9 million of capital expenditure from being added to Western Power's capital base due to unidentified cost overruns from the SPOW. Western Power considers that the fact that the expenditure on these projects is greater than the initial budget is not sufficient to conclude that the expenditure does not meet the NFIT.

The Authority's technical consultant indicates that it was unable to form a view on whether this amount complied with NFIT. In its draft decision the Authority has inferred that this was due to identified problems with the project's business case. Western Power understands that the technical consultant was unable to form a view on these amounts because it was not in receipt of a justification of the amounts. Western Power has provided NFIT compliance summaries in Appendix L to allow the authority to review these amounts for satisfaction of the NFIT.

7.2.2 Second Picton-Busselton 132 kV line.

The Authority excludes $102,000 capital expenditure relating to the planning of the second Picton-Busselton 132 kV line from Western Power's opening capital base. It has done this on the basis that the *project has been deferred indefinitely*[207].

Western Power does not accept that these costs do not meet the NFIT and has included them in the opening capital base.

Western Power should not be penalised and prevented from recovering the costs that were incurred on the basis that the expenditure was reasonably expected, at that time, to satisfy the NFIT. Execution of the NFIT and regulatory test under the Access Code requires Western Power to test a number of viable options to ensure it is efficiently minimising costs.

Western Power undertook planning activities to address the emerging voltage collapse issues on the Picton-Busselton 132 kV line. A new 132 kV line was investigated as a valid option as it offered advantages of addressing the voltage collapse issues and could also address the thermal constraint (emerging in later regulatory periods) and other asset condition issues on the existing 66 kV line.

Sections of the existing Picton-Busselton 66 kV line had been rebuilt over time for asset maintenance or replacement purposes to a 132 kV standard. It was therefore prudent to conduct preliminary investigations into a 132 kV line upgrade option. This investigation allowed an informed view of the relative merit of alternate options such as capacitor banks and building the new line leveraging the upgraded sections of the existing line.

The $102,000 incurred for the second Picton-Busselton 132 kV line established construction feasibility including planning and approval lead times, preliminary engineering design and

[207] Paragraph 420, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.

cost estimates for the line upgrade option. The environmental and approval investigations identified that there is considerable community and environmental concern about rebuilding sections of the line. This contributed to deferral of the line upgrade to allow further investigation of community and environmental issues. The immediate voltage collapse issues are subsequently being treated by the installation of capacitor banks.

7.2.2.1 Environmental and planning costs

The Authority has excluded capital expenditure of $4.5 million from the opening capital base[208] for planning and environmental costs which, in the Authority's technical consultant's view, are not directly *related to a specific project or program and… [GBA considers]… do not meet the requirements of the new facilities investment test*[209].

The Authority's technical consultant states that they:

> *do not question the validity or need for these costs…[but] … have not come across this accounting approach in other regulatory reviews.*[210]

The Authority's technical consultant also suggests that:

> *In our experience planning costs that cannot be attributed to a specific project are treated as opex and either recovered in full in the year that the expense was incurred or capitalised through a defined cost allocation process.*[211]

These are valid costs and were not forecast as operating costs for the AA2 period. These costs include early strategic planning costs which are incurred prior to Gate 1 in Western Power's works program model.[212] Project development and environmental costs are incurred after Gate 1. Following Gate 1, the business begins attributing costs directly to individual projects that are established to address a defined network need.

The forecast expenditure requirements have been revised to include these costs as indirect costs. This treatment provides for those elements of planning costs which are not directly attributable to projects to be allocated across capital and operating expenditure.

The opening capital base for AA3 includes the early strategic planning costs that have not been directly attributed to capital projects. The latest forecast of these costs for 2011/12 is $6.5 million.

[208] The Authority has reduced AA2 capex by $4.5 million. However, this is an error – as Western Power's initial submission proposed $4.3 million excluding real cost escalation. The error is apparent on page 60 of the *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

[209] Paragraph 420, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[210] Page 81, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

[211] Paragraph 7.2.5, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

[212] Western Power's works program model was described on page 70 of its Access Arrangement Information included in the September 2011 submission.

7.3 Inventory

Required amendment 9:

Western Power's proposed adjustment to include the cost of inventory in the capital base must be removed.

Western Power response:

Western Power accepts this amendment.

In its draft decision, the Authority requires Western Power to remove amounts related to the recovery of inventory costs in the opening capital base. Western Power accepts this amendment as this amount will be recovered through the working capital mechanism, as described in response to required amendment 16.

7.4 Depreciation

Required amendment 10:

Western Power must establish the value of any redundant assets included in its current asset base and to include accelerated depreciation to fully write them off.

Western Power response:

Western Power does not accept this amendment.

In its draft decision the Authority is satisfied that Western Power's approach to rolling forward the capital base - including the treatment of depreciation - is consistent with the Access Code objective. However, the Authority requires Western Power to establish the value of any redundant assets included in its current asset base and to include depreciation to fully write them off.

Western Power does not accept this amendment because it is not clear what the Authority requires. If this amendment requires Western Power to increase the depreciation amount used in rolling forward the asset base with the effect of reducing the opening asset base, then this is inconsistent with the roll-forward method and amounts to determining an amount of redundant capital. The Authority has provided no reasons for determining an amount of redundant capital or complied with sections 6.62 and 6.63 of the Access Code.

If this amendment provides for the recovery of an additional depreciation amount in rolling forward the notional capital base, the result would be higher prices to customers due to an increased amount of depreciation, and additional costs to Western Power to identify and calculate the additional depreciation amount. There is no benefit to customers of adopting the latter approach. It is inconsistent with section 6.4 of the Access Code, which allows only for the recovery of forward looking efficient costs.

Western Power has made no adjustment in the opening value of the capital base or the notional capital base.

7.5 Mid-year timing assumption in capital base

Required amendment 11:

The proposed revised access arrangement must be amended such that the 'time value of money adjustment' for mid-year capital expenditure timing is removed from the rolled forward capital base and the notional capital base for AA3.

Western Power response:

Western Power accepts this amendment.

In its draft decision, the Authority requires the removal of the assumption that capital investment is undertaken mid-year for the purposes of calculating the initial capital base and the return on the capital base for AA3.

Western Power accepts the Authority's amendment to remove the time value of money adjustment to the rolled forward capital base and the notional capital base for AA3. Although the Authority's approach differs from the AER methodology that Western Power proposed in its September 2011, Western Power acknowledges that the AER does not provide for working capital within the building blocks approach.[213]

The AER has also accepted that the mid-year timing assumption for capex with end of year timing assumption for revenues and opex is internally inconsistent.[214] However the AER has deferred further consideration of the cash-flow timing.[215]

Western Power accepts that a working capital allowance may provide a better forward looking estimate of costs incurred.

7.6 AA1 speculative investment

Required amendment 12:

Expenditure relating to investment from prior periods does not meet the new facilities investment test and must not be included in the capital base.

Western Power response:

Western Power does not accept this amendment.

In its draft decision, the Authority indicates that any improvements made by Western Power to its processes since the last access arrangement review will not change the findings of the Authority in relation to past expenditure.

The Authority does not agree that $244.4 million ($ real at 30 June 2012) of disallowed capital expenditure incurred during the first access arrangement period (AA1), which

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[213] Page 14, *Electricity distribution network service providers - Post-tax revenue model handbook, AER*, June 2008. Available from: http://www.aer.gov.au/content/item.phtml?itemId=720375&nodeId=1cc5d55c65999d998ffef7ad08d213b3

[214] Page 11, *Issues Paper - Guidelines, models and schemes for electricity distribution network service providers*, AER, November 2007, pg 11, Available from: http://www.aer.gov.au/content/item.phtml?itemId=716434&nodeId=f7b875874b4b19036be348d23fc73eb1&fn=Issues%20paper%20(November%202007).pdf

[215] Page 5, *Final Decision - Electricity distribution network service providers - Post-tax revenue model*, AER, June 2008. Available from: http://www.aer.gov.au/content/item.phtml?itemId=720375&nodeId=0f54ee3394ca3a17bed8e92403401d4e&fn=Final%20decision%20-%20Distribution%20PTRM%20(26%20June%202008).pdf

Western Power proposes was speculative investment, should be added to the opening capital base for the third access arrangement period.

The Authority considers that the expenditure relating to investment from prior periods does not meet the new facilities investment test (NFIT) and must not be included in the capital base[216] given[217]:

> *The Authority does not consider that the information included in Western Power's third access arrangement proposal … addresses the weaknesses outlined in paragraph 489 above.*

The Authority also did not incorporate $5 million for planning and design of the Mid West Energy Project (Southern Section), despite acknowledging in its draft decision that this amount was efficient:

> *The pre-approved expenditure* [in the Authority's Final Decision on the New Facilities Investment Test Application for the Mid West Energy Project (Southern Section)] *included all planning and design costs in relation to the Mid West Energy project (Southern Section) which the Authority deemed to be efficient.*[218]

Paragraph 489 of the draft decision reiterates the specific weaknesses relating to AA1 capital investment identified by the Authority during its review of the proposed access arrangement for AA2 in 2009. The specific weaknesses were:[219]

- Western Power not using best-practice design software for the design of transmission lines that would facilitate more effective economic optimisation of transmission line designs
- an absence of standard designs and guidelines for distribution assets
- unusually restrictive design specifications for equipment, limiting the number of potential suppliers
- lack of rigour in assessing options for network augmentations and documenting these assessments

In its September 2011 submission, Western Power provided additional documentation to support the addition of $244.4 million in speculative investment in the AA3 opening capital base. This included information about specific projects that the Authority (and its technical consultants) did not review during its review of the access arrangement for the second access arrangement period (AA2).

The projects and programs and the value are:

- Distribution Regulatory Compliance – Bushfire Mitigation
  - Wires Down Strategy $9 million
  - Replacement of Expulsion Drop out Fuses $0.1 million
  - HV Conductor Clashing $24 million
  - Installation of LV spreaders $5 million

Western Power also included information about specific projects that the Authority (and its technical consultants) did review during its review of the access arrangement for the AA2 period and had determined met the requirements of the new facilities investment test[220]:

[216] Required Amendment 12, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[217] Paragraph 492, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[218] Paragraph 476, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[219] Paragraph 737, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, ERA, 4 December 2009; Paragraph 489, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

- Distribution Regulatory Compliance – Connection Management
  - Overhead Customer Service Replacement $42 million

In its September 2011 submission, Western Power invited the Authority to request additional documentation for AA1 projects.[221] This offer was not taken up by the Authority. Western Power has provided documentation for a further significant program of work in Appendix M, totalling $56 million.

The targeted reliability program was reviewed by the Authority's technical consultant during the review of the access arrangement for AA2. The Authority's technical consultant concluded that all actual expenditure meets NFIT requirements and that it should be included in the AA2 opening asset base.

The information provided in the initial submission and the information supplied at Appendix M demonstrates that these projects complied with the NFIT and that the specific weaknesses suggested by the ERA did not apply.

Western Power has assessed the Bushfire Mitigation, Connection Management and Targeted Reliability projects and programs against the four specific weaknesses outlined by the Authority and found the following:

1. **Western Power not using best-practice design software for the design of transmission lines that would facilitate more effective economic optimisation of transmission line designs.**

   These projects and programs do not include new transmission lines and therefore the software that is used by Western Power for the design of transmission lines did not result in inefficiency.

2. **An absence of standard designs and guidelines for distribution assets.**

   The design of the works that comprise the Bushfire Mitigation and Connection Management projects and programs was undertaken in-house and therefore there is no inefficiency related to the use of external service providers. The majority of designs for targeted reliability were undertaken in-house and external designers used where simple standard designs could expedite the program.

3. **Unusually restrictive design specifications for equipment, limiting the number of potential suppliers.**

   The Bushfire Mitigation, Connection Management and Targeted Reliability projects do not include ring main units (RMUs), which were the only items of equipment the Authority raised concerns about.

4. **A lack of rigour in assessing options for network augmentations and documenting these assessments**

   These types of projects and programs are not driven by load forecasts and so therefore there was no inefficiency arising from the load forecasts.

Therefore, the amount that was disallowed for these projects and programs should be added to the capital base. This is $6.8 million, being 5% of $136 million (the total value of these three programs).

Western Power has also examined the application of the four specific weaknesses to all the capital expenditure in AA1 for inefficiencies in planning, design and governance and found:

- Western Power was using software that was considered to be good electricity industry practice at that time, consistent with the requirements in the Access Code

[220] *Review of New Facilities Investment Test Compliance Western Power AA1 Projects, Draft Final Report*, Geoff Brown & Associates Ltd, published 25 June 2009 including confidential appendices later removed from the public version.
[221] Page 5, *Appendix C – AA1 Speculative Investment: Access Arrangement Information for the period 1 July 2012 to 30 June 2017,* Western Power, 30 September 2011.

- the only projects that were designed by external resources were distribution undergrounding and automation projects. The designs were supervised by Western Power's designers and the rates charged were low to offset any additional time that may have been spent on the designs
- although the use of restrictive design specifications for equipment was identified as a potential issue, this was reviewed by expert consultant SKM[222], which found no evidence that it was a real issue
- any additional capacity provided as a result of load forecasts assessed to be high in AA1 has been critical to support the load growth in AA2 when capacity expansion investment has been relatively low.

The following sections further assess the applicability of the four weaknesses identified by the Authority to the investment undertaken during the AA1 period and the amount that passes NFIT and has been added to Western Power's opening capital base.

As a result of the assessment Western Power has amended the opening capital base to include $112 million in speculative investment that passes NFIT as follows:

- $107 million ($ real as at 30 June 2012) which should not have been disallowed for inefficiencies in planning, design and governance, this comprises:
  - $35 million or projects and programs that did not require software design for transmission lines
  - $71 million for projects and programs that did not incorporate issues associated with standard designs and guidelines for distribution asset or unusually restrictive design specifications
- $5 million ($ real at 30 June 2012) for planning and design of the North Country Region (Mid West) 330 kV transmission project, which has been assessed by the Authority as efficient.

7.6.1 Best-practice design software for the design of transmission lines

In the Draft Decision, *the Authority took the view that there had been inefficiencies in the planning and design of augmentations of the network as a result of … Western Power not using best-practice design software for the design of transmission lines that would facilitate more effective economic optimization of transmission line designs*[223]. The Authority referenced its decision to an SKM report[224] submitted by Western Power in response to the Authority's Draft Decision.

SKM reviewed Western Power's Transmission and Distribution planning standards and processes, and in particular:

- transmission substation standards
- transmission line standards
- distribution design standards

[222] Based on its review of the additional information requested on the RMU tender process, SKM has determined that a robust procurement process was used and has no outstanding concerns with the establishment of the RMU contract. Western Power used appropriate levels of probity and a robust value-based procurement process was evidenced; Page 49, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 3 September 2009.

[223] Paragraph 489, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[224] *Western Power's second submission to the Economic Regulation Authority's Draft Decision on the proposed revisions to the access arrangement for the SWIN*; Attachment F2 *Opinion by Sinclair Knight Merz* available at: http://www.erawa.com.au/cproot/7902/2/20090911%20Public%20Submission%20-%20Draft%20Decision%20-%20Access%20Arrangement%20Review%20-%20Western%20Power.pdf

SKM compared the transmission substation standards[225]

> *… to practices used in other jurisdictions in Australia and [were] found to be generally consistent with no material differences that would significantly affect the cost of Western Power infrastructure. Some minor regional differences were noted.*
>
> *…*
>
> *There are a number of apparent issues identified during the review of standards that could potentially result in higher costs and these may be (incorrectly) considered as indicators of inefficiencies in network asset establishment.*

SKM concluded that the transmission line design standards in the AA1 period were consistent with good electricity industry practice at that time and the requirements of the Access Code. It identified that best practice software for the design of transmission lines was an area of improvement. In SKM's opinion this was considered to be more an area of improvement than a deviation from good electricity industry practice at that time.[226]

Section 6.52 of the Access Code provides that new facilities investment meets the NFIT if the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs. The Access Code defines "efficiently minimising costs" as

> *The service provider incurring no more than would be incurred by a prudent service provider, acting efficiently, in accordance with good electricity industry practice.*

As Western Power's software for the design of the transmission lines was considered to be good electricity industry practice at that time, it can be concluded that Western Power was acting efficiently at that time.

Any potential inefficiency could only apply to projects that included a new transmission line, and only to the investment associated with the new transmission line rather than the whole project.

The only projects in AA1 that included a new transmission line were:

- SOUTHERN RIVER SS - CUT IN ST-WGP/APJ 81 — $3 million
- CT - RVE 81 LINE UPRATE TO 242 MVA — $5 million
- ESTABLISH CT-KDL & RVE-WE/BEL LINES — $11 million
- KENWICK LINK: ESTABLISH 330kV/132kV TRAN — $7 million
- KW-SF 81: CONVERT LINE TO DOUBLE CIRCUIT — $15 million
- MARGARET RIVER SS: 132KV LINE (BSN) & TX — $8 million
- MU-BTN 82 (part) : CONSTRUCT 132kV LINE — $3 million
- NEERABUP - ESTAB. NEW TERMINAL STATION — $52 million
- PJR - WNO : CONSTRUCT NEW 132KV LINE — $30 million
- Glt-Nt-St91-Conv To Glt-Nt 91&Glt-St91 — $6 million
- Kw - Kem 91 Line & Cap Bank At Guildford — $1 million
- Kw-St 92: New Ccts At St & Kw & Energise — $7 million
- Sho-Kem 91 Stringing 2Nd Side On 330 Kv — $20 million
- ST - CT 330 KV LINE & SUB ENDS — $1 million
- Wlo - Bsn 81 Line & Waterloo Sw/Yd — $8 million

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[225] Page 40, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 3 September 2009.

[226] Page 43, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 3 September 2009.

- BODDINGTON GOLD MINE EXPANSION $98 million
- POWER PROCUREMENT STAGE 1 (KEM) $10 million
- TRANSMISSION LINES : RIVER CROSSING WORK $6 million

The total expenditure on these projects during AA1 was $286 million[227] (in 30 June 2012 dollars), which included approximately $55 million of substation works. That is, the expenditure on transmission lines during AA1 was approximately $231 million (in 30 June 2012 dollars).

Western Power maintains that the conclusions of the Authority in relation to these projects being inefficient due to the use of design software that it considers was not best-practice for transmission lines should only result in 5% of $231 million being excluded from capital base, that is, $11.6 million (in 30 June 2012 dollars).

As a result, Western Power has included $35 million, as outlined in Table 24, in the opening capital base for projects and programs that did not require software design for transmission lines.

Table 24: Amount to be added to the capital base for projects and programs that did not require software design for transmission lines

$ million real at 30 June 2012	2006/07	2007/08	2008/09	Total
Authority's disallowed expenditure for four specific weaknesses (transmission)	-15.1	-15.6	-16.0	-46.7
Amount of disallowed expenditure that may apply for not using best-practice design software for transmission lines	-3.7	-5.2	-2.7	-11.6
Amount to be added to the capital base in response to four specific weaknesses (transmission)	**11.5**	**10.4**	**13.3**	**35.2**

7.6.2 Standard designs and guidelines for distribution assets

In the draft decision, *the Authority took the view that there had been inefficiencies in the planning and design of augmentations of the network as a result of … An absence of standard designs and guidelines for distribution assets*[228]. The Authority referenced its decision to an SKM report[229] submitted by Western Power in response to the Authority's draft decision.

SKM found that Western Power's distribution design policies and standards were well defined and robust. However, it noted that Western Power had increasingly used external service providers to undertake distribution designs, and that there was a lack of standard designs for these suppliers to work to. SKM expected that[230]:

> *… the introduction of a range of standard design drawings and guidelines would result in a more consistent output from design providers and assist providers in decreasing in design costs.*

As identified by SKM, Western Power had only recently started to use external service providers in AA1 to design distribution projects. This was an initiative to increase the pool of

[227] May not match values in table due to rounding.
[228] Paragraph 489, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[229] *Western Power's second submission to the Economic Regulation Authority's Draft Decision on the proposed revisions to the access arrangement for the SWIN*; Attachment F2 *Opinion by Sinclair Knight Merz* available at: http://www.erawa.com.au/cproot/7902/2/20090911%20Public%20Submission%20-%20Draft%20Decision%20-%20Access%20Arrangement%20Review%20-%20Western%20Power.pdf
[230] Page 44, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 3 September 2009

distribution designers as it was forecast that the amount of work and complexity of designs projected over future access arrangement periods would increase. As the distribution design resourcing strategy was only new:

- the work undertaken by the external service providers was supervised by Western Power's internal design resources to provide guidance to the external service providers and ensure that designs were consistent with Western Power's design policies and standards
- only design work for simple projects, such as undergrounding for capacity expansion projects, some customer driven projects and some automation projects, was undertaken by the external service providers in AA1. More complex design work was only undertaken by external service providers later, after there was sufficient confidence in their ability to carry out more complex work (for example overhead line design) without Western Power guidance
- the rates charged by the external service providers during AA1 were lower to begin with compared to internal rates, to reflect that this approach was in a training phase under supervision of Western Power's designers

The output from the design providers was consistent as the designs were supervised by Western Power's designers. During this time Western Power increased the quality and consistency of design documentation, including production of standardised design drawings and design manuals. The need to learn Western Power's design standards may have resulted in more time being undertaken by the external service providers, however this was offset by the lower rates, resulting in design costs that were comparable with those that would have been incurred had the designs been undertaken in-house.

The only regulatory categories that employed strategies of outsourcing some design components were:[231]

- Distribution capacity expansion $220 million
- Distribution customer driven $351 million
- Distribution reliability driven $56 million

The total expenditure on these regulatory categories during AA1 was $627 million (in 30 June 2012 dollars), which included design costs of approximately $31 million[232]. To be conservative, Western Power has included the total expenditure for categories where an external design resourcing strategy may have been used in the AA1 period.

Western Power maintains that there was no inefficiency resulting from the design of distribution projects by external service providers. However, using the method applied by the Authority in its Final Decision for AA1, 5% of the capital expenditure on design costs for distribution capacity expansion undergrounding projects, customer driven projects and automation projects should only result in $1.6 million (in 30 June 2012 dollars) being excluded from the capital base.

As a result, Western Power has included $71 million, as outlined in Table 25, in the opening capital base for distribution projects and programs that did not require design by external service providers or did not require expenditure on ring main units (discussed in the following section).

Table 25: Amount to be added to the capital base for projects and programs that did not require design by external service providers or the purchase of ring main units

$ million real at 30 June 2012	2006/07	2007/08	2008/09	Total
Authority's disallowed expenditure for four specific weaknesses (distribution)	-21.1	-23.1	-29.0	-73.2

[231] These values are net of capital contributions received in the AA1 period.
[232] Western Power assessed a sample set of distribution projects and determined that design costs are in the order of 5% of total expenditure.

$ million real at 30 June 2012	2006/07	2007/08	2008/09	Total
Amount of disallowed expenditure that may apply for an absence of standard designs and guidelines for distribution assets	-0.4	-0.5	-0.7	-1.6
Disallowed expenditure that may apply for unusually restrictive design specifications (ring main units)[233]	-0.1	-0.1	-0.1	-0.3
Amount to be added to the capital base in response to four specific weaknesses (distribution)	**20.6**	**22.6**	**28.1**	**71.4**

7.6.3 Design specifications

In its draft decision, *the Authority took the view that there had been inefficiencies in the planning and design of augmentations of the network as a result of … Unusually restrictive design specifications for equipment, limiting the number of potential suppliers* [234]. The Authority referenced their decision to an SKM report[235] submitted by Western Power in response to the Authority's Draft Decision.

SKM reviewed a number of selected plant specifications. SKM identified that[236]:

> *One of the dangers of plant specification is to over-prescribe, forcing the supplier market to maintain a certain product line or worse, to reduce the number of suppliers who are able to tender for the overly prescriptive specification.*

SKM concluded that the[237]:

> *… specifications appear to be conservative and robust and in line with good electricity industry practice. Overall, the specifications reviewed appear to be industry standard and, with minor exceptions, are similar to many used in other utilities in Australia.*

Notwithstanding this conclusion, SKM became concerned during this review about the purchase of ring main units (RMUs). As a result it reviewed additional information and concluded that:

> *A robust procurement process was used and [SKM] has no outstanding concerns with the establishment of the RMU contract.*[238]

While SKM had general concerns that unusually restrictive design specifications for equipment can limit the number of potential suppliers, there was no evidence in SKM's report that Western Power was not acting in accordance with good electricity industry practice.

The only program that purchased ring main units was distribution asset replacement: switchgear totalling $6 million[239].

Western Power maintains that its design standards were in line with good electricity industry practice at that time. However, using the method applied by the Authority in its Final Decision

[233] This is discussed in the following section 7.6.3 Design specifications.
[234] Paragraph 489, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[235] *Western Power's second submission to the Economic Regulation Authority's Draft Decision on the proposed revisions to the access arrangement for the SWIN*; Attachment F2 *Opinion by Sinclair Knight Merz* available at: http://www.erawa.com.au/cproot/7902/2/20090911%20Public%20Submission%20-%20Draft%20Decision%20-%20Access%20Arrangement%20Review%20-%20Western%20Power.pdf
[236] Page 46, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 3 September 2009.
[237] Page 47, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 3 September 2009.
[238] Page 49, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 3 September 2009.
[239] These values are net of capital contributions received in the AA1 period.

for AA1, only inefficient expenditure on ring main units should be excluded. That is, \$0.3 million (or 5% of \$6 million (in June 2012 dollars).

As a result, Western Power has included \$71 million, as outlined in Table 25 (see previous section), in the opening capital base for distribution projects and programs that did not require design by external service providers (as discussed in the previous section) or did not require expenditure on RMUs.

7.6.4 Rigour in assessing options for network augmentations

In its draft decision, *the Authority took the view that there had been inefficiencies in the planning and design of augmentations of the network as a result of … A lack of rigour in assessing options for network augmentations and documenting these assessments*[240]. The Authority referenced their decision to an SKM report[241] submitted by Western Power in response to the Authority's Draft Decision.

SKM also reviewed Western Power's options analysis for a range of projects and also concluded that:[242]

> *For all the projects reviewed multiple options were considered and of the options considered the most appropriate appears to have been selected.*

However, SKM also identified there is room for improvement in the presentation and discussion of options in the approvals documentation. This was based on two concerns by SKM related to use of demand side management options and presentation of load forecasts in a business case for the Bibra Lake substation.

SKM noted that a demand side management option had not been assessed for most projects, however it also noted that[243]:

> *.. many of these projects were designed before the current thinking in the electricity industry to consider the viability of demand side management.*

Western Power's analysis of demand management options at that time indicated that they were a relatively high cost alternative. Accordingly, these options would have only been considered where the costs of the other options were very high.

This was supported by Western Power's experience in procuring generation services at Bremer Bay. A diesel power station was established in 2003/04 (prior to disaggregation) to island Bremer Bay from the network and resolve the capacity issues. During 2005/06 this solution was assessed as too expensive to sustain over an extended period of time and as a result, it was proposed to reconnect Bremer Bay to the network. In 2006/07, Western Power commenced works to install capacitor banks and another voltage regulator on the Willyung (Bremer Bay's) feeder. Works were also performed to reconfigure the wind turbine connection to allow grid connection without operation of the diesel generators, this would permit receipt of renewable energy financial benefits to offset operating costs.

The SKM report noted some concern with the way the forecast that underpinned the Bibra Lake Substation was presented in the business case. This concern resulted in further investigation by SKM into the forecasting process. Although SKM believed the description in the business case did not effectively describe the basis of the forecast on which the decision to proceed was based and could not confirm the forecasting approach that was used at the

[240] Paragraph 489, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[241] *Western Power's second submission to the Economic Regulation Authority's Draft Decision on the proposed revisions to the access arrangement for the SWIN*; Attachment F2 *Opinion by Sinclair Knight Merz* available at: http://www.erawa.com.au/cproot/7902/2/20090911%20Public%20Submission%20-%20Draft%20Decision%20-%20Access%20Arrangement%20Review%20-%20Western%20Power.pdf
[242] Page 61, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 9 September 2009.
[243] Page 61, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, SKM, 3 September 2009.

time, it concluded that: *it has seen evidence that Western Power separately identified block loads and the load forecast was conservative in comparison to the actual load growth.*[244]

SKM's concerns only relate to projects being driven by load forecasts. Any difference in opinion on the method to derive load forecasts could potentially impact the timing of network augmentations. The only regulatory categories potentially impacted by discrepancies in the timing of augmentations as a result of differing opinion on load forecasts were:

- Transmission capacity expansion $386 million
- Distribution capacity expansion $220 million

Of the net $2,061 million of capital works in AA1, only $606 million is potentially driven by load growth. To be conservative, this includes the projects in these categories that were addressing other issues, such as Technical Rules compliance. Using the method applied by the Authority in its Final Decision for AA1, 5% of the capital expenditure driven by load growth is $30.3 million.

As the 10 POE maximum demand is now similar to the maximum demand that was being forecast in AA1, the augmentations that were undertaken during AA1 could no longer be considered to be inefficiently timed. Accordingly, any capital expenditure that was disallowed during the AA1 period due to the load forecasts should be added to the capital base at the end of AA2 in accordance with the speculative investment provisions in the Access Code.

In its final decision on the access arrangement for the second access arrangement period, the ERA indicated that, while capital costs could not be added to the capital base at that time,[245] it did not provide any reason as to why they could not be added to the capital base at a later time.

Consequently, expenditure of $30.3 million previously disallowed on load-driven projects should be included in the capital base at the end of AA2.

[244] Page 18, *Review of Selected Western Power Capital Works Projects,* provided as Appendix D to *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2,* SKM, 3 September 2009.

[245] Paragraph 700, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 4 December 2009.

7.6.5 Summary of speculative investment to be included in AA3 opening capital base

Table 26 provides an overview of AA1 capital investment that addresses the Authority's four specific weaknesses and consequently meets the NFIT and should be included in the AA3 opening capital base.

Table 26: AA1 investment to be added to the capital base for satisfying the new facilities investment test

$ million real at 30 June 2012	2006/07	2007/08	2008/09	Total
Transmission				
Authority's disallowed expenditure for four specific weaknesses (transmission)	-15.1	-15.6	-16.0	-46.7
Amount of disallowed expenditure that may apply for not using best-practice design software for transmission lines	-3.7	-5.2	-2.7	-11.6
Amount of disallowed expenditure that may apply for an absence of standard designs and guidelines for distribution assets	-	-	-	-
Amount of disallowed expenditure that may apply for unusually restrictive design specifications (ring main units)	-	-	-	-
Amount of disallowed expenditure that may apply for lack of rigour in assessing options for network augmentations	-	-	-	-
Sub-Total for adjustments for Authority's four specific weaknesses (transmission)	-3.7	-5.2	-2.7	-11.6
Amount to be added to the capital base in response to four specific weaknesses (transmission)	11.5	10.4	13.3	35.2
Amount to be added to the capital base for Mid West Energy project (Southern Section) planning costs	0.2	0.5	4.3	5.0
Sub-total to be added to capital base as satisfying the new faculties investment test (Transmission)	**11.7**	**10.9**	**17.6**	**40.2**
Distribution				
Authority's disallowed expenditure for four specific weaknesses (distribution)	-21.1	-23.1	-29.0	-73.2
Amount of disallowed expenditure that may apply for not using best-practice design software for distribution lines	-	-	-	0.0
Amount of disallowed expenditure that may apply for an absence of standard designs and guidelines for distribution assets	-0.4	-0.45	-0.73	-1.6
Amount of disallowed expenditure that may apply for unusually restrictive design specifications (ring main units)	-0.10	-0.07	-0.12	-0.3
Amount of disallowed expenditure that may apply for lack of rigour in assessing options for network augmentations	-	-	-	0.0
Sub-Total for adjustments for Authority's four specific weaknesses (distribution)	-0.5	-0.5	-0.8	-1.9
Sub-total to be added to capital base as satisfying the new facilities investment test (Distribution)	**20.6**	**22.6**	**28.1**	**71.4**
Total to be added to capital base as satisfying the new facilities investment test	**32.3**	**33.5**	**45.7**	**111.5**

7.7 AA3 opening capital base

Required amendment 13:

The opening capital base for 1 July 2012 in the proposed revised access arrangement must be amended to reflect the values in Table 43 and Table 44 above.

Western Power response:

Western Power does not accept this amendment.

In its draft decision, the Authority requires that the opening capital base for 1 July 2012 in the proposed revised access arrangement be amended to reflect the values specified in the draft decision.[246]

Western Power has continued to apply the roll forward method to determine the opening capital base but has made adjustments to adopt a mid-year inflation indexation assumption. Further, Western Power does not accept the Authority's amendments in relation to AA1 and AA2 past capital investment.

Western Power has provided further information to support the inclusion of additional AA1 speculative investment and AA2 capital expenditure in the opening capital base. As a result the revenue model has been revised and results in different values for the opening capital base for 1 July 2012 to the September 2011 submission and the Authority's draft decision.

[246] Page117, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.

7.7.1 Transmission capital base

Table 27 lists the actual and forecast new facilities investment undertaken during AA2, which has been added to the capital base.

Table 27: New facilities investment to be added to the transmission capital base

Asset Group $ million real at 30 June 2012	New facilities investment		
	2009/10	2010/11	2011/12 (Forecast)
Transmission cables	4.8	2.5	2.5
Transmission steel towers	53.1	41.8	15.7
Transmission wood poles	13.5	9.7	11.5
Transmission metering	0.0	0.0	0.0
Transmission transformers	33.7	20.4	18.6
Transmission reactors	1.0	0.6	0.3
Transmission capacitors	8.7	3.3	1.9
Transmission circuit breakers	35.9	46.1	38.7
Transmission SCADA and communications	10.8	6.2	12.3
Transmission IT	10.8	15.3	19.1
Transmission other non-network assets	7.8	12.8	14.7
Transmission land and easements	22.7	12.3	11.4
Total	202.9	171.1	146.5

Table 28 details the derivation of the new facilities investment (net of capital contributions and asset disposals).

Table 28: Derivation of the new facilities investment (net of capital contributions and asset disposals) to be added to the transmission capital base

Asset Group $ million real at 30 June 2012	Year of expenditure		
	2009/10	2010/11	2011/12 (Forecast)
New facilities investment	202.9	171.1	146.5
Less asset disposals	-6.1	-0.3	0.0
Total new facilities investment (net of capital contributions and asset disposals)	**196.8**	**170.8**	**146.5**

Table 29: Derivation of transmission capital base at 30 June 2012 details the calculation of the transmission capital base value at 30 June 2012.

Table 29: Derivation of transmission capital base at 30 June 2012

$ million real at 30 June 2012	30 June 2009	30 June 2010	30 June 2011	30 June 2012 (Forecast)
Opening capital base value		2,321.4	2,443.8	2,535.0
Less depreciation		-74.4	-79.6	-90.0
Less accelerated depreciation		0.0	0.0	0.0
Plus new facilities investment (net of capital contributions and asset disposals)		196.8	170.8	146.5
Plus investment from prior periods				53.5
Closing capital base value	**2,321.4**	**2,443.8**	**2,535.0**	**2,645.1**

7.7.2 Distribution capital base

Table 30 lists the actual and forecast new facilities investment undertaken during AA2, which has been added to the capital base.

Table 30: New facilities investment to be added to the distribution capital base

Asset Group	New facilities investment ($ million real at 30 June 2012)		
	2009/10	**2010/11**	**2011/12** (forecast)
Distribution lines – wood poles	149.0	142.8	202.8
Distribution lines – steel poles	0.0	0.0	0.0
Distribution underground cables	134.6	121.2	97.3
Distribution transformers	47.9	47.2	43.2
Distribution switchgear	50.3	50.1	57.7
Street lighting	14.4	14.6	11.7
Distribution meters and services	11.9	16.4	13.1
Distribution IT	17.1	25.9	31.5
Distribution SCADA and communications	3.6	3.4	3.4
Distribution other, non-network	12.3	21.5	24.3
Distribution land and easements	0.0	0.0	0.0
Total	**441.1**	**443.2**	**485.1**

Table 31 details the derivation of the new facilities investment (net of capital contributions and asset disposals).

Table 31: Derivation of the new facilities investment (net of capital contributions and asset disposals) to be added to the distribution capital base

Asset Group ($ million real as at 30 June 2012)	Year of expenditure		
	30 June 2010	**30 June 2011**	**30 June 2012** (Forecast)
New facilities investment	441.1	443.2	485.1
Less asset disposals	-0.9	0.0	0.0
Total new facilities investment (net of capital contributions and asset disposals)	**440.2**	**443.2**	**485.1**

Table 32 details the calculation of the distribution capital base value as at 30 June 2012.

Table 32: Derivation of distribution capital base as at 30 June 2012

($ million real at 30 June 2012)	30 June 2009	30 June 2010	30 June 2011	30 June 2012 (forecast)
Opening capital base value		3,005.2	3,288.4	3,561.4
Less depreciation		-152.8	-166.1	-183.7
Less accelerated depreciation		-4.2	-4.1	-4.0
Plus new facilities investment (net of capital contributions and asset disposals)		440.2	443.2	485.1
Plus investment from prior periods				95.4
Closing capital base value	**3,005.2**	**3,288.4**	**3,561.4**	**3,954.2**

7.7.3 Inflation values

For the purposes of valuing the initial capital base the model assumes that capital investment occurs mid-year for the purposes of applying inflation. This is because this better reflects the costs incurred to establish the initial capital base.

Capital costs are incurred throughout the year, rather than at the end of the year and so it is appropriate to adjust for inflation. A mid-year timing assumption better approximates the actual timing and therefore the actual cost. An end of year timing assumption does not take into account the effect of inflation on costs incurred during the year, and results in the level of indexation in 30 June 2012 prices being understated.

Applying a different treatment to establishing the initial capital base and not applying the same approach for the notional capital base is appropriate because the opening capital base is established based on actual costs incurred during the period whereas forecast costs incorporate assumptions about timing. Further, it removes the incentive to delay capital investment to the end of the financial year. This is important given that some customers rely on investments being completed well in advance of the end of financial year, for example, the summer readiness program that must be completed before the summer season.

Western Power has applied the CPI (weighted average of eight capital cities) to determine the rolled-forward capital base value and calculated the half year inflation using the inflation figures in Table 33 and the following formula:

$$\text{half year inflation} = (\text{full year inflation}_{\text{June to June}})^{\frac{1}{2}}$$

Table 33 shows the inflation values applied when determining the rolled-forward capital base value to 30 June 2012.

Table 33: Inflation values applied when determining 30 June 2012 capital base

	30 June 2009	30 June 2010	30 June 2011	30 June 2012 (forecast)
June CPI	167.0	172.1	178.3	
Inflation	1.46%	3.05%	3.60%	1.25%

The inflation values use actual CPI data published by the Australian Bureau of Statistics for the June quarter[247] where available. Where Australian Bureau of Statistics data is not available, Western Power has used forecast CPI data from the Reserve Bank of Australia's Statement on Monetary Policy.

The revenue model is attached at Appendix A

7.8 Capital base value over AA3

Consistent with section 6.51 of the Access Code, forecast capital investment that is reasonably expected to satisfy the new facilities investment test is included in Western Power's calculation of the capital base at the end of the AA3 period (30 June 2017).

Forecast closing values at 30 June 2017 ($ million real at 30 June 2012) are:

- transmission system capital base = $3,924.1
- distribution system capital base = $6,129.6

Net new facilities investment is determined for each year as follows:

Net new facilities investment$_t$ = Forecast new facilities investment$_t$ – forecast contributions$_t$

7.8.1 Transmission capital base

Table 34 provides an overview of the forecast transmission capital base values for each year of AA3.

Table 34: Assessment of transmission capital base Table 35:

($ million real at 30 June 2012)	30 June 2012	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Opening capital base value		2,645.1	2,860.9	3,133.1	3,291.6	3,568.9
Less depreciation		-87.3	-96.3	-105.9	-113.1	-122.6
Less accelerated depreciation		0.0	0.0	0.0	0.0	0.0
Plus new facilities investment (net of capital contributions)		303.1	368.5	264.5	390.4	477.8
Less asset disposals		0.0	0.0	0.0	0.0	0.0
Closing capital base value	**2,645.1**	**2,860.9**	**3,113.1**	**3,291.6**	**3,568.9**	**3,924.1**

[247] Australian Bureau of Statistics, 6401.0 - Consumer Price Index, TABLES 3 and 4. CPI: Groups, Weighted Average of Eight Capital Cities, Index Numbers and Percentage Changes, Series Id: A2325846C, available from:http://www.abs.gov.au.

Table 36 details the derivation of forecast net transmission new facilities investment for each year of AA3.

Table 36: Transmission new facilities investment[248]

($ million real at 30 June 2012)	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Forecast new facilities investment	323.5	402.7	299.6	426.3	514.4
Less forecast contributions	20.4	34.3	35.1	35.9	36.6
New facilities investment added to the capital base	**303.1**	**368.5**	**264.5**	**390.4**	**477.8**

7.8.2 Distribution capital base

Table 37 below provides an overview of the forecast distribution capital base values for each year of AA3.

Table 37: Assessment of distribution capital base

($ million real at 30 June 2012)	30 June 2012	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Opening capital base value		3,954.2	4,386.7	4,846.0	5,289.9	5,717.2
Less depreciation		-198.2	-219.9	-244.2	-249.6	-264.8
Less accelerated depreciation		-3.4	-0.5	0.0	0.0	0.0
Plus new facilities investment (net of capital contributions)		634.1	679.7	688.2	676.9	677.1
Less asset disposals		0.0	0.0	0.0	0.0	0.0
Closing capital base value	**3,954.2**	**4,386.7**	**4,846.0**	**5,289.9**	**5,717.2**	**6,129.6**

Table 38 details the derivation of forecast net distribution new facilities investment for each year of AA3.

Table 38: Distribution new facilities investment[249]

($ million real at 30 June 2012)	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Forecast new facilities investment	725.0	760.1	761.2	750.8	752.0
Less forecast contributions	91.0	80.4	73.0	73.8	74.9
New facilities investment added to the capital base	**634.1**	**679.7**	**688.2**	**676.9**	**677.1**

[248] Western Power allocates its corporate capital expenditure between the transmission system and distribution system in accordance with the method set out in the cost and revenue allocation methodology.
[249] Western Power allocates its corporate capital expenditure between the transmission system and distribution system in accordance with the method set out in the cost and revenue allocation methodology.

8 AA3 capital expenditure

In its draft decision, the Authority accepts Western Power's proposed AA3 capital expenditure on distribution and transmission asset replacement and regulatory compliance.

The Authority notes that the proposed forecasts were *consistent with the experience of other distribution network service providers, reasonable on safety related grounds, and not unexpected as Western Power is under pressure to improve the quality of its overhead lines in extreme and high fire risk areas*.[250] The Authority also agrees with the findings of its technical consultant that the proposed expenditure for distribution customer access, reliability, SCADA and communications, smart grid and SUPP (State Underground Power Program) is reasonable.[251]

The Authority's main variation from Western Power's capital investment proposal relates to growth-related expenditure. The Authority proposes reductions to transmission and distribution growth-driven expenditure based on the latest forecasts of peak demand growth[252] and an alternative method for forecasting transmission customer driven expenditure.

The Authority also proposes reductions to transmission SCADA and communications investment relating to Western Power's master station, as the Authority considered that *System Management should pay for it, not Western Power's customers*[253].

Western Power has considered the Authority's required amendments to forecast capital expenditure, along with new requirements that have emerged since September 2011, and has adjusted its forecast to reflect:

- reductions to growth driven investment as a result of revised 2011 demand forecasts
- reductions to transmission customer driven investment arising from the Authority's forecasting method
- reductions for SPOW efficiencies (see section 6.6.1.1)
- increases in SF6 (gas insulated switchgear) costs and fuel costs arising from the impact of the Australian Government's Clean Energy Future Package and carbon tax legislation
- increases in wood pole investment to improve safety outcomes in line with the expectations of Energy*Safety* and the Parliamentary Inquiry
- increases in Western Power's negotiated distribution delivery partner unit rates
- increases in metering costs to reflect amendments to the *Electricity Industry Metering Code 2005*

[250] Paragraph 543, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[251] Paragraph 572, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[252] Paragraph 537, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[253] Paragraph 544, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

8.1 Wood pole investment

Required amendment 14:

The proposed access arrangement revisions must be amended to include expenditure relating to wood pole management in the investment adjustment mechanism.

Western Power response:

Western Power accepts this amendment.

The Authority acknowledges that the *investment for wood pole management may change as Western Power further develops its understanding of what is required*[254]. It proposes that adjusting for this expenditure through the investment adjustment mechanism (IAM) will ensure Western Power is able to incur the efficient level of expenditure required to meet its regulatory obligations.

