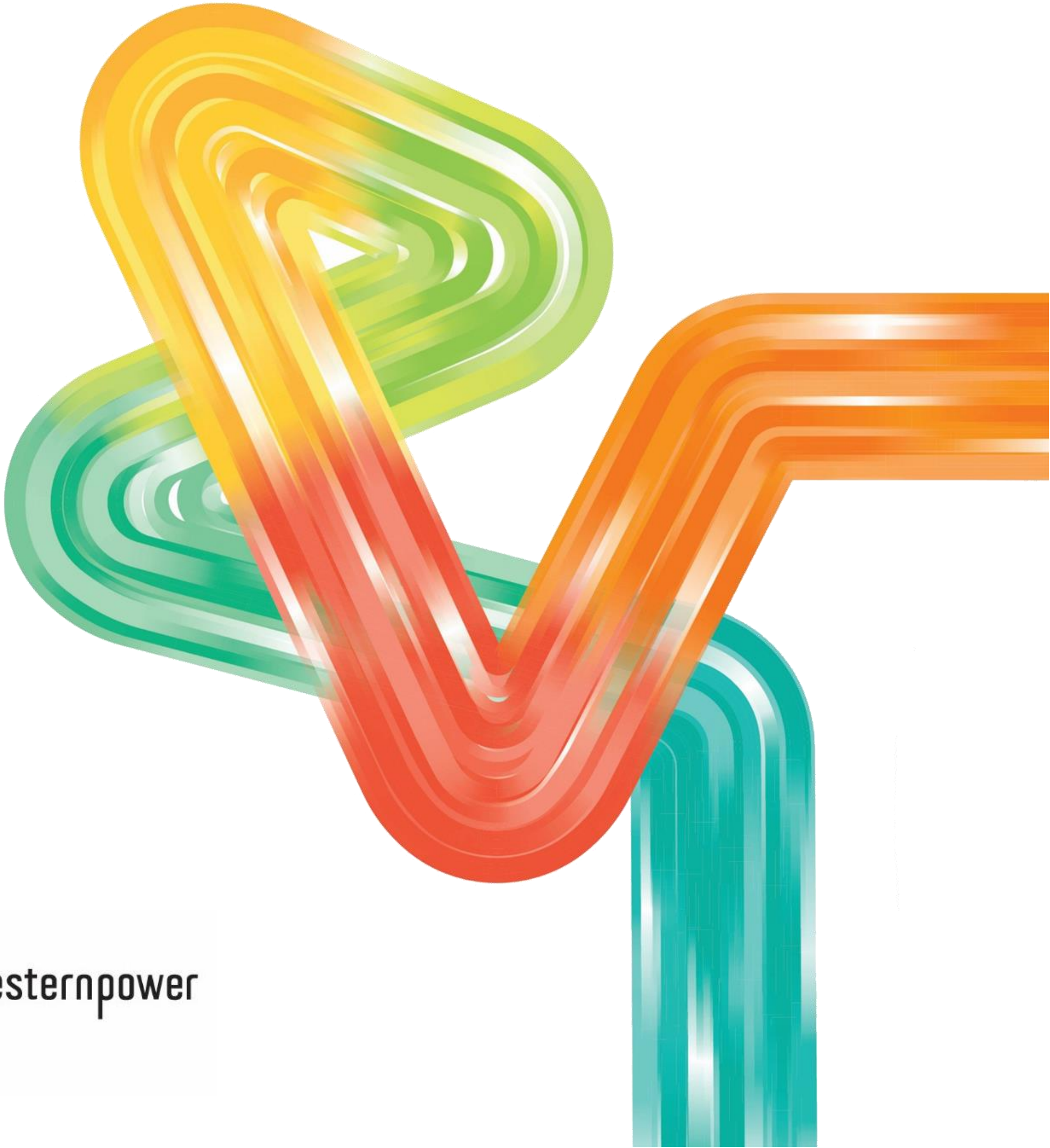
Framework and approach for Western Power's sixth access arrangement

Response to the ERA's issues paper

6 February 2026



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Executive summary

This submission outlines Western Power's response to the Economic Regulation Authority's (ERA) issues paper for the 'framework and approach' for the sixth access arrangement (AA6) that covers the period between 1 July 2027 and 30 June 2032.

Establishing an effective framework and approach is an important step in ensuring AA6 can accommodate rapid changes across the energy system. It will enable Western Power to continue to deliver safe, reliable and affordable network services in the long-term interests of the Western Australian community. As a government-owned corporation, Western Power plays a central role in supporting economic development, advancing the State's decarbonisation objectives, enabling renewable energy uptake and maintaining a resilient network for households and businesses.

Some elements of the access arrangement, such as the approach to revenue recovery and the design of certain incentive mechanisms, are determined through the framework and approach step before Western Power submits its full access arrangement proposal.

Western Power supports the ERA's decision to broaden the issues paper to cover improvements to the current access arrangement and the revision process, while also acknowledging the longer-term demands of an energy transition that will run well past 2030. Decisions taken for AA6 will shape the path to long-term success.

This expanded scope also recognises the exciting but challenging time at which the access arrangement review occurs. It reflects the shared need for regulatory frameworks that can adapt to the pace and complexity of the energy transition.

Western Power will face several major challenges over the AA6 period and beyond, including:

- Providing services to customers in an affordable manner in the face of significant investment drivers and broad input cost pressures.
- Maintaining a safe and reliable network as demand grows and changes, the change in types and locations of grid-scale generators, distributed energy resources expand, and climate-related risks such as bush fires, heatwaves and storms intensify.
- Investing in a timely way to support government decarbonisation targets, as well as to enable housing policies, and facilitate the development of new economic and industrial activities.

The energy transition is underway; the challenge is navigating when and how it unfolds while positioning Western Power to respond decisively and support the State's policy objectives. The goal for the access arrangement review, therefore, is to establish an access arrangement that:

- Enables the delivery of the Government and Western Power's long-term vision and development plans.
- Drives prudent and efficient expenditure decisions, across both capital and operating costs.
- Provides a robust and flexible cost-recovery framework, ensuring Western Power can recover prudent and efficient costs as uncertainties around energy demand, technology and policy settings continue to unfold.

The current access arrangement approach is not well suited to the scale of change ahead. It exposes Western Power, and its customers, to mounting financial risks, such as:

- Revenue recovery gaps, which arise because Western Power currently lacks a reasonable opportunity to recover the revenue approved in the access arrangement. External factors – for example, changes in customer and retailer behaviour driven by rooftop solar, behind-the-meter storage, electric vehicles and changing consumption patterns – can cause outcomes that diverge from reasonable forecasts, leading to under-recoveries that cannot be recovered in subsequent years.

- Cost recovery gaps, which arise when material cost changes occur during the term of the access arrangement that are beyond Western Power's control. These are not routine business risks, or matters of efficiency, but broader shifts, for example, in input prices, supply chain conditions, global geo-political developments, changes in environmental law and other regulatory changes or significant weather events. The existing adjustment process is narrow and slow-moving and increasingly mismatched to the type and pace of change shaped by the energy transition and other developments.

For customers, these risks can have tangible consequences. Sustained revenue inadequacy and cost recovery gaps reduce the organisation's financial headroom and flexibility. This can result in less certainty, deferral or de-prioritisation of planned investments. This, in turn, results in less efficient investment pathways, higher long-term costs for customers, and diminished safety, service performance, and reliability.

Over time, these pressures also increase Western Power's reliance on debt and diminish returns to Government, limiting the organisation's capacity to respond quickly and efficiently to emerging Government and community priorities. The inflexibility of the current framework further exposes customers to unavoidable and unexpected tariff movements and other risks as cost pressures build between five-year resets.

To address these risks and prepare the network for the transition ahead, Western Power proposes a package of improvements. These measures draw on best-practice regulation across Australia and internationally, and are designed to protect customers, support Government priorities and maintain Western Power's financial sustainability. The package includes:

- **A fair and stable revenue-recovery mechanism** that corrects under or over-recovery of approved revenue in subsequent years, so customers face predictable costs and pay over time.

- **Flexible tools to manage uncertainty in capital expenditure**, allowing the network to expand efficiently when demand is higher than forecast and return funds when it is lower.

- **A matching mechanism for operating expenditure** so costs can adjust when circumstances change unexpectedly and in ways beyond Western Power's control.

- **Clear, pre-defined triggers for mid-period revisions**, providing certainty about when and how relevant elements of the access arrangement can be updated.

- **A stable, technology-neutral tariff framework with targeted improvements** to support customer needs and avoid network costs.

- **Simple, transparent and achievable service performance measures** that maintain strong incentives for reliability while protecting customers.

- **Refinements to efficiency incentives** so customers and Western Power share genuine efficiency gains.

The remainder of this submission explores these issues and other matters raised by the ERA, and Western Power's proposals, in greater detail.

The ERA has placed emphasis on improving transparency around network plans and service performance. Western Power shares this focus: customer visibility, accountability and clear communication are core to how we operate, and substantial steps have already been taken to enhance the information available to customers. Further detail on the information we already publish, and the improvements underway – for example, around connection times estimates – is provided in section 3.