Western Power proposes to increase its wood pole investment (outlined in section 8.2.2.2) to the greatest extent possible under current delivery constraints. This results in 204,820 additional wood pole reinforcements during the AA3 period. Expenditure related to these additional 204,820 reinforcements will be added to the forecast and recovered through the AA3 target revenue and subject to the IAM.

Western Power is also investigating options to *further* increase wood pole reinforcements *during* the AA3 period by securing the services of a second service provider and reinforcement method. This could result in up to a further 75,000 reinforcements.

Western Power proposes that the costs associated with these additional 75,000 reinforcements are not added to the expenditure forecasts, but are recovered through the IAM if they are incurred. In addition to wood pole replacement and replacement and reinforcement, Western Power proposes to add its stay wires program to the IAM.

This means customers will only pay for wood pole treatment that actually occurs. It also provides Western Power the flexibility to be able to address this critical public safety risk to the maximum extent possible during the period.

Table 39 outlines programs included in the investment adjustment mechanism for the AA3 period.

Table 39: New programs subject to the investment adjustment mechanism

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Distribution asset replacement: wood pole management	168.3	194.3	209.0	223.2	238.5	1,033.2
Transmission regulatory compliance: wood pole management	10.7	11.7	12.5	13.6	13.8	62.3
Distribution regulatory compliance: stay wires	1.5	1.5	10.8	10.9	11.1	35.9
Transmission regulatory compliance: stay wires	1.1	1.1	1.1	1.1	-	4.4
Total of new programs subject to the investment adjustment mechanism	181.6	208.6	233.5	248.9	263.4	1,135.9

[254] Paragraph 565, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

8.2 Total forecast capital investment

Required amendment 15:

The proposed access arrangement revisions must be amended to incorporate a forecast of capital expenditure as listed in Table 62.

Western Power response:

Western Power does not accept this amendment.

The Authority requires Western Power to reduce its AA3 forecast capital expenditure by 15% (or $889 million). The Authority has determined this reduction to forecast capital expenditure by:

- disallowing forecast movements in real materials costs and reducing forecast movements in real labour costs, as discussed in section 6.2
- constraining Western Power's indirect cost forecast by 13.7%, as discussed in section 6.5
- removing $564.5 million of growth-driven investment based on a broad-brush approach to applying the peak demand forecast reductions and advice from the Authority's technical consultant on projects it considers can be deferred
- reducing customer-driven expenditure by using an alternative period of historical expenditure to prepare the forecast
- removing all expenditure for Western Power's transmission SCADA and communications master station on the basis this should be paid for by the ring-fenced System Management business
- reducing Western Power's metering expenditure to reflect reduced meter replacement volumes and a Victorian benchmark for smart meter costs
- constraining Western Power's IT expenditure to historical expenditure levels

Western Power has revised its forecast capital expenditure from $5,962 million[255] to $5,997 million, an increase of $35 million compared to its September 2011 submission[256]. This is $924 million higher than the Authority's draft decision.

This is largely attributed to increases in Western Power's wood pole management program, which are required to address the Energy*Safety* Order 01-2009 and expectations from the recent Parliamentary Inquiry[257].

Though Western Power has made reductions to its forecast to reflect the Authority's amendments, including a reduction to growth-related expenditure, these new wood pole requirements combined with further new obligations resulting from: carbon tax legislation, changes to the Metering Code, increases in delivery rates and acceleration of the streetlight switchwire program, offset the reductions and result in the overall increase.

Figure 16 shows the revised capital expenditure forecast compared to the Authority's draft decision and Western Power's September 2011 submission.

[255] Including the errata submitted to the Authority on the 25 October 2011.
[256] For the purpose of this capital investment chapter, the 'September 2011 submission' includes the adjustments made to capital investment made in the errata sheet issued to the ERA on 25 October 2011.
[257] *Report no.14 of the Standing Committee on Public Administration*, 20 January 2012.

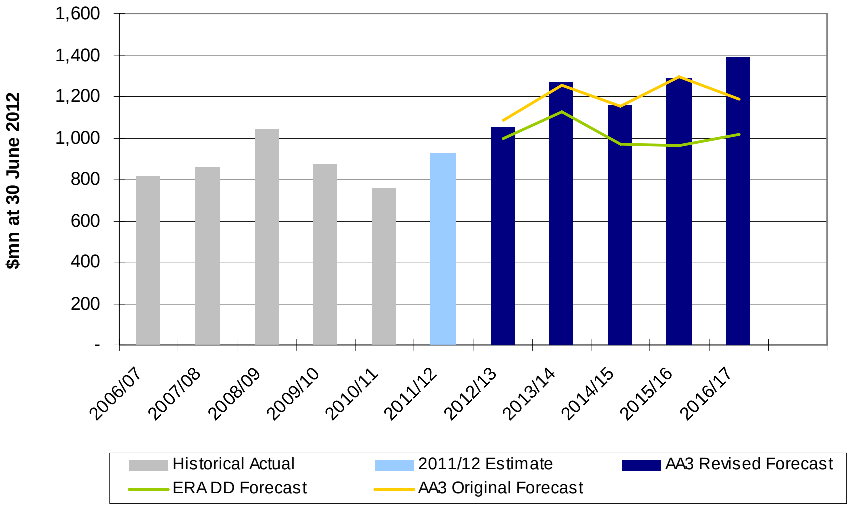

Figure 16: Western Power's revised AA3 capital expenditure

Table 40 summarises Western Power's revised proposal. The revised AA3 capital expenditure required to be recovered through reference tariffs is $5,124 million.

Table 40: Revised capital expenditure proposal

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial capital expenditure	1,073.0	1,239.2	1,158.1	1,298.4	1,193.1	5,961.8
Reduced growth investment	-19.9	-58.7	-78.8	-105.4	95.6	-167.3
Reduced transmission customer driven investment	-38.9	-14.3	-14.0	-13.8	-15.2	-96.1
Increase for carbon package	0.4	0.4	0.4	0.5	0.5	2.3
Increase for wood pole related investment[258]	56.3	71.7	81.9	84.9	85.0	379.9
Increased delivery rates	7.8	5.5	6.1	7.8	7.1	34.4
Accelerated streetlight switchwire program	8.8	8.9	-1.5	-1.5	-1.5	13.2
SPoW efficiencies	-2.0	-13.9	-14.5	-14.2	-14.0	-58.6
New obligations under the Metering Code	2.5	2.5	2.5	2.5	2.5	12.5
Other minor adjustments plus changes for indirect costs and real cost escalation	-11.8	-15.1	-16.1	-18.6	-23.2	-84.9
Revised capital expenditure	**1,076.2**	**1,226.3**	**1,124.2**	**1,240.5**	**1,329.9**	**5,997.1**
Less capital contributions	-174.8	-178.2	-171.6	-173.2	-175.0	-872.8
AA3 capital expenditure to be recovered through reference tariffs	**901.4**	**1,048.1**	**952.6**	**1,067.3**	**1,154.9**	**5,124.3**

[258] This includes the increased investment for wood pole replacement, reinforcement, stays and construction of a wood pole testing facility.

8.2.1 Transmission capital expenditure

Western Power has revised its forecast transmission capital expenditure to reflect the revised 2011 demand forecasts, revised customer-driven forecasts, the impact of the carbon tax and investment to increase the wood pole management program. The forecast has reduced by $238 million, from $2,079 million[259] to $1,842 million. This is $421 million more than the Authority's draft decision (see Figure 17).

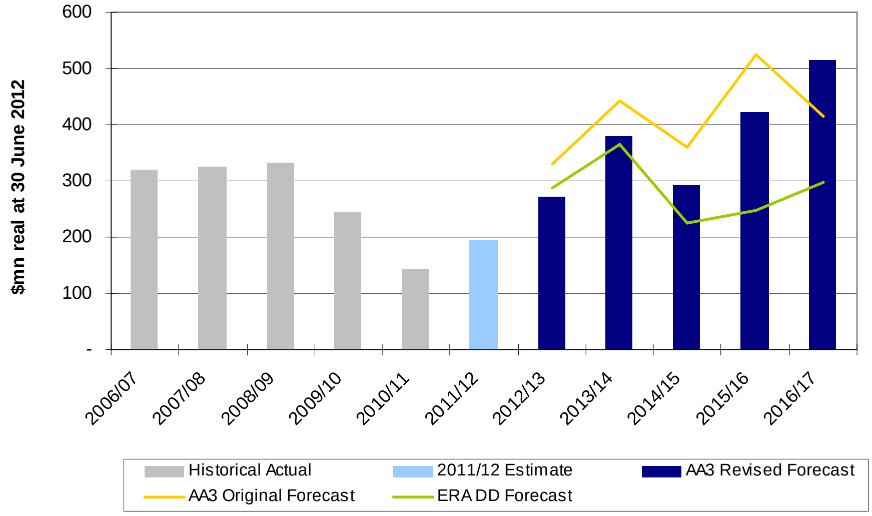

Figure 17: Western Power's revised AA3 transmission capital expenditure

Table 41 summarises the revised proposal. The AA3 capital expenditure required to be recovered through reference tariffs is $1,679 million.

Table 41: Revised AA3 transmission capital expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial transmission capital expenditure	334.3	438.2	363.3	526.9	416.7	2,079.3
Amendment to capacity expansion expenditure	-14.5	-50.4	-67.0	-104.1	98.3	-137.8
Amendment to customer driven expenditure	-38.9	-14.3	-14.0	-13.8	-15.2	-96.1
Amendment to asset replacement expenditure	-0.8	-1.8	-1.9	-2.0	-2.8	-9.4
Amendment to SCADA & Communications expenditure	-0.4	-0.4	-0.4	-0.6	-0.9	-2.7
Amendment to regulatory compliance expenditure	4.1	2.8	0.9	0.5	0.1	8.3
Revised transmission capital expenditure	**283.7**	**374.1**	**280.9**	**406.8**	**496.1**	**1,841.6**
Capital contributions	-20.4	-34.3	-35.1	-35.9	-36.6	-162.3
Revised AA3 transmission capital expenditure to be recovered through reference tariffs	**263.3**	**339.8**	**245.8**	**371.0**	**459.5**	**1,679.3**

[259] Including the errata submitted to the Authority on the 25 October 2011.

8.2.1.1 Transmission capacity expansion

Western Power has revised its forecast capacity expansion capital expenditure from $1,329 million[260] to $1,192 million. This is a reduction of $138 million to reflect the lower 2011 peak demand forecasts. This is $400 million more than the Authority's draft decision.

Mid West Energy Project

Western Power included $37.7 million in its AA3 submission for stage 2 of the Mid West Energy Project (southern section). The Authority has misinterpreted this expenditure as relating to the northern section of the Mid West Energy Project and was not satisfied that this expenditure would satisfy the NFIT. The Authority therefore removed it from forecast capital expenditure as there is considerable uncertainty regarding when the northern section of the project will proceed.[261]

However, this $37.7 million expenditure relates to the southern section of the project. It is required to allow the approved Mid West Energy Project (southern section) to be upgraded so that both sides of the double circuit operate at 330 kV. The work is necessary to accommodate forecast generation developments and new block loads in the region. The increased level of customer enquires received since the announcement that the Mid West Energy Project (southern section) passed NFIT, substantiates retaining this expenditure in the AA3 forecast.

CBD substation and supply cable

Western Power included $134 million in its AA3 submission for a new CBD substation and associated supply cable. The Authority proposes that this expenditure be removed from AA3 forecast transmission capital expenditure. The Authority is concerned that this is not a least-cost option, and that deferring this expenditure to AA4 would provide Western Power time to undertake a strategic planning study for the CBD.[262]

Since the September 2011 submission, Western Power has further developed its long-term network development plan for the CBD area. Based on the latest demand forecasts, Western Power considers that the CBD substation and associated supply cable can be deferred by two years from the date proposed in its September 2011 submission. However, a level of investment is required for the works that are required during AA3 to facilitate a deferral and manage network risk in the CBD area.

Western Power has reduced forecast expenditure in East Perth and CBD Load Area to $118.5 million. This will all allow the CBD substation and supply cable to be deferred while still allowing Western Power to address congestion issues, particularly at the Hay and Milligan Street substations. It will also address non-compliance to the N-1-1 criteria under the Technical Rules. The proposed works include completion of the conversion of the Joel Terrace substation to 132 kV and stage 1 of the James Street substation.

As previously mentioned, this revised proposal for East Perth and the CBD has been developed through further refinement of Western Power's 25-year network development plan, which Western Power was still developing at the time of its September 2011 submission. The Authority's technical consultants acknowledged this in its report to the Authority.[263]

The plan provides an economic least-cost network development strategy to address emerging limitations both within the CBD load area and supplying the CBD load area, across a 25-year horizon. The plan uses 2011 demand forecasts to review the timing of emerging limitations. The plan reviews a number of Western Power's Planning techniques, and the existing Perth CBD boundary, as defined in the Technical Rules. It integrates transmission

[260] Including the errata submitted to the Authority on the 25 October 2011.
[261] Paragraph 530, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[262] Paragraph 531-532, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[263] Section B2.3, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

and distribution planning requirements and incorporates sensitivity analysis to ensure the proposed development strategy is robust to differing generation and load scenarios.

Eneabba Terminal Station

Western Power included $18 million in its September 2011 submission for a new Eneabba Terminal Station. The Authority recommends that this expenditure be removed from AA3 forecast transmission capital expenditure because its technical consultant considered investment was uncertain given it was to support potential new wind farm generation in the area.[264]

The establishment of the Eneabba Terminal Station was based on specific localised generation connection proposals proceeding, consistent with the generation scenarios developed by ROAM[265] for Western Power's September 2011 submission. Western Power believes that this generation is likely to proceed during the AA3 period. However, the costs for the terminal are adequately provided for in the customer-driven regulatory category. These costs have been removed from the AA3 capacity expansion expenditure.

Environmental and planning

The Authority excludes capital expenditure of $56.3[266] million for environmental and planning costs from the AA3 forecast. This is based on the Authority's technical consultant's view that this expenditure would not meet the NFIT. The consultant noted that, prior to 2011/12, no expenditure was recorded to this category as all expenditure on environmental and planning was directly attributed to individual capital expenditure projects.

The Authority's technical consultant did not question the validity or need for these costs but noted that it has:

> *not come across this accounting approach in other regulatory reviews. In our experience planning costs that cannot be attributed to a specific project are treated as opex and either recovered in full in the year that the expense was incurred or capitalised through a defined cost allocation process.*[267]

Despite its consultant noting that these are valid costs, the Authority did not allow the AA3 environmental and planning costs as capital expenditure and also did not allow these costs as operating expenditure.

Western Power has amended its AA3 forecast environmental and planning costs to remove those elements of planning costs that are not directly attributable to projects from the capital expenditure forecast. Instead, these costs are included in indirect costs. Environmental and planning costs that are directly attributable to projects remain in forecast.

The September 2011 submission included environmental costs, project development costs and early strategic planning costs.

Early strategic planning costs are incurred prior to Gate 1 in Western Power's works program model and project development and environmental costs are incurred post Gate 1. Following Gate 1, costs are directly attributable to individual projects that are established to address a defined network need.

Planning and environmental costs are forecast as an individual item because the building block costs on which Western Power's transmission capacity expansion projects are based only include the components associated with design and execution of the project. They do not include the planning and environmental costs associated with assessing options or planning the investment.

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[264] Paragraph 533, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, March 2012.
[265] *Generation Scenarios for 2011 Revenue Reset Application*, ROAM Consulting, 17 February 2011.
[266] This is $59.2 million in Western Power's Access Arrangement Information September 2011, including real cost escalation
[267] Page 80, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

Although these costs were forecast as a separate cost line item, this did not mean that they will not be directly attributable to projects. Only the costs incurred prior to Gate 1, that is, early strategic planning costs, do not form part of individual project costs.

Reduced load growth

The Authority proposes that transmission supply and transmission voltage investment be reduced by $133.3 million.[268] This reflects a 40% reduction in the proposed capital expenditure forecasts put forward by Western Power in these categories. This reduction was based on an assumption that there is a direct relationship between the forecast transmission capacity expansion expenditure and the system wide peak demand forecast. As there was a 40% reduction in forecast system wide peak demand between the 2010 demand forecast and 2011 demand forecast a 40% reduction in expenditure was proposed.

Western Power does not consider that this methodology provides a reasonable estimate of efficient costs. Western Power is concerned at the Authority's technical consultant's approach as there is not a one-to-one relationship between forecast system wide peak demand and growth investment. Investment is planned at a much more granular (substation) level.

Western Power did not include the 2011 demand forecasts in its initial proposal. The business produces demand forecasts annually. These are usually not published until October of each year and were unavailable at the time of the September 2011 submission.

SKM/MMA has completed an independent review of the forecasting method, input assumptions and results of the 2011 growth forecasts. SKM/MMA considered:

> *…the methodology and its application to be commensurate with good forecasting practice.*[269]

Western Power also notes that the Authority's technical consultant stated that it had:

> *…reviewed Western Power's demand forecasting methodology and consider it consistent with good industry practice.*[270]

Western Power has undertaken a thorough review of the impact of the 2011 demand forecast on transmission growth investment and where necessary updated or amended long term strategies and project specific scopes of work. In addition to the 25-year CBD strategy provided at Appendices S, T & U, Western Power has provided the 25-year strategy for the Western Terminal load area at Appendix V. Additional load area plans are in draft, but available at the Authority's request.

Table 42 outlines the variance between the 2010 and 2011 demand forecasts for the AA3 period.[271] The years in the table reflect the first and last summer peak across the AA3 period.

Table 42: Forecast growth for the AA3 period (10 PoE)

Forecast	Peak in 2013	Peak in 2017	Demand growth (MW)
2010	4,531	5,068	537
2011	4,143	4,619	476
Variance	388	449	61

The 2013 10% POE in the 2011 demand forecast is 4,143 MW, which is 388 MW (8.6%) lower than the 4,531 MW forecast for the same summer in the 2010 demand forecast. This is a lower starting demand position.

[268] Paragraph 535, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[269] Refer to Appendices S, T & U for SKM report
[270] Page 80, *Technical Review of Western Power's Proposed Access Arrangement For 2012-2017*, Geoff Brown and Associates Ltd.
[271] 2012 reflects the summer peak of the 2011/12 financial year.

The 2011 demand forecast, incorporates a demand increase across the five years of AA3 of 476 MW which is 61 MW (12%) less than the 537 MW of growth forecast for the same period in the 2010 demand forecast. This shows a lower growth position, but importantly the peak demand is still projected to grow at a significant rate over the AA3 period.

Western Power has reassessed its investment requirement as a result of the lower demand forecast and has reduced its forecast investment by $96 million compared to its September 2011 submission. Despite the lower starting demand of 388 MW, the majority of proposed growth investment is still required at the same in service dates as initially proposed. This is driven by a number of factors, which are already placing customers at risk of long duration or widespread outages including:

- a lack of transmission investment during the AA2 period[272]
- the existing level of non-compliance with aspects of the Technical Rules
- existing capacity shortages
- AA3 projects that were not able to be scheduled for completion by their required in service dates due to delivery constraints

Western Power does not comply with aspects of the planning criteria under the Technical Rules (N-1-1 criteria) and is continuing to implement its non-cyclic rating (NCR) wind back policy that commenced in AA2. This brings Western Power in line with requirements under the Technical Rules. The reduced demand forecasts have not had any impact on the AA3 projects which are addressing these existing issues.

Table 43 provides a summary of substations where Western Power has experienced actual peak loading that is already in excess of calculated substation capacity.[273] These substations are already at risk of capacity overloads and hence no change to their expenditure forecast has resulted from the reduced demand forecasts.

Table 43: Substations where actual peak loading is already in excess of available substation capacity

Substation	AA3 project	Impact on forecast capital expenditure	2012 % loading against ideal capacity	2012 % loading against available capacity
Mandurah	Establish new substation: Mandurah in 2015/16	Nil	102.6%	115.9%
Shenton Park	Establish new substation: Shenton Park in 2015/16	Nil	96.3%	113.0%
Meadow Springs	Meadow Springs additional transformer in 2017/18	Nil	72.4%	112.0%
Osborne Park	Establish new substation: Osborne Park in 2016/17	Nil	100.4%	110.9%
Bunbury Harbour	Establish new substation: Dalyellup in 2016/17	Nil	108.1%	108.1%
Padbury	Wangara 2nd Transformer in 2014/15	Nil	86.3%	105.1%

In the September 2011 submission, the agreed in service dates (AIS) for many projects had already been deferred one or more years beyond their required in service dates (RIS) due to

[272] This was described in section 8.2.2 of Western Power's Access Arrangement Information for 1 July 2012 to 20 June 2017, dated September 2011.

[273] In practice it is unrealistic to achieve perfect balancing across all transformers within a substation due to inherent diversity in feeder loads on switchboards. This unbalance is taken into account when determining overall substation capacity for planning purposes.

the need to secure regulatory or environmental approvals. The lower load forecasts compared to the 2010 demand forecast have not changed project timelines in the majority of cases. However, they have resulted in RIS that more closely align to AIS dates, which moderately reduces the number of customers at risk of long duration or widespread outages.

Kojonup-Albany 132 kV Line Reinforcement

The Authority proposes that two load-driven projects be deferred from the AA3 period; namely the Kojonup-Albany line projects and the 132 kV Mungarra-Geraldton.[274]

The recommendation to defer the Kojunup-Albany 132 kV line was based primarily on the reduction in system-wide peak demand between the 2010 and 2011 demand forecasts.

The Authority's proposed deferral does not consider existing network constraints on supply to the Albany area. There are currently severe restrictions on transfer capability to the Albany region. Demand has already reached the point where there is insufficient transmission capacity to meet the planning criteria in the Technical Rules. Western Power is pursuing a number of options to address this issue including contracting for network control services. As the reduced demand growth has no effect on existing transfer capability constraints, the investment remains in the forecast.

To determine the optimum timing of the Albany-Kojunup 132 kV reinforcement, Western Power compared forecast annual network control service costs against annualised network reinforcement costs. On the basis of this analysis, network control service costs were proposed to efficiently defer network reinforcement until 2017.

Since the September 2011 proposal, environmental approval requirements have resulted in the project being deferred by one year to 2018. Though deferral does not impact the proposed AA3 network control services operating expenditure, it has shifted transmission capital expenditure by one year, reducing the forecast transmission capital expenditure by $2.6 million.

Mungarra-Geraldton 132 kV Line Reinforcement

The Authority has proposes that all expenditure for the new Mungarra-Geraldton 132 kV line be deferred.[275] This recommendation is based on the Authority's technical consultant's view that the proposed line reinforcement is:

- *growth-driven, with timing influenced by a lower system wide peak demand forecast in the 2011 demand forecast compared with that published in the 2010 demand forecast*

and

- *not consistent with the proposed MWEP (northern section)*[276]

The Authority's proposed deferral does not account for existing network constraints on supply to the North Country area. There are currently severe restrictions on transfer capability to the North Country region. The demand has already reached the point where there is insufficient transmission capacity to meet the planning criteria in the Technical Rules. Western Power is pursuing a number of options to address this issue including contracting for network control services. As the reduced demand forecast has no effect on existing transfer capability constraints, the investment remains in the forecast.

To determine the optimum timing of the Mungarra-Geraldton 132 kV reinforcement Western Power compared forecast annual network control service costs in the area against annualised network reinforcement costs. On the basis of this analysis, network control service costs were proposed to efficiently defer network reinforcement until 2017. There has

[274] Paragraph 536, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, March 2012.
[275] Paragraph 536, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[276] Paragraph 536, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

been no change to the forecast for the required operating or capital expenditure for this project.

The Authority also raises concerns that the proposed reinforcement option is not consistent with previous publications on the Mid West Energy Project Northern Section. Planning is underway to identify the optimal solution to ensure reliable and secure supply for underlying demand in the region, as well as accommodating new block loads and new generation.

Ongoing planning work may identify that higher capacity options are preferable to given the additional benefits delivered in terms of connecting block loads and new generation. Therefore the costs of the Mungarra-Geraldton 132 kV reinforcement remains in Western Power's AA3 expenditure forecast as it represents the minimum capital expenditure required to address safety and reliability constraints in the Geraldton area relating to underlying demand.

Conclusion

Table 44 and Figure 18 summarise the amendments to the transmission capacity expansion expenditure.

Table 44: Revised AA3 transmission capacity expansion expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial expenditure[277]	201.4	300.8	215.1	364.3	247.7	1,329.3
Mid West Energy Project[278]	-2.2	-6.8	0.4	0.4	-0.4	-8.6
CBD substation and supply cable	1.3	2.3	-9.2	-63.4	53.6	-15.5
Eneabba terminal station	-	-	-3.1	-13.6	-1.5	-18.2
Revised forecasts as a result of 2011 demand forecasts[279]	-13.6	-46.0	-55.1	-27.4	46.6	-95.5
Revised expenditure	186.9	250.4	148.0	260.2	346.0	1,191.5

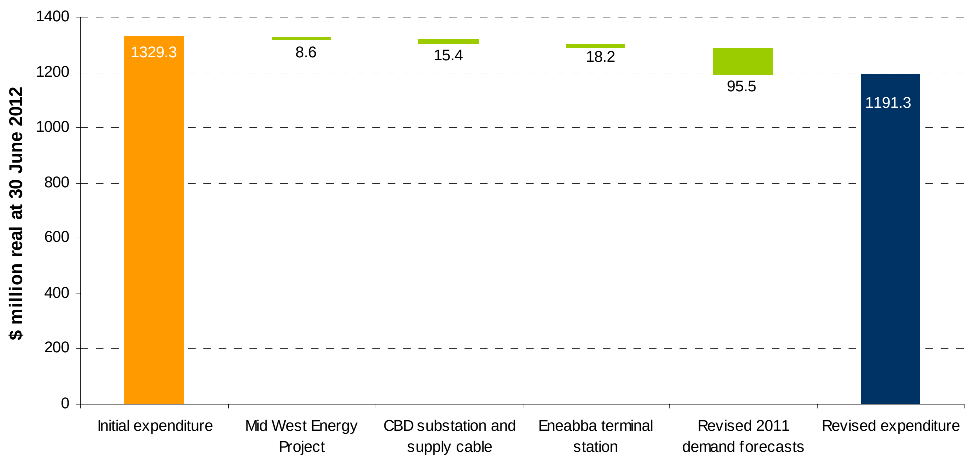

Figure 18: Revised AA3 transmission capacity expansion expenditure

[277] Including the errata for Mid West Energy Project.
[278] This reduction includes a minor reduction to the Mid West Energy project amount submitted in Western Power's errata to the September 2011 submission to align with the Mid West Energy project amount in the Authority's NFIT pre-approval and the impact of amendments to indirect costs and real cost escalation.
[279] These costs include environmental and planning costs which have now been directly allocated to individual projects as outlined in section 8.2.1.1.

8.2.1.2 Transmission customer-driven

Western Power has revised the forecast customer driven capital expenditure from $378 million to $282 million. The reduction of $96 million adopts the Authority's draft decision methodology and revised project-specific forecasts for 2012/13. This is $5 million less than the Authority's draft decision.

Western Power has revised the proportion of forecast capital contributions from 50% to 53.3%, adopting the methodology used in the Authority's draft decision. Western Power has also adjusted the most recent 2011/12 forecasts and accounted for the different nature of contributions for different activities. This is $45 million less than the Authority's draft decision.

Customer-driven expenditure

The Authority and its technical consultant considers that the forecast average gross customer driven capital expenditure should be adjusted so it exceeds the average in the current access arrangement period by only 10%.[280] This forecast method is reasonable as it reflects Western Power's recent history and adjusts for future growth.

Western Power has replicated this method by adjusting for the most recent 2011/12 expenditure forecast[281], as shown in Table 45. Based on this methodology, the revised customer-driven forecast expenditure (excluding real cost escalation) for the period 2013/14 to 2016/17 is $57.9 million per annum.

The annual planning cycle, revealed project specific forecasts for 2012/13 of $34.4 million.

Table 45: Transmission customer driven historical average expenditure calculation

$ million real at 30 June 2012	2009/10	2010/11	2011/12	Average of AA2 period	Average + 10%
Transmission line relocations	7.6	3.1	3.0	4.6	5.0
Customer access expenditure	51.2	39.1	53.9	48.1	52.9
Total customer driven expenditure	58.8	42.2	56.9	52.6	57.9

Capital contributions

The Authority and its technical consultant consider that forecast capital contributions should be increased to the historical levels received during the first and current access arrangement periods.[282]

The Authority proposes a 65% recovery rate on the basis that this is the average contribution rate across the first and current access arrangement periods. Western Power agrees that the Authority's method of averaging the contribution rate is reasonable, however, Western Power has not been able to reconcile the value of 65%.

The transmission customer driven category consists of two activities; transmission customer access and transmission line relocations. The Authority's forecast method is reasonable for transmission customer access activities however transmission line relocations are expected to be 100% funded by contributions.[283]

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[280] Paragraph 540, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[281] The 2011/12 forecast has been based on year to date actual expenditure to March 2012 and a forecast for April to June 2012.
[282] Paragraph 541, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[283] This is in line with section A8.19 of the Electricity Networks Access Code 2004 which states: *The maximum contribution for an applicant who seeks… (c) to have an existing network asset relocated;… is the forecast cost for the required work*. As a consequence, Western Power charges a capital contribution of 100 per cent for relocations.

Western Power has determined a contribution rate for transmission customer access by averaging contributions received across the AA1 and AA2 periods and adjusting for the most recent 2011/12 expenditure forecast (see Table 46**)**.

Table 46: Transmission customer driven historical average contribution rate calculation

$ million real at 30 June	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	Average
Customer access expenditure	95.8	98.0	59.6	51.2	39.1	53.9	66.3
Customer access contributions	39.3	58.1	10.9	35.9	17.0	50.6	35.3
Average recovery rate							53%

The revised contribution rate is 53.3%, compared to 50% used in Western Power's September 2011 submission. The forecast contribution rate of 100% for transmission line relocations remains.

Table 47 shows the revised forecast gross and net transmission customer driven expenditure.

Table 47: Revised AA3 transmission customer driven expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial expenditure	73.4	74.0	75.2	76.5	79.0	377.9
Transmission line relocation expenditure	4.3	5.2	5.3	5.4	5.6	25.9
Transmission line relocation contributions	-4.3	-5.2	-5.3	-5.4	-5.6	-25.9
Transmission customer access expenditure	30.1	54.6	55.9	57.1	58.3	255.9
Transmission customer access contributions	-16.0	-29.1	-29.8	-30.4	-31.1	-136.4
Net total customer driven expenditure	14.0	25.5	26.1	26.7	27.2	119.5

8.2.1.3 Transmission SCADA & Communications

The Authority recommends that expenditure for Western Power's master station ($15.5 million) be removed from the forecast capital expenditure[284]. This is on the basis that if the SCADA XA/21 master station is for the use of the 'ring-fenced' system management business, System Management should pay for it, not Western Power's customers.[285]

The Authority invited Western Power to respond by stating:

> *if Western Power does need to use the master station for its activities then it should provide detailed information of the need, in its response to this draft decision.' The $15.5 million included in the original submission for the XA/21 master station is for replacement*

[284] Paragraph 544, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[285] Paragraph 544, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

> *of the emergency back-up generator, and airconditioning chillers, and should therefore be included in the original submission capex.*[286]

Western Power has not amended the forecast expenditure as the master station is required to provide security to Western Power's customers. The following section clarifies the difference in roles between 'System Management' and 'System Management (Markets)', and explains the role of the SCADA XA/21 master station.

System Management is a division of Western Power. It is responsible for ensuring sufficient capacity, system integrity and network configuration to meet the predicted load and to provide centralised control and access to the Western Power Network. The SCADA XA/21 master station is vital to deliver this functionality and to ensure that Western Power, as the network service provider, can meet its obligations under the Technical Rules including:

- to monitor and control power system performance to meet power system performance standards (for example, maintenance of steady state nominal voltages through automatic/manual transformer tap changing controls) (Technical Rules, Sections 2.2, 2.3.9 to & 3.2.1)
- to monitor power quality to ensure the network is operating within correct tolerances of the acceptable (planned) limits (Technical Rules, Section 3.3)
- to provide operational co-ordination of the power system, which includes the requirement to "coordinate high voltage switching procedures and arrangements in accordance with good electricity industry practice in order to avoid damage to equipment and to ensure the safety and reliability of the power system" (Technical Rules, Section 5.3.1)
- allow for the automatic transfer of affected loads in the event of an unplanned outage in the Perth CBD (Technical Rules, Section 2.5.3)

The SCADA XA/21 master station is used to monitor and control the transmission network. It interfaces with the transmission network via a suite of remote terminal units located in transmission substations. The data captured through the SCADA XA/21 master station enables Western Power to calculate and report on performance against the service standard benchmarks set out in the access arrangement and broader performance and compliance measures as detailed in the *ERA's Electricity Compliance Reporting Manual*[287] .

System Management (Markets) is the 'ring-fenced' business unit within the System Management Division. The Wholesale Electricity Market Rules define the functions of System Management (Markets).

System Management (Markets) is responsible for managing and reporting generation data and monitoring market compliance for the Independent Market Operator (IMO). System Management (Markets) uses the System Management Market IT System (SMMITS) to provide this function. There are defined boundaries between 'SMMITS' the asset owned by System Management (Markets) and the SCADA XA/21 master station owned by System Management Division.

The SCADA XA/21 master station enables System Management (Markets) to monitor generators connected to the transmission network and to control some of the generators where System Management (Markets) has been given this authority. The number of generator monitoring and control points is only a very small proportion of the total (0.4% of the total number of transmission SCADA points). Some of these generation points are captured in the SCADA database and transferred to SMMITS which in turn is provided to the IMO for use in Wholesale Electricity Market settlements and compliance.

[286] Paragraph 544, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[287] Available at: http://www.erawa.com.au/cproot/6461/2/20080401 Electricity Compliance Reporting Manual including Corrigenda.pdf.

8.2.1.4 Transmission asset replacement

Western Power has revised the forecast asset replacement capital expenditure from $173 million to $163 million. This increase reflects an increase in the unit price of assets containing SF6 gas as a result of the Australian Government's Clean Energy Future Package and carbon tax legislation, offset by efficiencies to be achieved from strategic IT projects.

Carbon tax legislation and associated policies

The AA3 forecast operating and capital expenditure will need to increase to reflect the impact of new obligations and increased costs associated with the Australian Government's recently announced Clean Energy Package including the carbon tax and associated policies.

The key legislative changes that will directly affect Western Power's activities include changes to the Ozone Protection and Synthetic Greenhouse Gas (Manufacture Levy) Amendment Act 2011 and Ozone Protection and Synthetic Greenhouse Gas (Import Levy) Amendment Act 2011. This legislation will increase forecast AA3 capital expenditure costs associated with SF6 filled switchgear.

SF6 gas is used in transmission gas filled switchgear, therefore Western Power expects that the unit price of assets containing SF6 gas will increase and thereby increase asset replacement costs.

Western Power estimates that 80% of its SF6 relates to asset replacement (and the remaining 20% relates to operating and maintenance activities). Western Power has assumed that the average annual usage will reflect the volume of SF6 assets used over the last three years (see Table 48).

Table 48: Western Power's actual SF6 volume: 2008/09 to 2010/11

	2008/09	2009/10	2010/11	Average
Total SF6 assets (kg)	10,130	9,360	8,570	9,353

As a result, the forecast asset replacement costs will increase by $2.3 million over AA3 (see Table 49).

Table 49: Revised transmission asset replacement: SF6

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
SF6 carbon tax impact	0.4	0.4	0.4	0.5	0.5	2.3

8.2.1.5 Transmission regulatory compliance

As detailed in section 8.2.2.2 below, Western Power has continued discussions with Energy*Safety* regarding the wood pole management program since the September 2011 submission.

To meet Energy*Safety* expectations, as outlined in Energy*Safety* Order 01-2009 as well as the recent Parliamentary Inquiry findings, Western Power has reviewed its forecast investment pole replacement and pole reinforcement.

Western Power has revised its forecast transmission regulatory compliance capital expenditure from $121 million to $129 million, an increase of $8 million, to reflect the identified increased costs of wood pole management, offset by efficiencies to be achieved from strategic IT projects.

This forecast expenditure reflects an average increase of 70 pole replacements and average reduction of 36 pole reinforcements per year. Combined with the distribution requirements, this represents the maximum number of wood poles which can be reinforced with current delivery constraints.

The stay replacement program forecast for the AA3 period has reduced due to higher than anticipated volumes being completed in 2011/12.

Table 50 outlines the original and revised forecast volumes and expenditure for transmission pole replacement, pole reinforcement and stay replacements.

Table 50: Original and revised forecast volumes and expenditure for transmission pole replacement, pole reinforcement and stay replacements

$ million real at 30 June 2012	Initial submission volumes	Revised submission volumes	Initial submission expenditure	Revised submission expenditure
Pole replacement	2,600	2,950	39.5	53.5
Pole reinforcement	3,940	3,760	8.2	8.9
Stay replacement	1,504	1,240	4.7	4.4

8.2.2 Distribution capital expenditure

Western Power has revised its forecast distribution capital expenditure from $3,581 million to $3,850 million. This is an increase of $269 million from the initial proposal and is $476 million more than the Authority's draft decision.

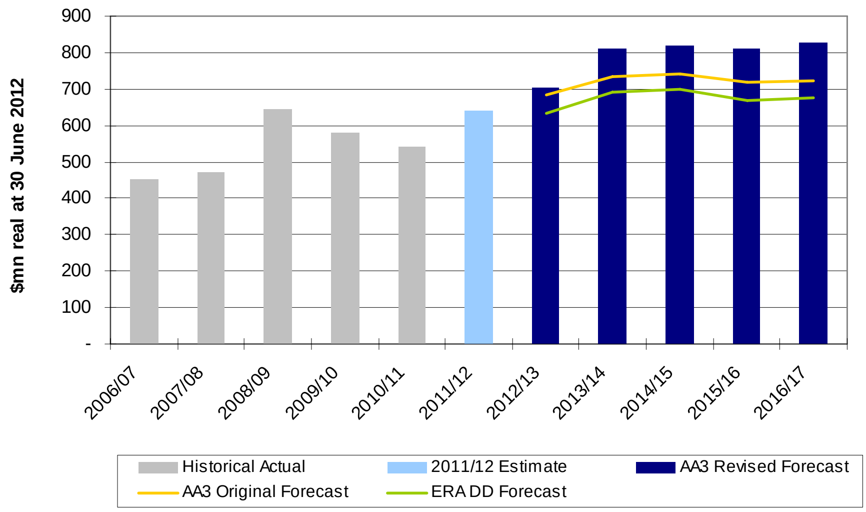

Figure 19: Western Power's revised AA3 distribution capital expenditure

Western Power has revised the forecast distribution capital expenditure to reflect the impact of the carbon tax, revised requirements for wood pole management, increases to delivery rates, acceleration of the streetlight switch wire program and amendments to the Metering Code and the 2011 peak demand forecast.

Table 51 outlines the revised forecast. The AA3 capital expenditure required to be recovered through reference tariffs is $3,140 million.

Table 51: Revised AA3 distribution capital expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial expenditure	662.3	726.7	745.3	719.4	727.4	3,581.1
Amendment to capacity expansion expenditure	-5.4	-8.3	-11.8	-1.3	-2.7	-29.5
Amendment to asset replacement expenditure	50.9	60.5	64.2	66.9	66.6	309.0
Amendment to regulatory compliance expenditure	14.6	8.9	8.0	10.5	9.9	52.0
Amendment to other categories for indirect costs and real cost escalation	-9.3	-11.7	-11.9	-13.4	-16.1	-62.4
Revised capital expenditure	**713.1**	**776.1**	**793.8**	**782.1**	**785.1**	**3,850.2**
Capital contributions	-154.4	-143.9	-136.5	-137.3	-138.3	-710.5
Revised expenditure to be recovered through reference tariffs	**558.7**	**632.2**	**657.3**	**644.8**	**646.8**	**3,139.7**

8.2.2.1 Distribution capacity expansion

Western Power has revised the forecast distribution capacity expansion capital expenditure from $414 million to $384 million. This reduction of $29 million reflects the reduced expenditure requirements as a result of the lower 2011 peak demand forecasts. This is $76 million more than the Authority's draft decision.

Transmission-driven distribution works

The Authority proposes that transmission-driven distribution capacity expansion expenditure should be limited to 10% of associated transmission expenditure noting that *this 10 per cent limit is conservative based on historical data.*[288] The Authority's technical consultant found *it difficult to see why the distribution costs should be, on average, greater than about 10 per cent of the associated costs of the transmission equipment that drives the expenditure*.[289]

Western Power has undertaken detailed modelling and produced forecast expenditures based on the building blocks method of estimating as described in the September 2011 proposal.

Western Power has analysed a sample of transmission projects across AA1 and AA2 to determine, on average, the associated distribution costs and to asses the method adopted by the Authority's technical consultant.

The consultant did not compare the total cost of the transmission project and the related distribution project over their entire project lifecycle. Comparing total project costs determines the average cost ratio between transmission and associated distribution works and accounts for projects that may have been started and completed in different regulatory periods.

Western Power's assessment looked at a variety of transmission projects including:

- implementation of a new zone substation
- upgrade of an existing zone substation (2nd or 3rd Transformers installations)
- voltage conversions

[288] Paragraph 552, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[289] Paragraph 552, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

The analysis found that on average, the cost of the distribution works was approximately 26% of the associated transmission project costs.[290] The findings of this analysis are consistent with the estimated costs for transmission and associated distribution projects in AA3.

Reduction in demand growth – HV distribution projects

The Authority proposes that minor distribution capacity expansion capital expenditure should be reduced by 20% as a result of the recommended 40% reduction to transmission capital expenditure. Its technical consultant proposes a 20% reduction as *it would not expect the correlation to be as direct as that for transmission driven capital expenditure. The Authority agreed that 20 per cent is a reasonable approximation*.[291]

The Authority's approach incorrectly assesses the impact of a reduction in the system wide forecast peak demand.

Western Power has reassessed its investment requirement as a result of the lower demand forecast and has determined that forecast investment for HV driven projects will reduce by $42 million compared to the September 2011 submission.

HV distribution works, which the Authority's technical consultant has referred to *as 'minor distribution capacity expansion projects'*, are aimed at addressing:

- over-utilisation of distribution feeders (greater than 80%)
- voltage compliance issues on long country feeders

Over-utilisation of distribution feeders was recognised as an issue by the Authority's technical consultant:

> *Utilisation of some distribution feeders is greater than 80% which is high by industry standards….Reduction of high distribution feeder utilisation is consistent with good industry practice…*[292]

Figure 20 demonstrates the variance in metro feeders with more than 80% utilisation between the 2010 and 2011 demand forecasts for the AA3 period. Feeders with more than 80% utilisation at 10% Probability of Exceedence (PoE) formed the basis for Western Power's September 2011 proposal. With the reduction in the demand forecast, the number of feeders with more than 80% utilisation reduced from 343 to 309, a 9.9% reduction.

[290] This analysis is presented in Appendix N.
[291] Paragraph 554, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[292] Page 96, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

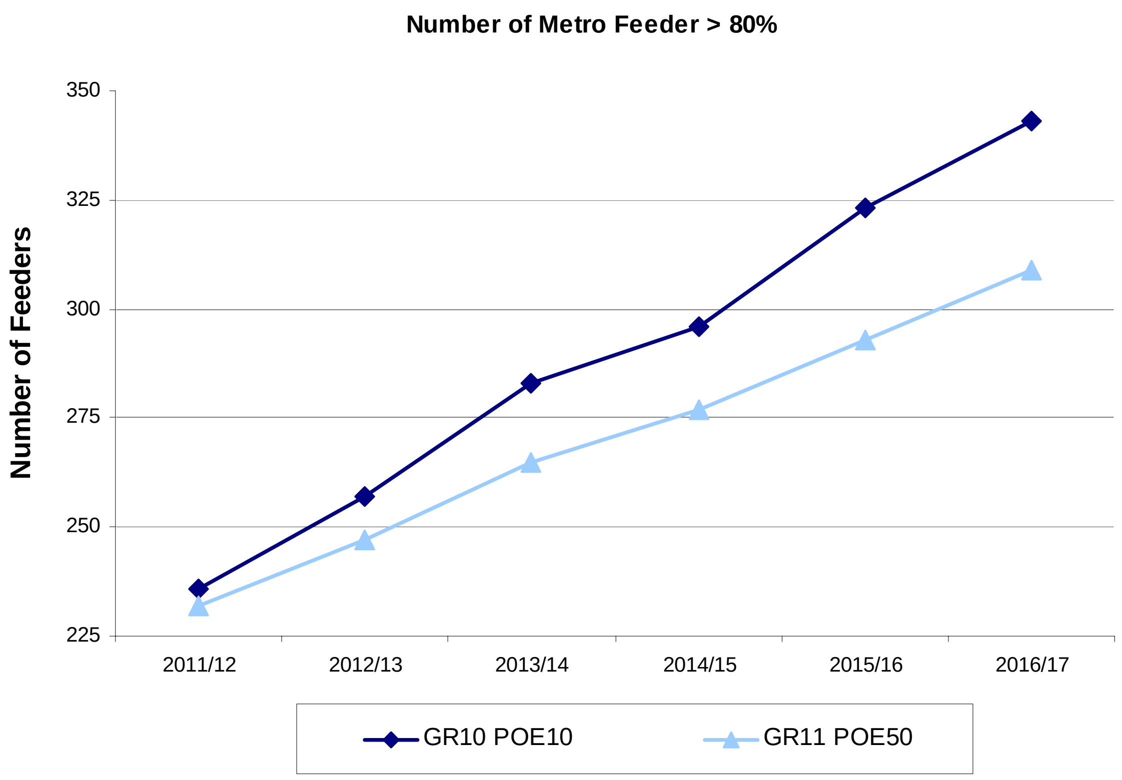

Figure 20: Number of metro feeders with utilisation over 80%: assessed for the 2010 and 2011 demand forecasts

8.2.2.2 Distribution asset replacement

Western Power has revised the forecast asset replacement capital expenditure from $919 million to $1,228 million. This increase of $309 million reflects the revised wood pole management plan which includes an increase in the volume of reinforcements to the maximum deliverable. Expenditure on distribution asset replacement is $342 million more than the Authority's draft decision.

Wood pole investment

The distribution wood pole management plan submitted as part of the initial proposal specified that Western Power would replace 97,500 aged and poor condition distribution wood poles during AA3. This is the maximum number of poles that can be replaced during the period due to current materials and delivery constraints. These pole replacements were to be complemented with 12,000 distribution wood pole reinforcements per year.

The September 2011 submission was consistent with a sustainable rate of wood pole replacement over 20 years, and would have provided an improvement in safety across the network. The Authority accepted the forecast expenditure ($748 million) in relation to wood pole management in its draft decision. Further, the Authority proposed that the costs of wood pole management be subject to the investment adjustment mechanism.

Since the initial proposal, Western Power has continued to discuss its proposed wood pole management program with Energy*Safety*. In a letter dated 5 December 2011, Energy*Safety* advised that it cannot accept prolonging the very significant community safety risk over the next 20 years.

Further, in its submission to the Authority in response to the *Issues Paper on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network*, Energy*Safety* recommended that a different mix of replacement or reinforcement could provide a better outcome. As part of the ongoing dialogue with Energy*Safety* and following the recent Parliamentary Inquiry into Western Power's wood pole network, Western Power has reviewed its wood pole management program.

Western Power cannot currently increase the number of distribution pole replacements during the AA3 period, but can increase the rate of distribution pole *reinforcement* to 45,000 in 2012/13 and 55,000 in the following four years of the AA3 period. There has also been an increase of transmission pole replacement and reinforcement volumes. This represents the maximum number of wood poles Western Power's current service provider can reinforce.

The additional cost of this rate of reinforcement is $255 million over the period, bringing the total cost of the wood pole management program to $1,136 million[293] over the AA3 period. Western Power considers that this increased expenditure should be included in the AA3 target revenue to ensure the costs of financing this program can be recovered.

In addition, Western Power is investigating opportunities to increase wood pole reinforcement by a further 75,000 poles over the AA3 period. This would require the use of a second service provider and second method of reinforcement. Western Power's current wood pole management position is included at Appendix W.

Western Power proposes that costs associated with this additional 78,740 wood poles reinforcement be managed through the investment adjustment mechanism. The cost of this further investment is estimated at $103.6 million.

Table 52: Original and revised forecast volumes and expenditure for distribution pole replacement and pole reinforcement

$ million real at 30 June 2012	Initial submission volumes	Revised submission volumes	Initial submission expenditure	Revised submission expenditure
Pole replacement	97,500	97,500	617.2	695.0
Pole reinforcement	60,000	265,000	83.5	338.3

Increase in delivery rates

Western Power has revised its proposal to reflect an increase in the unit rates for a number of asset replacement programs that are delivered by Western Power's distribution delivery partners (DDPs). This is an increase of $10 million compared to the September 2011 submission and applies to $192 million (16%) of the distribution asset replacement program.

Western Power's Works Delivery Strategy is based on the balanced portfolio approach.[294] The balanced portfolio involves delivering distribution preventative maintenance, asset replacement and growth driven programs using a mix of Western Power's internal workforce, external contractors (including DDPs) and preferred vendors.

The DDPs comprise major national service providers who together provide flexible delivery of distribution construction and maintenance services.

Western Power negotiated the initial umbrella deed contract with three DDPs in April 2010 following an extensive tender process and benchmarking of east coast distribution network operators. In the initial proposal, Western Power forecast a contract price increase in the order of 6% based on market conditions at that time. The DDP service umbrella deed provides for annual price re-negotiations and further promotes price efficiencies by maintaining the competitive tensions between the delivery partners.

The annual price re-negotiations occurred in September and October 2011. The DDPs proposed increases in excess of Western Power's assumed contract price increase for reasons including:

[293] The total wood pole management program includes transmission and distribution pole replacements, pole reinforcement and stays as outlined in Table 27: New facilities investment to be added to the transmission capital base.
[294] Page 73, Access Arrangement Information and Appendix A, Western Power, September 2011.

- labour rate increases above CPI arising from market resource constrained in the face of increasing demand
- increase in capital expenditure set up costs in line with work delivery growth requirements
- risks being borne by the DDPs as a result of uncertainty over work programming and work delays

Western Power tested these reasons as part of the negotiation process, undertaking a review of the costs and profits presented by the delivery partners as described in Appendix Z. The profit margin being sought by the DDPs was in line with what was generally expected in the industry across other jurisdictions.

The negotiation process resulted in average price increases 14% across the affected programs. For Western Power’s largest volumetric programs, wood pole replacements, increases were constrained to be in line with the forecast contract price increase. Western Power also provided more certainty on the forward work volumes to reduce the risk component of the delivery partner costs. Subsequently, one distribution delivery partner withdrew from the market due to ongoing operating losses.

As a result, the revised forecast for distribution asset replacement programs delivered by the DDPs has increased by 1%.

Increase in pole replacement rates

The increase in the unit rates for pole replacements has been revised upwards by $76 million (15%) compared to the September 2011 submission.

In December 2011, Western Power advised the Authority of increases to the wood pole replacement unit rates. Western Power engaged KPMG following the September 2011 submission to provide assurance on Western Power’s forecasting methodology for pole unit rates, and requested KPMG to review the current forecasting methodology and identify an appropriate method to calculate new wooden pole replacement unit rates. KPMG reviewed the unit cost forecasting methodology and associated data for pole replacements and estimated a revised set of unit rates using top-down and bottom-up forecasting approaches.

As a result Western Power is satisfied that the unit rates included in the revised proposal are accurate and in line with recent experience in 2011/12.

Table 53: Revised AA3 distribution asset replacement capital expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial expenditure	160.4	172.1	181.4	194.7	210.7	919.3
Amendment to conductor management expenditure	0.7	0.9	1.1	1.2	0.9	4.7
Amendment to protective device management expenditure	0.2	0.4	0.4	0.6	0.4	2.1
Amendment to transformer management expenditure	0.3	0.4	0.5	0.6	0.5	2.3
Amendment to switchgear management expenditure	0.1	0.1	0.1	0.1	0.0	0.3
Amendment to pole management expenditure	50.5	66.4	69.9	72.8	73.0	332.5
SPOW efficiencies	-0.9	-7.5	-7.7	-8.2	-8.1	-32.4
Amendment to other categories for indirect costs and real cost escalation	-0.1	-0.1	-0.0	-0.0	-0.1	-0.5
Revised expenditure	211.3	232.6	245.6	261.6	277.3	1,228.3

8.2.2.3 Distribution regulatory compliance

Western Power has revised the forecast regulatory compliance capital expenditure from $485 million to $537 million. The increase of $52 million reflects the revised requirements of wood pole management plan including stay wires, the increase in delivery rates and the acceleration of the streetlight switchwire program. This is $70 million more than the Authority's draft decision.

Western Power has amended the following programs in response to the progress achieved with Energy*Safety* on reducing the safety risk associated with Western Power:

- stay wires (regulatory compliance program)
- wood pole testing facility (see section 8.2.3.1)

Stay wires

Stay wires are cables attached between a transmission or distribution pole and an anchor point. They are used to support poles that have high forces applied to them by overhead equipment such as conductors and transformers and by environmental factors such as high wind.

Stay wires are conductive as they are constructed from steel. In order to prevent stay wires becoming live as a result of conductor failure, stays are fitted with a strain insulator of sufficient resistance in installations where they are in potential reach of the public or other risk mitigation steps are required.

The stay wire program is being increased as a complementary method of reducing public safety risk from Western Power's wood pole networks.

In the September 2011 submission, approximately 6,176 distribution and transmission stays were planned for remediation. Based on information at that time, this addressed 75% of non-compliant stay and insulators.

In response to discussions with Energy*Safety* and updated information from inspections and asset data, a further 19,464 stays have been estimated to need remediation. For transmission the number of stays required to be addressed in AA3 is lower than the initial submission as Western Power has been able to deliver increased volumes of transmission stays remediation during AA2

If the forecast volume of work in the September 2011 submission is maintained, approximately 16,000 distribution stay conditions will remain unaddressed at the end of AA3.

The increase in expenditure of $30 million required for the stays program is included in the distribution regulatory compliance category of expenditure.

It is proposed that investment in stays is also subject to the IAM to provide Western Power the flexibility to be able to address this critical public safety risk to the maximum extent possible during the period.

Table 54: Original and revised forecast volumes and expenditure for distribution and transmission stay wires

$ million real at 30 June 2012	Initial submission volumes	Revised submission volumes	Initial submission expenditure	Revised submission expenditure
Distribution stay replacement	4,670	24,400	5.6	35.9
Transmission stay replacement	1,504	1,240	4.7	4.4

Increase in delivery unit rates

Western Power has revised the proposed expenditure to reflect an increase in the unit rates for a number of regulatory compliance programs that are delivered by the distribution delivery partners (DDPs). This is an increase of $23 million compared to the initial proposal and applies to $392 million (73%) of Western Power's distribution regulatory compliance portfolio. The programs impacted by these increases are outlined in Table 55.

Table 55: Revised AA3 distribution regulatory compliance capital expenditure

$million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial expenditure	100.7	107.3	110.4	79.3	87.6	485.3
Amendment to bushfire management expenditure	2.7	3.5	3.6	4.3	4.1	18.3
Amendment to substandard conductor clearance and river crossings expenditure	0.3	0.4	0.5	0.6	0.6	2.5
Amendment to overhead customer service connections and URD pillars expenditure	3.2	-0.3	-0.3	0.2	0.2	2.9
Amendment to pole top switches expenditure	0.1	0.2	0.2	0.2	0.2	0.8
Amendment to stay wires expenditure	0.4	0.4	9.7	9.8	9.9	30.2
Amendment to streetlight management expenditure	8.8	8.9	-1.5	-1.5	-1.5	13.2
Amendment to transformer poles expenditure	-0.1	-0.2	-0.2	-	-	-0.4
SPOW efficiencies	-0.5	-3.7	-3.7	-2.8	-2.9	-13.7
Amendment to other categories for indirect costs and real cost escalation	-0.3	-0.3	-0.3	-0.3	-0.7	-1.9
Revised expenditure	115.4	116.2	118.4	89.8	97.5	537.3

Accelerated streetlight switchwire program

Overhead streetlight switchwires are used to switch streetlights from streetlight control boxes and provide power for the streetlights. The Streetlight Switchwire Replacement program aims to remove streetlight switchwires in poor condition, which have the potential to cause electric shocks and streetlight outages.

This program's risk ranking was reassessed following the serious incident in Geraldton in January 2011, which resulted in a fatality. The program has been accelerated to address this risk.

The revised investment forecast, as outlined in Table 56, reflects acceleration of the program to remove all streetlight switch wires on the network as soon as possible.

Table 56: Original and revised forecast volumes and expenditure for streetlight switchwire program

$ million real at 30 June 2012	Initial submission length of switchwire (km)	Revised submission length of switchwire (km)	Initial submission expenditure	Revised submission expenditure
Streetlight switchwire program	1,050	4,096[295]	7.4	20.6

[295] Estimates of the length of streetlight switchwire to be replaced have been based upon the number of lamps on the system (excluding lamps on steel streetlight standards), the number of lamps shown to be connected to the LV mains in the Distribution and Facilities Information System (DFIS) and the estimated length of switchwire between lamp poles. This exercise estimated that there is about 5,475

As the business reassessed the pace at which this program was to be complete, it also reviewed the financial treatment of the costs. The review concluded that labour costs associated with the decommissioning and removal of switchwire and control boxes under the program should be treated as operational expenditure, as the activity does not result in the creation of a new or extension of life of an existing asset. The labour (and material) costs associated with the installation of new low voltage mains and photo electric cells continue to be classified as capital expenditure. This treatment is consistent with the Australian Accounting Standards, AASB116 – Property, Plant and Equipment.

The result is to include 45% of labour costs in forecast operating expenditure. The amounts are outlined in Table 57.

Table 57: Adjustment to streetlight switchwire program due to capitalisation policy change

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial expenditure	1.5	1.5	1.5	1.5	1.5	7.4
Amended capital expenditure	8.8	8.9	-1.5	-1.5	-1.5	13.2
Operating expenditure (amendment for streetlight switchwire capitalisation policy change)	6.6	6.7	-	-	-	13.3
Revised total expenditure	16.8	17.1	-	-	-	33.9

8.2.2.4 Distribution SCADA and Communications

Type 1 obligations

As discussed in section 6.3.4.4, Western Power has increased AA3 forecast operating and capital expenditure to increase compliance with its Type 1 Compliance Obligations as set out in the Code of Conduct for the Supply of Electricity to Small Use Customers (Small Use Customers Code).

Additional expenditure of $1.3 million is required to introduce a low voltage distribution management system as part of system upgrades to the ENMAC[296] system at the East Perth control centre. This expenditure supports the introduction of real-time 24x7 central management of the low voltage network to allow for improved monitoring and prevent future breaches.

Forecast distribution SCADA and communications expenditure has increased by $1.3 million since the initial submission as outlined in Table 58.

Table 58: Revised distribution SCADA and communications capital expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Amendment for Type 1 obligation	0.4	0.6	0.3	-	-	1.3

8.2.2.5 Distribution metering

The Authority proposes reductions to metering capital expenditure to:

- reduce capital expenditure for new and replacement standard meters by 10% - the Authority's technical consultant expected this expenditure to reduce reflecting the

km of streetlight switchwire on the Western Power Network, of which 1,379 km are estimated to be replaced in the AA2 period.

[296] The name ENMAC is a GE trademark/brand name from the generic term 'Electricity Network Management and Control' system. It is a business critical system that provides visibility and control of the distribution network and the management of customer outages.

meter replacements which were now being carried out as part of the smart meter replacement program[297]

- reduce smart meter expenditure by 5% as the costs of the program appear to be overstated based on benchmarking analysis from the Victorian advance meter rollout program [298]

Western Power has revised its forecast expenditure to reflect the Authority's draft decision and reassessed the expected volumes of meter replacements to occur taking into consideration meters being replaced under the smart meter program. Western Power considers the 10% reduction proposed by the Authority's technical consultant to be reasonable.

Western Power is continuously assessing the market for smart meters. Though it will not commence a full tender assessment until later this year, Western Power believes the market has altered slightly and it is reasonable to reduce the smart meter cost by 5% as per the Authority's draft decision.

Western Power has revised the forecast metering capital expenditure from $176 million to $170 million. The reduction of $6 million incorporates the Authority's proposed amendments, offset by new obligations resulting from amendments Metering Code (discussed below).

Amended Metering Code

Western Power has amended its forecast capital expenditure to include $12.5 million for high voltage tariff metering to be installed at Verve generator sites.

Western Power is required to comply with the Electricity Industry Metering Code 2005. In August 2011, the Office of Energy published a final report[299] detailing amendments to the Electricity Industry Metering Code 2005. This included an amendment to clause 3.14 to remove the exemption that had allowed for certain transitional matters regarding metering installations commissioned prior to the commencement of the Code. This amendment affects licensed generators' metering installations, primarily Verve Energy, which does not currently have tariff metering in place at a number of its generation sites. The amendment of Clause 3.14 requires the majority of Verve sites to install meters capable of meeting the accuracy requirements of the Metering Code before 30 June 2017.

In the circumstance proposed by the amendment to the Metering Code, it is not clear who will be the beneficiary of the meter upgrade and therefore which party should bear the costs. While Western Power is of the view that these costs are the responsibility of Verve Energy, $12.5 million has been included in Western Power's capital expenditure forecast to ensure that Western Power does not breach the amended Metering Code when gazetted. Western Power has communicated this position to the Public Utilities Office.

If Western Power pays for the works and they can be demonstrated to meet the new facilities investment test, then these costs will be borne by all of Western Power's customers through network tariffs.

8.2.3 Corporate capital expenditure

Western Power has revised the forecast corporate capital expenditure from $301 million to $305 million, an increase of $4 million, to reflect the requirements of wood pole management including the introduction of a wood pole testing facility. This is $27 million more than the Authority's draft decision.

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[297] Paragraph 568, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[298] Paragraph 570, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[299] The Final Recommendations Report can be found at http://www.finance.wa.gov.au/cms/content.aspx?id=14551&terms=metering+code

8.2.3.1 Business support capital expenditure

Wood pole testing facility

Western Power's AA3 forecast operating and capital expenditure will need to increase to reflect the establishment and management of an in-house pole testing facility.

Additional expenditure of $2.4 million is required to introduce a wood pole testing facility to better understand the reasons for unassisted wood pole failure. The outcomes of these tests will be used to inform Western Power's wood pole management program and ensure it is effectively responding to the Energy*Safety* Order 01-2009. These costs are offset in part by amendments to real input cost escalation.

Forecast corporate real estate capital expenditure has increased by $0.9 million since the September 2011 submission as outlined in Table 59.

Table 59: Revised corporate real estate expenditure

$ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Initial expenditure	32.1	31.3	22.6	22.9	18.8	127.6
Amended corporate real estate capital expenditure	1.2	1.2	-	-	-	2.4
Amendments in real cost escalation	-0.3	-0.4	-0.3	-0.3	-0.2	-1.5
Revised expenditure	32.9	32.1	22.3	22.6	18.6	128.5

8.2.3.2 IT Business as Usual capital expenditure

The Authority proposes that 'IT Business As Usual' expenditure be reduced to mirror the average expenditure in this category over the AA2 period. Western Power does not agree that the level of expenditure during AA2 represents the requirements of the business during the AA3 period and therefore is not representative of its forward-looking efficient costs.

As outlined by the Authority's technical consultant, Western Power utilises its 'IT Business As Usual' expenditure to undertake ongoing minor business system enhancements. Increases compared to AA2 period and in the later years of AA3 are to accommodate the need to undertake minor enhancements of new systems, which were previously delivered by the enterprise systems modernisation program.

As demonstrated in Figure 21, increases in IT Business As Usual expenditure over the latter years of AA3 correspond with the finalisation of several Enterprise System projects. Western Power has demonstrated the efficient spend on the Enterprise System projects and therefore forecast incremental increases in maintenance costs to support the programs are justified.

In the context of the wider IT capital expenditure, the AA3 forecast continues to be constrained below level of expected demand to force prioritisation of candidate projects and avoid excessive tactical spend, in line with Western Power's governance process for IT projects.

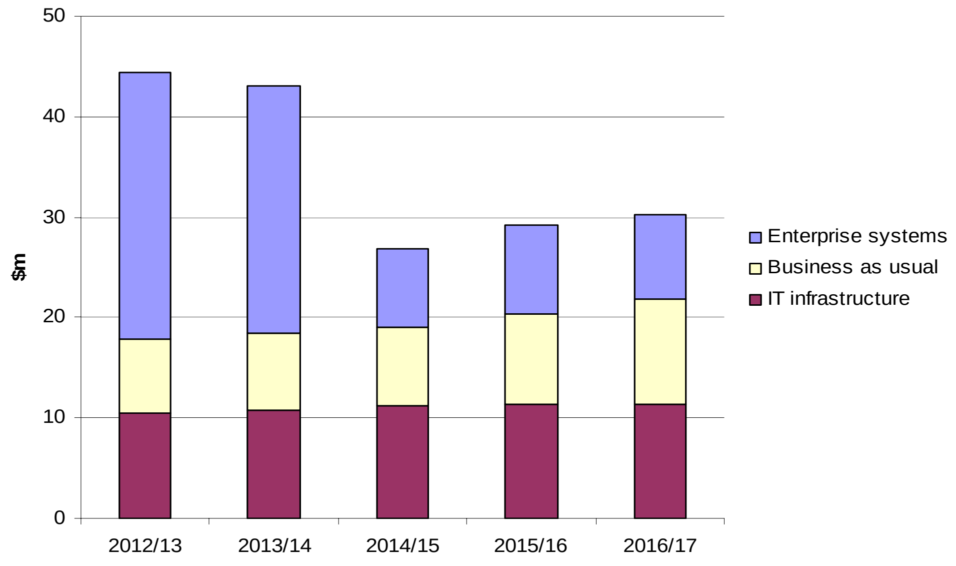

Figure 21: IT AA3 capital expenditure

Type 1 obligations

Western Power has increased AA3 forecast operating and capital expenditure to increase compliance with its Type 1 Compliance Obligations as set out in the Code of Conduct for the Supply of Electricity to Small Use Customers (Small Use Customers Code).

Additional expenditure of $2.7 million is required to undertake upgrades to the ENMAC[300] system and Distribution Network Access Request (DNAR) system.

Forecast IT expenditure has increased by $2.7 million since the initial submission as outlined in Table 60.

Table 60: Revised business support capital expenditure: Type 1 obligations

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Type 1 Obligation IT Capex	0.8	1.1	0.5	0.1	0.1	2.7

People and culture plan

Western Power has increased AA3 forecast operating and capital expenditure to reflect the IT and system enhancements required to ensure the success of the people and culture initiative.

The program will engage Western Power's staff through an extensive program of development and training to improve business performance and culture. This expenditure will enable:

- development of an online system for managing performance appraisal and development plans
- automated HR forms and other system enhancements to promote simplified HR policies and processes

Forecast business support capital expenditure has increased by $2.2 million since the initial submission as outlined in Table 61.

[300] The name ENMAC is a GE trademark/brand name from the generic term 'Electricity Network Management and Control' system. It is a business critical system that provides visibility and control of the distribution network and the management of customer outages.

Table 61: Revised business support capital expenditure: People and culture plan

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
People & culture plan	1.8	0.4	-	-	-	2.2

8.3 Statutory inventory adjustments

Required amendment 16:

Western Power's proposed adjustment to the capital base for the third access arrangement period for changes to the stock of inventory must be removed.

Western Power response:

Western Power accepts this amendment.

In its draft decision, the Authority adjusts Western Power's capital base to remove amounts related to the recovery of inventory costs. While it acknowledges that there are costs to Western Power in holding inventory, the Authority argues that Western Power's approach to determining the efficient level of inventory is overly complex and lacks transparency, and requires these costs to be recovered instead through the working capital mechanism.

Western Power agrees that the recovery of inventory costs can occur through the working capital mechanism. However, the Authority's methodology for determining the efficient level of inventory does not result in an appropriate estimate of the costs.

Western Power proposes that its September 2011 calculation of inventory be adopted. The Authority's technical consultant reviewed the conclusions Western Power derived from its original analysis that place its inventory holdings as comparable with the experience of other network business, and has determined them as appropriate.

The Authority's technical consultant concludes that not only it is appropriate to recover these costs through the regulated asset base, but also that the projected levels of inventory across the AA3 period align reasonably with the works program.[301]

Western Power does not agree with the Authority's view that the methodology utilised in Western Power's September 2011 submission is overly complex or lacking in transparency.

Western Power will amend its submission to include the efficient level of inventory as calculated in the September 2011 submission through the working capital adjustment.

[301] Page A8, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

8.4 All amounts related to mid-year timing assumption

Required amendment 17:

The proposed revised access arrangement must be amended to remove any amounts in relation to a mid-year timing assumption.

Western Power response:

Western Power does not accept this amendment

In its draft decision, the Authority requires Western Power to amend its proposed revised access arrangement to remove the assumption that capital investment is undertaken mid-year for the purposes of calculating the initial capital base and the return on the capital base for AA3.

Western Power accepts the Authority's amendment to remove the time value of money adjustment to the rolled forward capital base and the notional capital base for AA3 for the same reasons set out in response to required amendment 11.

However, Western Power has assumed that capital investment occurs mid-year when applying inflation for the purposes of valuing the initial capital base for the reasons set out in section 7.7.3.

8.5 Economic life of SCADA and Comms equipment

Required amendment 18:

Western Power's revised access arrangement must be amended to reflect a 20 year economic life for depreciation purposes for transmission SCADA and communications.

Western Power response:

Western Power does not accept this amendment

The Authority requires the revised access arrangement to be amended to reflect a 20-year economic life for depreciation purposes for transmission SCADA and communications. This is based on advice from its technical consultants that 11 years would be realistic if it related to SCADA master station equipment only, but other equipment would be likely to last much longer. The Authority determined that 20 years is a reasonable weighted average life.[302]

Western Power does not accept this amendment, as it believes that 11 years economic life for depreciation purposes for transmission SCADA and communications is reasonable.

Western Power determined the economic life for transmission SCADA and communications having regard to the various types of assets within this category. The 11-year depreciation profile is not solely based on SCADA master station equipment. It is based on a weighted average life based on the expenditure forecast over AA3 for each type of asset including fibre optic, control cables and remote terminal equipment. Western Power's assumptions are set out in Table 62.

[302] Paragraph 599, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Table 62: Economic life of SCADA and Comms assets

SCADA and Comms sub asset category	Years	Weighting	Typical asset type
Internal plant SC/MS/IT	7	31.4%	Servers, HMI's, datastores, network management software, modems, test equipment, radios, master station
Internal plant SC	11	52.1%	Teleprotection systems, microwave radio, digital multiplexers, batteries, RTU's, GPS clocks, RS232/485 drivers, telephony equipment, voltage converters, fibre line drivers
Part fibre/part SC	20	0.7%	Fibre termination equipment, power supplies, Powerline carrier systems,
External plant SC	25	8.4%	Communications towers, communications site equipment, control/power cabling, earthing systems, pilot cables, fibre optic cables,
Calculated weighted average	**11 years**	**100%**	

The Authority's proposed 20-year asset life for transmission SCADA and communications does not reflect the life of the full range of assets and the technical obsolesces within this asset category.

Western Power' revised proposal retains an 11-year depreciation profile for transmission SCADA and communications.

8.6 Depreciation

Required amendment 19:

Western Power must establish the value of any redundant assets included in its notional capital base for the third access arrangement period and include accelerated depreciation to fully write them off.

Western Power response:

Western Power does not accept this amendment.

Western Power does not accept this amendment because it is not consistent with the roll-forward method and requires more revenue to be recovered from customers during the period compared to Western Power's proposal.

In Western Power's initial proposal, the notional capital base for AA3 was reduced for the depreciation forecast for the AA2 period. The forecast depreciation amount was based on the economic lives of assets that the Authority considered reasonable. The forecast depreciation also included an amount of accelerated depreciation for those assets subject to the SUPP program.

The Authority indicates that it is satisfied that Western Power's proposed approach to rolling-forward the asset base is consistent with the Access Code objective.[303]

However, the Authority noted its technical consultant's comment that some assets will be replaced before they are fully depreciated, and refers specifically to wood poles and meters.

[303] Paragraph 431, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

In response, the Authority requires that the value of any redundant assets (assets replaced before the end of their assumed economic life) be established and that this amount is accelerated and to include accelerated depreciation to fully write those assets off.

Assets are rarely replaced on exactly the date corresponding to the assumed economic life of the asset. More likely, some assets are replaced prior to their economic life expiring and others are replaced beyond their economic life.

The decision to replace an asset is usually based on an assessment of asset condition. The economic life guides the period over which the financial value of that asset is depreciated. A longer economic life results in a smaller amount of depreciation in any particular year, reducing the impact on prices. A shorter economic life results in a larger amount of depreciation in any particular year, increasing the impact on prices. Regardless of the economic life, the full cost of depreciation is paid for over the life of assets, affecting the timing of recovery, not the amount of recovery.

This approach creates considerable uncertainty where it is applied retrospectively and would provide a disincentive to replace assets that have been assessed as being in poor condition as Western Power could potentially incur a financial penalty for doing so.

The Authority's proposed approach has very little effect but also creates significant practical difficulties. These practical difficulties include the need to assess in advance for the five year period the individual assets that are likely to be replaced prior to the end of the economic life and to calculate the remaining depreciation of that asset based on the age of the asset compared to the assumed economic life. This is a complex, inexact and time consuming task. The costs of undertaking this approach would far outweigh the benefits as there is no net impact on customers over time.

A simpler way to achieve the same outcome would be to reduce the average economic life of the asset. However, it is difficult to support a different average economic life than the one currently adopted as many poles are replaced early and many are replaced beyond their life as is the case with wood poles.

Western Power proposes to retain the current average economic life given the limited value of changing the approach. A reduced average asset life also increases AA3 prices compared to the Western Power proposal.

To illustrate the magnitude of the issue and the likely effect, the *Western Power* has the value of the wood poles and meters remaining in the capital base for the AA3 period.

At the beginning of AA1, Western Power's initial capital base was based on the optimised deprival value (ODV) of assets as at 30 June 2004. This had been determined on the basis of the WA Government's Electricity Reform Implementation Unit's (ERIU) independently commissioned valuation, and adjusted for inflation, depreciation and capital expenditure between 30 June 2004 and 1 July 2006.

The value of the assets in the initial capital base remaining through subsequent access arrangement periods declines as regulatory depreciation is applied. This declining value is shown in Figure 22.

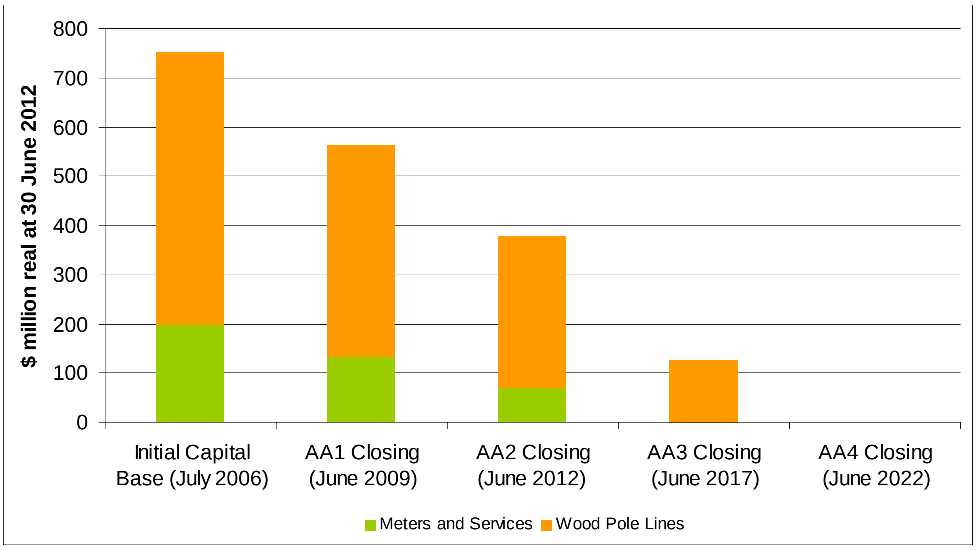

Figure 22: Value of wood pole lines and meters and services remaining in the initial capital base

8.6.1 Meters and services

At the commencement of AA1 (1 July 2006), Western Power's meters and services had an opening value of $197 million and an average remaining life of 9.2 of years. At the end of the AA3 period (30 June 2017) all of the assets included in the initial capital base at the commencement of AA1 will have been depreciated.

As a result, accelerating depreciation on these assets will have no impact on the value of the capital base at the end of AA3 or prices (due to the revenue smoothing approach).

8.6.2 Wood pole lines

At the beginning of AA1, Western Power's wood pole lines had an opening value of $553 million and an average remaining life of 14.5 years. At the end of AA3, the average remaining life of the wood pole line assets included in the initial capital base at the beginning of AA4 will be only 3.5 years.

As a result, only $126 million of the value of these assets will remain in the capital base. This amount is expected to be fully depreciated in the early years of AA4.

8.6.3 SUPP assets

In previous access arrangements, Western Power has proposed accelerated depreciation for State Underground Power Program (SUPP) projects included in the expenditure forecasts.

Western Power has proposed to continue the same approach adopted in AA1 and AA2 for the AA3 period. The approach to depreciating SUPP assets is different because these assets are often replaced before the asset has been assessed as needing replacement. For example, when a wood pole is replaced outside of the SUPP program it is because it has been assessed as being in poor condition or beyond its economic life and needs to be replaced to ensure it is safe and able to perform. Under the SUPP program, assets are replaced even if the condition of the asset is good and it has not reached the end of its economic life.

9 Return on investment

Required amendment 20:

Western Power's Proposed Revisions must be amended to adopt a real post-tax rate of return of 3.87 per cent.

Western Power response:

Western Power does not accept this amendment

Western Power has revised its estimate of the real post-tax weighted average cost of capital (WACC) to:

- adopt the Authority's requirement to move to a post-tax estimate of WACC on the basis that this provides an accurate estimate of its tax costs. Western Power's estimate of tax liabilities for the AA3 period is outlined in Chapter 11 of this document
- update various WACC parameters for movements in market conditions since the September 2011 submission and to ensure compliance with the Access Code
- reduce the equity beta to remove the costs associated with the additional risk arising from an ex-post review from the estimate of WACC. Western Power proposes to recover these costs through the revenue building blocks as outlined in section 9.10 of this document

Western Power does not accept the required amendment to adopt a real post-tax WACC of 3.87%, on the basis that it is inconsistent with the Access Code. Further, the Authority's estimate is significantly below the expectations of an investor in an electricity network business.

Western Power's revised real post-tax WACC is 6.39%. The business has derived this estimate using the Capital Asset Pricing Model (CAPM), taking into account alternative estimates of the cost of equity derived from other well accepted financial models. The estimate also considers cash flow requirements to support the operations of a business with a benchmark credit profile of BBB+.

Western Power's revised WACC estimate is consistent with the requirements of sections 6.4 and 6.64 of the Access Code and the Access Code objective and accordingly must be accepted by the Authority.[304] The following analysis and evidence demonstrates that the revised WACC estimate is reasonable and robust.

[304] Refer to Section 4.28, *Electricity Networks Access Code 2004*.

Table 63 presents the WACC parameter estimates for Western Power's original proposal, the Authority's draft decision and the revised real post-tax WACC.

Table 63: Comparison of WACC parameters

Parameter	Western Power initial proposal	ERA draft decision	Western Power revised proposal	Comment
Nominal risk free rate	5.40	3.67	4.21-5.99 (4.21)	Based on 10 year term to maturity
Inflation rate	2.70	2.55	2.42	Based on 10 year term to maturity
Gearing	60	60	60	Consistent with Authority's approach
Risk margin	3.96-4.43	2.152	3.80-4.16 (3.80)	Based on BBB+ credit rating and 10 year Bloomberg FVC
Market risk premium	6.8-8.0	6.0	6.5-8.5 (7.75)	Recognising the inverse relationship with the prevailing risk free rate
Equity beta	0.90-1.10	0.65	0.80-1.00 (0.80)	Reduced to reflect ex post review risk recovery as non-capital cost
Corporate tax rate	30	NA	NA	Consistent with Authority's approach
Gamma	25	25	25	Consistent with Authority's approach
Nominal post-tax cost of debt	9.36	5.82	8.01	Reduced due to changes in market conditions
Nominal post-tax cost of equity	11.90	7.57	10.41	Consistent with CEG method 2 – consistent approach to the Rf and the market risk premium
Real post-tax vanilla WACC	7.47	3.87	6.00-7.97 (6.39)	Consistent with benchmark credit rating

Where a range has been determined, Western Power has generally adopted a conservative position in order to balance the impact on prices to customers with its responsibility to efficiently invest in the network.

9.1 Regulatory framework

Section 2.1 of the Access Code states that the objective for estimating a reasonable return on the capital base is:

> *to promote the economically efficient investment in and 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.*

The Authority must have regard to this objective when performing its functions.[305]

Section 6.4 of the Access Code provides that Western Power should be given the opportunity to earn revenue for the *access arrangement period* as follows:

> *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.*

Section 6.66 of the Access Code provides that the WACC:

[305] Section 2.2, *Electricity Networks Access Code 2004.*

must represent an effective means of achieving the Code objective and the objectives in section 6.4.

The WACC is defined as being expressed as a percentage and means a weighted average of the cost of debt and the cost of equity as calculated under section 6.64.

The Access Code does not require the mechanical application of a financial model to determine the reasonable return. If this was required, then section 6.4 would simply direct the application of such a model and there would be no need for a reference to the general factors of the return over the access arrangement period meeting the forward-looking and efficient costs of providing covered services and being commensurate with commercial risks. The Access Code requires that the overriding criteria of the Access Code must be achieved in estimating the return on investment.

The Access Code also requires the Authority to approve Western Power's proposed revisions if the Authority considers that the Access Code objective and the requirements of Chapter 6 (including Sections 6.4, 6.64 and 6.66 noted above) are satisfied.[306]

9.2 Estimate of the cost of equity

The Authority and Western Power have both adopted the Sharpe-Lintner CAPM to estimate the cost of equity. However, in its draft decision the Authority does not assess the reasonableness of its cost of equity estimate (or the cost of debt estimate) nor properly considers whether it meets the requirements of the Access Code. That is, the Authority does not analyse whether its proposed WACC will provide Western Power an amount that meets the forward-looking and efficient costs of providing covered services over the AA3 period.

Further, the WACC used by the Authority is substantially below that used by other Australian regulators. The Authority has not provided an explanation as to why a business in Western Australia would raise capital at a cost far below that of equivalent businesses operating elsewhere in Australia.

The parameters used by the Authority are a substantial departure from regulatory precedent in respect of the determination of the risk free rate, the debt risk premium and the equity beta. Western Power submits that such drastic adjustments to the determination of the WACC are in themselves a breach of the requirement to promote economically efficient investment. Western Power considers investment cannot be promoted in the face of such regulatory uncertainty.

The Authority has derived the cost of equity by adding a 3.9% equity premium (the equity beta multiplied by the market risk premium) to the short-term average yield that is observed on the 5-year Commonwealth Government Bond. This reflects the Authority's approach of considering each of the input parameters in isolation, without considering the interrelationships between parameters and adopting the output without analysing whether the cost of equity is consistent with the criteria in the Access Code.

Western Power has sought expert assessment of Western Power's and the Authority's approach to the cost of equity. This includes a review by Ernst & Young of the Authority's application of the CAPM and a review by Competition Economists Group (CEG) of the cost of equity.

Western Power has also undertaken a series of cross-checks to test whether the proposed overall rate of return is reasonable and satisfies the Access Code. These cross-checks have been applied to the Authority's 3.87% WACC estimate and Western Power's revised 6.39% WACC estimate, and comprise:

- analysis of the cost of equity using alternative models to the Sharpe-Lintner Capital Asset Pricing Model

[306] Section 4.28, *Electricity Networks Access Code 2004*.

- analysis of the cost of equity using the Dividend Growth Model (DGM). The analysis also considers the interrelationship between the risk free rate and the market risk premium
- analysis of whether the estimated return is consistent with a credit rating assessment of A-

The key opinions from these expert reports are addressed further below.

9.2.1 Application of the CAPM

In its review of the Authority's application of the CAPM, Ernst & Young (Appendix 0.2) provided an overview of limitations that must be considered, which are:

1. empirical research has shown that the CAPM does not provide good estimates of expected rates of return on financial assets
2. the CAPM only explains expected rates of return in terms of one type of risk; the effects of other types of risks (such as regulatory risk) are excluded by the form of the model of choice from which the CAPM is derived
3. the CAPM is essentially a static model; when the dynamics of investment behaviour are taken into account at least one other risk factor is required to explain asset prices
4. the CAPM does not account for company specific risks; the effects of these risks are assumed to be eliminated by portfolio diversification, but the existence of the required diversification is not supported by the evidence
5. for derivation of the CAPM, investor expectations about investment opportunities and returns are assumed to be homogeneous; recent research finds that investor expectations are heterogeneous and that idiosyncratic factors are important
6. the CAPM is derived from the assumption of rational decision making; this has led to the emergence of behavioural finance, which further challenges the adequacy of the CAPM

Therefore, while the CAPM remains widely used, financial market practitioners who use it apply the model with care. They recognise its limitations and the difficulties of parameter estimation. Commercial judgement must be used to ensure that the outcomes of model use are consistent with market reality. Western Power has engaged experts to undertake cross-checks to ensure its estimate of the cost of equity is reasonable.

9.2.2 Alternative methods to estimate the cost of equity

Other asset pricing models have been developed to address the limitations of the Sharpe-Lintner CAPM. Table 64 shows Ernst & Young's estimates for the cost of equity flowing from these alternative models as follows. For comparative purposes, the Authority's point estimate is also included.

Table 64: Alternative measures of cost of equity

Item	Suggested range
Black's CAPM	10.71
Fama-French three factor model	10.21-10.91
Zero-beta Fama-French three factor model	13.01
Overall range	10.21-13.01
Authority's estimate	7.57

Ernst & Young's analysis shows that when cross checked against cost of equity estimates derived from alternative asset pricing models, the Authority's cost of equity is extremely low for comparative service providers.

Western Power engaged Competition Economists Group (CEG) to provide expert opinion on measuring the cost of equity in a manner that is consistent with the Access Code (Appendix O.5).

CEG proposes a range of 10.41% to 14.59% for a cost of equity that meets the requirements of the Access Code. This is higher than the Authority's point estimate of 7.57%.

The primary reason for the disparity is that CEG recognises that there is an inverse relationship between the market risk premium (MRP) and the risk free rate. An inverse relationship arises because in periods of high investor risk aversion, there is a flight from risky assets to safe assets. This tends to push up the price and push down the yields on safe assets. For this reason, falling risk free rates tend to be associated with rising investor premiums (and vice versa). CEG provides evidence that such a flight to safety has occurred in late 2011 and is ongoing. CEG also provides evidence that the lower yields on Commonwealth Government securities (CGS) have not been associated with a commensurately lower required yield on riskier debt. In fact, risk premiums measured relatively to CGS yields have risen. The Authority's approach to estimating the cost of equity fails to recognise these conditions in the market.

The Authority's cost of equity estimate does not consider this interrelationship, since it utilises a (forward looking) spot rate to estimate the risk free rate and a long term average (which is backward looking) to estimate the market risk premium. The Authority has justified this inconsistency on the basis that:

> *investors' expectations of the long-run forward-looking MRP is unlikely to change frequently in response to any developments in the financial markets in the short term.*[307]

Western Power notes that no evidence is put forward by the Authority to justify its view of investors' expectations.

However, CEG's report makes the point that:

> *it would be an error to argue…that the regulatory MRP should not be increased to reflect heightened uncertainty/risk aversion because this may only be temporary. Even if we know that the heightened risk aversion is temporary (which we do not), if we are using the prevailing CGS as our estimate of the risk free rate, we must still reflect even temporarily higher MRP levels in our cost of equity estimate. To do otherwise would be to pass through a temporarily lower CGS yield that is the 'other side of the coin' of temporarily higher risk aversion.* [308]

In light of the need to maintain internal consistency in the risk free rate and the market risk premium, CEG suggests that the cost of equity be measured in one of three ways:

1. directly estimating the cost of equity using the Dividend Growth Model
2. directly estimating the prevailing market risk premium relative to the prevailing CGS yield being used as the risk free rate
3. estimating a 'normal' cost of equity for regulated businesses by estimating each of the CAPM parameters using suitable historical time periods

Table 65 outlines the outcome from each of these methods. For comparative purposes, the Authority's point estimate is also included.

[307] Paragraph 691, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[308] Paragraph 154, *CEG – Internal consistency of risk free rate and MRP in the CAPM*, May 2012.