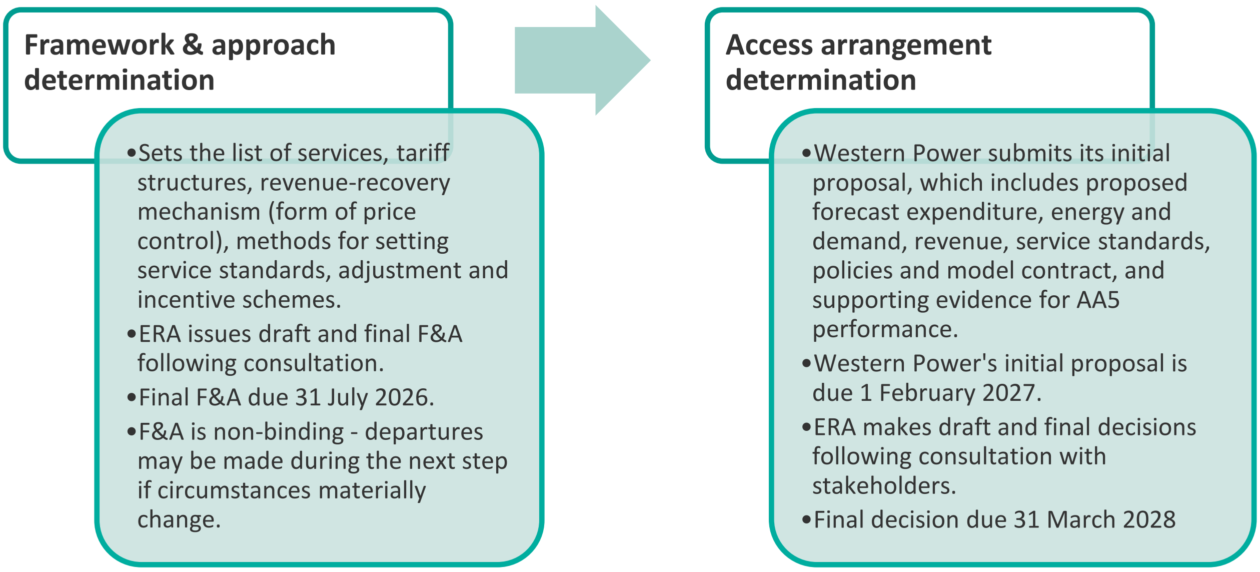
1. Overview

The access arrangement revision process unfolds in two broad stages that guide how Western Power's future regulatory period is shaped. The access arrangement, which is periodically reviewed to reflect changing customer and system needs, sets out the rules, expenditure incentives, service standards and revenue Western Power is permitted to recover for operating and investing in the network. The revision process is depicted in Figure 1.

The ERA's determination of the framework and approach (F&A) is the first step. The F&A sets out several important elements, such as the classification of services, the revenue recovery mechanism, and the application of incentive mechanisms.

The ERA initiated the F&A stage with the release of its issues paper on 1 December 2025, inviting stakeholder submissions by 6 February 2026. The ERA will publish its draft and final F&A decisions following stakeholder consultation, with the final F&A due by 31 July 2026.

Figure 1. Broad stages of the access arrangement revision process



The determination of the regulatory settings through the F&A then informs Western Power's initial proposal, due by 1 February 2027, and the ERA's subsequent determination for the AA6 period (1 July 2027 to 30 June 2032).

Western Power is required to submit its revised access arrangement proposal in accordance with the ERA's F&A determination. However, the F&A determination is non-binding. Both Western Power and the ERA may depart from it where there has been a material change in circumstances.

The proposal must support efficient investment, facilitate access to covered services, and reflect the long-term interests of consumers.

Western Power supports the ERA's view that the AA6 review comes at a pivotal time for the development of the South-West Interconnected System (SWIS), taking place in a broader environment of rapid and ongoing transformation of the energy sector. Establishing an effective F&A is therefore an important step to ensuring Western Power's AA6 can accommodate industry, market and regulatory changes to provide the network services required to meet the long-term interests of consumers.

In the issues paper, the ERA identifies eight broad issues for consultation. For each of these issues, Western Power has considered the impact on customers and the broader energy sector, and has proposed an approach that supports the State Electricity Objective (SEO).[1]

This document forms Western Power's response to the issues paper, and is structured as follows:

- the remainder of this section outlines the evolving energy, macroeconomic and policy landscape in which Western Power operates, the impacts of this on Western Power and its customers, and introduces the improvements that can be made to the access arrangement to address the uncertainty this creates for Western Power and customers.
- section 2 focuses in more detail on four key areas where changes to the regulatory framework could allow Western Power to better manage the uncertainties.
- section 3 covers the remaining issues highlighted by the ERA for consultation.