Table 65: Comparison of cost of equity estimates

Item	Suggested range
CEG method 1	10.86-14.59
CEG method 2	10.41
CEG method 3	10.78
Cost of equity estimate (CEG)	10.41-14.59
Cost of equity estimate (Authority)	7.57

As can be seen in Table 65, the cost of equity determined by the Authority's application of the CAPM is considerably below the estimate using alternative approaches. CEG's analysis suggests that the cost of equity determined by the Authority is below a reasonable range and does not meet the Access Code objective. It is also by far the lowest cost of equity allowance set by any Australian energy regulator.[309]

Western Power's proposed cost of equity of 10.41% (based on an market risk premium of 7.75%, a risk free rate of 4.21% and a beta of 0.80) is the lower bound of the cost of equity range recommended by CEG and is supported by cross-checks against alternative asset pricing models. Western Power's proposed cost of equity recognises the inverse relationship between the risk free rate and market risk premium and adopts cost of equity parameters that comply with the Access Code. Based on this evidence, Western Power's estimate of the cost of equity meets the requirements of the Access Code and must be approved by the Authority.

9.3 Credit rating assessment

This section examines whether the Authority's estimated return on investment is consistent with its assessment of the appropriate benchmark credit rating for a network service provider.

There are two basic components to a credit rating: the business profile (qualitative) and the financial profile (quantitative). The business profile analysis considers factors such as:

- country risk
- industry factors
- competitive position
- profitability/peer group comparisons

The Authority has determined that the business profile for the notional benchmark network service provider is consistent with the benchmark A- credit rating. Western Power has undertaken a quantitative analysis of the key financial ratios (credit metrics) expected to be achieved over the AA3 period to assess whether the return on investment provided by the Authority is consistent with the attraction and retention of a A- credit rating.

The Authority supports the Standard and Poor's method in assessing credit risk stating in its recent Dampier to Bunbury Gas Pipeline Final Decision that:

> *there is no better alternative approach, which is as simple, independent, and transparent as the Standard and Poor's method, in assessing credit risk.*[310]

Western Power has analysed the key credit rating metrics used by Standard & Poor's and calculated them based on the Authority's draft decision. The business has assessed whether the generated cash flows are sufficient to attract an A- credit rating. This assessment ensures a consistency check between the inputs and the outputs of the application of the CAPM to estimate the WACC.

[309] See Section 2.2, *CEG – Internal consistency of risk free rate and MRP in the CAPM*, May 2012
[310] Paragraph 551, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, ERA, 31 October 2011.

9.3.1 Analysis of credit metrics

Credit ratings are designed to be forward looking and valid over the entire business cycle. Therefore, the forecast financial metrics and their overall trend are important considerations in any credit rating analysis.

In its analysis Western Power has adopted the benchmark gearing ratio to test the internal consistency of the Authority's assumptions of a benchmark efficient firm. For the same reason, Western Power has also adopted the business risk of a benchmark firm when assessing the Authority's determination of the cost of capital.

Standard & Poor's has developed a matrix that outlines the financial metrics associated with each level of business risk. The majority of regulated Australian utilities have a business risk rating of 'Excellent'. Table 66 shows the metrics associated with a business risk of 'Excellent'[311].

Table 66: Credit metrics for firm with 'Excellent' rated business risk

	Minimal	Modest	Intermediate	Significant	Aggressive	Highly leveraged
Credit rating	AAA	AA	A	A-	BBB	-
Cash flow (Funds from operations/Debt)	>60	45-60	30-45	20-30	12-20	<12
Debt leverage (Total debt/Capital)	<25	25-35	35-45	45-50	50-60	>60
Debt/EBITDA	<1.5	1.5-2.0	2.0-3.0	3.0-4.0	4.0-5.0	>5.0

Table 67 outlines the forecast credit metrics for Western Power over AA3 based on the cash flows and assumptions outlined in the Authority's draft decision.

Table 67: Credit metrics for Western Power over AA3 based on draft decision

Financial Metric	2013	2014	2015	2016	2017
	Financial risk level				
FFO/Debt	Highly leveraged	Highly leveraged	Highly leveraged	Highly leveraged	Highly leveraged
Debt/Capital	Aggressive	Aggressive	Aggressive	Aggressive	Aggressive
Debt/EBITDA	Highly leveraged	Highly leveraged	Highly leveraged	Highly leveraged	Highly leveraged

The above analysis suggests that, given the Authority's draft decision, Western Power would attract a credit rating below BBB over the AA3 period. While Standard & Poor's undertakes a detailed process to determine official credit ratings, the ranges in the table *would ordinarily span one notch above and below the indicated rating*[312].

Therefore a credit rating of BBB would be a best case scenario.

On this basis the Authority's estimate of WACC is inconsistent with the benchmark credit rating determined by the Authority.

[311] Page 4, *Standard & Poor's, Criteria Methodology: Business Risk/Financial Risk Matrix Expanded*, 2009.
[312] Page 2, *Standard & Poor's, Criteria Methodology: Business Risk/Financial Risk Matrix Expanded*, 2009.

9.4 Risk free rate

The risk free rate (being the return on a truly risk free asset) cannot be measured directly as there are no such assets. To determine the risk free rate it is necessary to identify a proxy and then determine the period over which that proxy is to be observed.

The Authority has used Commonwealth Government bonds with a term to maturity of five years as a proxy. The risk free rate is estimated from the yield of these securities.

Western Power adopts a risk free rate of 4.21% which is based on the 20 day average of spot rates to 30 March 2012.

Western Power has two concerns with the approach used by the Authority:

1. the Authority has used spot rates (a forward looking estimate) for the risk free rate and a backward looking estimate for the market risk premium
2. use of a five year term to maturity understates the true cost and is inconsistent with section 6.4 of the Access Code

9.4.1 Spot rates

There are two issues with using spot rates:

1. use of too short a period increases the risk of the data being distorted by random factors
2. in current economic conditions, yields on bonds are reduced due to excess demand created by the "flight to quality" of risk averse investors[313]

Using an average of long term historical rates would align the risk free rate with the measurement term of Western Power's proposed market risk premium. It would also reduce noise in the data as well as providing a more stable estimate of the cost of equity, which reflects forward looking efficient costs commensurate with the commercial risks involved.

If the Authority intends to use spot rates for the risk free rate, it should also use an appropriate approach for the determination of the market risk premium.

9.4.2 Five year term to maturity

The Authority notes that it gave consideration on the appropriate term to maturity in its recent Dampier to Bunbury Natural Gas Pipeline decision[314]. Western Power had concerns with the Authority's reasoning and engaged CEG to undertake an independent review. CEG identified a number of issues with the Authority's reasoning which are summarised in Table 68.

Table 68: Issues with adopting an assumed term to maturity of five years

Authority argument from DBNGP Final Decision	CEG response[315]
The Authority found that privately owned energy networks in Australia have 52.5% of total debt instruments with an average term of less than five years. The Authority also looked at a sample of government-owned energy networks in Australia which have approximately 44% of total debt instruments with an averaging term of less than five years.	The Authority is failing to appreciate that the term of debt data taken from company accounts is the remaining life of the debt – not the term of the debt at the time of issue. When determining the cost of debt funding, businesses need to be funded for the interest rate they commit to when they issue debt. This is determined by the term of the debt at the time of issue. Correctly interpreted, the evidence presented by the Authority is entirely consistent with a ten year term of debt at issue.

[313] As demonstrated by CEG in its report attached at Appendix O.5.
[314] *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, ERA, 31 October 2011.
[315] *Internal consistency of risk free rate and MRP in the CAPM*, CEG, May 2012.

Authority argument from DBNGP Final Decision	CEG response[315]
Interest rate swaps are used by privately owned energy networks to exchange floating interest amounts for fixed interest amounts. Regulated businesses normally borrow floating rate debts and then fix the interest rate for the term of the reset period, which is usually five years, using interest rate swaps.	In relation to the use of interest rate swaps by regulated businesses, the Authority appears to believe that this practice means that businesses can be treated 'as if' they issued five year debt. This is wrong. Even if a business issued ten year debt but used interest rate swaps in the way the Authority suggests, it still must pay a debt risk premium equal to the debt risk premium on ten year debt. Using interest rate swaps in the manner described by the Authority only changes the profile of the (relatively risk free) swap rate component of debt. It does not alter the fact that a business which issues ten year debt must pay a debt risk premium associated with ten year debt. If the Authority did rely on the assumption that, as well as issuing ten year debt, firms also immediately swapped their (risk free) interest rate exposure to term of the regulatory period then one would have to, at a minimum, adopt the approach of the Queensland Competition Authority where the business is compensated for the cost of swap contracts.
The three year government bond future contracts are highly traded compared with the three year government bonds. The Authority considers that the shorter trading term is preferred by market participants over the longer trading term of ten years.	The marginal differences in liquidity are trivial in the context of setting a regulatory WACC and do not provide a basis for choosing between different terms for the risk free rate for that purpose.

CEG also notes that the actual practice of Australian utilities is to issue debt of more than ten years duration. Therefore, the evidence presented by CEG supports a ten year term to maturity assumption. Western Power has adopted a ten year term to maturity assumption which it considers to be consistent with the Access Code.

9.4.3 Preferred approach

The Authority has proposed using a risk free rate based on a 20-day observation period with a market risk premium of 6.0 and a beta of 0.65. In Western Power's view this does not result in a cost of equity that provides an opportunity to recover forward looking efficient costs over the access arrangement period. The expert analysis of CEG provided at Appendix O.5 supports this view.

In addition, the Authority has erred by using a five year term to maturity. To address these issues, Western Power proposes a range for the nominal risk free rate of 4.21% to 5.99%, based on analysis from CEG. The lower end of the range is based on a 20-day average to 30 March 2012 using Commonwealth Government securities (CGS) and the upper end is based on long term averages of indexed CGS rates plus a forward looking inflation premium of 2.5%, as estimated by CEG. Both of the range boundaries have been determined using ten year terms to maturity.

As a conservative assumption, Western Power proposes to adopt a value at the lower end of the range of 4.21%. This estimate is within the range of estimates resulting from the CEG analysis and the 20-day average using CGS. Western Power therefore considers this proposal to be consistent with the forward looking efficient costs of providing the services and consistent with the Access Code. It must be approved by the Authority.

Ultimately, Western Power's proposal is for a cost of equity based, in part, on a sampling period that gives it an opportunity to earn revenue that meets the forward-looking and efficient costs of providing covered services. Western Power proposes that the 20 days to 30 March 2012 is such a period. Western Power notes that for administrative convenience there has been agreed a different period for estimating the risk free rate. If this period, however, does not achieve the overriding criteria of the Access Code, as a matter of law it must give way to one that does.

The Authority must consider the implications of the agreed upon sampling period and ensure a cost of equity that meets the requirements of the Code. Given the timing of this current process and that of the final decision by the Authority, it is immaterial if that period is in the past.

9.5 Market risk premium

In its draft decision, the Authority proposes a market risk premium of 6.0%. The Authority has relied on statistical analysis, survey evidence and current Australian regulatory practice. Western Power has concerns with each element of the Authority's analysis.

9.5.1 Statistical analysis

As noted throughout its submission, the Authority has used a (forward looking) spot rate to estimate the risk free rate and a long term average (which is backward looking) to estimate the market risk premium. This is internally inconsistent and results in a cost of equity that does not satisfy the Access Code objective.

Western Power also has concerns with the averaging periods used by the Authority to determine the historical market risk premium. Analysis presented by the Authority only supports the conclusion that there are three different time periods where the average excess return was between 5% and 6%. The Authority does not provide any statistical details of the confidence interval around these estimates nor whether there were other sub periods with materially higher average excess returns. CEG notes that the market risk premium estimate is very sensitive to the sample period (Appendix O.5). In particular:

- if 1979 instead of 1980 were chosen as the beginning date for one of the sub-periods the estimated average market risk premium would be around 6.6% (there was a 32% excess return in 1979 that the ERA period that starts in 1980 does not capture)
- if 1967 instead of 1968 were chosen as the beginning date for one of the sub-periods the estimated average market risk premium would be around 6.0% (there was a 40% excess return in 1967 that the ERA period that starts in 1968 does not capture. Given there are only 44 years in the ERA's estimation period adding an excess return of 40% increases its estimate by almost one full percentage point.)
- using a longer time series, the AER's adviser, Handley estimates the average market risk premium relative to 10 year CGS from 1958 to 2010 is 6.5%[316]. However, Handley reports a 95% confidence interval which extends up to 12.9%. Using the longest stretch of data (1883 to 2010) increases the number of estimates but does so at the cost of introducing less reliable estimates. Even in that case the average is 6.2% and the 95% upper bound is 9.1%

Therefore, the Authority's analysis is limited by the sample periods it has selected and potentially contains confidence intervals that are consistent with Western Power's proposed market risk premium of 7.75%. The increase in the market risk premium estimate since Western Power's initial submission recognises the inverse relationship that exists between the risk free rate and market risk premium and is required in order to account for the significant change in the risk free rate since early 2012.

[316] Using an assumed utilisation rate for imputation credits of 0.35.

9.5.2 Survey evidence

In its draft decision, the Authority gives some weight to survey evidence in its measurement of the market risk premium. The use of survey evidence to determine the market risk premium has significant limitations. The Australian Competition Tribunal stated in a recent decision on Envestra that:

> *Surveys must be treated with great caution when being used in this context. Consideration must be given at least to the types of questions asked, the wording of those questions, the sample of respondents, the number of respondents, the number of non-respondents and the timing of the survey. Problems in any of these can lead to the survey results being largely valueless or potentially inaccurate.*
>
> *When presented with survey evidence that contains a high number of non-respondents as well as a small number of respondents in the desired categories of expertise, it is dangerous for the AER to place any determinative weight on the results*[317]

The Authority notes that some of the survey evidence that it relies on preceded the global financial crisis in 2008 and caution needs to be exercised. However, there is no evidence that suggests the Authority has allowed for the shortcomings of the survey method, which have been noted by the Australian Competition Tribunal.

In respect of the 2009 and 2010 surveys to which the Authority refers, those surveys are also limited in that:

- the sample of Australian academics and analysts who responded to the surveys was small
- it is difficult to know how seriously to take the responses to such surveys when respondents are not responding in any real world context
- the responses gathered are nothing more than surveys which can only provide a limited insight into actual market risk premium estimates
- there is no evidence that the estimates of the market risk premium from the surveys are imputation adjusted[318]

Therefore, Western Power considers that it is not appropriate to rely on survey evidence to determine the market risk premium.

9.5.3 Australian regulatory practice

Western Power acknowledges that a market risk premium of 6.0% appears to be common regulatory practice but equally a market risk premium of 6.5% was derived by the AER in the May 2009 review of WACC parameters for electricity transmission and distribution networks. Like May 2012, May 2009 was a time in which world markets were severely affected by the financial crisis. Moves by the AER away from 6.5% to 6% since May 2009 were based on the view the world economy had improved since May 2009, an assumption which recent events have highlighted is not correct.

Regulatory decisions that have used a market risk premium of 6% have also used higher estimates of the equity beta and lower credit rating assumptions, thereby resulting in much higher overall rates of return than that reflected in the Authority's draft decision. The overall rate of return from the Authority's draft decision is unduly low compared to national outcomes (and Western Power's current access arrangement). This is demonstrated in Figure 23.

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[317] Paragraph 165-166, *Application by Envestra Limited (No 2) [2012] ACompT 4*, 11 January 2012.
[318] Paraphrased from the criticism raised by NERA in the *Application by Envestra Limited (No 2) [2012] ACompT 4*, 11 January 2012.

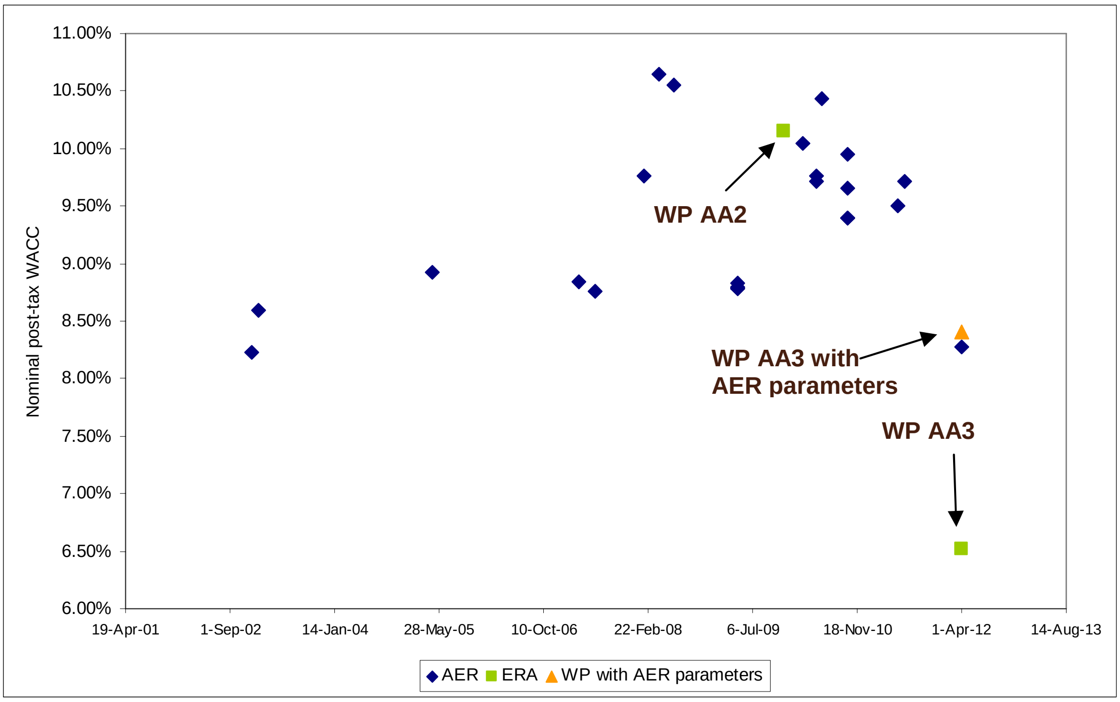

Figure 23: Nominal post-tax WACC from AER and ERA over time

Figure 23 includes the likely WACC outcome Western Power would achieve based on the AER's most recent decisions. The Authority proposes using a risk free rate based on a 20-day observation period to 29 February 2012, with a market risk premium of 6.0 and a beta of 0.65. In Western Power's view this does not result in a cost of equity that provides an opportunity to recover forward looking efficient costs.

To address this issue, based on analysis from CEG, Western Power proposes a range for the prevailing market risk premium (that is, measured relative to the prevailing risk free rate) of 6.5% to 8.5%. The lower end of the range is consistent with Western Power's initial submission, while the top of the range is consistent with new evidence surveyed by CEG including Bloomberg estimates of the prevailing market risk premium. Both of the range boundaries have been determined using 10-year Commonwealth Government Securities.

Western Power adopts a value of 7.75% based on a direct estimate of the prevailing market risk premium relative to the prevailing Commonwealth Government Securities yield being used to estimate the risk free rate. Western Power has based its proposed market risk premium on CEG's analysis for contemporaneous market risk premium during March 2012, resulting in a cost of equity of 10.41%. CEG's report makes clear that both the risk-free rate proxy and the market risk premium are volatile but have a negative relationship such that the overall cost of equity is relatively stable over time.

The Authority's proposed approach to estimate cost of equity is to combine a current estimate of the risk-free rate proxied by yields on Commonwealth Government Securities and to combine this with an market risk premium (and equity beta) calculated as an average over a long period of time. As noted by CEG, the practice of estimating the risk-free rate and the market risk premium over different periods is likely to give rise to an inaccurate estimate of the cost of equity, and at the current time when market risk premiums are above the historical average, this will underestimate Western Power's current cost of equity.

Consistent with this advice, whatever risk free rate a chosen sample period may deliver, a correlative approach to the market risk premium is required so that the cost of equity is such that Western Power is able to recover its forward looking and efficient costs. Such an adjustment would be consistent with the analysis from CEG that the cost of equity is stable over time and the cross-checks on the cost of equity undertaken by Western Power.

To the extent that the Authority prefers to adopt an market risk premium of 6.0% based on estimates of long run historical average excess returns, Western Power submits that internal consistency requires the adoption of a long run historical average risk free rate estimate. CEG estimates this to be 3.40% in real terms.

Further if the Authority was to persist in using its proposed equity beta and risk free rate values, this provides further justification for using a market risk premium value greater than 6.0%. It is worth noting that using Authority's values, 7.75% would not result in an overall rate of return that is consistent with a BBB+ credit rating. A value for market risk premium of less than 7.75% would move the proposed WACC further away from a level which would encourage efficient investment.

9.6 Equity beta

The Authority proposes an equity beta of 0.65. In making its determination, the Authority undertook a statistical analysis of a sample of Australian regulated infrastructure owners, based on analysis undertaken by Olan Henry utilised in the AER's 2009 WACC review. The Authority also considered the equity beta range it determined for the current access arrangement.

However, Western Power has a number of concerns with the statistical reliability of the Authority's approach and has sought advice from SFG on these issues (attached at Appendix O.1). SFG notes that these issues were not addressed by the AER in its 2009 WACC review. SFG's findings are summarised below.

- The sample size is small. The draft decision uses the same small sample of Australian firms as the AER used in its WACC Review. However, whereas the AER had regard to data from international comparables due to the perceived limitations of the data obtained from the Australian market (such as the number of firms and the reduction in the number of observations due to mergers and acquisition activities), the draft decision is based entirely on the small set of Australian firms.
- There is a large degree of variation between the Authority's calculated values and the AER's values for specific companies. The majority of estimates differ by more than 20% and in a number of cases the difference is more than 50%. The fact that two regulators have sought to estimate the same beta for the same firm using the same data period, and in the majority of the cases their estimates differ by more than 20% suggests that the regulatory estimates of beta are unreliable.
- The results do not pass standard statistical reliability tests. The Authority makes no use of standard errors or confidence intervals other than to conclude that both sets (Authority and AER) of regulatory estimates are so imprecise that it is statistically impossible to distinguish between them. In addition, the Authority has not reported any R^2 statistics which is inconsistent with standard statistical and econometric practice. The AER's 2009 analysis had low R^2 values, which means the results are less likely to be statistically reliable.
- No adjustment is made to correct for the demonstrated bias in beta estimates.

A more detailed explanation of these concerns is outlined at Appendix O.1.

In addition, SFG undertook some high level checks to verify the reasonableness of the Authority's estimate. Three areas of concern were identified:

- the Authority's methodology produces results in other industries that vary wildly over time. This suggests that the methodology is not robust and should not be relied upon
- the Authority's methodology produces internally inconsistent results. Based on the Authority's WACC parameters, a 100% equity investment in the benchmark firm is less risky than a 60% first-ranking debt investment in the same firm
- the Authority's methodology produces an allowed return on equity that is materially lower than returns available from comparable firms

Given these concerns with the Authority's approach, Western Power engaged CEG to undertake an independent assessment of the equity beta (Appendix O.3).

CEG also had concerns with the veracity of the Authority's estimate and noted that:

> *There is material uncertainty surrounding the beta for Western Power. Based purely on the daily, weekly and monthly Australian beta estimates for the ERA sample the most likely estimate may be in the vicinity of the ERA's chosen 0.65. However, when all the relevant data is taken into account, including the confidence intervals of the sample little confidence can be had that this is the correct estimate. That is, a reasonable range extends well upwards beyond the value of 0.8 determined by regulatory precedent. While the data in this sample provides some evidence in support of a reduction in beta from 0.8 to 0.65, in my view this evidence, even taken in isolation, is not persuasive.*[319]

To mitigate the issues flowing from the Authority's (small) sample, CEG incorporated US equity betas in its analysis. The use of overseas equity betas has a basis in regulatory precedent and was an input into the Authority's determination of equity beta for the AA2 period. CEG concluded that:

> *it is appropriate to give US equity beta estimates equal weight with Australian equity beta estimates. This gives rise to an equity beta estimate around 1.0 and certainly in excess of 0.8. Even if one determined not to give US equity beta's the same weight as Australian equity betas, the US betas provides compelling evidence that the ERA should not depart from regulatory precedent and lower beta below 0.8.*[320]

CEG also identified a number of other reasons why the Authority should err on the side of caution in its assessment of beta:

- there is evidence that the Australian betas have been depressed by the influence of the mining boom on the market index
- there is evidence that a 0.65 beta estimate is inconsistent with the risk premium allowed on the cost of debt
- there is empirical evidence that suggests that estimates of betas well below 1.0 should be adjusted upwards towards 1.0
- the aggressiveness of other aspects of the Authority's decision mean that there is negative or no 'margin for error' left in the WACC when assessing beta

On this basis, CEG concluded that a reasonable range for beta is 0.80-1.00.

It should be noted that while the Authority used a similar style of analysis to that used by the AER, the AER elected not to rely on its analysis. The AER established that the equity beta was in the range of 0.4 to 0.7, yet determined that an appropriate value for beta was 0.8. The AER stated:

> *In determining the value of the equity beta, the AER has also taken into account the revenue and pricing principles. The market data suggests a value lower than 0.8, however, the AER has given consideration to other factors, such as the need to achieve an outcome that is consistent with the NEO (in particular, the need for efficient investment in electricity services for the long term interests of consumers of electricity). The AER has also taken into account the revenue and pricing principles and the importance of regulatory stability. Having a taken broad view, the AER considers that an equity beta of 0.8 for a benchmark efficient NSP is appropriate.*[321]

[319] Paragraph 71, *Estimating equity beta for Australian regulated energy network businesses*, CEG, May 2012.
[320] Paragraph 97, *Estimating equity beta for Australian regulated energy network businesses*, CEG, May 2012.
[321] Pages 343-344, *Final Decision Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters*, 2009.

The AER recognised that a value for beta below 0.8 would be unlikely to result in efficient investment in electricity services and therefore would be inconsistent with the National Electricity Rules. Similarly in the case of the Access Code, a value below 0.8 will not promote economically efficient investment in Western Australian networks and use of such a value would contravene section 2.1 of the Access Code.

Western Power proposes an equity beta of 0.80 on the basis that:

- it is consistent with CEG's analysis
- it is consistent with regulatory precedent
- it is consistent with the Authority's own range
- it is the most conservative value that is consistent with the Access Code and so must be accepted
- the value determined by the Authority leads to unduly low rate of return outcomes, which is inconsistent with the Access Code objective

9.7 Cost of debt

The cost of debt is estimated as the sum of the nominal risk free rate of return and debt risk premium. The cost of debt must be sufficient to allow the necessary volume of debt to finance the debt portion of both the capital base and the forecast capital expenditure over AA3. The derivation of the cost of debt is discussed below.

9.7.1 Credit rating

The Authority determined a new benchmark credit rating based on the median credit rating of a sample of companies used by the AER in its 2009 WACC review.

Western Power has a number of concerns with the Authority's methodology.

The Authority has incorrectly assigned AGL a credit rating of A-, when it is rated by Standard and Poor's as BBB. When this error is corrected, the median credit rating observation in the Authority's sample is BBB. It is also worth noting that AGL has a negative outlook, which suggests that a move to A- or higher is unlikely in the near future.

Western Power's remaining concerns with the sample relate to the inclusion of entities which have credit ratings influenced by government support. The Access Code allows Western Power to earn a return on investment commensurate with the commercial risks involved. Government ownership can mask risk in terms of borrowing costs and credit risk. The Authority recognises the impact of government ownership on borrowing costs but not the impact of government support on credit risk.

The Authority's sample also includes credit ratings of three regulated businesses that reflect support by Australian state governments. Standard and Poor's states that its rating of Ergon Energy (AA) is not a standalone rating and:

> *…reflects our opinion that there is an 'extremely high' likelihood that the Queensland government would provide timely and sufficient extraordinary support to EEC in the event of financial distress to ensure the timely repayment of the group's financial obligations*[322]

Endeavour Energy (previously Integral Energy) and Essential Energy (previously Country Energy) no longer have ratings with Standard & Poor's. However, they have equivalent ratings of AA3 with Moody's. Moody's states that these credit ratings have been estimated based on these firms being government-related issuers and that that there is a:

[322] Based on Standard and Poor's summary dated 12 March 2012 referenced in Appendix O.4: CEG – Western Power's proposed debt risk premium, May 2012.

> *…high likelihood of support from, and high dependence on the state.* [323]

The Authority does not appear to have explored the consequences of the inclusion of Ergon Energy, Endeavour Energy and Essential Energy in its benchmark sample.

Section 6.4 of the Access Code requires that Western Power be provided an opportunity to earn revenue that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

In using credit rating benchmarks that reflect government support, the Authority is overestimating the credit rating of the benchmark firm and underestimating the cost of debt associated with providing covered services on a commercial basis.

Removing Ergon Energy, Endeavour Energy and Essential Energy from its analysis leaves the median credit rating observation from the Authority's sample unchanged at BBB. This is shown by the analysis undertaken by CEG (Appendix O.4).

Another issue with the sample is that the Authority has included the credit rating of SPI PowerNet and SP AusNet separately. SPI PowerNet is a subsidiary of SP AusNet therefore there is only one relevant observation provided by these two firms. Moreover, SP AusNet is ultimately owned by the Singapore government and rated A-. The AER's consultant, Oakvale Capital, stated in regard to bonds issued by SPI E&G:

> *During the averaging period the bond was attracting one of the lowest yields, in contrast to other A- bonds observed. The key feature supporting the bond was the parental support of the issuer's owners and the link to the Government of Singapore.* [324]

Consistent with arguments relating to Australian state-supported bonds, it is inappropriate to use these firms to determine the benchmark credit rating. Removing these firms leaves the median credit rating observation from the Authority's sample unchanged at BBB.

Western Power notes that the Authority suggests Synergy's A+ credit rating provides further support for an A- benchmark credit rating[325]. This is not appropriate given that the Authority noted in its *Inquiry into the Efficiency of Synergies Costs and Electricity Tariffs*:

> *Synergy's entire capital is entirely financed by equity which is the State Government of Western Australia*

Synergy would not be able to support anywhere near the benchmark gearing level of 60% and would be unlikely to achieve an investment grade credit rating with this level of gearing in the absence of community service obligation funding. Therefore, Synergy's current credit rating is not relevant for the determination of a benchmark credit rating for a network service provider.

Western Power proposes that the benchmark credit rating be established at BBB+ on the basis that:

- appropriate adjustment of the Authority's sample results in a median credit rating of BBB
- the analysis undertaken on the consistency with the Authority's proposed cost of capital with the benchmark credit rating suggests that A- would be an overly optimistic credit rating
- the AER adopts a benchmark credit rating assumption of BBB+

[323] Based on Moody's credit opinion, 25 September 2011 referenced in Appendix O.2: CEG – Western Power's proposed debt risk premium, May 2012.

[324] Page 24, *The impact of callable bonds*, Oakvale Capital, February 2011

[325] Paragraph 738, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

9.7.2 Debt risk premium

The Authority has determined a debt risk premium for Western Power based on its preferred bond-yield approach and a borrowing term of five years. Western Power has concerns regarding both aspects of the Authority's methodology and does not consider the cost of debt meets the requirements of the Access Code.

Western Power engaged CEG to review the appropriateness of the Authority's 5 year borrowing term assumption in light of the Code objective (Appendix O.4). CEG expressed the view that a ten year term is appropriate because this is based on actual business practice. The data that the Authority appears to rely on in support of a five year term has been misinterpreted. As CEG notes:

> *… it is important to look at what businesses actually do – which is what the ERA did do. However, the ERA made an error in its interpretation of this data. The ERA's review of the debt raising practices of regulated energy network businesses reveals that these businesses raise debt with terms to maturity of approximately 10 years. On this basis, I consider that a benchmark term for the cost of debt of 10 years will be consistent with the requirements of the Access Code. The ERA's proposed term of debt of 5 years is not consistent with these requirements.*[326]

CEG's evidence is that the use of a ten year term to maturity reflects actual business practice when properly considered.

Western Power engaged CEG to review the appropriateness of the Authority's bond yield approach in light of the Access Code objective (Appendix O.4). CEG expressed a broad concern with the sample of companies used to determine the debt risk premium:

> *Any approach based on a sample, across which an average is taken, starts with an assumption that a set of observations can be taken which are all of equal value in explaining DRP, or at least for which the value can be quantitatively assessed and captured in a weighted average across the sample. Necessarily, application of this approach also implies that any observations not included within the sample are irrelevant to assessing the DRP.*
>
> *In my view, it is not a supportable assumption that in the yields on 27 bonds the ERA has captured all information that is relevant or material to assessing the DRP on 5-year A- rated debt. However, for the purposes of this section I proceed upon the basis that a single sample approach is to be used to determine the benchmark DRP.*[327]

CEG undertook an analysis of a wider sample of bonds from both Bloomberg and UBS which met the Authority's criteria. CEG found that 72 companies meet the Authority's apparent criteria and that on a 5 year term to maturity the debt risk premium of this sample would be 3.11% - significantly larger than the Authority's estimate.

CEG were also engaged to review the appropriateness of Western Power's use of Bloomberg fair value curves for estimating the debt risk premium in light of the Code objective (Appendix O.4) – Western Power's proposed debt risk premium).

To determine the adequacy of the methodology, CEG undertook a number of cross-checks and found that:

> *these cross-checks establish conclusively the reasonableness of the extrapolated Bloomberg BBB fair value curve over the 5 March 2012 to 30 March 2012 period*[328]

CEG concludes that the use of Bloomberg fair value curves is superior to the bond yield approach:

[326] Paragraph 54, *Western Power's proposed debt risk premium,* CEG, May 2012.
[327] Paragraph 240-241, *Western Power's proposed debt risk premium,* CEG, May 2012.
[328] Paragraph 108, *Western Power's proposed debt risk premium*, CEG, May 2012.

> *The "bond-yield" analysis that the ERA prefers to estimate the DRP is not sufficiently developed or sophisticated that it could be capable of replacing the type of expertise provided in Bloomberg's fair value estimates.*[329]

As recently as January 2012, the Australian Competition Tribunal endorsed the reasonableness of using Bloomberg fair value curves for determining the DRP in the context of Envestra and APT Allgas. The Tribunal, on the basis of Dr Hird (CEG's) analysis of the AER's bond sample, accepted that there were no reasons shown from the available material why the use of the extrapolated Bloomberg fair value curve should not be adopted[330]. CEG has equally shown in its report prepared for Western Power that the Bloomberg fair value curve is a "good fit" to the available bond data, when properly analysed, and there is no reason to depart from the use of the extrapolated fair value curve.

Subsequently the AER, recognising the recent Tribunal decisions, has adopted the extrapolated Bloomberg BBB rated FVC to estimate the debt risk premium in its final decisions for Powerlink and Aurora.

CEG's advice suggests:

- the use of Bloomberg fair value curves is reasonable and consistent with the Access Code
- adopting a borrowing term assumption of 10 years is reasonable and consistent with the Access Code

In addition, the analysis in section 9.3 suggests that the overall rate of return set by the Authority is inconsistent with the benchmark credit rating. Therefore, Western Power proposes a debt risk premium range of 3.67-4.03%, which is based on possible extrapolations of the Bloomberg BBB fair value curve, being:

- the average annualised Australian Bloomberg BBB 7-year fair value over 5 March 2012 to 30 March 2012 of 7.63%; less
- the average annualised 7-year CGS yield over 5 March 2012 to 30 March 2012 of 3.97%; plus
- a range of 0.00% to 0.36%, being between 0 and 12 basis points per annum for three years

A value of 3.67% has been selected as a conservative estimate of the debt risk premium. Based on the analysis of CEG, this estimate for the cost of debt must be approved as it is consistent with providing a return on investment commensurate with the commercial risks involved, consistent with recent decisions of the Australian Competition Tribunal and the AER.

9.7.3 Debt raising costs

Western Power accepts the Authority's determination for an allowance of 12.5 basis points for debt raising costs.

9.8 Other parameter values

9.8.1 Gearing

Western Power accepts the Authority's determination of a gearing ratio of 60%.

9.8.2 Value of imputation credits

Western Power accepts the Authority's determination of a gamma value of 0.25.

[329] Paragraph 223, *Western Power's proposed debt risk premium*, CEG, May 2012.
[330] Paragraph 123, *Application by Envestra Ltd (No 2) [2012] ACompT*

9.8.3 Inflation

In its draft decision the Authority determines an inflation estimate for Western Power based on a geometric mean of RBA inflation forecasts for a term to maturity of five years.

Calculating the forecast rate of inflation using a geometric mean of the RBA's forecasts is consistent with Western Power's initial proposal and it accepts this aspect of the Authority's decision. However, Western Power does not accept that the appropriate term to maturity is five years.

As outlined in Western Power's proposal regarding the risk free rate and the debt risk premium, the Authority has erred in its justification of the use of a five year term. Therefore, Western Power maintains that ten year term should be utilised. This results in inflation of 2.42% over AA3, based on the RBA's May 2012 Statement on Monetary Policy.

9.9 Proposed return on capital

Consistent with the criteria in the Code (in particular the need to ensure economically efficient investment) Western Power submits that the WACC point estimate should be determined using the input parameters from the ranges as set out in Table 69.

Table 69: Reasonable range for WACC parameters

WACC parameters	Reasonable range
Nominal risk free rate	4.21% to 5.99%
Market risk premium	6.5% to 8.5%
Debt risk premium	3.67% to 4.03%
Beta	0.80% to 1.00%
Nominal post-tax cost of equity	10.41% to 14.69%
Nominal post-tax cost of debt	8.01% to 10.15%
Benchmark credit rating	BBB+

The ranges are based on the analysis undertaken for each parameter.

As a guide, the point estimate for the WACC should also be established such that:

- the cost of equity used in the WACC is within reasonable bounds (10.41% to 14.69% nominal post-tax)
- the expected sustainable cash flows generated by the business are reflective of those required to provide a credit profile consistent with the benchmark Standard & Poor's credit rating of BBB+ (5.7% to in excess of 7.8% real post-tax)[331]

Table 70 summarises Western Power's point estimates for each of the WACC inputs.

Table 70: Western Power's WACC Point estimate

WACC Parameters	Reasonable range	Point estimate
Risk free rate	4.21% to 5.99%	4.21%
Market risk premium	6.5% to 8.5%	7.75%
Debt risk premium	3.67% to 4.03%	3.67%
Beta	0.80 to 1.00	0.80
Nominal post-tax cost of equity	10.41% to 14.69%	10.41%

[331] It should be noted that the range is based on all of the financial metrics being within the aggressive category. In reality a rate of return higher than this range is still potentially consistent with BBB+

WACC Parameters	Reasonable range	Point estimate
Nominal post-tax cost of debt	8.01% to 10.15%	8.01%
Benchmark credit rating	BBB+	BBB+
Real post-tax WACC	6.00% to 7.97%	6.39%

Western Power's proposed rate of return balances the impact on prices to customers with its obligations and responsibility to efficiently invest in the network.

Western Power submits that a WACC of 6.39% (real post-tax) is the value that satisfies the requirements of the Access Code.

9.10 Treatment of ex-post review risk

Under the requirements of the Access Code, Western Power's capital expenditure is subject to ex-post review by the Authority. The Authority has the power to prevent the value of past investment from being added to Western Power's capital base and has exercised this power in the past.

As part of the initial AA3 proposal, Western Power sought compensation for this additional risk through a higher equity beta (0.9-1.1) than that recently granted to other Australian regulated energy network businesses (0.8). The Authority's draft decision stated that *no compensation via equity beta should be allowed with regard to the NFIT*[332].

Western Power accepts that it may not be appropriate to estimate the additional cost of this risk through the estimate of equity beta, the business believes that this is a real and significant risk that it must be compensated for. Therefore, Western Power has estimated this cost as a non-capital cost that will be incorporated into its forecast expenditures over AA3.

The Authority has stated that the ex post review process:

> *is not designed to introduce higher levels of risk for Western Power in comparison with other regulated businesses in Australia*[333]

The ex-post review process may not be designed to introduce a higher level of risk but clearly risk arises due to the potential for prudent and efficient expenditure being written down due to a difference of opinion. The risk can only be mitigated by the Authority providing significant leeway in its assessment of expenditure. It is worth noting that the AER as part of a proposed rule change submitted to the AEMC on 29 September 2011, dismissed the idea of introducing an ex post review process into the national regulatory framework for electricity on the basis that it increased regulatory risk.[334]

Some capital investment during the first and second access arrangement periods has been valued at zero for the purpose of rolling forward the capital base. Western Power considers that in some cases efficient investment has been valued at zero either without being assessed or due to a difference in opinion between Western Power and the Authority's technical experts.

Western Power has estimated the cost of this risk using an expected value approach.

The most recent example of ex-post review risk is the proposed write-down of AA2 expenditure of $21.2 million. As outlined in chapter 8 of this document, Western Power considers that this amount is due to a difference of opinion rather than inefficiency. This amount reflects around 1% of the investment undertaken in AA2. Therefore, Western Power has estimated the additional cost of this risk by assessing that 1% of the AA3 capital expenditure should be added to the non-capital cost allowance for the period.

[332] Paragraph 851, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[333] Paragraph 850, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[334] Pages 43-44, *Rule change request, Part B*, AER, 29 September 2011.

10 Target revenue

10.1 Tax on capital contributions

Required amendment 21:

No amounts in relation to tax on capital contributions must be included in Target Revenue.

Western Power response:

Western Power does not accept this amendment.

The Authority requires Western Power to remove any amounts related to tax on capital contributions from its target revenue for the AA3 period. In particular, the Authority states that it:

> *does not consider taxation costs relating to gifted assets or cash contributions should be borne by customers who do not make use of those assets*[335]

The Authority's position is that Western Power should recover these tax costs from the party providing the capital contribution or gifted assets.

Western Power does not accept this amendment as it penalises those customers that are required to pay a capital contribution or give assets to Western Power, even though those contributions relate to assets through which covered services are provided by Western Power. The Authority's position is also inconsistent with the approach taken in other jurisdictions.

In its September 2011 submission, Western Power proposed to recover this tax cost from all users of the Western Power Network via network tariffs.

Under section 6.4(a) of the Access Code target revenue is to be set to recover the forward looking and efficient costs of providing covered services. Section 2.10 of the Access Code requires Western Power to undertake and fund any required work subject to receiving capital contributions. Capital contributions and gifted assets, and the tax costs associated with them, are forward-looking and efficient costs of providing covered services.

The Authority's position that the tax costs should be recovered directly from the party providing the capital contribution or gifted assets is unique within Australia. Other monopoly network infrastructure regulators, including the AER, Essential Services Commission of Victoria and Independent Pricing and Regulatory Tribunal (IPART), make allowance for these contributions within the revenue allowance (via the tax building block). IPART considered the recovery of tax on capital contributions in December 2011 and determined that cash and asset contributions that contribute to regulated activities will be included in the assessment of tax.[336]

Capital contributions and gifted assets for regulated activities are usually viewed as contributing to regulated revenues and regulated expenses for calculating the regulatory tax liability. Under current ATO rules, businesses are required to pay tax on capital contributions and gifted assets and then can include these in their tax asset base.

Capital contributions and gifted assets are recognised as revenue under Australian Accounting Standards. Under the National Tax Equivalent Regime Western Power pays tax on this revenue. Western Power's tax treatment on capital contribution and gifted assets is consistent with the treatment applied by other entities under the National Tax Equivalent

[335] Paragraph 897, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[336] Page 13, *The incorporation of company tax in price determinations, Other Industries – Final Decision*, Independent Pricing and Regulatory Tribunal, December 2011.

Regime. Under the current treatment, Western Power receives no benefit from acceptance of the customer contribution or gifted asset.

Western Power believes that the tax costs are an unavoidable construct of three different and integrated regimes:

- accounting standards
- taxation requirements
- framework for economic regulation

The Authority requires that Western Power moves to a post-tax modelling approach. It indicates that one of the reasons for moving to a post-tax modelling approach is that it allows a regulated entity's effective tax liability to be estimated more precisely.[337] However, this can only be achieved if all of the regulated entities tax liabilities are included.

The Authority's position creates a disincentive for investment in Western Australia compared to other jurisdictions. In every other jurisdiction, these costs are shared by all the customers that benefit from the application of economic regulation.

Recovering these tax costs directly from customers penalises customers that wish to connect to the network. Charging the tax costs to customers may increase the capital contribution required by up to 25%.

Where customers build assets and then give them to Western Power, Western Power would require customers to pay an invoice for the tax costs prior to receiving the assets. This invoice could represent 25% of the costs incurred by the party 'gifting' the assets to Western Power.

The process of constructing and then gifting assets to regulated utilities plays an important role in state development. Customers usually give Western Power assets because they have determined that it would be quicker or cheaper to build the asset themselves rather than wait for Western Power to build it. If Western Power was required to charge customers the tax costs, it may dissuade customers from building the assets as the cost of gifting the asset may consume any cost saving.

To test the veracity of the respective approaches, Western Power engaged Ernst & Young to:

> *consider whether it is reasonable, with respect to the requirements of the Access Code, to recover the tax costs (or liabilities) flowing from the receipt of capital contributions from all users of Western Power's network rather than specifically from those making the contribution*[338]

Ernst & Young concluded that Western Power's approach is reasonable and identified a number of concerns with the Authority's approach. In making its assessment, Ernst & Young considered both how the cost should be determined and how it should be recovered.

In relation to determining the cost, the tax associated with a particular transaction can only be estimated having regard to the entity's overall tax profile. Ernst & Young notes that:

> *The ERA's approach does not do this. It cannot therefore objectively measure efficient tax costs. Nor can the ERA achieve its objectives in moving to a post-tax approach (i.e. to achieve economically efficient pricing by having a more precise estimate of the cost of tax).*[339]

In relation to recovering the cost, Ernst & Young identified a number of reasons why costs should be recovered from all users.

First, the nature of tax costs drives the most appropriate approach to their recovery. The estimated tax costs are not directly related to provision of capital contributions. The tax cost

[337] Paragraph 628, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[338] Paragraph 41*, Post-tax Recovery of Capital Contributions*, Ernst & Young, May 2012.
[339] Paragraph 35*, Post-tax Recovery of Capital Contributions*, Ernst & Young, May 2012.

is a function of the overall tax position of the taxpaying entity, not just capital contributions. The tax costs share the same characteristics of shared costs when considering how the costs should be allocated to services. They can not be directly related to a particular user or service.

Secondly, requiring recovery of the tax cost from specific users is likely to impose additional risk on Western Power where the estimate of the tax cost is challenged. This may occur as the tax costs would be estimates based on broad-brush assumptions of a cost that is affected by many other activities and parameters in the business. This may result in Western Power being unable to recover its efficient costs.

Thirdly, there are practical issues with recovering the tax cost from specific users such as:

- **estimating and demonstrating the efficiency of the costs**

  This is likely to be problematic as the charges could vary depending on how capital contributions are treated (e.g. how timing differences are measured) and how particular capital contributions are ranked, because the marginal tax cost may vary. They will also vary over time. This is likely to lead to significant issues with the acceptability of the charges (e.g. for equity).

- **determining the value of gifted assets**

  Where an asset is gifted, there may be a challenge in agreeing the appropriate value of the asset and the resulting tax cost to the customer. Recovering tax costs direct from users would likely create incentive to game the value of the gifted assets.

A copy of the Ernst & Young report is attached at Appendix T.

Western Power maintains that the recovery of these costs as part of the tax building block in the post tax revenue model provides the best option to ensure Western Power's efficient costs are recovered.

10.2 Return on working capital

Required amendment 22:

The amounts included in target revenue for working capital must be amended to the values in Table 93 and 94.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

In its September 2011 submission, Western Power proposed to include a return on working capital within the revenue building blocks.

In its draft decision, the Authority accepts working capital as a legitimate business cost. The Authority accepts Western Power's use of the working capital cycle model to estimate its AA3 working capital requirement but requires Western Power to amend the creditor days assumption (to 25 days for transmission and 28.5 days for distribution) and to estimate the costs of holding inventory by assuming the cost represents 4% of total expenses.

Western Power has amended its working capital requirements for AA3 to reflect:

- the post-tax method of determining the cost of service
- the updated operating and capital expenditure forecasts for the AA3 period
- an updated estimate of creditor days
- the inclusion of the inventory forecast within working capital

Table 71 shows the amended working capital requirements over the AA3 period.

Table 71: Working capital - closing value

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17
Distribution	137.7	152.8	163.5	168.6	177.4
Transmission	53.9	62.3	73.3	68.4	70.5

The Authority accepts Western Power's use of the working capital cycle model to estimate its AA3 working capital requirement. Western Power calculates working capital as the difference between the implicit cost incurred by providing credit to users of services and the implicit benefit of receiving credit from suppliers.

The Authority accepts Western Power's estimate of receivable days of 45 days, which has been retained by Western Power.

The Authority does not accept Western Power's estimate of creditor days of 20 days. The Authority re-estimated creditor days to be 25 days for transmission and 28.5 days for distribution.[340] Western Power understands that this is based on the Authority's estimate of the relative weighting of Western Power's expenditure on labour and materials. The Authority's estimate was based on an expense lead of ten days on labour costs and an expense lead of 30 days on direct costs of materials and services.

Western Power has recalculated creditor days to be 16 days for transmission and 15.5 days for distribution based on a weighted average of the forecast expenditures for AA3. The weighted average is based on an expense lead of ten days on labour costs, an expense lead of 30 days on direct costs of materials and services and no expense lead on internal costs of materials and services or other costs.

Table 72 and Table 73 detail the labour, materials and internal costs split and the resultant weightings applied in the calculation of creditor days.

Table 72: Transmission expenses

	2012/13	2013/14	2014/15	2015/16	2016/17	% over AA3
Labour – capital expenditure	163.7	213.6	156.2	220.4	269.2	
Labour – operating expenditure	78.6	77.7	83.4	90.0	98.2	
Total Labour	**242.3**	**291.3**	**239.6**	**310.5**	**367.5**	**56%**
Materials – operating expenditure	29.1	29.1	30.3	31.6	33.1	
Materials – capital expenditure	127.9	167.5	112.8	160.7	192.5	
Total Materials	**157.0**	**196.6**	**143.1**	**192.3**	**225.6**	**35%**
Indirect – operating expenditure	10.8	9.5	9.9	10.1	10.8	
Indirect – capital expenditure	22.0	21.6	30.6	45.1	52.7	
Total Indirect	**32.7**	**31.1**	**40.5**	**55.2**	**63.5**	**9%**

[340] Paragraph 925, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

	2012/13	2013/14	2014/15	2015/16	2016/17	% over AA3
Expenses grand total	**432.1**	**519.0**	**423.2**	**557.9**	**656.6**	**100%**

Table 73: Distribution expenses

	2012/13	2013/14	2014/15	2015/16	2016/17	% over AA3
Labour – operating expenditure	265.4	279.7	287.3	295.4	310.3	
Labour – capital expenditure	361.0	393.8	395.3	398.8	412.1	
Total Labour	**626.4**	**673.4**	**682.6**	**694.3**	**722.4**	**56%**
Materials – operating expenditure	75.2	76.2	78.2	78.6	80.8	
Materials – capital expenditure	299.0	324.3	326.6	320.1	311.4	
Total Materials	**374.2**	**400.4**	**404.8**	**398.6**	**392.2**	**32%**
Indirect – operating expenditure	41.8	40.7	39.5	37.3	37.4	
Indirect – capital expenditure	102.6	105.5	102.8	95.3	91.9	
Total Indirect	**144.3**	**146.2**	**142.2**	**132.6**	**129.3**	**11%**
Expenses grand total	**1,144.9**	**1,220.0**	**1,229.6**	**1,225.5**	**1,243.9**	**100%**

In required amendments 7 and 9 the Authority requires Western Power to remove inventory from the capital base. The Authority states that it:

> *consider it clearer and more transparent to consider it (inventory) as part of working capital requirements.*[341]

Western Power accepts that the costs of holding inventory can be included as part of working capital. However, the Authority's method for determining the efficient level of inventory does not result in an appropriate estimate of the costs.

The Authority's technical consultant reviewed the conclusions Western Power derived from its original analysis. The level of inventory holdings in the September 2011 submission was at a reasonable level when compared with other networks businesses. The Authority's technical consultant concluded that not only is it appropriate to recover these costs given that inventory is necessary to efficiently operate a network business, but also that the projected levels of inventory across the AA3 period align reasonably with the works program.[342]

Western Power does not agree with the Authority's position that the method used in Western Power's September 2011 submission to determine the level of inventory holdings is overly complex or lacking in transparency.

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[341] Paragraph 926, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[342] Page A8, *Technical Review of Western Power's Proposed Access Arrangements for 2011-2017*, Geoff Brown and Associates, March 2012.

Western Power has included an efficient level of inventory as a working capital adjustment by using the method detailed in the September 2011 submission. Western Power maintains the view, as does the Authority's technical consultant, that this method forecasts and efficient value of inventory for the AA3 period.

The amount of inventory each year is determined with the following formula:

Inventory investment = (regulated materials consumed / asset turnover) + (regulated insurance spares)

Where:

'Materials consumed' refers to the value of materials used for construction and ongoing maintenance.

'Asset turnover' identifies the forecast number of times per annum that inventory items in the 'materials consumed' category are utilised and reordered (and hence turned over). Western Power has used an asset turnover rate of 'three times per annum'.

'Insurance spares' are held specifically for assets that are of critical importance to the covered network.

10.3 Tax liabilities

Required amendment 23:

The Authority requires that Western Power model its tax liabilities explicitly, as a separate nominal 'building block', applying the method set out in this Draft Decision.

To this end, the Authority requires that Western Power amend the tax liabilities for the purposes of determining its maximum annual revenue requirements to those estimated by the Authority as set out in Table 4 and 5.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

In its September 2011 submission, Western Power adopted a pre-tax model to calculate the target revenue for the AA3 period.

In its draft decision, the Authority requires Western Power to adopt a post-tax model to calculate the target revenue for the AA3 period, as it believes that the post-tax approach allows a regulated entity's effective tax liabilities to be estimated more precisely.[343]

Western Power accepts the post-tax form of revenue modelling on the basis that this provides an accurate estimate of its tax liabilities. However, Western Power does not accept the Authority's method for determining the opening value for the tax asset base as at 30 June 2012.

The tax asset base is used to determine the depreciation allowance in the calculation of the tax liabilities. The Authority's methodology does not result in a tax asset base that can be used to accurately determine Western Power's tax liabilities.

Western Power has determined an appropriate opening value for the tax asset base as at 30 June 2012 that will result in an accurate estimate of Western Power's tax liabilities so that it can recover the forward looking efficient costs of tax.

[343] Paragraph 628, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

The following sections provide further detail on Western Power's approach to modelling target revenue and the method for setting the tax asset base for the AA3 period.

10.3.1 Modelling target revenue

Western Power has revised its revenue modelling to incorporate the post-tax approach to modelling. The revenue model uses the building block method to determine the target revenue for the transmission system and distribution system.

The following formula is a simple representation of how the target revenue for providing covered services is calculated:

$$\mathbf{TR_t = r.RAB_{t,open} + Dep_t + O\&M_t + Tax_t\text{-}ImputationCredits_t + AA2_t + TEC_t}$$

where:

TR_t = target revenue for providing covered services in year t.

r = WACC (in real post-tax terms)

$RAB_{t,open}$ = opening value of the capital base (which takes into account forecast new facilities investment over the access arrangement period)

Dep_t = depreciation in year t (which takes into account forecast new facilities investment over the access arrangement period)

$O\&M_t$ = forecast of operating and maintenance costs for year t

Tax_t = estimate of the tax costs for year t.

$\text{Imputation Credits}_t$ = estimate of the value of the imputation credits to investors for year t.

$AA2_t$ = target revenue adjustment due to the SSAM, GSM, IAM, unforeseen events, Technical Rules changes, D-factor and deferred revenue for year t.

TEC_t = forecast of the tariff equalisation contribution for year t.

The revenue model reflects this calculation of the target revenue and incorporates the following high level assumptions:

- revenue modelling occurs on a real post-tax basis
- all expenses are modelled on an as-incurred basis
- end of year timing for modelling revenues, expenses and tax in real terms
- separate modelling of the transmission system and distribution system
- the estimate of tax costs is calculated based on:
  - all calculations of the tax costs occur in nominal dollar terms. The tax is then converted into real dollar terms for inclusion in the building block calculation
  - revenue includes smoothed revenue from revenue cap services, revenue from non-revenue cap services and forecast gifted assets and capital contributions
  - the interest cost is based on:
    - o the opening debt balance for each year of the AA3 period is based on 60% (being the benchmark gearing assumed in the WACC) of the nominal opening value of the capital base
    - o the interest rate applied to the opening debt balances is based on the nominal cost of debt that is consistent with the WACC calculation
  - tax depreciation is calculated from:
    - o Western Power's tax asset base roll forward over the AA3 period, based on the remaining life of the opening tax asset base and the tax lives of the

various capital assets. This reflects that tax depreciation is generally based on a much shorter tax life or calculated in a different way

- o the tax asset base roll forward includes Western Power's forecast of gifted assets and assets funded by a capital contribution. This is consistent with the actual treatment and more precisely estimates Western Power's tax liabilities over time by providing a tax shield in future years through higher depreciation in recognition of the tax paid on the revenue associated with gifted assets and capital contributions

- any estimated tax losses are carried forward
- the estimate of tax costs is calculated for Western Power as a single entity and then apportioned between the transmission and distribution businesses in proportion to an estimate of the tax position of each separate business

The revised calculation of Western Power's target revenue, which includes the forward-looking efficient costs, is set out in chapter 5 of this document.

10.3.2 Modelling tax asset base

The Authority requires Western Power to determine the tax asset base from the closing value of the regulated asset base for 2011/12.

The regulated asset base is not the relevant reference for the purposes of estimating tax liabilities.

Western Power engaged Ernst & Young to determine the most appropriate and reliable information to use as a starting tax asset base. Table 74 shows appropriate values for the tax asset base as at 30 June 2012 calculated by Ernst & Young.

Table 74: Tax asset base at 30 June 2012

$ million real at 30 June 2012	Tax depreciable base
Distribution	4,291.6
Transmission	2,289.3
Total	6,580.9

Ernst & Young calculated the opening tax asset base at 30 June 2012 from:

- Western Power's fixed asset register as at 1 April 2006, including all contributed and gifted assets
- additions and disposals for 1 April 2006 – 30 June 2006 and the financial years 2006/07, 2007/08, 2008/09, 2009/10, 2010/11 and 2011/12, including all contributed and gifted assets
- depreciation based on effective lives for depreciation purposes using the prime cost method.

Ernst & Young's detailed report, outlining the method and value of the tax asset base, is attached in Appendix S.

For the AA3 period Western Power has rolled forward the value of the tax asset base by:

- adding all capital expenditure (including contributed and gifted asset) on an as-incurred basis
- deducting the depreciation based on the applicable effective tax lives calculated on a straight-line basis

This method ensures that the revenue model properly estimates Western Power's effective tax liabilities over the AA3 period.

Western Power determines the life to use for tax depreciation purposes from the Commissioner of Taxation's effective lives. Table 75 and Table 76 detail the lives used to determine the depreciation on the tax asset base:

Table 75: Transmission asset groupings and tax lives for depreciation purposes

Asset group	Tax life (years) for depreciation purposes
Transmission transformers	40
Transmission reactors	40
Transmission capacitors	40
Transmission circuit breakers	40
Transmission lines – steel towers	47.5
Transmission lines – wood poles	47.5
Transmission cables	47.5
Transmission metering	25
Transmission SCADA and communications	12.5
Transmission IT	4
Transmission other, non-network assets	12.5
Equity raising costs	5

Table 76: Distribution asset groupings and tax lives for depreciation purposes

Asset group	Tax life (years) for depreciation purposes
Distribution lines – wood poles	45
Distribution underground cables	50
Distribution transformers	40
Distribution switchgear	30
Street lighting	15
Distribution meters and services	25
Distribution IT	4
Distribution SCADA and communications	10
Distribution other, non-network	10
Equity raising costs	5

10.4 Costs of raising equity

Required amendment 24:

The Authority requires that Western Power determine the forward looking efficient costs of raising equity according to the method set out in its Draft Decision. To this end, the Authority requires that Western Power amend the cost of raising equity for the purposes of determining the revenue requirement to those estimated by the Authority as set out in Table 65 and Table 66.

Western Power response:

Western Power does not accept this amendment.

In its draft decision, the Authority accepts that equity raising costs are legitimate costs incurred by a benchmark firm. However, it did not accept Western Power's assumptions underlying the cash flow modelling and specifically the assumption relating to dividend reinvestment program costs.

Western Power has based its assumptions on those the AER has adopted and applied to a number of regulated businesses.

The Authority has adopted a different approach in relation to the costs associated with dividend re-investment. The Authority believes that there should be not be any costs associated with dividend reinvestment plans as it considers that participation requires nothing more than a 'tick the box' exercise.[344] The Authority's approach does not deliver an appropriate estimate of equity raising costs as it ignores the legitimate costs associated with raising equity through dividend reinvestment plans.

The AER has undertaken considerable analysis and research on this issue and found that the appropriate cost for dividend reinvestment is 1%. This estimate is based on the AER's own analysis and that of the Allen Consulting Group (ACG), Carlton[345] and Associate Professor Handley[346].

In its 2004 report, ACG suggests that the cost of raising equity through a dividend reinvestment plan should be zero. This reflected its own observation that the level of competition between brokers resulted in no cost for underwriting services, as brokers sought to profit by placing stock at a higher price than the standard dividend reinvestment plan price.

More recently, in 2009 Carlton suggested that anecdotal evidence showed underwriting fees of 2.5% were being charged by brokers. On the basis of ACG and Carlton's estimates, the AER's advisor Associate Professor Handley stated that a reasonable cost for a dividend reinvestment program is between 0% and 2.5%.[347] However, further investigation by Carlton revealed that underwriting fees were more likely to be half the 2.5%.

The AER undertook its own research into the costs of dividend reinvestment plans for domestic energy network businesses. Based on its assessment of Bloomberg data and annual report data, the AER found that the costs as a proportion of equity raised had a median of 0.75% and mean of 1%.[348] Taking this information into account, the AER

[344] Appendix 5: Treatment of Equity Raising Costs, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[345] *Indirect Costs of Equity and Debt Raising, Report Prepared for Energy Australia*, T Carlton, 12 January 2009.
[346] *Final Decision, Australian Capital Territory Distribution Determination 2009-10 to 2013-14*, AER, 28 April 2009.
[347] *Final Decision, Australian Capital Territory Distribution Determination 2009-10 to 2013-14*, AER, 28 April 2009.
[348] *Final Decision, Australian Capital Territory Distribution Determination 2009-10 to 2013-14*, AER, 28 April 2009.

considered that a conservative estimate of 1% is appropriate for the unit cost of equity raised by a dividend reinvestment plan.[349]

The Authority's departure from the AER's methodology equates to a $1.4 million reduction in equity raising costs over AA3.

Based on the above analysis, Western Power maintains that the costs associated with dividend reinvestment plans are greater than zero and are most likely to be consistent with the AER's estimate of 1%.

In its September 2011 submission, Western Power proposed forward looking efficient equity raising costs that were calculated using the AER's methodology and assumptions as follows:

- dividends are assumed to be paid at the benchmark payout ratio of 70 per cent of after-tax profits reflecting the assumptions underlying imputation credits
- retained earnings of 30% of after-tax profits are assumed to be available at zero costs
- 25% of dividends are assumed to be returned to the business through a dividend reinvestment plan at a cost of 1%
- Any further equity requirement is assumed to come from seasoned equity offerings at a cost of 3%

These assumptions are encompassed in the modelling of the regulated revenue model and result in $35.8 million ($ real at 30 June 2012) for the purposes of determining the revenue requirement.

10.5 Adjustments to target revenue

Required amendment 25:

The proposed revised access arrangement must be amended to include an adjustment to target revenue for the third access arrangement period taking account of any under-recovery or over-recovery of revenue under the revenue cap in 2010/11 and 2011/12.

Western Power response:

Western Power accepts this amendment.

The Authority's draft decision requires that Western Power amends the access arrangement to include an adjustment to target revenue for the third access arrangement period taking account of any under-recovery of revenue under the revenue cap in 2010/11 and 2011/12 to give effect to section 5.37 and 5.48 of the current access arrangement.[350]

Western Power accepts this amendment. Sections 5.6.7 and 5.7.7 of the revised proposed revisions to the access arrangement have been amended to provide for adjustments due to differences between the 2010/11 forecast revenue and the actual revenue and the 2011/12 forecast revenue and the actual revenue.

In its September 2011 submission, Western Power proposed to amend the K-factor calculation to reflect that the annual tariff-setting process typically takes place during April before the end of financial year. The K-factor calculation includes a forecast of the revenue earned in the year which is then adjusted in the calculation of the K-factor the following year.

Further, the distribution revenue correction factor has been amended to provide for corrections to the real value of the tariff equalisation contributions (TEC). The revenue

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[349] *Final Decision, Australian Capital Territory Distribution Determination 2009-10 to 2013-14*, AER, 28 April 2009.
[350] Paragraph 960, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

correction factor is calculated in real dollars terms whilst the TEC remains constant in nominal dollar terms. The conversion of the TEC from nominal dollars to real dollars results in different values when forecasts of inflation are utilised compared to when actual inflation is known. The amendment to the distribution revenue correction factor corrects for the differences in the real TEC value that arise due to differences between forecast and actual inflation.

The revised sections 5.6.7 and 5.7.7 are included in the proposed revised access arrangement that accompanies this submission.

10.6 Unforeseen events

Required amendment 26:

No adjustment to target revenue for the third access arrangement period should be made in relation to unforeseen events.

Western Power response:

Western Power accepts this amendment.

In its September 2011 submission, Western Power sought to recover costs associated with the March 2010 storm on the basis that it was an unforeseen event.

In its draft decision the Authority stated that:

> *The Authority recognises that the March 2010 storm was a major event. However, taking account of the uncertainties raised by the Committee regarding why Western Power does not have an insurance policy covering any of its above ground transmission and distribution lines; and the fact that recorded winds during the storm were below the level that industry standards require wooden power poles to be able to withstand, the Authority does not consider that Western Power sufficiently demonstrated that it took all steps that a reasonable and prudent person would to prevent or overcome the physical and financial damage that arose from the storm.*[351]

Western Power remains of the view that it is appropriate to seek an adjustment to target revenue in relation to unforeseen events when they occur. This will avoid customers incurring higher costs to reflect the costs associated with insurance or self-insurance against these risks each year.

Western Power notes the concerns expressed by the recent Parliamentary Inquiry in relation to the March 2010 storm.

Western Power is still working with Government to respond to the matters raised by the Parliamentary Inquiry. Western Power is also undertaking some further work to ensure its insurance coverage has been and continues to be appropriate.

[351] Paragraph 980, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

10.7 Service standard adjustment mechanism incentive rates

Required amendment 27:

The reward in relation to the service standard adjustment mechanism for the distribution service must be amended to use the Authority's approved post-tax WACC of 3.87 per cent.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

Western Power agrees that the reward in relation to the service standard adjustment mechanism (SSAM) for the distribution service should reflect the weighted average cost of capital (WACC). However, as outlined in chapter 9, Western Power does not accept the Authority's point estimate for the post-tax WACC of 3.87%.

In its draft decision, the Authority accepts Western Power's overall approach for calculating the AA3 service standards adjustment.[352]

However, the Authority notes that Western Power has based its calculation of the adjustment to target revenue on a proposed WACC of 8.82% for the 2012/13 financial year and that it should be changed to the approved post-tax WACC of 3.87%.[353]

Western Power will base its calculation of the adjustment to target revenue in relation to the SSAM on a real post-tax WACC of 6.39%, as per the response to required amendment 20.

10.8 SSAM adjustment

Required amendment 28:

Section 7.5 of the proposed access arrangement must be amended to include an adjustment resulting from any differences between forecast and actual network performance in 2011/12, based on the service standard benchmarks set for the second access arrangement period – to be made to target revenue at the beginning of AA4.

Western Power response:

Western Power accepts this amendment.

Western Power accepts that it is appropriate to adjust revenue for the difference between actual and forecast performance in 2011/12 against the service standard benchmarks (SSBs) that are included in the service standard adjustment mechanism (SSAM) for AA2, the "2011/12 SSAM SSBs".

Western Power will revise its proposal to include a revenue adjustment in AA4 that will provide for the difference between forecast and actual service performance in the financial year ending 30 June 2012 by applying the applicable incentive rate to the Service Standard Adjustment Difference, $SSAdj_{2011/12}$, which is calculated as follows;

$$SSAdj_{2011/12} = SSF_{2011/12} - SSA_{2011/12}$$

where:

[352] Paragraph 992, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[353] Paragraph 993, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

SSAdj$_{2011/12}$ is the service standard adjustment for the difference between forecast and actual service performance of the *2011/12 SSAM SSBs*

SSF$_{2011/12}$ is the forecast service performance for the *2011/12 SSAM SSBs* for the financial year ending 30 June 2012

SSA$_{2011/12}$ is the actual service performance in the financial year ending 30 June 2012 for the *2011/12 SSAM SSBs* as reported in the *service standard performance report* for that year

Section 7.5 of the proposed revised access arrangement will be amended to include the adjustment to target revenue in the next access arrangement for any differences between forecast and actual network performance in 2011/12 for the '2011/12 SSAM SSBs'.

10.9 Deferred revenue

Required amendment 29:

The proposed access arrangement must be amended to recover deferred revenue over ten years and include a similar provision to the existing access arrangement regarding how this will be reviewed at AA4.

Western Power response:

Western Power accepts this amendment.

The Authority's draft decision requires Western Power to recover deferred revenue over ten years and amend the access arrangement to include a provision detailing how deferred revenue will be reviewed at AA4. It found that this recovery period could be accommodated without resulting in price shock to customers.[354]

Western Power accepts recovery of deferred revenue over ten years to reduce price shock to customers.

Western Power will add a new section 7.7 to the access arrangement to detail the adjustment that will need to occur to target revenue in the next access arrangement to recover the outstanding amount of deferred revenue.

The new section 7.7 is included in the proposed revised access arrangement that accompanies this submission.

[354] Paragraph 1033, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

11 Service standard benchmarks

11.1 Transmission service standard benchmarks

11.1.1 Circuit availability

Required amendment 30:

The 'minimum standard' Circuit Availability service standard benchmark must be set at 97.6 per cent. This is the estimated 2.5 per cent PoE level derived from the application of a Weibull distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during AA3.

Western Power response:

Western Power accepts this amendment.

In its September 2011 submission, Western Power proposed that the circuit availability service standard benchmark (SSB) should be set at 97.3% based on:

- the estimated 2.5% probability of exceedence (PoE) level derived from the application of a Weibull distribution to the last five years of the historic circuit availability data and
- a 0.5% reduction to reflect the updated forecast impact of additional transmission network capital works during AA3

The Authority's technical consultant undertook its own analysis of the SSB and considered that there was no apparent basis for the 0.5% reduction.[355] Instead, it considered that a 0.2% reduction was justified.[356]

Western Power accepts the 0.2% reduction to reflect the updated forecast impact of additional transmission network works.

However, in accepting this amendment Western Power notes that the Authority has incorrectly removed adjustments for power transformers. The Authority appears to have confused power transformers and zone substation transformers as evidenced by the following comment:

> *Western Power appears to have included outages for the replacement of zone substation transformers in its analysis even though the availability of these assets is excluded from the performance measure.*[357]

The definition of circuit availability excludes the availability of zone substation transformers but includes the availability of power transformers[358], which are part of a 'transmission circuit'. As a result, the circuit availability service standard benchmark should be adjusted to take into account the forecast reduced availability of power transformers during AA3 with the

[355] Paragraph 1107, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[356] Paragraph 1108, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[357] Paragraph 1106, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[358] The term 'power transformer' refers to bulk or terminal transformers, which are for transformation between transmission voltage levels (for example 330kV/220kV, 330kV/132kV or 220kV/132kV). The works on zone substation transformers, which transforms transmission voltage levels to distribution voltage levels (such as 132kV/33kV or 132kV/22kV), has not been considered in the analysis. This is consistent with the exclusions for circuit availability.

planned replacement of power transformers. This has no material impact on the 0.2% reduction.

11.1.2 Individual customer service

Required amendment 31:

To warrant the resources involved, and to relate the measure to actual performance, Western Power must include in the transmission Individual Customer Service service standard benchmark measure a reporting element relating to the outcomes of the satisfaction survey. This could be achieved by amending the definition of this measure to be:

> The percentage of users over a 12 month period procuring a reference service A11 or B2 (after exclusions) that have:
>
> - an account manager for the full 12 month period;
> - an annually reviewed customer service management plan;
> - participated in an annual satisfaction survey; and
> - rated the overall performance of Western Power as satisfactory, good or excellent, but not unsatisfactory or poor.

Otherwise, this measure should not be implemented.

Western Power response:

Western Power accepts this amendment.

In its September 2011 submission, Western Power set out SSBs for transmission reference service customers. This included a new customer-focused measure that reflects the service received at each of Western Power's 51 transmission-connected customer sites. This new measure required that each transmission-connected customer has:

- *an account manager – providing a direct point of contact in Western Power*
- *an annually reviewed customer service management plan – which reflects the individual needs of the customer*
- *the opportunity to participate in an annual customer satisfaction survey – creating a channel for customers to provide their feedback to Western Power and enable measurement of each customer's service experience.*[359]

In its draft decision, the Authority states that Western Power should include the outcomes of the customer satisfaction survey, or otherwise not implement the measure. Western Power accepts that this measure should not be implemented.

Western Power did not include the outcome of the customer satisfaction survey in its proposal because:

- there is no historical data to assess the relative performance and
- Western Power is seeking to design a survey that maximises the value of information to improve performance and avoid designing the survey to meet a required target

Western Power still intends to provide each transmission-connected customer an account manager, an annually reviewed customer service management plan and the opportunity to participate in an annual customer satisfaction survey. During AA3 Western Power will also begin to collect data on the outcomes of the customer satisfaction survey. However, as it is

[359] Page 89, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, Western Power, September 2011.

not possible to set a reasonable target for the customer satisfaction survey at this time, in accordance with the Authority's amendment, the measure will not be included as an SSB for the AA3 period.

Western Power will amend clause 4.3.1 of its proposed revised access arrangement and will delete clauses 4.3.4 and 4.3.5.

11.1.3 Other transmission related benchmarks

Required amendment 32:

The proposed access arrangement revisions must be amended to reinstate the service standard benchmarks for:

- transmission circuit System Minutes Interrupted – for meshed (less critical) and radial (more critical) circuits;
- Loss of Supply Event Frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of low and high duration measured as system minutes interrupted; and
- Average Outage Duration, measured in minutes.

Table 114 provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power.

Western Power response:

Western Power does not accept this amendment.

In its September 2011 submission, Western Power included SSBs that reflected the service standard for reference services rather than for network performance, to meet section 5.1 of the Access Code.

The Authority has not accepted the SSBs for each reference service and requires Western Power to continue to use transmission network-based performance measures. The Authority considers that:

- SSBs should be consistent with the benchmarks that apply to transmission businesses in the National Electricity Market[360]
- that it requires the need to be able to separately assess the performance of the transmission and distribution networks[361]
- the transmission network service is a key component for the performance of all reference services[362]
- there has been significant underperformance on System Minutes Interrupted (radial)[363]
- the change would dilute the attribution of overall performance to distribution and transmission networks, and as a corollary, obscure priorities for improvement[364]

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[360] Paragraph 1115, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[361] Paragraphs 1113, 1114 and 1128, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[362] Paragraph 1113, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[363] Paragraph 1117, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[364] Paragraph 1128, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Western Power does not accept this amendment because:

- its proposed reference service measures meet the requirements of the Access Code
- the Authority's proposed network-based measures are not required under the Access Code
- Western Power's existing reporting requirements and the commitment in its September 2011 submission to report on additional transmission network performance measures, allows stakeholders to separately assess the performance of the transmission and distribution networks and to compare Western Power's performance with network businesses in other jurisdictions
- transmission network measures do not represent the actual experiences of customers receiving a transmission reference service because the performance of the reference service is significantly better than the performance of the transmission network
- transmission network performance is likely to have a greater effect on customers receiving a distribution reference service
- including transmission network events in SAIDI and SAIFI preserves the compliance and financial incentives to perform on the transmission network.

Further, Western Power does not believe it is appropriate to include the system minutes interrupted measure as an SSB because:

- the measure is not considered to be statistically sound[365] and is not included in revenue determinations for other transmission businesses
- the measure is not independent of the other transmission network measures that the Authority is proposing to include as SSBs

11.1.3.1 Meeting the Access Code requirements

The Access Code requires performance measures based on reference services, but does not require performance measures based on network performance.

Transmission network measures provide a poor representation of the transmission reference service that each user should expect to receive. As indicated in Western Power's September 2011 submission[366], transmission-connected customers experience a very low average number of interruptions and the actual number of interruptions that any individual transmission-connected customer may experience varies significantly. In most years, most transmission-connected customers will have no interruptions. However, there is still a small possibility that individual transmission-connected customers will experience an interruption. The impact of this interruption will vary depending on whether the customer has their own generation source.

This means that a minimum service standard on a reliability measure for transmission-connected customers would need to reflect a much lower level of performance than most customers would experience in any one year, to accommodate the volatility over a small number of customers. The minimum service standard therefore provides little information to the majority of transmission-connected customers on the performance that they are likely to receive in any one year, as the performance they receive will typically be significantly better than the minimum service standard. Contrary to the Authority's view, the transmission network performance measures are therefore not consistent with section 5.6(b) of the Access Code.[367]

[365] Page 5, *Transmission Network Service Provider (TNSP) – Service Standards, Final Report*, Report prepared for the Australian Competition and Consumer Commission (ACCC) by SKM, March 2003.
[366] Pages 89-90, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, Western Power, September 2011.
[367] Paragraph 1128, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012. Section 5.6(b) of the Access Code states that a

For example in 2008/09, the loss of supply event frequency for low duration interruptions was 18. In this same year, only two of the 51 transmission-connected customer sites experienced one low duration interruption[368] each. No other transmission-connected customers experienced low duration interruption. In 2008/09 the number of high duration interruptions was 3. In this same year, no transmission-connected customers experienced a high duration interruption[369].

Similarly, the duration of interruptions experienced by customers receiving a transmission reference service was significantly less than the average duration of interruptions on the transmission network. While the average outage duration in 2008/09 was 501 minutes, the duration of the interruption experienced by one transmission-connected customer was 77 minutes and the duration of the interruption experienced by the other customer was 245 minutes.

The system minutes interrupted performance measure provides system-wide information only. It does not provide any information that is directly relevant to any customer receiving a transmission reference service. For example, from 2007/08 to 2011/12, the system wide performance has been and is expected to be between 6.7 to 8.9 system minutes (system minutes interrupted meshed[370]) for each financial year. However the individual transmission-connected customer's experience is significantly different. The majority of transmission-connected customers did not experience any interruptions in the last five years. Only a small number of customers experienced an interruption - one customer in 2007/08, two customers in 2008/09 and one customer in 2011/12 (out of 51 customer sites) and the interruption durations were 184, 77 and 245, and 8 minutes respectively.

Western Power has proposed an approach that is consistent with the Access Code. Further, it believes that the measures it has proposed are more meaningful to customers considering or receiving a reference service.

11.1.3.2 Consistency with the other jurisdictions

The Authority has indicated that it prefers an approach that is consistent with the approach adopted in the other jurisdictions. Western Power believes that its approach is consistent with other jurisdictions because:

- Western Power will report on the same measures, as discussed above
- Western Power will have strong incentives to ensure that the service customers receive is consistent with the value they place upon it

There are differences between jurisdictions because the regulatory framework that applies to Western Power and to the other network businesses is different. While Western Power's access arrangement covers both the transmission and distribution networks, the revenue determinations for network businesses regulated under the National Electricity Rules cover only the transmission or distribution network.[371]

As a result, the performance measures for other transmission businesses reflect the service received by their transmission customers, which are mostly distribution network businesses – not individual distribution-connected customers. Western Power's distribution-connected customers have an advantage over distribution-connected customers in other jurisdictions

service standard benchmark for a reference service must be sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

[368] Consistent with the terminology in the Authority's Draft Decision, a low duration interruption is an interruption in which the system minutes interrupted is between 0.1 and 1.

[369] Consistent with the terminology in the Authority's Draft Decision, a high duration interruption is an interruption in which the system minutes interrupted is greater than 1.

[370] Each transmission-connected customer is connected to the meshed transmission network.

[371] The only exception is EnergyAustralia which has a small transmission network (approximately 900km). Most of EnergyAustralia's distribution network is connected to Transgrid's transmission network.

because the value they can receive from their distribution reference service is not reduced by the exclusion of events that occur on the transmission system.

11.1.3.3 Transmission network performance is a key component of performance for all reference services

Transmission network performance measures do not provide a reasonable indication of the service received by transmission reference service customers as the service to these customers is locational and connection arrangement dependent. Any change in the performance of the transmission network is likely to have little or no effect on transmission reference service customers.

However any change in the performance of the transmission network is likely to have a greater effect on distribution reference service customers, and will be included in Western Power's proposed SAIDI and SAIFI performance measures, which include transmission network events (refer to response to required amendment 33).

Western Power will still report on the transmission network performance measures, but they will not be relevant for the purpose of compliance or financial incentives. However, with the inclusion of transmission network events in the SAIDI and SAIFI performance measures, the performance of the transmission network will continue to be subject to compliance and financial incentives.

This is appropriate given the transmission network performance measures are less relevant to the service received by customers.

Western Power proposes to report on the transmission network performance measures during the AA3 period in the Annual Service Standard Performance Report, which is provided to the Authority and published on the Authority's website.

11.1.3.4 Allocation of overall performance to distribution and transmission

The Authority will continue to be able to attribute overall performance to the transmission and distribution networks.

As discussed, Western Power has committed to continuing to report on the transmission network performance measures. In addition, the Authority already requires Western Power to report on SAIDI and SAIFI, by network type with and without transmission network events included.

For example, the Authority's Electricity Distribution Licence Performance Reporting Handbook already requires Western Power to report on a large number of network related measures, including:[372]

- DB7 – overall SAIDI by Total Network, CBD, Urban, Short Rural and Long Rural – requires measurement of all interruptions including events on the transmission network
- DB9 – distribution network (Unplanned) SAIDI by Total Network, CBD, Urban, Short Rural and Long Rural – requires measurement of unplanned interruptions on the distribution network excluding events on the transmission network

As set out in its September 2011 submission[373] and discussed further in Western Power's response to required amendment 57 (section 13.3.7 of this document), Western Power also proposes:

[372] Available at http://www.erawa.com.au/cproot/9576/2/20110516%202011%20Electricity%20Distribution%20Licence%20Performance%20Reporting%20Handbook.PDF
[373] Pages 102-103, *Access Arrangement Information for 1 July 2012 to 30 June 2017,* Western Power, September 2011.

- that the rewards and penalties under the SSAM that are associated with the transmission component of SAIDI and SAIFI will be allocated to the transmission revenue
- that the rewards and penalties under the SSAM that are associated with the distribution component of SAIDI and SAIFI will be allocated to the distribution revenue

This means that performance of the distribution and transmission networks will be visible through the rewards and penalties awarded against each network's revenue.

11.1.3.5 System minutes interrupted

Western Power does not accept that the system minutes interrupted measures should be included as service standard benchmarks.

When considering suitable performance measures for transmission network service providers, the Australian Competition and Consumer Commission (ACCC) expressed the view that the system minutes interrupted measure is statistically unsound in terms of describing the underlying performance of transmission networks. It was replaced with the loss of supply event frequency measure.[374]

Table 119 in the Authority's draft decision demonstrates that transmission network service providers in the other jurisdictions have loss of supply event frequency measures in their revenue determinations but not system minutes interrupted measures.[375]

Western Power has established criteria to assess which performance measures should be included in the access arrangement.[376]

The system minutes interrupted measures are not independent of other measures as they are already effectively captured by the loss of supply event frequency measures.

Table 77 shows the loss of supply event frequency and average outage duration measures if they were to be included as service standard benchmarks in AA3. These are much greater than the corresponding experience for individual transmission reference service customers, as discussed further in the response to required amendment 54 and 55.

Table 77: Service standard benchmarks for loss of supply event frequency and average outage duration

Performance measure	SSB
Loss of supply event frequency	
0.1 to 1.0 system minutes (events)	30
Greater than 1.0 system minute (events)	4
Average outage duration (minutes)	904

[374] Page 5, *Transmission Network Service Provider (TNSP) – Service Standards, Final Report*, Report prepared for the Australian Competition and Consumer Commission (ACCC) by SKM, March 2003.
[375] Paragraph 1311, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[376] Page 86, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, Western Power, September 2011.

11.2 SAIDI and SAIFI

11.2.1 Definition of SAIDI and SAIFI

Required amendment 33:

The definition of the SAIDI and SAIFI service standard benchmark measures must be revised to include distribution network events only.

Western Power response:

Western Power does not accept this amendment.

In its September 2011 submission, Western Power included SSBs that reflected the service standard for reference services rather than for network services to meet section 5.1 of the Access Code. The reliability measures for distribution reference service customers – SAIDI[377] and SAIFI[378] – included the supply interruptions arising from the transmission network and the distribution network.

The Authority accepts that there is some merit in providing transmission outages within the distribution reference service measures. However, it considers that the transmission outages should not be included in the distribution reference service measures as:

- separate information on the performance of the distribution and transmission networks allows distribution reference service customers to assess the value of a reference tariff, as these measures are independent[379]
- the change would dilute the attribution of overall performance to distribution and transmission networks, and as a corollary, to obscure priorities for improvement [380]
- the definition of the measures for the distribution network need to be maintained as customers paid for improvements in service during AA2[381]
- it did not accept Western Power's argument that transmission networks performance is unrelated to the provision of reference services, whether these be for large transmission-only customers, or for distribution customers

Western Power does not accept this amendment because:

- the service distribution customers receive is affected by transmission network interruptions and therefore is relevant in assessing the value of distribution reference services
- Western Power's proposed reference service measures meet the requirements of the Access Code
- the Authority's proposed network-based measures are not required under the Access Code
- Western Power's existing reporting requirements and commitment to report on additional transmission network performance measures allow stakeholders to separately assess the performance of the transmission and distribution networks

[377] System Average Interruption Duration Index – the duration of supply interruptions.
[378] System Average Interruption Frequency Index – the number of supply interruptions
[379] Paragraph 1127, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[380] Paragraph 1128, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[381] Paragraph 1130, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

11.2.1.1 Meeting the Access Code requirements

Western Power's proposed performance measures for reference services meet the requirements of the Access Code. The Access Code does not require performance measures based on network services.

Western Power's approach provides information to enable users or applicants to determine the value of the reference service, as required under section 5.6 of the Access Code. In contrast, the Authority's approach provides information on distribution network performance only and enables users or applicants to determine part of the value of the reference service only.

The service experienced by distribution reference service customers is affected by both distribution and transmission events. Given Western Power manages both of these, it should not be excused for poor performance of the transmission network where it impacts on end-use customers. Western Power believes its proposal better reflects the service received by distribution reference service customers.

For example, under Western Power's proposal, the one million customers that receive a distribution reference service are able to determine the value of that service by reference to the SAIDI (for the expected duration of interruptions per annum) and SAIFI (for the expected frequency of interruptions per annum) that applies to their network type (CBD, Urban, Rural short or Rural long).

By comparison, under the Authority's proposal, the one million distribution customers will only be able to determine the value of that service by determining the combined effects of the following service standard benchmarks:

- duration of interruptions
    - SAIDI for the distribution network, based on network type, plus
    - system minutes interrupted on the transmission network, either meshed or radial
- frequency of interruptions
    - SAIFI for the distribution network, based on network type, plus
    - loss of supply event frequency between 0.1 and 1 system minutes on the transmission network, plus
    - loss of supply event frequency greater than 1 system minutes on the transmission network

Also, experience suggests that distribution reference service customers are indifferent as to whether their supply has been interrupted by a fault on the distribution network or on the transmission network. They are concerned only with whether there is an interruption to their supply, and if so, when their supply will be restored. For that reason, Western Power has proposed SSBs that include the performance of both the transmission and distribution networks.

11.2.1.2 Monitoring network performance

Western Power agrees that stakeholders may wish to separately monitor the performance of the transmission and distribution networks, and to be able to compare the performance of Western Power's networks to those in other jurisdictions. The Authority's Electricity Distribution Licence Performance Reporting Handbook already requires Western Power to report the following network related measures:[382]

- DB1 – the number of premises of small use customers to which the supply of electricity has been interrupted for more than 12 hours continuously

[382] Available at http://www.erawa.com.au/cproot/9576/2/20110516%202011%20Electricity%20Distribution%20Licence%20Performance%20Reporting%20Handbook.PDF

- DB2 – the number of premises of small use customers to which the supply of electricity has been interrupted more than the permitted number of times, as defined in section 12(1) of the Electricity Industry (Network Quality and Reliability of Supply) Amendment Code 2007
- DB3 – for each discrete area, the average length of interruption of supply to customer premises expressed in minutes
- DB4 – for each discrete area, the average number of interruptions to customer premises
- DB5 – for each discrete area, the average percentage of time that electricity has been supplied to customer premises
- DB6 – for each discrete area, the average percentage of time that electricity has been supplied to customer premises
- DB7 – overall SAIDI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB8 – distribution network (Planned) SAIDI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB9 – distribution network (Unplanned) SAIDI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB10 – normalised distribution network SAIDI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB11 – overall SAIFI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB12 – distribution network (Planned) SAIFI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB13 – distribution network (Unplanned) SAIFI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB14 – normalised distribution network SAIFI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB15 – overall CAIDI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB16 – distribution network (Planned) CAIDI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB17 – distribution network (Unplanned) CAIDI by Total Network, CBD, Urban, Short Rural and Long Rural
- DB18 – normalised distribution network CAIDI by Total Network, CBD, Urban, Short Rural and Long Rural

The overall SAIDI, SAIFI and CAIDI measures include the impact of interruptions on the transmission network. However, the unplanned, planned and normalised SAIDI, SAIFI and CAIDI measures exclude the impact of interruptions on the transmission network.

Measures DB7 – DB18 are based on the performance measures defined in the *National Regulatory Reporting for Electricity Distribution and Retailing Businesses*.[383] These performance measures enable the performance of network businesses in different jurisdictions to be compared, with and without transmission network events.

[383] These measures were developed in 2002 by the Standing Committee on National Regulatory Reporting Requirements (SCNRRR). Available at http://www.accc.gov.au/content/item.phtml?itemId=332190&nodeId=dc4aa2ded45414f0492929936649b125&fn=National%20Regulatory%20Reporting%20for%20Electricity%20Distribution%20and%20Retailing%20Businesses%20March%202002.pdf

11.2.1.3 Value of transmission network performance to customers receiving a distribution reference service

The Authority has stated that it:

> *… does not accept Western Power's argument that transmission networks performance is unrelated to the provision of reference services, whether these be for large transmission-only customers, or for distribution customers .*[384]

Western Power has not stated that transmission networks performance is unrelated to the provision of reference services. Western Power has in fact argued the opposite – that transmission networks performance is relevant to all customers, whether these be for large transmission-only customers or for distribution customers. However, as discussed above, the overall performance of the transmission network in its entirety bears little relationship to the service actually received by large transmission-connected customers.

11.2.2 Service standard benchmarks for SAIDI and SAIFI

Required amendment 34:

Western Power is required to update its analysis for the SAIDI and SAIFI service standard benchmark measures to base the service standard benchmarks on the most recent three years of data (Table 115 provides the Authority's estimates).

Western Power response:

Western Power accepts this amendment.

The Authority requires the SAIDI and SAIFI service standard benchmarks to be based on the most recent three years of data to more fairly reflect the investments that were made during AA2 to improve performance on the SAIDI and SAIFI measures.[385]

Western Power accepts that the AA3 targets should be set using the most recent three years of data for SAIDI and SAIFI.

Table 78 sets out Western Power's revised SSBs for SAIDI and SAIFI including transmission network events, based on the most recent three years of data. Western Power does not accept that transmission events be excluded from SAIDI and SAIFI as discussed under required amendment 33.

The proposed revised access arrangement will be revised in accordance with Table 78.

[384] Paragraph 1129, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[385] Paragraph 1134, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Table 78: Service standard benchmarks for SAIDI and SAIFI[386] for AA3 based on 3 years of historical data

Performance measure	CBD	Urban	Rural short	Rural long
SAIDI (minutes)	51	200	290	730
SAIFI (events)	0.40	2.20	3.30	5.70

Western Power does not accept that transmission events be excluded from SAIDI and SAIFI, as discussed in its response to required amendment 33.

Table 79 sets out the service standard benchmarks for the AA3 period if transmission network events are excluded from the SAIDI and SAIFI measures. The service standard benchmarks would be less than the corresponding experience for distribution reference service customers, which includes the impacts of both distribution and transmission network events.

Table 79: SSAM targets for SAIDI and SAIFI excluding transmission network events based on 3 years of historical data

Performance measure	CBD	Urban	Rural short	Rural long
SAIDI (minutes)	54	180	280	700
SAIFI (events)	0.30	2.00	3.20	5.20

[386] Including the impacts of distribution and transmission network events

11.3 Call centre performance

Required amendment 35:

The Authority requires that for the Call Centre Performance service standard benchmark measure:

- The definition point 'First speaking with a person in 30 seconds or less' be amended to:
    - 'First speaking with a person in 30 seconds or less, but excluding the time that the caller is connected to an automated interactive service (to a maximum of three minutes) that provides substantive information or elicits the caller's postcode, and which informs within the first 30 seconds that the call will be responded to by a human operator within three minutes.'
- The definition point 'First receiving an automated interactive message service message in 30 seconds or less' be deleted.
- The definition point 'The fault call response time commences when the postcode is automatically determined or when a valid postcode is entered by the caller or when the call is placed in the queue to be responded to by a human operator' be amended to:
    - 'The fault call response time commences when the call first enters the call centre and starts ringing.'

The Authority requires the exclusions be defined as follows:

One or more of:

- Calls abandoned by a caller in 4 seconds or less of their postcode being automatically determined or when a valid postcode is entered by the caller.
- Calls abandoned during the first three minutes of an automated message.
- Calls abandoned by a caller in 30 seconds or less of the call being placed in the queue to be responded to by a human operator.
- All telephone calls received on a major event day which is excluded from SAIDI and SAIFI.
- A fact or circumstance beyond the control of Western Power affecting the ability to receive calls to the extent that Western Power could not contract on reasonable terms to provide for the continuity of service.

Western Power response:

Western Power does not accept this amendment.

In its September 2011 submission, Western Power included a call centre performance measure that measures the experience of Western Power's distribution reference service customers when they contact the call centre. It included all calls made by distribution reference service customers to the call centre, irrespective of whether the required information was provided by a human operator or by the automated interactive message service.

The Authority considers the call centre performance measure should exclude the automated interactive message service component otherwise it:

> *… raises the prospect that calls are left ringing, or once answered, are simply diverted to an automated message.*[387]

Western Power does not accept this amendment because:

- Western Power's proposed definition of call centre performance meets the Access Code requirements – it provides an expectation to distribution reference service customers of the value provided to them by the call centre
- Western Power has addressed the Authority's concerns by amending its proposed definition of call centre performance to give precedence in the measure to a call placed in the queue for response by a human operator (while maintaining the relevance of the automated interactive message service) and has made it clear that a call left ringing will not be included as a call responded to.

11.3.1 Meeting the Access Code requirements

Western Power's call centre performance measure is consistent with the Access Code, which requires the access arrangement to include measures that reflect the nature of the reference service.

If it does not include calls where information is provided by the automated interactive message service, it will only reflect the service experienced by a subset of customers when contacting the call centre. This does not meet the requirements of the Access Code.

When customers ring the call centre they expect to receive information about their interruption and when their supply will be restored. The automated interactive message service provides customers with this information and is therefore a key part of providing a call centre service.

Western Power therefore does not propose to amend the call centre performance definition to exclude the response provided by the automated interactive message service.

However, Western Power does recognise the importance of giving precedence to the human operator aspect of the measure and has modified the call centre performance definition accordingly.

In particular, the revised definition provides that the response time of the recorded message is used for the measure where the call has not been placed in the queue for response by a human operator. Where the call has been placed in that queue, the response time of the human operator is the relevant measure. This is achieved through the drafting of "unless paragraph (a)(ii) applies".

Western Power's automated interactive message service interfaces with its outage management system to provide up-to-date outage information. The automated interactive message service detects the area the customer is calling from if they are using a fixed line telephone and provides information that is directly relevant to them, for example, "we are experiencing faults in Duncraig and the estimated restoration time is 11am". After receiving the message, the customer can either hang up or choose to speak with a human operator, if the customer so chooses.

Where the automated interactive message service is not able to detect the area where the customer is calling from, for example if the call is made from a mobile phone, the customer has the option of entering a postcode or speaking to a human operator. If a valid postcode is entered, the customer will receive a relevant automated interactive message. The caller can then either hang up or choose to speak to a human operator, if required. If an invalid postcode is entered, the call is placed in the queue to be responded to by a human operator.

[387] Paragraph 1138, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

The fault call response time commences when the customer enters a valid postcode or when the customer is queued to speak to a human operator.

Of the 754,121 fault calls received by the call centre in 2010/11, 461,495 did not choose to speak with a human operator. The Authority's proposed definition would not recognise the service that was provided to these customers by the call centre.

When the caller chooses to speak to a human operator, the fault call response time commences at the time that the call is placed into the queue. If the callers that choose to speak to a human operator are not responded to within 30 seconds, then Western Power's performance against the call centre performance measure will be negatively impacted.

11.3.2 Addressing the Authority's concerns regarding calls left unanswered

The call centre measures commence from when the automated system either automatically determining the caller's postcode or invites entry of a valid postcode. Western Power recognises that it is possible that the service may occasionally fail to initiate either of these actions and as such the call is 'left ringing'.

Western Power has addressed this concern by expressly providing that such calls are not included in the numerator of the call centre definition and so those instances will negatively impact the measure.

The revised call centre performance measure will be amended in section 4.2.8 of the proposed revised access arrangement as follows:

	Call centre performance
Unit of Measure	Percentage of calls per year.
Definition	Over a 12 month period, in relation to interruptions and life threatening emergencies, percentage of calls responded to in 30 seconds or less (after exclusions), that is: <u>Number of fault calls responded to in 30 seconds or less</u> Total number of fault calls where: (a) Number of fault calls responded to in 30 seconds or less is: (i) unless paragraph (a)(ii) applies, where the caller's postcode is automatically determined or when a valid postcode is entered by the caller, the number of fault calls where a recorded message commences within 30 seconds from that determination or entry ; or (ii) where the call is placed in the queue to be responded to by a human operator, the number of fault calls where the human operator commences to speak with the caller within 30 seconds of that placement. (b) A fault call is a telephone call from a caller entering the fault line or life threatening emergency line. (c) A call may be placed in a queue to be responded to by a human operator when the caller: (i) chooses to hold (when invited to do so) at the end of the recorded message; (ii) chooses to hold (when invited to do so) rather than enter a postcode when prompted to do so; (iii) enters an invalid postcode. (d) For a call to be counted as being responded to under paragraph (a), the caller must receive from the recorded message or the human operator information regarding power interruptions in their area and related restoration information. (e) A call where the interactive message service fails to automatically determine the caller's postcode or invite the entry of a postcode, as a

	Call centre performance
	result of which the service of providing information regarding power interruptions in their area and related restoration information does not commence, will be counted as a fault call not responded to in 30 seconds or less.
Exclusions	One or more of: • Calls abandoned by a caller in 4 seconds or less of their postcode being automatically determined or when a valid postcode is entered by the caller. • Calls abandoned by a caller in 30 seconds or less of the call being placed in the queue to be responded to by a human operator. • All telephone calls received on a major event day which is excluded from SAIDI and SAIFI. • A fact or circumstance beyond the control of Western Power affecting the ability to receive calls to the extent that Western Power could not contract on reasonable terms to provide for the continuity of service.

There is precedence for Western Power's proposed definition. In the 2006-10 Victorian electricity distribution price determination, the Essential Services Commission included a call centre measure which included calls to the interactive voice response (IVR) system.

When the AER began to regulate Victorian electricity distributors, it excluded calls to the IVR from its telephone answering performance measure. However, it accepted that the performance and targets with and without the IVR included cannot be compared. The performance and targets are lower with the IVR excluded compared to when IVR is included in the measure.[388]

If the definition of the call centre performance measure is amended as proposed by the Authority, the SSB will decrease from 75% to 53%.

11.4 Other distribution reference service measures

Required amendment 36:

The Authority requires that Western Power remove transmission network Circuit Availability as a distribution network service standard benchmark measure.

Western Power response:

Western Power accepts this amendment.

The Authority considers that circuit availability should not be mixed with distribution network measures.

Western Power accepts this amendment and that the circuit availability measure will only apply to transmission reference service customers.

[388] Page 667, *Victorian electricity distribution network service providers, Distribution determination 2011-2015, Draft decision*, Australian Energy Regulator, June 2010.

Required amendment 37:

Western Power is required to collect monthly data for the average number of momentary interruptions of one minute or less per distribution network customer for each of the distribution sub-classes (CBD, Urban, Rural short and Rural long), and report these as part of its annual service standards benchmarks report to the Authority. This would provide a basis for establishing service standard benchmarks and service standard targets for the fourth access arrangement period for a Momentary Average Interruption Frequency Index measure.

Western Power response:

Western Power accepts this amendment.

Western Power accepts the collection and reporting of momentary interruptions. As indicated in its September 2011 submission, Western Power is seeking to improve monitoring of momentary interruptions during the AA3 period so that Western Power will be in a stronger position to consider its inclusion as a SSB in AA4.[389]

Western Power will need to engage with the Authority to agree on the detailed definition for momentary interruptions.

Western Power will collect monthly data from the commencement of AA3 and will commence public reporting of momentary interruptions for the year following the year in which a detailed definition is agreed, which Western Power expects to be 2013/14.

11.5 Exclusions

Required amendment 38:

Only those exclusions that are approved by the Authority in the access arrangement may be included for the purposes of the service standards measures. The proposed clause 4.5.2 must be removed.

Western Power response:

Western Power does not accept this amendment.

The Authority states that the new proposed clause 4.5.2 is not acceptable as:

> *… it provides incentive for Western Power to introduce exclusions without review through the annual service report.*[390]

Western Power does not accept removing clause 4.5.2 because it would then have an incentive to over-invest to prevent network events occurring that may subsequently be excluded from the performance measurement for the SSBs and SSAM.

Clause 4.5.2 was not intended to allow Western Power to introduce exclusions without the Authority's approval. The objective of clause 4.5.2 is to provide certainty on an annual basis as to which events will be excluded from the service standard performance measures so that Western Power can appropriately adjust its plans (including investment) in response to these exclusions.

Western Power proposes that its annual service standard performance report to the Authority will explain the events that are to be excluded from the service standard performance

[389] Page 88, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, Western Power, September 2011.

[390] Paragraph 1161, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

measures. This will be reviewed and approved by the Authority each year through publishing Western Power's annual service standard performance. This is aligned with section 11.2 of the Access Code.

> *The Authority must monitor and, at least once each year, publish a service provider's actual service standard performance against the service standard benchmarks.*

Only those exclusions under the access arrangement and approved by the Authority will be excluded from the performance measurement for the purposes of the service standard benchmarks and SSAM.

To provide greater clarity, Western Power will replace clause 4.5.2 in the proposed revised access arrangement with the following alternate wording:

> *Whether or not particular circumstances meet the criteria to be an exclusion, such that the resulting units are not included in the measure, may be considered by the Authority when it publishes Western Power's actual service standard performance against the service standard benchmarks under section 11.2 of the Code. Where the Authority accepts an exclusion in such a report, it will be an exclusion for the purposes of the application of this access arrangement and the Code.*

11.6 Customer charter service measure

Required amendment 39:

The proposed revised access arrangement should include a service standard measuring compliance with Western Power's Customer Charter. The benchmark must be set at 100 per cent.

Western Power response:

Western Power does not accept this amendment.

The Authority requires the access arrangement to include an additional SSB that measures compliance with Western Power's Customer Charter, with the target set at 100%. This requirement reflects concerns raised by WA Farmers Federation (WAFarmers) regarding the conduct of Western Power staff and contractors when entering and conducting work on farm land.

Western Power does not agree that a service standard benchmark measuring compliance with Western Power's voluntary[391] customer charter should be included in the Access Arrangement.

Western Power recognises the need to provide more effective notification to regional customers where access to property is required. Western Power will continue to work with WAFarmers to improve the notification process and has already agreed initial steps forward to achieve this.

Western Power will also comply with its legislative and regulatory obligations on land access[392] and continue to either pay compensation to landowners for damage caused or make good damages through repairs and reinstatement, as and when required.

[391] "From 1 July 2010, electricity retailers and distributors are no longer required to produce a customer service charter and the Economic Regulation Authority will not undertake any further assessment of electricity customer service charters." This is stated on the Authority's website: http://www.erawa.com.au/3/797/51/electricity_licensing__archive_documents__customer.pm

[392] Under section 43 of the Energy Operators (Powers) Act 1979, Western Power is able to access property without informing landowners of access to property for works in relation to its performance of its functions. However, under section 46, Western Power must provide notice to the owner or occupier if it is entering for the purposes of inspecting land for prospective use.

In its September 2011 submission, Western Power included the criteria that it had established to assess the service standard benchmark performance measures.[393] The Authority's proposed customer charter performance measure does not meet a number of these criteria because:

- the aspect of service that is targeted by this performance measure would only be valued by a relatively small proportion of customers
- the Access Code requires service standard benchmarks for each reference service. Access to land is not a reference service and therefore the Access Code does not require a service standard benchmark relating to access to land
- data is not available to support the setting of a minimum service standard using the same approach as used to set the other minimum service standards
- the outcome can be distorted in a number of ways – those who own or lease land that Western Power needs to access may make it difficult for Western Power to provide notification
- Western Power can amend its customer charter at any time to reflect the actual level of service

For these reasons, Western Power does not accept the inclusion of a service standard measuring compliance with Western Power's customer charter.

From a practical perspective, Western Power does not hold or have access to accurate information about the owner or lessee of land and it is not always obvious where property boundaries are. This means that there are often difficulties in identifying the appropriate person to inform about intended access. This is particularly difficult in rural areas when assets are located on private land, often well inside private property boundaries.

Securing access to, or developing accurate information on, the owner or lessee of land would further improve notification to landholders. Western Power is aware, for example, that the Western Australian Department of Agriculture and Food (DAFWA) has a database that provides up-to-date information on farm boundaries and landowner and/or lessee contact details for farming properties. However, for privacy reasons Western Power is not able to access to those details without permission from those on the database. Without access to this database or development of an alternative, Western Power will continue to have difficulty providing notification of property access consistent with the current Customer Charter.

11.6.1 Next steps

The requirement to access private properties will increase in the next access arrangement period with the increased works program in rural areas, including the Mid West Energy Project, Wood Pole Replacement Program and the Field Survey of Network Assets.

In light of this, Western Power and WAFarmers have committed to the following actions at their May 2012 meeting:

- Western Power and WAFarmers will meet regularly to explore how to practically address the concerns of WAFarmers' members
- Western Power will amend its Customer Charter to recognise that it is not able to guarantee the notification of land owners and lessees of access to their properties in all cases
- Western Power, with the support of WAFarmers, will continue to work with DAFWA to seek permission from individuals to access its landowner and lessee database.

[393] Page 86, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, Western Power, September 2011

12 Pricing methods, price list and price list information

12.1 Amended price list and price list information

Required amendment 40:

The proposed revised Price List and Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Draft Decision.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

The Authority requires Western Power to amend its proposed revised price list and price list information for 2012/13 to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in its draft decision.

This submission includes a price list and associated price list information for the 2012/13 financial year. This price list reflects the transmission network revenue cap and distribution network revenue cap proposed by Western Power and will only apply following the Authority's approval of the revisions to the access arrangement.

12.2 Transmission revenue cap

Required amendment 41:

Clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement must be amended to be consistent with clause 5.27 and 5.38 of the current access arrangement.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

The Authority requires Western Power to amend clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement to be consistent with clause 5.27 and 5.38 of the current access arrangement. The Authority advises that Western Power's proposed wording for clauses 5.6.1 and 5.7.1 would be to the potential disadvantage of users as the requirement to not exceed the revenue cap is weakened.[394]

Clauses 5.6.1 and 5.7.1 of Western Power's proposed revised access arrangement introduce the revenue cap for revenue cap services for each of the transmission and distribution systems respectively. It also states that Western Power's intention is to use reasonable endeavours to recover the revenue cap each financial year.

In its September 2011 submission, Western Power changed the words of clause 5.6.1 and 5.7.1 to reflect actual practice. Each year Western Power sets prices so that the forecast revenue is within a reasonable margin of the maximum transmission revenue and the maximum distribution revenue. The Authority has previously approved price lists where the forecast revenue is expected to slightly exceed the maximum transmission revenue and the

[394] Paragraph 1198, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

maximum distribution revenue.[395] Western Power will use the K-factor to correct any differences between the revenue cap and actual revenue collected in transmission and distribution prices in future pricing years.

Western Power is concerned that the previous wording ('will use reasonable endeavours to ensure actual revenue does not exceed the maximum revenue cap') will create an upward bias on price increases due to the K-factor adjustment always catching up for a short-fall in revenue from previous years (given the requirement to always set prices to collect less than the revenue target).

To address this, Western Power changed the words of clauses 5.6.1 and 5.7.1 from 'will use its reasonable endeavours to ensure that the actual revenue… does not exceed [the maximum revenue cap]' to 'will use its reasonable endeavours to ensure that the actual … revenue… is within a reasonable margin of [the maximum revenue cap]'.

In its draft decision, the Authority expresses the view that Western Power's proposed wording changes would potentially disadvantage users by weakening the requirement to not exceed the revenue cap. It also comments that the current access arrangement would still enable the revenue target to be slightly exceeded if it was not reasonably possible to stay within the maximum revenue cap.[396]

The changes to clauses 5.6.1 and 5.7.1 do not weaken the requirement for Western Power to set prices that collect the revenue target. Customers are protected from differences between actual revenue collected and the revenue caps through the K-factor. The Authority has demonstrated that it will accept prices that cause the revenue target to be slightly exceeded. Western Power's preference is that the wording of the access arrangement reflects the way in which Western Power expects to operate during AA3.

Western Power also recognises that its ability to influence the actual revenue it will earn in any particular year is limited to the prices that are set in the price list. Throughout the year Western Power has no other mechanism within its control to influence the revenue it receives from customers. Western Power will revise its access arrangement to clarify that it will set the prices within the price list to collect the revenue target.

The changes will address the reasoning set out in paragraph 1198 of the Authority's draft decision by stating the requirement for Western Power to set the prices in the price list to collect the revenue cap.

12.3 Revenue from standby services

Required amendment 42:

The proposed revised Price List for 2012/13 must be amended to include revenue from standby services in forecast transmission revenue.

Western Power response:

Western Power accepts this amendment.

The Authority requires the revised price list for 2012/13 to be amended to include revenue from standby services in forecast transmission revenue.

In its September 2011 submission Western Power incorrectly excluded revenue from standby services from the forecast transmission revenue recovered in the proposed 2012/13 price list information.

[395] Most recently in the *2011/12 Price List determination - Determination on the Proposed 2011/12 Price List for Western Power's Covered Electricity Network* - Submitted by Western Power, 19 May 2011.

[396] Paragraph 1198, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Western Power accepts the Authority's required amendment and has submitted a revised price list and price list information in response to the draft decision that includes revenue from standby services in forecast transmission revenue.

12.4 Revenue cap allocation between reference and non reference services

Required amendment 43:

The proposed revised access arrangement must be amended to explain how the revenue cap will be allocated between reference and non reference access services.

Western Power response:

Western Power accepts this amendment.

The Authority requires Western Power to explain how the revenue cap will be allocated between reference and non reference access services in the proposed revised access arrangement.

The revenue cap will be allocated between reference and non-reference access services by deducting the expected non-reference service revenue from the revenue cap to determine the reference service revenue. Western Power will amend clause 6.3.1 of the proposed revised access arrangement to explain how the revenue cap will be allocated between reference and non-reference access services.

12.5 Side constraints adjustment parameters

Required amendment 44:

Western Power must revise the specification of the adjustment parameters in the side constraints for transmission and distribution to make them consistent.

Western Power response:

Western Power accepts this amendment.

The Authority requires Western Power to revise the specification of the adjustment parameters in the side constraints for transmission and distribution to make them consistent. The Authority is of the view that the difference in specification of the adjustment parameters will probably not have a material effect on the side constraint.[397]

Western Power accepts this amendment and has amended the distribution side constraint to be consistent with the transmission side constraint. Western Power clarifies that *TEC* in the A'_t term relates to differences in the Tariff Equalisation Contribution between years t-1 and t.

In preparing the 2012/13 price list for this submission it was identified that the side constraint proposed in the initial submission did not operate as expected with q_t^{xy} on the numerator and q_{t-1}^{xy} on the denominator.

It was found that changes in customer number, energy consumption or demand between 2011/12 and the forecasts for 2012/13 restricted changes in prices. This is not the intention of the side constraint. The purpose of the side constraint is to mitigate the effects of price shock on individual customers during AA3, not restrict price movements due to changes in

[397] Paragraph 1206, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

customer number, energy consumption or demand between years. To address this unintended outcome of the side constraint Western Power has refined the formula to have q_t^{xy} on both the numerator and denominator.

The side constraint originally proposed for distribution was of the form:

$$\frac{\sum_{y=1}^{n} p_t^{xy} q_t^{xy}}{\sum_{y=1}^{n} p_{t-1}^{xy} q_{t-1}^{xy}} \leq (1 + CPI_t)(1 - DX_t) + A'_t + 0.02$$

where:

$$A'_t = \frac{DK_t + DAA2_t + TEC_t}{(1 + CPI_t)(1 - DX_t)\sum_{x=1}^{r} \sum_{y=1}^{n} p_{t-1}^{xy} q_t^{xy}}$$

The transmission side constraint originally proposed was similar to the distribution side constraint (above) except that there was a B'_t term rather than an A'_t term where:

$$B'_t = \frac{TK_t + TAA2_t}{TR'_t}$$

Western Power will amend the access arrangement so that the A'_t term becomes:

$$A'_t = \frac{DK_t + DAA2_t + \Delta TEC_t}{DR'_t}$$

where:

> ΔTEC_t is the difference in the cost incurred by the *distribution system* between the financial years t-1 and t as a result of the tariff equalisation contribution in accordance with section 6.37A of the *Code*.
>
> DR'_t is DR_t (as set out in section 5.7.6 of the access arrangement) converted to nominal dollars.

The form of the side constraints for transmission and distribution are consistent to the extent possible. It is noted that the distribution side constraint allows for the TEC.

12.6 Consistency of incremental and stand alone costs with transmission and distribution revenue caps

Required amendment 45:

The estimated incremental and stand-alone revenue included in the proposed revised Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Draft Decision. Western Power should include commentary to explain any material variations in its estimate of incremental and stand-alone costs compared with the current 2011/12 Price List Information.

Western Power response:

Western Power accepts this amendment.

The Authority requires Western Power to amend the estimated incremental and stand-alone revenue included in the proposed revised price list information for 2012/13.

Western Power accepts this amendment and has submitted a revised price list and price list information in response to the draft decision.

In setting the prices within this price list, Western Power will ensure that the prices are between incremental and stand-alone costs of service provision (as required by section 7.3 of the Access Code).

Western Power will also include an explanation of any material variations in estimates of incremental and stand-alone costs compared with the current 2011/12 price list information.

12.7 Incremental and stand alone costs

Required amendment 46:

All proposed tariffs for 2012/13 must be set between incremental and stand-alone costs in order to comply with section 7.3 of the Access Code.

Western Power response:

Western Power accepts this amendment.

The Authority requires Western Power to set proposed tariffs for 2012/13 to be between incremental and stand-alone costs.

Western Power accepts this amendment and has submitted a revised price list and price list information in response to the draft decision.

In setting the prices within this price list, Western Power will ensure that the prices are between incremental and stand-alone costs of service provision (as required by section 7.3 of the Access Code).

12.8 Side constraints to apply from the first year

Required amendment 47:

Western Power's proposed side constraint must apply from the first year of the third access arrangement.

Western Power response:

Western Power accepts this amendment.

The Authority requires Western Power to apply the proposed side constraint from the first year of the AA3 period. The Authority considers that any tariff rebalancing should be phased in over a period of time so as to avoid sudden material tariff adjustment between succeeding years.[398]

Western Power accepts this amendment and has submitted a revised price list and price list information in response to the draft decision.

12.9 Streetlight tariffs

Required amendment 48:

Western Power's proposed additions to streetlight asset types must ensure existing assets are not charged on a higher band compared with the current access arrangement.

Western Power response:

Western Power accepts this amendment.

The Authority requires that the proposed additions to streetlight asset types must ensure existing assets are not charged on a higher band compared with the current access arrangement.

In its September 2011 submission, Western Power published prices for all streetlight asset types that are installed in the Western Power Network. The additional streetlight asset types are for streetlight assets that are now obsolete and no longer available for new installation.

The newly published prices for obsolete light types simply make the prices for the obsolete streetlights more transparent to its customers. Western Power is not charging the obsolete streetlights on a higher band compared with the current access arrangement.

[398] Paragraph 1232, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

13 Adjustments to target revenue in the next access arrangement period

13.1 Gain sharing mechanism

Required amendment 49:

Western Power must provide a clearly stated methodology for making this adjustment which is based on the scaling factors approved by the Authority in this draft decision and includes details of how actual scaling factors will be verified.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

In its draft decision, the Authority accepts the principle that Western Power should assess the gain sharing mechanism (GSM) using efficiency and innovation benchmarks (EIBs) that are adjusted for the actual drivers of network scale during AA3.

However, the Authority does not accept Western Power's proposed scale escalation method and requires that:

> *there needs to be a clearly stated methodology for making this adjustment which includes establishing the scaling factors used in the forecast and verifying the actual scale factors. As discussed above, the Authority has not accepted Western Power's proposed scaling factors.*
>
> *The methodology should set out:*
>
> - the underlying assumptions and calculations in relation to scaling factors included in the efficiency and innovation benchmarks approved by the Authority; and
> - the method for recalculating the efficiency and benchmarks taking account of actual scaling factors.[399]

Western Power has revised its access arrangement to provide a clearly stated method for making scale escalation adjustment to the efficiency and innovation benchmarks in response to this amendment. However, it has based the method on proposed scale escalation factors that Western Power has outlined in relation to the Authority's required amendment 6.

The reasons for this revised approach are set out below.

13.1.1 Required amendment 49 cannot be incorporated as the Authority specified

The purpose of adjusting for scale escalation is to adjust the EIBs for any difference between forecast and actual network scale drivers. However, the Authority's scale escalation method does not rely on a forecast of scale escalation drivers.

While the Authority accepted the principle of adjusting the EIBs for actual growth drivers that transpire during AA3, it required that this be done in a manner consistent with its draft decision method for scale escalation.

The draft decision scale escalation method relies upon the average historical growth in scale escalation drivers. This means there is no scale escalation relationship requiring true-up in

[399] Paragraphs 1260-1261, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

the EIBs (i.e. because the forecasts are not based on a forecast of the relevant underlying scale driver).

For the reasons set out in section 6.3.3, it is unreasonable to assume that the forecast activity required to operate and maintain the network will not be a function of the forecast scale of the network.

Therefore Western Power has forecast its scale escalation on the basis of forecast growth in relevant scale drivers and has designed its EIB scale adjustment method (set out below) to true-up for differences between the forecast and actual growth in these scale drivers.

13.1.2 Scale adjustment method

The purpose of EIB scale adjustment is to achieve an EIB that represents the non-capital cost forecast the Authority would have approved had it known the actual values of relevant scale drivers in each year, rather than having to rely upon a forecast.

Western Power's proposed scale adjustment method is therefore identical to its method for forecasting the impact of scale escalation, but substituting actual data for each scale driver instead of forecast values.

This will require that at the next access arrangement review, the EIB values in the access arrangement will be:

- deflated using the scale escalation factors assumed when setting the forecast non-capital costs
- reinflated using the scale escalation factors calculated using actual data for each scale escalation driver

The scale escalation drivers accepted by the Authority in its draft decision are chosen to be fit for purpose for each cost category, and are either:

- growth in customer numbers; or
- a composite network scale measure which is calculated as the average of growth in line length, distribution transformers and substation capacity

Table 80 sets out the forecast growth for each scale driver and resulting scale escalation factor for each year of AA3.

Table 80: Calculation of forecast scale escalation factors

Item	Calculation	2012/13	2012/14	2014/15	2015/16	2016/17
Customer numbers factor	Year on year growth	2.59%	2.62%	2.66%	2.69%	2.72%
Distribution line length (a)	Year on year growth	1.28%	1.19%	1.25%	1.27%	1.33%
Transmission line length (b)	Year on year growth	3.90%	3.11%	0.00%	0.46%	1.18%
Distribution transformers (c)	Year on year growth	2.97%	2.80%	2.86%	2.96%	2.97%
Substation capacity (d)	Year on year growth	2.56%	1.25%	7.33%	5.36%	12.51%
Distribution network factor	Average of a, c and d	2.27%	1.75%	3.82%	3.19%	5.60%
Transmission network factor	Average of b, c and d	3.14%	2.39%	3.40%	2.92%	5.55%

Table 81 lists the relevant form of scale escalation for each cost category.

Table 81: Scale escalation factor for each category of expenditure

Cost category	Scale escalation factor
Transmission	
Operations	
SCADA & Communications	Transmission network factor
Non-revenue cap services	N/A
Network Operations	Transmission network factor
Maintenance	
Maintenance Strategy	N/A
Preventive Condition	Transmission network factor
Preventive Routine	Transmission network factor
Corrective Deferred	Transmission network factor
Corrective Emergency	Transmission network factor
Customer service and billing	
N/A	N/A
Corporate	
Business Support	N/A
Other	
Non-recurring Opex	N/A
Distribution	
Operations	
Reliability Improvement	Distribution network factor
SCADA & Communications	Distribution network factor
Non-revenue cap services	N/A
Network Operations	Distribution network factor
Smartgrid	N/A
Maintenance	
Maintenance Strategy	N/A
Preventive Condition	Distribution network factor
Preventive Routine	Distribution network factor
Corrective Deferred	Distribution network factor
Corrective Emergency	Distribution network factor
Customer service and billing	
Call Centre	Customer numbers
Metering	Customer numbers
Guaranteed Service Level Payments	N/A
Distribution Quotations	N/A
Corporate	
Business Support	N/A

Cost category	Scale escalation factor
Other	
Non-recurring Opex	N/A

13.1.3 Verification of actual scale driver data

Western Power will report actual data on customer numbers, line length, distribution transformers and substation capacity for each year of the AA3 period. This data will be verifiable against relevant business records listed in Table 82.

Table 82: Sources of verification for actual scale driver data

Scale driver	Source of data verification
Customer numbers	Western Power Annual Report
Distribution line length	Western Power Annual Report
Transmission line length	Western Power Annual Report
Distribution transformers	Western Power Annual Report
Substation capacity	Western Power Annual Report

13.2 Proposed efficiency and innovation benchmarks

The GSM applies to the efficiency gains in excess of the efficiency and innovation benchmarks. Western Power's efficiency and innovation benchmarks for AA3 are based on forecast operating expenditure, adjusted for uncontrollable costs. This is consistent with the efficiency and innovation benchmark for the AA2 period.

Table 83 details the proposed efficiency and innovation benchmarks for AA3.

Table 83: Efficiency and innovation benchmarks

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17
Total forecast operating expenditure	500.8	512.8	528.6	542.9	570.6
Less forecast costs for defined benefit superannuation schemes	2.9	3.0	3.1	3.2	3.3
Less forecast non-revenue cap services cost	17.5	17.9	18.9	19.7	20.7
Less forecast licence fees	0.05	0.05	0.05	0.05	0.05
Less forecast energy safety levy	4.1	4.1	4.1	4.1	4.1
Less network control service	13.0	7.0	12.4	15.5	21.8
Efficiency and innovation benchmark (forecast)	463.3	480.7	490.1	500.3	520.6

13.3 Service standards and incentive mechanism

Required amendment 50:

Western Power must amend its proposed revision to clarify how, in the event that service standard benchmarks are not achieved, it will be determined how and to what extent there is a relationship between costs savings and the underperformance on service standards.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

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In its draft decision, the Authority notes Western Power's proposed revision to clause 7.4.3 of the access arrangement is consistent with section 6.26 of the Access Code and accepts the proposed revision as reasonable.

Western Power has interpreted the Authority's required amendment 50 to be requesting that additional text is included in clause 7.4.3 of the access arrangement that clarifies how and to what extent it will be determined there is a relationship between cost savings and underperformance on service standards in the event that a service standard benchmark is not met.

Western Power agrees that additional clarity would be useful, however, the circumstances of an event where a service standard benchmark is not achieved can vary significantly. Therefore it would not be appropriate to state in the access arrangement how the relationship between cost savings and underperformance will be determined, as the relevant factors may vary in each case.

However, to provide some further clarity for the Authority, a high-level overview of the general process Western Power would follow to determine the relationship between cost savings and underperformance is provided below.

Summary of process:

If there is underperformance on a service standard in a year, Western Power will demonstrate to the Authority how and to what extent there is a relationship between cost savings and underperformance on that service standard, through consideration of:

- which service standard benchmark has not been met in that year
- an analysis of the causes for not meeting the service standard benchmark in that year
- the categories of operating expenditure that impact on the achievement of that service standard benchmark
- after normalising the operating expenditure in those categories for CPI, inflation and scale escalation factors, whether there has been an underspend in those operating expenditure categories
- any other issues that are relevant

This information will be used to determine whether there has been underspending in an area that directly or in part impacts on the service standard benchmark against which Western Power has underperformed.

13.3.1 SSAM formula

Required amendment 51:

Western Power should establish the SSAM formula as follows:

$SSD_t = (SST_t – SSA_t) – AF * (SST_{t-1} – SSA_{t-1})$ for the first and subsequent years of the AA

where:

SSD_t is the service standard difference in year t, and SST_{t-1} is the service standard difference in year t-1;

SST is the SSAM target;

SSA_t is the actual service performance in year t, and SSA_{t-1} is the actual service performance in year t-1, with respect to the SSAM measure;

AF is the 'attenuation factor' that takes the value 0.6.

Western Power response:

Western Power does not accept this amendment.

In its September 2011 submission, Western Power proposed that the SSAM formula be the same as that used by the AER, whereby the actual performance against each measure is compared to the relevant target on an annual basis.

The Authority indicates that it is concerned that the proposed SSAM formula will over-reward Western Power because:

1. Western Power will have an incentive to invest in reliability improvements that customers do not value[400]
2. Western Power will be able to recover the investment on reliability improvements through the incentive adjustment mechanism (IAM)[401]
3. Western Power's investment proposal will lead to an improvement in reliability[402]
4. Western Power would be over-rewarded if capital expenditure was forecast for reliability improvements[403]

The Authority also considers that the proposed SSAM formula creates incentives for Western Power to undertake improvements early in the access arrangement period (or else to defer to the start of the next access arrangement period).[404]

The Authority proposes an alternative formula which is based on the SSAM formula in the current access arrangement and includes an 'attenuation factor'.

Western Power does not accept the alternative SSAM formula proposed by the Authority for the AA3 period because:

- the value likely to be delivered to customers is constrained to a level much less than the estimate of the value to customers of reliability (VCR)
- the Authority's reasoning is based on the incorrect assumption that Western Power will undertake inefficient investment that customers will be required to pay for

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[400] Paragraph 1296 and Appendix 4, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[401] Verbal discussions between ERA and Western Power, 19 April 2012.
[402] Verbal discussions between ERA and Western Power, 19 April 2012.
[403] Verbal discussions between ERA and Western Power, 19 April 2012.
[404] Paragraph 1296 and Appendix 4, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

The Authority's formula limits the financial incentive to Western Power to less than the value to customers of service performance. This reduces the incentive for Western Power to improve service, even though customers may place a higher value on service improvements.

It also reduces the incentive for Western Power to maintain current service levels. There is a greater potential for services to deteriorate where the costs of maintaining service levels is greater than the financial penalty of not doing so.

Western Power considers that this will reduce the value to customers over the AA3 period compared to its proposal.

Western Power's proposed formula should be adopted as it is consistent with the formula used by the AER for electricity businesses in other jurisdictions. The AER's formula has been proven to achieve the appropriate balance between providing incentives for electricity businesses to pursue investment that delivers service improvements to customers and ensuring customers pay no more than the estimated value to those customers of those improvements.

Western Power addresses each of the concerns raised by the Authority in the following sections.

13.3.1.1 ERA concern # 1 - incentive to invest in reliability improvements that customers do not value

The Authority's proposed SSAM formula is designed to address the risk that Western Power will undertake investment that is inefficient, resulting in customers paying more for service improvements than the value the service improvements provide. However, this cannot and will not occur under Western Power's proposal for the following reasons.

First, as a commercially-focused business, Western Power will only invest in reliability improvements where there is a net benefit to Western Power. The net benefit to Western Power of a reliability improvement is the difference between the revenue received from customers (through the SSAM and if the capital expenditure is added to the capital base, through the return on and return of the capital investment) and the present value of the initial capital investment. The net benefit to Western Power increases as the revenue earned through the SSAM increases.

That is:

Present value of amount paid by customers > Present value of initial investment

$$\frac{V}{i}\left(1-\frac{1}{(1+i)^{j}}\right)+\left(Ron\ \&\ RofX\right) > X \qquad (1)$$

where:

X is the initial capital investment

V is the value to the customers of the reliability improvement

i is the rate of return

j is the number of years remaining in the access arrangement period

Ron & Rof X is the present value of the return on and the return of the capital investment over the life of the asset, assuming the capital expenditure is added to the capital base at the end of the access arrangement period

As the investment may not be added to the capital base and the return on and return of the asset could be zero, Western Power will not seek to undertake investments unless it delivers at least the value available under the financial incentive scheme.

The financial incentive Western Power receives reflects the value of the service *outcome* to customers. Undertaking the investment alone is not enough to ensure the receipt of the benefit under the financial incentive scheme - the service improvement must also be delivered. Any investment will be subject to a risk assessment that the service outcome will be delivered, increasing the hurdle rate for going ahead with any investment. Therefore, all investment that results in a financial benefit will be at a cost less than the financial incentive received.

Secondly, the net benefit to Western Power will be maximised if the investment is added to the capital base. Any investment undertaken by Western Power that delivers a service improvement, which results in a financial benefit, will only be added to the capital base at the commencement of the next access arrangement period if it meets NFIT.

Investment in reliability improvement will most likely be required to meet the net benefits limb of NFIT. The net benefits test under NFIT considers the net benefits to Western Power and to its customers. The capital investment will only meet the net benefits test if the present value of the reliability improvements exceeds the present value of the initial capital investment.

That is, to meet NFIT:

Present value of the value to customers> Present value of initial investment

$$\frac{V}{i}\left(1-\frac{1}{(1+i)^{n}}\right) > X \qquad (2)$$

where:

n is the life of the asset

From formulae (1) and (2) it can be seen that the present value of the initial capital must be:

- less than the present value of the revenue received from customers, and
- less than the present value of the value of the reliability improvements

This implies that the present value of the amount paid by consumers to Western Power must always be less than the present value of the reliability improvements. If not, the net benefits limb of NFIT would not be met, the capital investment could not be added to the capital base, the revenue earned by Western Power would decrease and the investment would be less commercially viable. Therefore, customers will never pay more for reliability improvements then they value the reliability improvements, as demonstrated by formula (3):

$$\frac{V}{i}\left(1-\frac{1}{(1+i)^{j}}\right)+\left(Ron\,\&\,RofX\right) \leq \frac{V}{i}\left(1-\frac{1}{(1+i)^{n}}\right) \qquad (3)$$

The cost to customers during the access arrangement period is limited to the financial incentive payment. The cost to customers in subsequent access arrangement periods is limited to the regulated return on and of the investment for the life of the investment, assuming that the capital expenditure is added to the capital base and any carryover benefits from the financial incentive.[405] Western Power receives no further additional financial incentive in subsequent access arrangement periods despite the service improvement benefit to customers of that investment continuing for the life of that investment. Importantly, any investment that does not deliver a net benefit to customers over the life of the investment will not meet NFIT, and will not be included in the capital base and will not be paid for by customers.

There may also be opportunities to achieve a service improvement outcome by incurring additional operating expenditure. In this circumstance, Western Power must weigh up the likelihood of receiving the financial benefit with the loss it would incur during the period,

[405] If the SSAM targets for the AA4 period are based on the most recent five years of data, consistent with the AER's approach, then the financial incentives are paid for five years, regardless of the year in which the investment occurred. This is consistent with the AER's approach and ensures that the incentive to invest in reliability improvements is consistent across the access arrangement period.

including forgone revenue under the gain sharing mechanism. In this case, the prospect of receiving a financial benefit would need to be significantly greater than the costs. Therefore, any additional payments from customers would still be significantly less than the value of the service improvement.

Western Power has a strong incentive to reduce operating expenditure and would only undertake service improvement expenditure where the financial benefit was greater than the reduction of profit and forgone benefit under the GSM. The costs would need to be much less than the financial benefit to risk incurring a loss.

Under no circumstances will Western Power be rewarded for investment that does not deliver value to customers greater than the reward. Economic efficiency is maximised as there is an incentive to deliver the maximum value to customers without incurring costs greater than the value.

Response to the examples in Appendix 4 of the Authority's draft decision

The Authority's analysis in Appendix 4 of its draft decision is based on an assumption that Western Power will undertake a balance of service improvement projects that cost more or less than the financial benefit. This assumption is not supported.

Western Power will not undertake an investment where the forecast costs are more than the expected financial benefit. As illustrated above, this is because the financial benefit paid by customers is only paid when the improvement is delivered and any further payments are contingent on the investment providing a net benefit to the customer – that is, meeting NFIT and being included in the capital base.

The Authority provides three examples to demonstrate why it considers its approach to be better. The first example refers to a situation where customers experience an improvement in service and Western Power incurs no costs but receives a financial benefit. This is an example of a windfall gain that would accrue due to events outside of the control of Western Power.

The scheme is designed to ensure an appropriate balance between windfall gains and losses. It is equally as likely that Western Power receives a financial penalty for an event beyond its control unless it has characteristics that qualify the event as an 'excluded event'. This limits the downside financial risks for significant events beyond its control such as storms. There are very few events beyond Western Power's control that result in a significant improvement. The most likely is consistent mild weather (no wind, no light rain) over a sustained period, which is a very low probability event.

The Authority's next example is where Western Power undertakes an investment that costs half as much as the financial benefit resulting from the service improvement. Under this example, customers would pay the financial benefit in each of the remaining years of the access arrangement period and a return of and on the value of the investment for the life of the asset where the investment provides a net benefit to customers. The costs to the customer over the remaining life of the asset will be less than the benefit the customer receives for the life of the asset.

In the third example, the cost to Western Power is equivalent to the VCR. This circumstance would not occur as Western Power would only undertake an investment that was forecast to deliver a financial reward greater than the investment. In making this assessment, Western Power must discount the financial benefit to reflect the risk of the service improvement actually being delivered. The investment is likely to always be much less than the financial benefit, resulting in a net benefit to customers over the life of the investment.

13.3.1.2 ERA concern # 2 - Recovery of investment in reliability improvements through IAM

The Authority is concerned that Western Power will be able to recover the investment on reliability improvement through the IAM. This is not the case.

The Authority's *Guidelines for Access Arrangement Information*[406] require that, when preparing regulatory financial statements, capital expenditure must be disaggregated and allocated to business segments. Within each business segment, capital expenditure must be disaggregated into the following asset categories[407]:

- Growth – capital expenditure for the purposes of increasing the capacity of assets or construction of new assets to meet growth in demand
- Asset replacement and renewal – capital expenditure for the purposes of replacing assets and maintaining service levels
- Improvement in service – capital expenditure for the purposes of improving service levels and reliability to meet customer preferences
- Compliance – capital expenditure for the purposes of meeting regulatory obligations
- Corporate – capital expenditure for corporate activities

In accordance with the *Guidelines for Access Arrangement Information*, capital investment undertaken to improve reliability must therefore be allocated to "Improvement in service".

The investment adjustment mechanism adjusts target revenue in the following access arrangement period to leave Western Power and customers economically neutral as a result of any differences between the AA3 forecast and actual transmission and distribution capital expenditure in designated categories.

Clause 7.3.7 of the *Proposed Revisions to the Access Arrangements for the Western Power Network* sets out the designated categories of expenditure as:

> 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; and*
>
> e) *undertaken for augmentation of the distribution system under the state underground power project.*

Except for the state underground power program (SUPP) and rural power improvement programs, which are obligations placed on Western Power by Government, these designated categories align with the growth category of capital expenditure and are consistent with the current Access Arrangement.

The Authority has accepted these designated categories but required that pole replacement and reinforcement also be included as a designated category for the AA3 period.

Capital investment for reliability improvement projects has not and will not be included as a designated category for the purposes of the Investment Adjustment Mechanism.

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[406] Available at http://www.erawa.com.au/cproot/9113/2/20101206%20D47095%20Electricity%20Networks%20Access%20Code%202004%20-%20Guidelines%20for%20AAI%20(Version%202).PDF

[407] Pages 8-9, *Electricity Networks Access Code 2004: Guidelines for Access Arrangement Information,* ERA, 6 December 2010

13.3.1.3 ERA concern # 3 - Western Power's investment proposal will lead to an improvement in reliability

Western Power's investment proposal is based on maintaining average service levels. It has not included any investment aimed directly at improving average service levels.

While some growth-related and asset replacement capital works may result in localised improvements in service levels, service levels deteriorate as assets continue to age. Generally, without the work program, service levels would deteriorate due to asset age. Western Power has sought to balance these improvements and deteriorations across the network so that average service levels are maintained.

13.3.1.4 ERA concern # 4 - If capital expenditure was forecast for reliability improvements, Western Power would be over-rewarded

Western Power has not included any investment for reliability improvements during AA3. However, if it had done, then it would expect that the SSAM targets for AA3 would be adjusted so that Western Power continues to expect to achieve the targets 50% of the time.

By setting the service standard benchmarks and SSAM targets based on the most recent three years of data, service performance improvements resulting from expenditure in the AA2 period will be captured.

13.3.1.5 Consistent incentives through the access arrangement period

The SSAM formula proposed by Western Power provides a more consistent incentive to invest in improvements across the access arrangement period than the formula proposed by the Authority.

Under the Authority's formula, Western Power would only invest in reliability improvements where:

Present value of amount paid by customers> Present value of initial investment

$$\frac{V}{i}+\frac{0.4V}{i}(1-\frac{1}{(1+i)^{j-1}}+\left(Ron\;\&\;RofX\right) > \mathrm{X}$$

where:

X is the initial capital investment

V is the value to the customers of the reliability improvement

i is the rate of return

j is the number of years remaining in the access arrangement period

Ron & Rof X is the present value of the return on and the return of the capital investment over the life of the asset, assuming the capital expenditure is added to the capital base at the end of the access arrangement period

The amount that is paid by customers for reliability improvements under the Authority's formula is the same as under Western Power's formula in the first year in which the reliability improvement is delivered. However, the amount that is paid by customers for reliability improvements is less in subsequent years under the Authority's formula than under Western Power's formula.

Under the Authority's formula there is therefore a greater incentive than under Western Power's formula to delay investment until late in the access arrangement period to reduce the present value of the initial investment.

Under Western Power's formula, the business would invest in reliability improvements where:

$$\frac{V}{i}\left(1-\frac{1}{(1+i)^{j}}\right)+\left(Ron\;\&\;RofX\right) > \mathrm{X}$$

As investments are delayed over the access arrangement period, the present value paid by customers for reliability improvements will decrease. When investments are delayed, the present value of the initial investment also decreases. If the reduction in the present value paid by customers for reliability improvements is the same as the reduction in the present value of the initial investment, then the incentive to invest is the same in each year of the access arrangement period.

If the reduction in the present value of the initial investment is greater than the reduction in the present value paid by customers for reliability improvements, then there is an incentive to invest early in the access arrangement period. However, as customers will never pay more than the value they place on reliability improvements, an incentive to invest early is better than an incentive to invest late.

13.3.2 Circuit availability

Required amendment 52:

The Circuit Availability target must be set at 98.0 per cent. This is the 50 per cent PoE level derived from the application of a Weibull distribution to the last five years of historic data, but with a reduction of 0.2 per cent included.

Western Power response:

Western Power accepts this amendment.

In its September 2011 submission, Western Power proposed that the circuit availability target should be set at 97.7%, based on:

- the estimated 2.5% Probability of Exceedence (PoE) level derived from the application of a Weibull distribution to the last five years of the historic circuit availability data, and
- a 0.5% reduction to reflect the updated forecast impact of additional transmission network capital works during AA3

The Authority considers a 0.5% reduction was not justified, and a 0.2% reduction is appropriate given the increased capital works program anticipated during AA3.[408]

Western Power accepts the 0.2% reduction to reflect the updated forecast impact of additional transmission network works.

However, in accepting this amendment Western Power notes that the Authority has incorrectly removed adjustments for power transformers due to confusion between *power* transformers and *zone substation* transformers.

The definition of circuit availability excludes the availability of *zone substation* transformers but includes the availability of *power* transformers[409], which are part of a "transmission circuit". As a result, the circuit availability service standard adjustment mechanism (SSAM) target should be adjusted to take into account the forecast reduced availability of *power* transformers during AA3 with the planned replacement of *power* transformers.

This has no material impact on the 0.2% reduction.

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[408] Paragraph 1308, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[409] The term power transformer refers to bulk or terminal transformers which are for transformation between transmission voltage levels, for example, 330kV/220kV, 330kV/132kV or 220kV/132kV. The works on zone substation transformers, which is for the transformation from transmission voltage levels to distribution voltage levels, such as 132kV/33kV or 132kV/22kV, has not been considered in the analysis, consistent with the exclusions for circuit availability .

13.3.3 Transmission measures – system minutes interrupted

Required amendment 53:

The System Minutes interrupted (meshed and radial networks) measures must be retained as SSAM incentive measures. The SSAM SST for these measures should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimates).

Western Power response:

Western Power does not accept this amendment.

The Authority does not accept the use of performance measures for each reference service and requires Western Power to continue to use network-based performance measures, including system minutes interrupted. The Authority considers that:

- the transmission network service is a key component of all reference services, not just for reference services for large customers connected to the transmission network[410]
- system minutes interrupted (meshed and radial) are important SSAM incentive measures to help to ensure that the maintenance of service levels related to elements such as radial networks are not neglected.[411]

Western Power does not accept this amendment. In its September 2011 submission, Western Power included SSAM performance measures that reflected the service standard for reference services rather than for network performance to meet section 5.1 of the Access Code.

As discussed in the response to required amendment 32:

- Western Power's proposed reference service measures meet the requirements of the Access Code
- the Authority's proposed network-based measures are not required under the Access Code

Additionally:

- the service provided to customers receiving a transmission reference service is significantly better than the performance of the transmission network and so transmission network measures provide little information to them
- the performance of the transmission network largely reflects the service received by distribution reference service customers and is in included in Western Power's proposed performance measures for distribution reference services
- Western Power's proposed reference service measures will ensure that reliability improvements are targeted where it is economically efficient, rather than inefficiently biasing investment to improving reliability of radial networks

It is not appropriate to include the system minutes interrupted measures in the SSAM as:

- the measure is considered to be statistically unsound and is therefore not included in the financial incentive schemes for other transmission businesses
- the measures are not independent of the other transmission network measures that the Authority is proposing to include in the SSAM

[410] Paragraph 1309, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[411] Paragraph 1310, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

13.3.3.1 Meeting the Access Code requirements

As discussed under amendment 32, the Access Code requires performance measures based on reference services. Performance measures based on network performance such as system minutes interrupted are not required under the Access Code.

Additionally, transmission network performance measures such as system minutes interrupted do not provide a reasonable indication of the service received by transmission reference service customers.

Western Power has proposed an approach that is consistent with the Access Code requirement. Further, Western Power considers that the measures it proposed are more meaningful to customers considering or receiving a reference service.

13.3.3.2 Transmission network performance is a key component of all reference services

Western Power agrees that transmission network service performance is a key component of all reference services.

Customers receiving a distribution reference service do not care whether their supply has been interrupted by a fault on the distribution network or on the transmission network. All they are concerned about is whether there is an interruption to their supply and when supply will be restored. For that reason, Western Power has proposed performance measures for distribution reference services that include the performance of both the transmission network and the distribution network.

The performance of the transmission network is valued by customers receiving a transmission reference service, but only that part of the transmission network that directly impacts on their security and reliability of supply. The transmission network performance measures do not provide a reasonable indication of the service received by transmission reference service customers. Any change in the performance of the transmission network is likely to have little or no effect on transmission reference service customers as the service received by them is significantly better than the performance of the transmission network.

Any change in the performance of the transmission network is likely to have a greater effect on distribution reference service customers, and will be reflected in SAIDI and SAIFI measures that include transmission network events.

13.3.3.3 Efficient maintenance of service levels

The Authority considers that the system minutes interrupted (meshed and radial networks) measures are important SSAM incentive measures to ensure that service levels related to elements such as radial networks are not neglected.[412] This implies that Western Power should invest to maintain service levels on radial networks even where this is not valued by customers and is thus not economically efficient.

Western Power's approach ensures that service levels are maintained (or improved) only where the impact on the service level is received and valued by customers and is thus economically efficient. The performance measures that have been proposed for distribution reference services include the performance of the distribution and transmission networks to the extent that it affects the service received by customers. The SSAM formula and incentive rates proposed provide Western Power an incentive to maintain (or improve) service levels where it is valued by customers and thus economically efficient.

The Authority notes that the performance of radial networks has deteriorated. However, this deterioration is not reflected in the service received by transmission reference service customers. Any incentive to maintain (or improve) the performance of radial networks

[412] Paragraph 1310, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

through the system minutes interrupted measure will have little or no impact on the service to transmission reference service customers.

Any incentive to maintain (or improve) the performance of radial networks will have a greater impact on the service to distribution reference service customers, and will be reflected in SAIDI and SAIFI measures that include transmission network events.

13.3.3.4 SSAM targets

Regardless of which approach is used, the system minutes interrupted measures should not be included in the SSAM.

When the Australian Competition and Consumer Commission originally developed the Service Target Performance Incentive Scheme (STPIS) for transmission network service providers, the system minutes interrupted measure was not recommended for inclusion in the transmission network service providers' STPISs. It was deemed to be statistically unsound in terms of describing the underlying performance of transmission networks and was replaced with the loss of supply event frequency measure.[413]

Accordingly, as illustrated by Table 119 in the Authority's draft decision[414], the transmission network service providers in the other jurisdictions have loss of supply event frequency measures in their STPISs but not system minutes interrupted measures.

Western Power established a number of criteria to assess the inclusion of particular performance measures in the access arrangement.[415] The system minutes interrupted measures do not meet the principles that the measure is independent of other measures and reflects the nature of the reference service. The system minutes interrupted are already effectively captured by the loss of supply event frequency measures. In addition, the measure is statistically unsound in describing the underlying performance of the transmission reference service and the underlying performance of the transmission network.

13.3.4 Transmission measures – loss of supply event frequency

Required amendment 54:

The Loss of Supply Event Frequency measures must be retained as SSAM incentive measures. The SSAM SSTs should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimates).

Western Power response:

Western Power does not accept this amendment.

The Authority does not accept the use of performance measures for each reference service and requires Western Power to continue to use network-based performance measures, including loss of supply event frequency. The Authority considers that:

- reliability of supply is a key element in network service[416]
- loss of supply event frequency measures are included in the service target performance incentive schemes for other service providers[417]

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[413] Page 5, *Transmission Network Service Provider (TNSP) – Service Standards, Final Report, Report prepared for the Australian Competition and Consumer Commission* (ACCC) by SKM, March 2003

[414] Paragraph 1311, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[415] Page 86, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, Western Power, September 2011.

[416] Paragraph 1312, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

- Western Power's performance against these measures is inferior and has been variable[418]

Western Power does not accept this amendment. As discussed under amendment 32:

- Western Power's proposed reference service measures meet the requirements of the Access Code
- the Authority's proposed network-based measures are not required under the Access Code

Additionally:

- the loss of supply event frequency performance provided to customers receiving a transmission reference service is significantly better than the transmission network loss of supply event frequency performance and so the loss of supply event frequency measure provides little information to them
- the performance of the transmission network largely reflects the service received by distribution reference service customers and is in included in Western Power's proposed performance measures for distribution reference services
- Western Power's proposed reference service measures will ensure that reliability improvements are targeted where it is economically efficient
- Western Power will continue to report loss of supply event frequency to monitor performance and to enable stakeholders to compare its performance with other transmission networks if required

13.3.4.1 Meeting the Access Code requirements

As discussed under Amendment 32, the Access Code requires performance measures based on reference services. Performance measures based on network performance such as loss of supply event frequency are not required under the Access Code.

Additionally, transmission network performance measures such as loss of supply event frequency do not provide a reasonable indication of the service received by transmission reference service customers.

Table 84 illustrates the difference between the loss of supply event frequency experienced by transmission reference service customers over the last five years compared to loss of supply event frequency for the transmission network.

[417] Paragraph 1314, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.
[418] Paragraphs1313 and 1314, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Table 84: Frequency of interruptions experienced by transmission-connected customers, 2007/08 – 2011/12

Performance measure		2007/08	2008/09	2009/10	20010/11	2011/12 (forecast)
Frequency of low duration interruptions (0.1 – 1.0 system minutes)						
Individual Customer	Number of transmission-connected customers experiencing a low duration interruption	1	2	0	0	0
Network Average	Loss of supply events on the transmission network (0.1 – 1.0 system minutes)	27	18	27	18	25 (target)
Frequency of high duration interruptions (more than 1.0 system minutes)						
Individual Customer	Number of transmission-connected customers experiencing a high duration interruption	0	0	0	0	0
Network Average	Loss of supply events on the transmission network (more than 1.0 system minutes)	2	3	2	1	2 (target)

In the period from 2007/08 to 2011/12, the number of interruptions experienced by customers receiving a transmission reference service has been, and is forecast to be, significantly below the number of interruptions on the transmission network.

For example in 2008/09, the loss of supply event frequency for low duration interruptions was 18. In this same year, only two of 51 transmission-connected customers experienced one low duration interruption each. No other transmission-connected customer experienced a low duration interruption. In 2008/09, there were three high duration interruptions. In this same year, no transmission-connected customers experienced a high duration interruption.

Western Power has proposed an approach that is consistent with the Access Code requirement and is more meaningful to customers considering or receiving a reference service.

13.3.4.2 SSAM targets

The SSAM targets for loss of supply event frequency for the transmission network would be much greater than the corresponding experience for transmission reference service customers, as set out in Table 85.

Table 85: SSAM target for the loss of supply event frequency measures

Performance measure	SST
Loss of supply event frequency	
0.1 to 1.0 system minutes (events)	25
Greater than 1.0 system minute (events)	2

13.3.4.3 Reliability of supply is a key component in network service

Western Power agrees with the Authority that reliability of supply is a key component of all reference services.

Customers receiving a distribution reference service do not care whether their supply has been interrupted by a fault on the distribution network or on the transmission network. They are concerned mainly with whether there is an interruption to their supply and when supply will be restored. For that reason, Western Power has proposed performance measures for distribution reference services (SAIFI) that include the number of interruptions resulting from both the transmission network and the distribution network.

The performance of the transmission network is valued by customers receiving a transmission reference service, but only that part of the transmission network that directly impacts on their security and reliability of supply. As illustrated in Table 84, loss of supply event frequency measures do not provide a reasonable indication of the service received by transmission reference service customers. Any change in the performance of the transmission network is likely to have little or no effect on transmission reference service customers as the service received by them is significantly better than the performance of the transmission network.

Any change in the performance of the transmission network is likely to have a greater effect on distribution reference service customers and will be reflected in SAIDI and SAIFI measures that include transmission network events.

13.3.4.4 Consistency with other jurisdictions

Western Power disagrees with the need to have the same loss of supply event frequency measures in the SSAM as those used by other transmission network service providers. Because Western Power will continue to report on the loss of supply event frequency measures, the performance of the Western Power transmission network can be compared to other jurisdictions without the measures being included in the SSAM.

Comparing the financial outcomes under a financial service incentive scheme rather than the level of service is meaningless as it will be affected by:

- the definition of the measures, noting that the definition of low and high duration interruptions varies by jurisdiction
- the approach to establishing the targets in each jurisdiction
- the value determined for the incentive rate for the specific network
- the behaviour of the network business

Western Power does not agree that the Authority should be able to directly compare the performance of the Western Power Network with the transmission networks in other jurisdictions. For historical reasons, there are parts of the Western Power Network that do not have the level of redundancy as in other jurisdictions or as required by the Technical Rules[419]. These parts of the network are therefore less secure and more susceptible to interruptions.

[419] These parts of the network were grandfathered when the Technical Rules were introduced.

The Authority considers that Western Power's performance for loss of supply event frequency appears to be inferior compared to other jurisdictions[420], even though the individual transmission connected customer experience is significantly below the number of interruptions on the transmission network.

If the Authority is of the view that Western Power's performance against the loss of supply event frequency measures should achieve levels more consistent with the other jurisdictions then additional expenditure would be required to achieve performance improvement. However, given the difference in performance between the network and the service received by customers, it is unlikely that customers would want to pay more to a improve service that they will receive very little benefit from.

Under Western Power's approach, the reliability in these parts of the network will be improved where it is valued by customers and thus economically efficient. Western Power's proposed performance measures (SAIDI and SAIFI including transmission network events), incentive rates and SSAM formula will ensure that reliability improvements will be made where it is valued by customers.

13.3.5 Transmission measures – average outage duration

Required amendment 55:

The Average Outage Duration measure must be retained as SSAM incentive measures. The SSAM SST must be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimate).

Western Power response:

Western Power does not accept this amendment.

The Authority does not accept the use of performance measures for each reference service and requires Western Power to continue to use network-based performance measures, including average outage duration. The Authority considers that:

- average outage duration is a key measure of transmission network performance[421]
- further improvement in this measure, or at least maintenance of performance, is desirable[422]

Western Power does not accept this amendment. As discussed under amendment 32:

- Western Power's proposed reference service measures meet the requirements of the Access Code
- the Authority's proposed network-based measures are not required under the Access Code

Additionally:

- the service provided to customers receiving a transmission reference service is significantly better than the performance of the transmission network and so transmission network measures provide little information to them

[420] Paragraphs1313 and 1314, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[421] Paragraph 1315, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[422] Paragraph 1316, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

- the performance of the transmission network largely reflects the service received by distribution reference service customers and is in included in Western Power's proposed performance measures for distribution reference services
- Western Power's proposed reference service measures will ensure reliability improvements are targeted where it is economically efficient

13.3.5.1 Meeting the Access Code requirements

As discussed under Amendment 32, the Access Code requires performance measures based on reference services. Performance measures based on network performance such as average outage duration are not required under the Access Code.

Additionally, transmission network performance measures such as average outage duration do not provide a reasonable indication of the service received by transmission reference service customers.

Table 86 illustrates the difference between the duration of outages experienced by transmission reference service customers over the last five years compared to the average outage duration on the transmission network.

Table 86: Duration of outages experienced by transmission-connected customers, 2007/08 – 2011/12

Performance measure		2007/08	2008/09	2009/10	20010/11	2011/12 (forecast)
Duration of interruptions						
Individual Customer	Outage duration (minutes) for transmission-connected customers who experienced an outage	184	Outage 1 - 77 Outage 2 - 245	No outages experience d	No outages experience d	8
Network Average	Average outage duration on the transmission network (minutes)	715	501	679	675	764 (target)

Over the period from 2007/08 to 2011/12, the duration of outages experienced by customers receiving a transmission reference service was significantly less than the average duration of outages on the transmission network. While the average outage duration in 2008/09 was 501 minutes, one transmission-connected customer experienced an outage duration of 77 minutes and another customer experienced an outage duration of 245 minutes.

Western Power proposes an approach that is consistent with the Access Code requirement and is more meaningful to customers considering or receiving a reference service.

13.3.5.2 SSAM targets

The SSAM targets for the average duration of outages on the transmission network would be much greater than the corresponding experience for transmission reference service customers, as set out in Table 87.

Table 87: SSAM target for average outage duration

Performance measure	SST
Average outage duration (minutes)	670

13.3.5.3 Average outage duration is a key measure of transmission network performance

Western Power agrees that average outage duration is a key measure of transmission network performance.

Customers receiving a distribution reference service do not care whether their supply has been interrupted by a fault on the distribution network or on the transmission network. When an interruption occurs, they are concerned mainly with when supply will be restored. For that reason, Western Power has proposed performance measures for distribution reference services that include the duration of interruptions resulting from both the transmission network and the distribution network (SAIDI).

The performance of the transmission network is valued by customers receiving a transmission reference service, but only that part of the transmission network that directly impacts their security and reliability of supply. As illustrated in Table 86, average outage duration does not provide a reasonable indication of the service received by transmission reference service customers. Any change in the performance of the transmission network is likely to have little or no effect on transmission reference service customers as the service received by them is better than the performance of the transmission network.

Any change in the performance of the transmission network is likely to have a greater effect on distribution reference service customers and is reflected in SAIDI and SAIFI measures that include transmission network events.

13.3.5.4 Desire for an improvement in this measure

The Authority states that further improvement in this measure, or at least maintenance of performance, is desirable[423].

Under Western Power's approach, reliability of supply will be improved where it is valued by customers and thus economically efficient. Under the Authority's approach, the incentives available under the SSAM may not be sufficient to improve this measure. If the Authority is of the view that Western Power's performance against the average outage duration measure should be improved, it should provide additional expenditure so that improvement in performance levels can be achieved. However, this may not be consistent with what customers' value or desire.

Western Power's proposed performance measures (SAIDI and SAIFI including transmission network events), incentive rates and SSAM formula will ensure that reliability improvements will be made in the Western Power Network where they are valued by customers and thus economically efficient.

[423] Paragraph 1316, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

13.3.6 Transmission revenue at risk

Required amendment 56:

Western Power must:

- increase the transmission revenue at risk to 1 per cent of the annual average maximum transmission revenue and the potential reward to 1 per cent of the annual average maximum transmission revenue, taking account of the revisions to allowable transmission revenue set out in this draft decision;
- apply separate incentive penalty and reward rates where non-normal distributions are applied, so as to evenly span the rewards and penalties across the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively;
- adopt the weightings set out in Table 120 to allocate the revenue at risk across the various measures.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

Western Power accepts that the transmission revenue at risk be limited to 1% and that separate incentive penalty and reward rates are applied where the performance measure exhibits a non-normal probability distribution.

Western Power does not accept that the transmission revenue at risk be the allowable transmission revenue as set out in the Authority's draft decision or that the weightings in Table 120 of the Authority's draft decision be adopted.

13.3.6.1 Revenue at risk and potential reward

In its September 2011 submission, Western Power proposed the rewards and penalties under the SSAM during the AA3 period be capped at 1% of transmission revenue, consistent with the limits applied during AA2 and with the approach taken by the Australian Energy Regulator.[424]

The Authority considers that Western Power's initial proposal placed only 0.5% of the transmission revenue at risk through the circuit availability measure and stated that the transmission networks SSAM is relatively underpowered.[425] The Authority requires the rewards and penalties under the SSAM to be capped at 1% of the annual average transmission revenue as set out in the Authority's draft decision. [426]

Western Power accepts that the transmission revenue at risk and the potential reward should be 1% of the annual average maximum transmission revenue, because this is what Western Power proposed in its initial submission. Western Power believes that the Authority misunderstood that Western Power was proposing that the transmission revenue would be adjusted based on rewards and penalties associated with circuit availability **and** the transmission component of SAIDI and SAIFI respectively.

In its September 2011 submission, the penalties associated with circuit availability were limited to 0.5% of average annual maximum transmission revenue. The rewards and

[424] Pages 104-105, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, Western Power, September 2011.
[425] Paragraph 1317-1318, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[426] Paragraph 1320, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

penalties associated with circuit availability **and** the transmission component of SAIDI and SAIFI were limited **in total** to 1.0% of average annual maximum transmission revenue.

Western Power will adopt incentive rates based on the annual average maximum transmission revenue for the AA3 period based on this response, not the Authority's draft decision annual average maximum transmission revenue. Western Power's annual average transmission revenue is determined from the annual transmission revenues as set out in section 5.2.

13.3.6.2 Separate penalty and reward incentive rates

In its initial submission, Western Power used the same penalty and reward incentive rates based on the units of difference between the PoE 50% SSAM target and the PoE 97.5% service standard benchmark.

The Authority notes that most of the best fit statistical distributions applied to the performance measures were not symmetric. In these cases, the Authority states that there should be:

> *… separate incentive penalty and reward rates so as to evenly span the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively.*[427]

Western Power accepts that separate penalty and reward incentive rates should apply where the performance measure exhibits a non-normal probability distribution.

Circuit availability does not exhibit a normal probability distribution. The revised penalty and reward incentive rates for circuit availability, based on Western Power's revised forecast average annual maximum transmission revenue, are set out in Table 88.

Table 88: SSAM incentive rates for circuit availability

Performance measure	SSAM target (SST)	Reward side incentive rate ($ per 0.1%)	Penalty side incentive rate ($ per 0.1%)
Circuit availability (Percentage of total possible hours available)	98.0%	-1,181,191	-598,550

The proposed revised access arrangement for the Western Power Network will be revised in accordance with Table 88.

13.3.6.3 Weightings to allocate revenue at risk across measures

In its September 2011 proposal, Western Power proposed reference service measures rather than network performance measures and that the revenue at risk on the circuit availability measure be 0.5% of annual average transmission revenue with up to 1% of the annual average transmission revenue at risk in aggregate through the transmission component of the SAIDI and SAIFI measures and the circuit availability measure.

The Authority requires transmission network service measures to be included in the SSAM, as discussed under Amendments 53, 54 and 55, with the following weightings applied[428]:

- circuit availability 0.2%
- system minutes interrupted (meshed circuits) 0.1%

[427] Paragraph 1321, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[428] Paragraph 1325, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

• system minutes interrupted (radial circuits)	0.2%
• loss of supply event frequency (0.1 – 1 system minute)	0.1%
• loss of supply event frequency (> 1 system minute)	0.2%
• average outage duration	0.2%

As discussed under required amendments 53, 54 and 55, Western Power does not accept that the SSAM performance measures should change. In particular, it does not consider that the system minutes interrupted measure should be included in the SSAM for the reasons discussed in Amendment 53.

As Western Power does not accept the changes to the SSAM performance measures, it does not accept the changes to the weightings to allocate revenue at risk across measures.

As initially proposed:

- the penalties associated with circuit availability should be limited to 0.5% of average annual maximum transmission revenue
- the rewards and penalties associated with circuit availability **and** the transmission component of SAIDI and SAIFI should be limited **in total** to 1.0% of average annual maximum transmission revenue, as illustrated in Figure 34 of Western Power's initial submission

If the Authority determines that transmission network performance measures should be included in the SSAM, then the transmission revenue at risk weightings would need to be allocated across circuit availability, loss of supply event frequency and average outage duration and further consultation between Western Power and the Authority would need to occur to agree the appropriate weightings.

13.3.7 SAIDI and SAIFI measures

Required amendment 57:

Western Power must:

- adopt revised estimates that remove the transmission network events from the SAIDI and SAIFI measures;
- base the targets on the most recent three years of data – the Authority's estimates of these revised SSTs are set out in row 7 of Table 121 and Table 122 (see also Table 115)

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

Western Power accepts that the targets for SAIDI and SAIFI should be based on the most recent three years of data. However, it does not accept the removal of transmission network events from the SAIDI and SAIFI measures.

In its September 2011 submission, Western Power proposed reference service measures rather than network performance measures. Western Power proposed that the SAIDI and SAIFI measures would include transmission network events and that the SSAM targets would be based on the most recent five years of data.

13.3.7.1 Definition of SAIDI and SAIFI

As discussed under Western Power's response to required amendment 33, the Authority did not accept the inclusion of transmission network events in the SAIDI and SAIFI measures. In addition to the reasons discussed under required amendment 33, the Authority considers that by including transmission network events in the SAIDI and SAIFI measures:

- there would be considerable additional complexity required to allocate the resulting SSAM incentive rewards or penalties to each of the transmission and distribution network elements[429]
- there would be further additional complexity introduced by the need for 'transitional' SSTs[430]

As discussed under Amendment 33, Western Power does not accept removing transmission network events from the SAIDI and SAIFI measures because:

- Western Power's proposed reference service measures meet the requirements of the Access Code
- the Authority's proposed network-based measures are not required under the Access Code
- Western Power's existing reporting requirements and commitment to report on additional transmission network performance measures allow stakeholders to separately assess the performance of the transmission and distribution networks

The Authority also overstates the complexities associated with including transmission network events in SAIDI and SAIFI.

Allocating SSAM incentive rewards or penalties to transmission and distribution network elements is not complex. The Authority already requires Western Power to report SAIDI and SAIFI, by network type with and without transmission network events included. For example:

- DB7 – overall SAIDI by Total Network, CBD, Urban, Short Rural and Long Rural – requires measurement of all interruptions including events on the transmission network
- DB9 – distribution network (Unplanned) SAIDI by Total Network, CBD, Urban, Short Rural and Long Rural – requires measurement of unplanned interruptions on the distribution network excluding events on the transmission network

The data is therefore available to determine the distribution and transmission components of the SAIDI and SAIFI SSAM targets. The Authority has used this data in the draft decision for estimating the SAIDI and SAIFI SSAM targets with transmission network events excluded[431], and to report on the actual performance.

The financial impact of the performance of the distribution and transmission components of SAIDI and SAIFI would be determined using the same SSAM formula and the same incentive rates.

The SSAM incentive rewards or penalties determined by applying the SSAM formula and incentive rates to the distribution component of SAIDI and SAIFI would be allocated to the distribution revenue. The SSAM incentive rewards or penalties determined by applying the SSAM formula and incentive rates to the transmission component of SAIDI and SAIFI would be allocated to the transmission revenue.

The Authority's amendment 28 requires Western Power to amend section 7.5 of the proposed revised access arrangement to include an adjustment in the target revenue for the fourth access arrangement period resulting from any difference between forecast and actual network performance in 2011/12, based on the service standard benchmarks set for the second access arrangement period. Western Power's understanding of paragraph 994 of the

[429] Paragraph 1328, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[430] Paragraph 1328, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[431] Table 115, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Authority's draft decision is that this amendment replaces the adjustment proposed based on transitional SSAM targets.

Western Power accepts this amendment. That is, Western Power has accepted that there will be no transitional SSAM targets.

The exclusion of transmission network events from SAIDI and SAIFI therefore does not introduce any complexity associated with transitional SSAM targets.

13.3.7.2 SSAM targets for SAIDI and SAIFI

As discussed under Western Power's response to required amendment 34, the Authority requires that the targets for SAIDI and SAIFI measures should be based on the most recent three years of data.

Western Power accepts that the AA3 SSAM targets should be set using the most recent three years of data for SAIDI and SAIFI.

Table 89 sets out Western Power's revised SSAM targets for SAIDI and SAIFI including transmission network events, based on the most recent three years of data. Western Power does not accept that transmission events are excluded from SAIDI and SAIFI as discussed under required amendment 33.

The proposed revised access arrangement will be revised in accordance with Table 89.

Table 89: SSAM targets for SAIDI and SAIFI[432] for AA3 based on 3 years of historical data

Performance measure	CBD	Urban	Rural short	Rural long
SAIDI (minutes)	26	169	235	621
SAIFI (events)	0.23	1.80	2.68	4.63

If transmission network events are excluded from the SAIDI and SAIFI measures, the SSAM targets would be less than the corresponding experience for distribution reference service customers, as set out in Table 90.

Table 90: SSAM targets for SAIDI and SAIFI excluding transmission network events based on 3 years of historical data

Performance measure	CBD	Urban	Rural short	Rural long
SAIDI (minutes)	23	157	221	599
SAIFI (events)	0.14	1.61	2.47	4.21

[432] Including the impacts of distribution and transmission network events.

13.3.8 Incentive rates for SAIDI and SAIFI

Required amendment 58:

Western Power must update its estimates of the Value of Customer Reliability to account for the findings of the Oakley Greenwood report – in particular to take account of the revised value of customer reliability estimates and the escalation method.

Western Power response:

Western Power accepts this amendment.

Western Power's September 2011 submission included SSAM incentive rates for SAIDI and SAIFI that were based on the latest information on the value of customer reliability (VCR) estimates available at that time.

The Authority accepted that Western Power's proposed approach is consistent with the Access Code objectives.[433] However, it also noted that the Australian Energy Market Operator (AEMO) recently reviewed this issue. A report by Oakley Greenwood provided updated estimates of VCRs by customer type and by State and provides recommendations on escalation approaches.[434] The Authority required that the VCR estimates be updated to account for the findings of the Oakley Greenwood report.

The Authority referred to an AEMO report published in January 2012. This is now the latest information available on the derivation and escalation of VCRs by jurisdiction. Western Power accepts that the Oakley Greenwood methodology should be applied to update the incentive rates for the Western Power Network.

By using this approach, the aggregate VCR for the Western Power Network is increased from $62,256 per MWh to $67,787 per MWh (in June 2012 dollars).

Required amendment 59:

Western Power must;

- amend the SAIFI incentive rate to be '$ per 0.01 SAIFI event away from the SST';
- retain the proposed SAIDI incentive rate as being '$ per SAIDI minute away from the SST'.

Western Power response:

Western Power accepts this amendment.

In its September 2011 submission, Western Power expressed the SSAM incentive rates for SAIDI and SAIFI as $ per SAIDI minute and $ per event, consistent with the current access arrangement.

The Authority requires that the SSAM incentive rate for SAIFI be expressed as $ per 0.01 SAIFI events. This amendment does not change Western Power's approach substantively – it is a presentational issue and consistent with the accuracy with which Western Power monitors and reports the data. Western Power therefore accepts this amendment.

[433] Paragraph 1340, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[434] Paragraph 1339, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

The revised incentive rates for SAIDI and SAIFI, using the revised VCR based on the Oakley Greenwood methodology and incorporating the presentational changes, are set out in the following Table 91 and Table 92.

Table 91: SSAM incentive rates for SAIDI[435] for AA3

Performance measure	SSAM target (SST)	Reward side incentive rate ($ per SAIDI minute)	Penalty side incentive rate ($ per SAIDI minute)
SAIDI - CBD (minutes)	26	69,897	69,897
SAIDI - Urban (minutes)	169	535,400	535,400
SAIDI - Rural Short (minutes)	235	219,734	219,734
SAIDI - Rural Long (minutes)	621	66,263	66,263

Table 92: SSAM incentive rates for SAIFI[436] for AA3

Performance measure	SSAM target (SST)	Reward side incentive rate ($ per 0.01 event)	Penalty side incentive rate ($ per 0.01 event)
SAIFI - CBD (events)	0.23	$68,895	$68,895
SAIFI - Urban (events)	1.80	$519,575	$519,575
SAIFI - Rural Short (events)	2.68	$208,990	$208,990
SAIFI - Rural Long (events)	4.63	$96,599	$96,599

If transmission network events are excluded from the SAIDI and SAIFI measures, the SSAM incentive rates for SAIDI and SAIFI would change and further consultation between Western Power and the Authority would need to occur to agree on these changes.

13.3.9 Incentive rates for call centre performance

Required amendment 60:

Western Power must:

- adjust the Call Centre Performance incentive rate to reflect the changes to total distribution revenue set out in this Draft Decision;
- apply separate incentive penalty and reward rates to the Call Centre Performance incentive, so as to evenly span the rewards and penalties across the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

Western Power accepts that separate incentive penalty and reward rates are applied where the performance measure exhibits a non-normal probability distribution.

Western Power does not accept that the call centre performance incentive rate be adjusted to reflect the changes to total distribution revenue as set out in the draft decision.

[435] Including the impacts of distribution and transmission network events.
[436] Including the impacts of distribution and transmission network events.

In its September 2011 submission, Western Power calculated the SSAM incentive rates for call centre performance as -0.04% of total distribution revenue for each 1% variation in performance. The same SSAM incentive rates were calculated for rewards and penalties, and were calculated using Western Power's forecast distribution revenue.

The Authority requires the incentive rates to be recalculated based on the distribution revenue set out in its Draft Decision. [437]

The Authority also noted that:

> *The distribution applied to Call Centre Performance for the purposes of establishing the SSB and SST is a Weibull distribution, which is not symmetric around the SST. Asymmetric reward and penalty rates would improve the allocation of incentives*.[438]

The Authority therefore required that separate incentive rates for call centre performance be applied for rewards and penalties.

As the Call Centre Performance measure does not exhibit a normal probability distribution function, Western Power accepts that there should be separate incentive penalty and reward rates to improve the allocation of incentives.

The incentive rate for call centre performance of -0.04% of distribution revenue for each 1% variation in performance has been derived from a 'willingness to pay' study that was conducted in South Australia. In determining the separate incentive rates, Western Power has assumed that this is the willingness to pay for improvements in the call centre, rather than to be paid for deteriorations in call centre performance.

Western Power has therefore maintained the incentive rate of -0.04% of the distribution revenue for each 1% variation in performance for the reward incentive rate. Western Power has determined the penalty incentive rate by calculating the potential reward if the call centre performance was at the 97.5 PoE upper bound. The penalty incentive rate is then determined by assuming that this same amount is the penalty if the call centre performance is at the 2.5 PoE lower bound.

Western Power has updated the SSAM incentive rates for the call centre performance measure based on the annual average distribution revenue proposed in this submission, and not the Authority's draft decision. Western Power's annual distribution revenue is set out in section 5.2.

Table 93 sets out the revised separate penalty and reward incentive rates for Call Centre Performance including the automated interactive message service, based on Western Power's revised forecast average annual distribution revenue.

Table 93: SSAM incentive rates for Call Centre Performance for AA3

Performance measure	SSAM target (SST)	Reward side incentive rate ($ per 0.1%)	Penalty side incentive rate ($ per 0.1%)
Call centre performance (Percentage of calls responded to within 30 seconds)	88.0%	-54,246	-32,781

If calls answered by the automated interactive message service are excluded from the Call Centre Performance measure, the SSAM incentive rates would change as shown in Table 94.

[437] Paragraph 1345, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[438] Paragraph 1346, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Table 94: SSAM incentive rates for Call Centre Performance excluding calls answered by the automated interactive message service

Performance measure	SSAM target (SST)	Reward side incentive rate ($ per 0.1%)	Penalty side incentive rate ($ per 0.1%)
Call centre performance (Percentage of calls responded to within 30 seconds)	63.0%	-54,246	-54,246

13.4 D-factor

Required amendment 61:

The D-factor scheme must be removed from the proposed revised access arrangement.

Western Power response:

Western Power does not accept this amendment.

The Authority requires that the D-factor be removed from the proposed revised access arrangement. The Authority stated that:

> *… under the Access Code there is provision for the service provider to apply at any time under 6.76 and 6.41 to have these costs recovered. On reflection, the Authority considers that the existing provisions of the Access Code in relation to the approval of non-capital costs as set out in sections 6.40, 6.41 and 6.76 provide sufficient mechanisms to enable Western Power to claim any such costs as are contemplated by the proposed D-factor scheme.*
>
> *Given that section 6.76 enables a service provider to apply at any time for such costs to be determined, the Authority does not consider that it is necessary for an additional mechanism such as the proposed D-factor scheme, and agrees that any such cost should be treated no differently to any other expenditure to provide covered services.*[439]

Western Power proposes to retain the D-factor to allow the recovery of efficient costs incurred when undertaking demand management initiatives. The D-factor provides for the recovery in the next access arrangement period of any additional:

- operating expenditure incurred as a result of deferring or avoiding a capital expenditure project during the forthcoming access arrangement period
- operating or capital expenditure incurred in the forthcoming access arrangement period in relation to demand management initiatives[440]

The purpose of the D-factor scheme is to allow the recovery of efficient costs incurred through deferring capital projects for non-capital projects and when undertaking demand management initiatives. The intent of the D-factor is that any operating expenditure incurred is required to meet the efficiency tests (sections 6.40 and 6.41 of the Access Code) and any capital expenditure incurred is required to meet the test for adding new facilities investment to the capital base (section 6.51A of the Access Code).

While section 6.76 provides a mechanism for recovering operating costs during future access arrangement periods, the effect of subsequent sections of the Access Code, specifically

[439] Paragraphs 1361-1362, *Draft Decision on the Proposed Revisions to the Access Arrangement, ERA*, March 2012.
[440] Pages 304-305, *Access Arrangement Information for 1 July 2012 to 30 June 2017,* Western Power, 30 September 2011.

section 6.79, is that operating costs incurred during the *current* access arrangement period cannot be recovered. The rationale for this is described below.

Section 6.76 of the Access Code states:

> *A service provider may at any time apply to the Authority for the Authority to determine whether:*
>
> a) actual non-capital costs incurred by the service provider meet the requirements of section 6.40; or
>
> *b) forecast non-capital costs proposed to be incurred by the service provider is forecast to meet the requirements of section 6.40.*

If Western Power uses the mechanism under section 6.76, the Authority is required to make a determination under clause 6.77 of the Access Code. Section 6.79 of the Access Code states that:

> *The effect of a determination under section 6.77 is to bind the Authority when it approves proposed revisions, but in the case of forecast non-capital costs under section 6.76(b) the Authority is only bound if the non-capital costs were incurred as proposed.*

This means that while a determination under section 6.77 of the Access Code provides a mechanism to recover non-capital costs that are incurred in the next access arrangement period, it does not provide a mechanism to recover any non-capital costs that are incurred within the current access arrangement period.

A determination under section 6.77 also does not provide any mechanism for capital costs to be recovered.

Therefore, the existing provisions of the Access Code in relation to the approval of non-capital costs as set out in sections 6.40, 6.41 and 6.76, do not have the same effect at the D-factor scheme.

The removal of the D-factor scheme will impact customers who would have benefitted from the efficient deferral of capital projects, where a non-network solution is viable. Retaining the D-factor will facilitate Western Power to investigate ways of reducing the cost of transporting electricity over the long term through incorporating more initiatives that reduce the impact of peak demand.

Western Power will retain the D-factor scheme to ensure that the disincentive to identify and implement non-capital solutions is reduced.

13.5 Deferred revenue

Required amendment 62:

The current adjustment mechanism in relation to the recovery of deferred revenue must be retained in the proposed revised access arrangement with the deferred amounts of revenue to be updated to:

$48.6 million ($ as at 30 June 2012) for transmission services; and

$365.2 million ($ as at 30 June 2012) for distribution services.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

The Authority requires Western Power to recover the deferred revenue over a ten year period. This change requires the adjustment mechanism in relation to the recovery of deferred amounts of revenue to be updated.

While Western Power accepts that the deferred revenue will be recovered over ten years (required amendment 29), Western Power does not accept required amendment 62 because the amounts of revenue will change to reflect Western Power's proposed return on investment.

Section 7.7 of the revised proposed revisions to the access arrangement reflects that in present value terms (as at 30 June 2012) $278.9 million and $37.1 million of deferred revenue is to be collected over a five year period commencing in AA4 for the distribution and transmission systems respectively.

13.6 Depreciation

Required amendment 63:

The proposed revised access arrangement must be amended to remove the proposed change to the treatment of depreciation in establishing the opening capital base for the fourth access arrangement.

Western Power response:

Western Power accepts this amendment.

The Authority requires Western Power to amend the proposed revised access arrangement to remove the proposed change to the treatment of depreciation in establishing the opening capital base. The Authority was concerned it would increase the incentive to over-forecast capital expenditure, which could potentially result in Western Power recovering a higher level of depreciation through target revenue than is actually incurred.[441]

In its September 2011 submission, Western Power proposed to establish the opening capital base for the fourth access arrangement period using *actual* depreciation for the categories of expenditure that are **not** subject to the investment adjustment mechanism (IAM) and forecast depreciation for the categories of expenditure that are subject to the IAM.

Western Power accepts the use of forecast depreciation for all expenditure categories, as the use of actual depreciation will create a relative disincentive for Western Power to incur additional expenditure on assets with a short economic life relative to those with a longer

[441] Paragraph 1367, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

economic life. This incentive particularly affects investments in IT infrastructure and other 'smarter' technologies, which are expected to become more pronounced in future years given the investment being made in smart grid technology.

Western Power will amend modify clauses 5.3.5 and 5.3.6 of the access arrangement to give effect to this required amendment.

14 Standard access contract

Section 5.1(b) of the Access Code requires that an access arrangement include a standard access contract for each reference service. Western Power's standard access contract is called the Electricity Transfer Access Contract (ETAC) sets out the terms and conditions under which a user may obtain access to a reference service at the reference tariff.

In its draft decision, the Authority requires a number of amendments related to the standard access contract. Western Power accepts three of these required amendments. Western Power does not accept the amendment related to interest on cash security deposits.

In addition to addressing the relevant required amendments, Western Power has addressed a number of formatting issues in the ETAC. They are not material and have no impact on any party to the ETAC - they simply correct formatting errors.

14.1 Deletion of a connection point

Required amendment 64:

The Authority requires that clause 3.6 be amended as set out in paragraph 1426 above.

Western Power response:

Western Power accepts this amendment.

Clause 3.6 of the ETAC relates to the deletion of a connection point. In its draft decision, the Authority accepts all Western Power's proposed revisions to clause 3.6. However, it requires two additional changes to:

- allow premises with generating plant up to and including 30kVA that is used to offset load (e.g. PVs) to be disconnected with one month's notice from User – that is, treat such premises like consuming premises and not like traditional generators.[442]
- require WP to advise a User when a deletion of a connection point takes effect or that Western Power refuses to make a deletion 'as soon as reasonably practicable'[443]

Western Power has amended clause 3.6 to give effect to the Authority's required amendment. The amended clause 3.6 is included in the revised ETAC, which is attached at Appendix A of the proposed revised access arrangement that accompanies this submission.

[442] Paragraph 1420, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[443] Paragraph 1424, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

14.2 Limitations of warranty obligations

Required amendment 65:

Clause 18.1(a)(i) and 18.2(a)(i) must be amended as set out in paragraph 1448 (of the draft decision).

Western Power response:

Western Power accepts this amendment.

Clause 18 of the ETAC deals with representations and warranties. In its draft decision, the Authority requires Western Power to amend clause 18 to clarify what will occur in circumstances where a user is in breach of its warranty or representations as a direct result of Western Power breaching its obligations. This reflected concerns raised by Synergy about the lack of clarity.

In its September 2011 submission, Western Power did not propose any revisions to clause 18.

Western Power accepts the Authority's amendment, and have amended clause 18.1(a)(i) and 18.2(a)(i) accordingly. Western Power notes that there is a small error in the drafting of clause 18.2(a)(i) in the Draft Decision (paragraph 1448). In the part of the clause which is not being amended the Draft Decision incorporates the wording "its" instead of "the User's*". Western Power has retained the words "the User's*" within clause 18.2(a)(i).

The amended clause 18 is included in the revised ETAC, which is attached at Appendix A of the proposed revised access arrangement that accompanies this submission.

14.3 Security for charges

Required amendment 66:

An amendment is required to the electricity transfer access contract to reflect the amendments set out in paragraph 1498 above.

Western Power response:

Western Power accepts this amendment.

Clause 9 of the ETAC deals with security for charges. In its draft decision, the Authority requires Western Power to amend clause 9 to include new sub-clauses that stipulate:

- when security held by Western Power must be returned
- when security may be called upon
- the 'two month' period for calculating the quantum of security

Western Power has made this required amendment by adding three paragraphs (f) (g) and (h) to clause 9.

The amended clause 9 is included in the revised ETAC, which is attached at Appendix A of the proposed revised access arrangement that accompanies this submission.

14.4 Interest on cash security deposits

Required amendment 67:

An amendment is required to the electricity transfer access contract to include a clause requiring Western Power to pay interest on cash security deposits provided by users.

Western Power response:

Western Power does not accept this amendment.

Clause 9(a) of the ETAC provides circumstances under which a User is required to pay security deposits. Users have a range of options for providing security including:

- cash deposit
- bank guarantee or equivalent financial instrument
- parent company guarantee.

The Authority noted the submission from Landfill Gas and Power which expressed the view that:

> *… Western Power should also pay interest on cash security deposits, in common with the practice of the [independent market operator (IMO)].*[444] [445]

The Authority agreed that it:

> *would be reasonable for Western Power to pay interest on cash security deposits",*
>
> but did not provide reasons for this position.[446]

Western Power has since reviewed the requirements to pay interest on cash security in similar access contracts across Australia including for:

- Dampier to Bunbury Natural Gas Pipeline (DBNGP)
- Goldfields Gas Pipeline
- WA Gas Network
- access arrangements for distribution pipelines – SA, Vic, Qld, NSW
- access arrangements for transmission pipelines regulated by Australian Energy Regulator (AER) – SA, Vic, Qld, NSW
- system/co-ordination agreements between electricity retailers/distributors – SA, Vic, Qld, NSW

General industry practice is to not receive security in the form of cash deposits. In the few instances where cash deposits are received, the majority do not pay interest. Western Power found that only Goldfields Gas Pipeline and Jemena Sydney Gas Distribution Network contracts include a clause related to interest on cash security. In both cases it provides for the accrued interest to become part of the security.

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[444] Paragraph 1493, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[445] The IMO's obligation to pay interest is specified in clause 2.38.5 of the Wholesale Electricity Market Rules. The amount paid to the market participant is the interest accumulated on the deposit less any liabilities and expenses incurred by the IMO, including bank fees and charges as follows:
cxxxiv. 2.38.5 Where Credit Support is provided as a Security Deposit in accordance with clause 2.38.4(b), it will accrue interest daily at the Bank Bill Rate, and the IMO must pay the Market Participant the interest accumulated at the end of each calendar month less any liabilities and expenses incurred by the IMO, including bank fees and charges.
[446] Paragraph 1501, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Western Power is not a financial institution whose business focuses on dealing with financial transactions, such as investments, loans and deposits. Western Power does not hold an Australian Financial Services Licence (AFSL) and is not an Authorised Deposit-taking Institution (ADI) under the Banking Act 1959. Paying interest on security deposits may create legal and/or additional regulatory implications due to Western Power becoming an entity which pays interest on customer deposits.

Specifically under section 911A(1) of the *Corporations Act 2001* a person who carries on a financial services business must hold an AFSL.

Under sections 761A and 766A financial services include dealing in a financial product (sections 766C-766D) and providing a custodial or depository service (section 766E).

The payment of interest on cash security deposits may constitute a managed investment scheme (which is a financial product/service) and therefore may require an AFSL.

A managed investment scheme is defined in section 9 of the *Corporations Act 2001* as a scheme which has the following features:

(a) people contribute money or money's worth as consideration to acquire rights (*interests*) to benefits produced by the scheme (whether the rights are actual, prospective or contingent and whether they are enforceable or not);

(b) any of the contributions are to be pooled, or used in common enterprise, to produce financial benefits, or benefits consisting of rights or interests in property, for the people (the *members*) who hold interests in the scheme (whether as contributors to the scheme or as people who have acquired interests from holders);

(c) the members do not have day-to-day control over the operation of the scheme (whether or not they have the right to be consulted or to give directions).

The pooling of cash security deposits and the remission of interest earned on the deposits may satisfy this definition.

If it does then, because an unregistered managed investment scheme is a financial product for the purposes of section 764(1)(ba), paying of interest on cash deposits would constitute dealing in a financial product.

Secondly an arrangement under which Western Power collects interest on behalf of users and pays this interest to them may be a "custodial or depositary service". Under section 766E of the *Corporations Act 2001* a provider provides such a service to another person (client) if:

> *"under an arrangement between the provider and the client, or between the provider and another person with whom the client has an arrangement, (whether or not there are also other parties to any such arrangement), a financial product, or a beneficial interest in a financial product, is held by the provider in trust for, or on behalf of, the client or another person nominated by the client."*

The holding of the cash deposit and paying interest on that deposit may constitute Western Power holding a financial product on behalf of a client (ie the security provider).

To make a final determination of whether it would require an AFSL Western Power will need to seek legal advice. The provision of that legal advice in itself will involve a material cost.

If Western Power is required to hold an AFSL then it will need to put in place procedures to ensure compliance with the requirements of that licence including establishing arrangements for managing conflicts of interest, training of personnel in financial securities law and reporting obligations.

In addition to the AFSL issues, the collecting of cash security, accruing interest and repaying this to Users may constitute banking business for the purposes of section 5 of the *Banking Act 1959*. In such case Western Power could only engage in such business if approved as an ADI by APRA. While Western Power sees this as less of a risk than Western Power being regarded as providing a financial service (and therefore needing an AFSL) the impact of the *Banking Act 1959* would be a further issue on which Western Power would require legal advice.

Users have the power to invest funds in a manner which provides the best use of their resources whilst providing Western Power with the appropriate level of security as required. The User may seek alternative and more appropriate arrangements (i.e. providing a bank guarantee and investing their funds in a bank) should they wish to make a return on the funds held as cash security.

Putting aside the legal issues, Western Power has investigated its practical ability to pay interest on cash security deposits.

Cash deposits are not a common form of security received. Currently, Western Power holds six cash security deposits totalling approximately $700,000 and earning approximately $30,000 of interest income per annum. Western Power note that the number and value of cash on deposit held by Western Power varies throughout the year, however the current scenario is a fair reflection of the average amounts held.

Initially in order for Western Power to be in a position to pay interest it would need to develop a new business model and policies and procedures to capture, calculate, track, apportion and report on interest. This would incur a large investment of time and resources by the business.

To undertake the operational resourcing aspects of calculating and paying interest, including bank account set up, accounting set up, ongoing monthly reconciliations, ongoing account processing, monthly statement production, annual/biannual audit examinations; and termination and withdrawal costs it is estimated this would require an increase in resourcing of up to $40,000. This cost alone is currently greater than the interest Western Power would receive in interest income.

Additionally, Western Power's financial accounting IT system is not set up to perform interest calculations and payments, and provide user statements. An IT system upgrade would be required to provide this functionality and would likely incur a one-off cost in the vicinity of $25,000.

Paying interest may incentivise customers to provide cash rather than bank guarantees as security. Over time the quantity of funds held on deposit may in turn increase Western Power's costs.

In summary, Western Power does not accept the requirement to pay interest on cash security deposits provided by users because:

- the industry standard is to not receive security in the form of cash deposits, but where cash deposits are accepted there is generally not an obligation to pay interest
- it may create legal and/or additional regulatory implications due to Western Power becoming an entity which pays interest on customer deposits
- it results in Western Power incurring additional costs greater than the interest paid.

Western Power has not amended its access arrangement revisions for required amendment 67.

15 Application and queuing policy

In its draft decision, the Authority requires ten amendments to Western Power's application and queuing policy (AQP). Western Power considers the Authority's changes to be reasonable and in some cases improves the clarity and operation of the AQP.

Of the ten required amendments to the AQP, Western Power accepts six exactly as proposed and has modified its position on the remaining four to address the Authority's requirements.

Western Power also considers that the Authority's amendments are consistent with feedback provided by customers during stakeholder engagements regarding the AQP conducted in February 2012. The engagements allowed stakeholders to raise their views and suggest improvements. It also allowed Western Power address concerns and clarify how the proposed AQP would work in practice. The Authority has acknowledged the value of this engagement:

> *Western Power held a stakeholder workshop on 3 February 2012 to provide further explanation and opportunity for comment in relation to the proposed applications and queuing policy. The forum was attended by a broad cross-section of interested parties. Many issues, queries, questions and criticisms were raised and discussed in what appeared to be a very beneficial workshop for all attendees.*[447]

Western Power believes that the revised proposed AQP, attached at Appendix B of the proposed revised access arrangement, addresses the Authority's amendments and will be satisfactory for customers.

15.1 Western Power to 'act reasonably'

Required amendment 68:

The applications and queuing policy must be amended to include an express requirement for Western Power to act reasonably in deeming that an application has been withdrawn.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

The Authority proposes there should be an express requirement for Western Power to act reasonably in deeming that an application has been withdrawn based on the public submission feedback received from Landfill Gas and Power[448].

Western Power accepts the required amendment's intent but has revised the AQP to require Western Power and applicants to act reasonably and in good faith with each other in relation to an application generally. This general statement will capture all aspects of dealing with an application, including the process of determining when an application is deemed to have been withdrawn.

Western Power will amend clause 3.1 of the AQP as follows:

> ***Applications to be made in good faith***
>
> > *Western Power and an applicant must act reasonably and in good faith with regard to each other in relation to an application.*

[447] Paragraph 1524, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[448] Paragraph 1529 and 1530, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

The amended clause 3.1 is included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

15.2 Technical disputes

Required amendment 69:

Clause 20.4 of the applications and queuing policy must be amended to include the following:

"Nothing in this clause limits the matters that may be the subject of an access dispute."

Western Power response:

Western Power accepts this amendment.

The Authority proposes clause 20.4 of the AQP be amended to include an express statement that it does not limit the matters that are subject to an access dispute.[449] This responds to ERM Power's public submission that suggested that technical disputes should be treated as an access dispute.[450]

However the Authority does not agree that clause 20.4 should expressly reference technical disputes as:

> *An access dispute is defined in section 1.3 of the Access Code and may include a dispute in relation to any of the terms, including technical requirements, for access. As such, the Authority does not consider it necessary for clause 20.4 to expressly state that technical disputes are to be referred to arbitration.*[451]

Western Power accepts the required amendment. Clause 20.4 of the AQP will be amended to include:

> *Nothing in this clause limits the matters that may be the subject of an access dispute.*

The amended clause 20.4 is included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

[449] Paragraph 1532, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[450] Paragraph 1531, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[451] Paragraph 1532, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

15.3 Fees for enquiry stage

Required amendment 70:

The applications and queuing policy must include specific reference to the Price List in relation to the relevant fees.

Western Power response:

Western Power accepts this amendment.

The proposed Price List for 2012/13 (included as Appendix F.1 to Western Power's September 2011 submission) includes a list of lodgement fees applicable to the AQP.[452] The Authority believes that it would be clearer to applicants if the AQP specifically referred to the price list, which includes a list of AQP lodgement fees.[453]

Western Power accepts this amendment and will include a reference to the price list at clause 18.4 (enquiry fee), clause 24.3(a) (preliminary offer processing fee), and clause 24.5(b) (preliminary acceptance fee).

Clause 18.4 of the AQP will be amended to include:

> *At the time that the applicant lodges an enquiry under this clause 18, Western Power may charge a non-refundable fixed fee for processing the* ***enquiry as specified in the price list****… (emphasis added)*

Clause 24.3(a) of the AQP will be amended to include:

> *… paying the preliminary offer processing fee* ***as specified in the price list****… (emphasis added)*

Clause 24.5(b) of the AQP will be amended to include:

> *…a preliminary acceptance fee* ***as specified in the price list****...(emphasis added)*

There are fees that are levied on applicants that are not firm value fees in the price list, which includes some applicant specific costs. For avoidance of doubt, Western Power will include a note in the price list definition, in clause 2.1, to inform applicants that some applicant specific costs that may be levied may not be specified as firm value fees in the price list.

The clause 2.1 price list definition will be amended as follows:

> *"price list" means the price list (as defined in the Code) in the access arrangement.*
>
> *{Note: Some costs and fees that may be levied under this applications and queuing policy may not be specified as firm values in the price list.}*

The amended clauses are included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

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[452] Paragraph 1536, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

[453] Paragraph 1536, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

15.4 Application specific solutions

Required amendment 71:

To ensure the applications and queuing policy is consistent with sections 2.10 and 2.11 of the Access Code, the applications and queuing policy must provide for an applicant to have an application treated independently of any other application. To give effect to this requirement:

- clauses 24.2 and 24.3 must be amended to provide for an applicant to opt out of the competing applications group process before that process commences and for the application to be treated as an application for an applicant-specific solution; and
- clause 24.5 be amended so that if an applicant does not reach agreement with Western Power on a preliminary access offer as part of the competing applications group process, the application is not deemed to be withdrawn but is to be treated as an application for an applicant-specific solution.

Western Power response:

Western Power accepts this amendment.

In its draft decision, the Authority considers the proposed AQP does not provide for an applicant to have an application treated independently of any other application and suggested amendments to the AQP to ensure applicant rights are preserved under sections 2.10 and 2.11 of the Access Code.[454]

Western Power accepts this amendment and will make the necessary changes to the AQP described below.

Clause 24.2 is amended as follows:

> *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 preliminary offer processing fee is not payable by an applicant who under clause 24.3(b) elects to opt out of the competing applications group or who under clause 24.3(c) withdraws their application)****. (emphasis added)*

Clause 24.3 is amended to include a new 24.3(b) as follows:

> *advising that they wish to opt out of the competing applications group, in which case they will be treated as having made an application for an applicant-specific solution and the applicant's connection application will be processed as an applicant-specific solution in accordance with clauses 19 and 20 (and the other relevant provisions) of this applications and queuing policy; or*

Clause 24.5(a)(ii) is amended as follows:

> *…but if Western Power and the applicant have not agreed on the form of the preliminary access offer within 30 business days, then the* ***applicant will, unless it notifies Western Power that it wishes its connection application and any associated electricity transfer application, to be taken to be withdrawn, be treated as having made an application for an applicant-specific solution and the applicant's connection application will be processed as an applicant-specific solution in accordance with clauses 19 and 20 (and the other relevant provisions) of this applications and queuing policy****; or (emphasis added)*

[454] Paragraph 1545, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, ERA, 29 March 2012

Western Power notes that the opted out application will follow the standard applicant specific process and will not avoid the objections component of that process (that is in clause 20.3).

The changes to clauses 24.3 and 24.5 (plus the changes through Amendment 76) also require a modification to clause 24.7 to recognise that the composition of a competing applications group may change when an applicant is to be treated as having made an application for an applicant-specific solution. Western Power has therefore amended clause 24.7 by adding the following words:

> *or applicants whose applications are to be treated, under a clause of this applications and queuing policy, as having been made for an applicant-specific solution (for example under clause 24.3(b), 24.5(a)(ii) or clause 24.1(c)).*

Western Power also notes a small correction to clause 20.3(b)(ii) – the "is" in that clause should be a "was" (any *competing applicant* that ~~is~~ was within the same *competing applications group* as the *applicant*) because once an applicant has been moved into an applicant-specific solution option they are no longer part of a *competing applications group*.

The amended clauses are included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

15.5 Detail on how AQP will operate

Required amendment 72:

The mechanisms and processes relating to the competing applications group must be more clearly defined by setting out:

- how competing applications in a 'competing applications group' will be processed;
- how timing of network augmentations will be coordinated with the applications;
- how the competing applications group concept will operate; and
- what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants.

Western Power response:

Western Power accepts this amendment.

Section 5.7 (b) of the Access Code requires that the AQP must:

> *Be sufficiently detailed to enable users and applicants to understand in advance how the applications and queuing policy will operate.*

The Authority considers that

> *mechanisms and processes with respect to the competing applications group could be more clearly defined, whilst ensuring that those mechanism do not become unworkable.*[455]

Previously Western Power has provided stakeholders with discussion documents, scenario based case studies and forum presentations to provide a level of detail on how the AQP will operate in practice. Some submitters[456] have asked for further clarification and detail on the operation of the competing applications group (CAG). However the submissions were not specific on areas where this is required. Western Power raised this issue at the February

[455] Paragraph 1550, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[456] Paragraph 1549, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

2012 stakeholder forum on specific areas that required further detail but no specific areas were identified.

Western Power has found it difficult to respond to stakeholder requests for further information because to date stakeholders have not been able to articulate with precision the specific issues on which they want more detail and the nature of the detail they want. They have only made general requests for more detail in respect of general topics.

It is Western Power's wish and intent to provide stakeholders more detail. Given the above difficulty, Western Power has given thought to how best to draw out from stakeholders the additional detail they require.

Western Power also notes, and agrees with, the Authority's recognition of the need to balance prescription with flexibility:

> *The Authority acknowledges that there needs to be a balance between a prescriptive process and flexibility for Western Power to identify an efficient network investment that meets the needs, collectively, of applicants.*[457]

This balance can best be achieved by including a requirement in the AQP for Western Power to publish an AQP guideline document. The AQP guideline will detail how the policy will operate in practice, including the steps that will be followed when applications are placed in a CAG. The guideline can be written in a more practical manner than compared to the legal style of the AQP, allowing it to provide a more hands on guide to stakeholders.

Western Power will develop the AQP guideline in consultation with stakeholders, including a forum process, to ensure that it provides the appropriate level of detail required by stakeholders. This will provide applicants with an opportunity to specify the types of detail they are seeking.

The AQP guideline will contain, but is not limited to, the Authority's requirement for:

- how competing applications in a 'competing applications group' will be processed
- how timing of network augmentations will be coordinated with the applications
- how the competing applications group concept will operate and
- what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants

The AQP guideline will also include case studies that provide details of how the AQP will be applied in practice.

Western Power accepts this amendment with the modification that detailed descriptions of the mechanisms and processes are contained in a separate AQP guideline.

To protect stakeholders, they can refer to the Authority any complaint that the AQP guideline does not comply with the Code or the AQP or is not sufficiently detailed. The Authority can direct Western Power to amend the guideline to address a valid complaint.

Accordingly, the AQP will be amended to include a new clause 2.7. The new clause 2.7 is included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

[457] Paragraph 1550, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

15.6 Time limits

Required amendment 73:

Timelines for applicant-specific solutions must be stated in line with the timelines for competing application groups.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

Section 5.7(c) of the Access Code requires that an AQP must:

> *set out a reasonable timeline for the commencement, progressing and finalization 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.*

The Authority considers that timelines for applicant-specific solutions must be be included in the AQP. It has referred specifically to ERM Power's public submission:

> *In its submission, ERM Power considers that time limits should be included in section 20.3 which deals with applicant-specific solutions.*[458]

The initial stages of the AQP processes are common for CAG and applicant-specific solution applications. In later stages the CAG process becomes multilateral but the applicant-specific solution process remains bilateral and so different milestones and timelines apply.

Western Power consider the Authority's required amendment is best achieved by including specific process milestones in the AQP. The AQP should also note that achieving the timelines depends on the applicant's cooperation with Western Power.

Western Power accepts that the AQP will be revised in clause 20.3 to include timelines for the applicant-specific solution process. They do not necessarily match the timelines for competing applications groups reflecting the different nature of each process. It has also revised the wording of the clause to provide that when Western Power is preparing the study, achieving the timeline is dependent on the applicant's cooperation.

The amendments are summarised below.

- 60 business days for the study and timeline is dependent on the applicant's cooperation when preparing the study. Clause 20.3(a) will be amended to include:

  > *Western Power will endeavour, subject to receiving any necessary cooperation from the applicant, to complete the study within 60 business days.*

- 30 business days for objections. Clause 20.3(c) will be amended to include

  > *An existing user and competing applicant may object to the applicant-specific solution **within 30 business days**… (emphasis added), and*

- 30 business days for Western Power to make an offer. Clause 20.4(e) will be amended to include:

  > *…then Western Power **within 30 business days** must make an access offer…(emphasis added).*

The amended clauses are included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

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[458] Paragraph 1555, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

Required amendment 74:

Clause 18.2A(b) must be amended to state that Western Power must provide a response letter to applicants within 20 business days or, if not all the information is available within that timeframe, provide the applicant with as much information as possible within 20 business days and an estimated time, being not greater than 20 business days, of when the balance of outstanding information will be provided.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

The Authority considers that Western Power must provide a response letter to applicants within 20 business days with an option for a longer time frame for cases with greater complexity.

However, the Authority submits that it is reasonable that a best endeavours basis is appropriate in response to a submission by Moonies Hill on changing section 18.2A(b) from “endeavour” to “must”.

> *The Authority considers it reasonable that such a requirement should be placed on Western Power if the activity to which the timeline relates is one that is predictable for which a pre-determined timeline can reasonably be established. However, for activities which are difficult to predict, the Authority considers it reasonable that it be on a best endeavours basis.* [459]

The Authority also considers that most information in relation to responding to enquiries is available and on that basis reasonably expects a response to be prepared within 20 business days rather than 40 business days based on feedback from Wind Prospect.[460]

Western Power accepts that it is reasonable to expect Western Power to respond to an applicant’s letter within 20 business days and that this is likely to be achieved in most cases in practice.

However, as the Authority acknowledges, it may not be possible to respond within 20 days in all circumstances:

> *The Authority acknowledges there may be some cases with greater complexity which require a longer time frame and, in such cases, Western Power should be required to provide an expected response time to the applicant within 20 business days of lodgement of the enquiry.*[461]

Western Power therefore does not accept the Authority’s amendment that states Western Power **must** provide a response within 20 days. Western Power proposes that it would be appropriate to amend the access arrangement revisions to include an obligation for Western Power to **endeavour** to provide the balance of the outstanding information within 20 business days. This is both reasonable and workable.

Western Power will amend clause 18.2A(b) to state that:

> *Western Power will endeavour to send the enquiry response letter to the applicant within **20** business days of the lodgement of the enquiry, or within **20** business days of completion of any system studies or other works requested by the applicant under*

[459] Paragraph 1558, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[460] Paragraph 1559 and 1561, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.
[461] Paragraph 1561, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

> *clause 18.2.* ***If Western Power is not able to provide all the information to be contained in the enquiry response letter to the applicant within 20 business days then it will within that 20 business days, send an enquiry response letter to the applicant with as much information as is available to Western Power, together with an estimated time within which the balance of the information will be provided. Western Power will endeavour to send the balance of the information to the applicant within a further 20 business days.*** *(emphasis added)*

The amended clause 18.2A(b) is included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

15.7 Information provision by Western Power

Required amendment 75:

The applications and queuing policy must be amended to include an obligation for Western Power to provide potential applicants with all commercial and technical information reasonably requested, and subject to any reasonable confidentiality requirements, at the pre-enquiry stage.

Western Power response:

Western Power does not accept this amendment. Western Power has modified its response to address the required amendment.

Section 5.7(d) of the Access Code requires:

> *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.*

The Authority considers that the pre-enquiry stage, specified in clause 17A.1 should include:

> *… a specific requirement for Western Power to provide potential applicants with all commercial and technical information reasonably requested and subject to any reasonable confidentiality requirements.*[462]

At the pre-enquiry stage Western Power will provide any information that is existing and available to Western Power. However Western Power would not be undertaking studies or creating new analysis at this stage. This would be an unreasonable burden at a pre-enquiry stage and is inconsistent with the later provisions of the AQP which require applicants to fund the costs of studies required to process applications.

In respect of confidentiality requirements, clause 6.2 of the existing and initial proposed AQP covers confidentiality requirements under the AQP generally.

> *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*
>
> *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*

[462] Paragraph 1567, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

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.*

To give effect to Amendment 75, Western Power has inserted a new AQP clause 17A.3. The amended clause 17A.3 is included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

15.8 Supplier of last resort

Required amendment 76:

The applications and queuing policy must be amended to include arrangements to enable:

- 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
- 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 (5.7(g)).

Western Power response:

Western Power accepts this amendment.

Section 5.7(g) of the Access Code requires that an AQP must

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.

The Authority has indicated that the AQP needs to allow for retailer of last resort and default supplier transfers.[463]

It notes Clause 9.1 of the AQP deals with customer transfer requests[464] which are made by retailers. This provision is identical in the existing AQP.

Western Power will insert a new AQP clause 24.1(c) to permit an applicant at any time to avoid the CAG processes and be treated as an applicant-specific solution where the applicant is:

- 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

- a 'default supplier' under regulations made in respect of section 59 of the Act to enable it to comply with its obligations under section 59 of the Act and the regulations (5.7(g))

[463] Paragraph 1579, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, ERA*, 29 March 2012.
[464] Paragraph 1578, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 29 March 2012.

The new clause 24.1(c) is included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

15.9 Drafting amendments

Required amendment 77:

The proposed revised access arrangement should be amended to incorporate the drafting amendments set out in paragraph 1596 (of the draft decision).

Western Power response:

Western Power accepts this amendment.

The Authority has proposed drafting amendments to the AQP. Western Power accepts these amendments. They are as follows:

Definitions

The following phrases will be italicised as they are defined terms:

"reasonable and prudent person", wherever it appears in the policy; and

"confidential information", at the end of clause 6.1.

Clause 14.4(f)(ii)(B)

The underlining of the full stop at the end of the clause will be removed.

Clause 24.10(a)

The italicisation of the word "unused" will be deleted and the "and" after it deleted

Clause 24A.3(b)

The word "its" on line 5 will be amended to "it", so that part of the clause reads:

"......timing, cost and terms of it obtaining access......"

Clauses 24A.3(d) and (e)

The phrase "Preliminary Access Offer" on the last line of sub-clause (d), and in all places in sub-clause (e), will be changed to lower case so that the term reads "preliminary access offer".

These drafted amendments are included in the revised AQP, which is attached at Appendix B of the proposed revised access arrangement that accompanies this submission.

16 Contributions Policy

In addition to addressing the relevant required amendments, Western Power has addressed a number of formatting issues in the Contributions Policy, Distribution Headworks Methodology and Distribution Low Voltage Connection Scheme methodology. They are not material and have no impact - they simply correct formatting errors.

16.1 Distribution Low Voltage Connection Scheme

Required amendment 78:

The proposed revised access arrangement must be amended to delete all reference to the proposed distribution low voltage scheme.

Western Power response:

Western Power does not accept this amendment.

The Authority requests that the proposed revised access arrangement be amended to delete all reference to the proposed distribution low voltage connection scheme (DLVCS). At the time of the draft decision the Authority was unable to consider the scheme as it was contingent on an amendment to the Access Code being gazetted.

In subsequent discussions, the Authority has indicated that it will evaluate Western Power's mid-period submission to revise the Contributions Policy to allow for the DLVCS. On the assumption that the mid-period revision is approved, Western Power does not propose to amend the Contribution Policy. If the mid-period revision is not approved, Western Power will re-submit its Contributions Policy for approval.

16.2 Headworks scheme

Required amendment 79:

The Distribution Headworks Methodology and Contributions Policy must clarify how revenue offsets are calculated and how they are taken account of when determining headworks contributions.

Western Power response:

Western Power accepts this amendment.

The Authority requires Western Power to amend the Distribution Headworks Methodology and Contributions Policy to clarify how revenue offsets are calculated and how they are taken into account when determining headworks contributions. The rationale for the amendment was to provide increased clarity to customers.

Western Power agrees that there would be some benefit in implementing the Authority’s amendment and has varied the Distribution Headworks Methodology and the Contributions Policy accordingly.

Required amendment 80:

The Distribution Headworks Methodology must include a copy of the relevant price lists together with an explanation of any significant changes to those charges compared to the previous period.

Western Power response:

Western Power accepts this amendment.

The Authority requests that the Distribution Headworks Methodology includes a copy of the relevant price lists together with an explanation of any significant changes to those charges compared to the previous period. The basis for the amendment is to make process more transparent.

Western Power agrees with the Authority and will amend the Distribution Headworks Methodology to include a copy of the relevant price lists as well as an explanation of any significant changes to those charges compared with the previous period.

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O.3 CEG - Estimating equity beta for Australian regulated energy network businesses

O.4 CEG - Western Power's proposed debt risk premium

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Appendix Y. Draft Business Case - Field Survey Data Capture Project

Appendix Z. Explanation of negotiation process with distribution delivery partners (confidential)

Glossary

The following table shows a list of abbreviations and acronyms used throughout this document.

Abbreviation / Acronym	Definition
AA1	Access arrangement for the first period, 2006/07 to 2008/09
AA2	Access arrangement for the second period, 2009/10 to 2011/12
AA3	Access arrangement for the third period, 2012/13 to 2016/17
AA4	Access arrangement for the fourth period, 2017/18 to 2021/22
AA	Access arrangement
AAI	Access arrangement Information (AAI) - supporting information submitted to the ERA and published for public review.
AAI Guidelines	Guidelines to the Access Arrangement Information, published by the ERA in December 2010.
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
Access Code	Electricity Networks Access Code 2004
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	Australian Gas Light Company
the Authority	Economic Regulation Authority
AQP	Applications and queuing policy
AWOTE	Average weekly ordinary time earnings
AWP	Approved works program
CAG	Competing applications group
CAPM	Capital asset pricing model
CBD	Central business district
CGS	Commonwealth Government securities.
CPI	Consumer price index
DAFWA	Department of Agriculture and Food Western Australia
DDP	Distribution delivery partners assist Western Power in the delivery of its network maintenance and investment programs
DM	Document management
DLVCS	Distribution low voltage connection scheme methodology
DNAR	Distribution Network Access Request (DNAR) is a formal request to access the high voltage distribution network and to provide visibility of planned low voltage (240/415 V) customer interruptions
DRP	debt risk premium
EIB	Efficiency and innovation benchmark
EOPS	Extended outage payment scheme

Abbreviation / Acronym	Definition
ETAC	Electricity Transfer Access Code
ERA	Economic Regulation Authority
EV	Electric vehicles
FESA	Fire and Emergency Services of Western Australia
GBA	Geoff Brown and Associates – technical consultants to the Authority
GE's ENMAC	General Electric's ENAMC is a distribution management system used by Western Power to manage the operation of the distribution networks
GSM	Gain sharing mechanism
GSP	Gross State Product
GWh	Gigawatt hours
IAM	Investment adjustment mechanism
IFRS	International financial reporting standards
IMO	Independent Market Operator
IVR	Interactive Voice Response system
kV	Kilovolts
kVA	Kilovolt amperes
LDV	Light duty vehicles
LTIFR	Lost time injury frequency rate
MRP	Market risk premium
MW	Megawatts
MWEP	Mid West Energy Project
MWS	Mobile workforce solution
Metering Code	Electricity Industry Metering Code 2005
NFIT	New facilities investment test
NCS	Network control service
NEO	National Electricity Objective
PE	Photo electric – light sensitive device used to switch streetlights
PHEV	Plug-in hybrid electric vehicle
PoE	Probability of exceedance
PV	Photovoltaic
RMU	Ring main unit
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SMMITS	IT systems used by Western Power to manage the Market Participant Interface
SPOW	Strategic Program of Work – a Western Power program of IT and business projects
SSAM	Service standard adjustment mechanism

Abbreviation / Acronym	Definition
SWIN	South west interconnected network – SWIN is commonly used to describe the network portion of the SWIS.
SWIS	South west interconnected system – the SWIS includes the SWIN and generation plant and associated equipment.
SSB(s)	Service standard benchmark(s)
STPIS	Service target performance incentive scheme
SUPP	State Underground Power Project
Technical Rules	'Technical Rules' are the Technical Rules for the network proposed by the network service provider (Western Power) and approved by the Economic Regulation Authority under chapter 12 of the Access Code.
TNSP	Transmission network service provider
UMS	Unmetered Supply
VCR	Value of customer reliability
WACC	Weighted average cost of capital
WAFarmers	WA Farmers Federation
Western Power Network	The Western Power Network is the portion of the SWIN that is owned by Western Power. The Western Power Network incorporates the integrated transmission and distribution networks. It is commonly referred to as 'the network' throughout this document.
WPAMP	Wood pole asset management plan
WPI	Wage Price Index

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AER final determinations for: Qld gas distribution	http://www.aer.gov.au/content/item.phtml?itemId=747106&nodeId=f8f4aa5eecb6b96b51b5fab14b393eed&fn=Access%20arrangement%20final%20decision%20-%20Envestra%20(Qld).pdf
AER final determinations for: SA electricity distribution	http://www.aer.gov.au/content/item.phtml?itemId=736345&nodeId=3554008b804b9019e53df0ac3f8b2313&fn=South%20Australian%20decision.pdf
AER final determinations for: SA gas distribution	http://www.aer.gov.au/content/item.phtml?itemId=747093&nodeId=3f36a6f3aaab7dc7aeb06f936fc5eb03&fn=Access%20arrangement%20final%20decision%20-%20Envestra%20(SA).pdf
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Access Arrangement Information Document Index

As per the Electricity Networks Access Code 2004 Guidelines for Access Arrangement Information (6 December 2010), requires a document index.

…the service provider must provide the Authority with a "document index" that identifies the following information for each document or group of documents

- Document title and, if applicable, document reference number/identifier
- Date of issue/publication
- A summary of the document's purpose and relevance (that is, the specific reason as to why the document has been provided)
- Page references to specific information of relevance within the document

Ref	Title	Issue Date	Purpose and relevance	Page Ref
A	Revenue model summary	29 May 2012	This is a summary of the revenue model outputs showing the total target revenue, price path and annual revenue caps (distribution, transmission and total revenue). The revenue model implements the calculations to determine the target AA3 revenue for the transmission and distribution systems in the Western Power Network.	All
B	Koncar – Voltage instrument transformers – instructions for use and maintenance	29 May 2012	Provides instructions for voltage instrument transformers. The instructions confirm that these assets have annual maintenance requirements and that the honeymoon effect is therefore not applicable.	All
C	Scale escalation model	29 May 2012	This model is used to develop recurrent operating expenditure forecasts for AA3.	All
D	SKM MMA – Review of Western Power's Energy and Maximum Demand Forecasting Methodologies and Forecasts	29 May 2012	Provides assurance around Western Power's demand forecasts.	All
E	Cost sharing methodology with System Management Markets	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All
F.1	CEG – Updated labour and materials escalation factors	29 May 2012	Outlines material and labour escalators used for Western Power's capital and operating expenditure forecasts.	All

Ref	Title	Issue Date	Purpose and relevance	Page Ref
F.2	Macromonitor – Updated forecasts of Labour Costs – Electricity, Gas, Water and Waste Services Sector – Western Australia	29 May 2012	Outlines forecasts of labour costs used for Western Power's capital and operating expenditure forecasts.	All
G	GHD – Report for Review of ERA Technical Consultants Report	29 May 2012	Provides an independent review of specific components of the Geoff Brown & Associates report commissioned by the Authority to determine if its conclusion on specific issues is reasonable.	All
H	Revised 2011 growth forecasts	29 May 2012	Outlines updates made to growth forecasts since the September 2011 submission.	All
I.1	Opex Scale Escalation Table	29 May 2012	Provides references to documents that describe the scale drivers adopted by Western Power.	All
I.2	Opex Efficiency Examples	29 May 2012	Provides specific examples of the efficiency of Western Power's largest operating expenditure programs.	All
J	Wedgewood White – Review of Operating Expenditure Efficiency Adjustment	29 May 2012	Provides an independent review of the reasonableness of the efficiency dividend imposed by the Authority.	All
K	Extract and restate of June 2010 and June 2011 Regulatory Financial Statements	29 May 2012	Outlines changes made to the regulatory financial statements for the 2009/10 and 2010/11 financial years.	All
L.1	NFIT Compliance Summary for Equip and Works Data Warehouse	29 May 2012	Provides additional information to demonstrate the compliance of the Equipment and Works Management Data Warehouse project with NFIT.	All
L.2	NFIT Compliance Summary for Ellipse 6.3	29 May 2012	Provides additional information to demonstrate the compliance of the upgrade of the Ellipse Enterprise Resource Planning software from version 5.2.3.8 to version 6.3 with NFIT.	All
L.3	NFIT Compliance Summary for NetCIS 3	29 May 2012	Provides additional information to demonstrate the compliance of the first phase of the NCIS project with NFIT.	All
M	AA1 NFIT compliance for Target Reliability	29 May 2012	Provides additional information to demonstrate the compliance of the Targeted Reliability Driven Automation and Reinforcement/40 Worst Feeders program with NFIT.	All

Ref	Title	Issue Date	Purpose and relevance	Page Ref
N	Calculation to support distribution project costs as a percentage of transmission project costs	29 May 2012	Outlines the historical relationship between the average cost of distribution works for corresponding transmission projects. The output is used in distribution capital expenditure forecasts.	All
O.1	SFG Consulting – Estimating beta: Reply to Draft Decision	29 May 2012	Provides an independent assessment of the approach used by the Authority to determine Western Power's equity beta.	All
O.2	Ernst &Young – Advice on Capital Asset Pricing Model for response to ERA Draft Decision	29 May 2012	Provides an independent assessment of whether the cost of equity determined by the Authority meets the requirements of the Access Code. The report also posits reasons why CAPM might understate the cost of equity and outlines alternative estimates for the cost of equity.	All
O.3	CEG – Estimating equity beta for Australian regulated energy network businesses	29 May 2012	Provides an independent assessment of the reasonableness of the Authority's determination on the equity beta. The report also provides an alternative estimate of the equity beta.	All
O.4	CEG – Western Power's proposed debt risk premium	29 May 2012	Provides an independent assessment of the reasonableness of the Authority's determination on the debt risk premium. The report also provides an alternative estimate of the debt risk premium.	All
O.5	CEG – Internal consistency of risk free rate and MRP in the CAPM	29 May 2012	Outlines an analysis of the relationship between the risk free rate and the MRP. The report also provides an independent estimate of the MRP and the risk free rate.	All
P	Ernst & Young – Tax liabilities for regulated revenue purposes	29 May 2012	Provides an independent assessment of the appropriate value for Western Power's opening tax asset base for AA3.	All
Q	Ernst & Young – Recovering the tax costs flowing from the receipt of capital contributions	29 May 2012	Reviews the reasonableness of both Western Power's and the Authority's approach to the recovery of tax on capital contributions.	All
R	Energy Forecast 11/12 – 16/17 – Energy & Customer Numbers	29 May 2012	Outlines Western Power's energy and customer number forecasts for 2011/12 and over AA3.	All
S	SKM - CBD 25 year strategy - Review of Planning Philosophies	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All
T	SKM - CBD 25 year strategy - Load Area Development Report	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All

Ref	Title	Issue Date	Purpose and relevance	Page Ref
U	SKM - Western Terminal Area Long Term Strategic Option	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All
V	Project list - Response to draft decision	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All
W	Current Wood pole management position	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All
X	Alliance Power & Data - Wood pole testing facility presentation to Energy Safety - 15 March 2012	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All
Y	Draft Business Case - Field Survey Data Capture Project	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All
Z	Explanation of negotiation process with distribution delivery partners (confidential)	29 May 2012	This information is confidential and has been supplied separately as confidential supplementary documents and form a part of this submission.	All