1.1 The AA6 review takes place against a backdrop of change

This AA6 review comes at a critical point in the energy transition, alongside a network expansion designed to address Western Australia's housing supply and support government policies aimed at strengthening the state's manufacturing base, creating jobs and future-proofing Western Australia's economy. AA6 will consider changes to the energy landscape, and the challenges and opportunities to meet our ever-changing customer and community requirements. It is imperative that AA6 sets Western Power and the Western Australian community up for success as the energy transition and technological, economic and demographic changes continue at pace.

Western Power's considerations in this paper reflect these drivers, alongside Western Power's obligations to ensure safety, reliability and efficiency of solutions employed, and our commitment to the community in connecting Western Australians' homes, businesses and essential community infrastructure to our distribution and transmission network.

Changing use of the Western Power Network

Western Power is seeing significant changes to the quantity of energy being used, and how it is being used, across its network. This includes changes to long-term trends of energy demand and peak load, with peak demand projected to grow faster than total energy volumes across future years.

Shifting customer behaviours, statewide decarbonisation initiatives, and rapid technological advancement across Western Australia's energy landscape are driving significant changes in how the SWIS network is used and operated, reflected through changes such as:

- Accelerating growth in rooftop solar photovoltaics (PVs) and large-scale renewables, which now account for more than one-third of all electricity generated, with renewables supplying up to 89 per cent of all demand at times.[2]

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1 The State Electricity Objective, set out in section 3A of the *Electricity Industry Act 2004*, is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity in relation to —
(a) the quality, safety, security and reliability of supply of electricity; and
(b) the price of electricity; and
(c) the environment, including reducing greenhouse gas emissions.
This objective is similar to the Access Code objective in section 2.1 of the Access Code, which relates to the promotion of efficient investment in, and efficient operation and use of, services of networks in Western Australia for the long-term interests of consumers.

2 See Australian Energy Market Operator, 21 November 2025, WA Electricity Consultative Forum presentation, p. 17.

- More than two in five homes now have rooftop solar PVs, with households in Western Power's network continuing to install rooftop PV systems at a steady rate of around 2,500 systems per month, but with the average size of PV systems increasing from below 7kW per system at the start of the AA5 period to between 8 and 10kW more recently.
- Completion of the Project Symphony virtual power plant pilot, which piloted the capability of distributed energy resources (DER) by households and businesses to be aggregated and coordinated to provide services to the network and wholesale electricity market.
- Following the first large scale battery installation in 2023, there is now more than 1,000 MW of large-scale batteries connected to the network and small-scale battery uptake is accelerating, supported by State and Commonwealth Government incentives.
- Connection of over 600 MW of new large-scale wind and solar generation to the Western Power network since 2020, including the first solar-battery hybrid project, with connection enquiries and development progressing on a substantial pipeline of new large-scale renewable projects.
- Retirement of around 400 MW of coal-fired generation since 2022, with a further 700 MW scheduled to retire by 2030 and several gas-fired generators approaching the end of their economic lives in the early 2030s.
- After almost a decade of relatively flat peak demand levels, peak demand on the Western Power network has grown strongly since the end of the COVID-19 pandemic. This strong growth is predicted to continue, placing increasing pressure on network capacity requiring several major capacity expansion projects and summer ready works to ensure the required network capacity is available to meet demand and to maintain network safety and reliability.
- The system is also experiencing record low demand periods as generation from rooftop PV systems is abundant during low load sunny shoulder seasons. These dips in demand create new challenges for keeping the network stable, such as managing excess generation and maintaining voltage stability and control.
- Commencement of Western Power's first major transmission expansions in over a decade, with the Clean Energy Link – North project in execution stage.
- Installation of standalone power systems to replace traditional network infrastructure in areas where it makes sense, with 406 systems now installed (with this figure expected to rise to 620 by the end of the AA5 period) and over 700 km of distribution lines removed (with more than another 100km expected to be removed prior to the end of the AA5 period).
- Other recent technological advancements including electric vehicles and behind-the-meter solutions, which increasingly offer our customers more choice to optimise their generation, storage and use of electricity, including for transport.
- Accelerated uptake of behind-the-meter residential batteries, driven by the introduction of the WA Residential Battery Scheme and the Australian Government's Cheaper Home Batteries Program. These initiatives will see up to 100,000 household batteries connected to the network. Since 1 July 2025, more than 20,000 behind-the-meter batteries have already been installed, materially increasing the amount of distributed storage interacting with the network.

In some of these areas, there is substantial uncertainty in the forecasts of future uptake and use. For example:

- A range of forecasts around electric vehicle (EV) uptake (there are a range of CSIRO forecast scenarios across years).[3]
- Variances around electrification rates and population growth (with WA Tomorrow 12 using a range of scenarios).[4]
- Significant uncertainty around forecast uptake of distributed batteries (see the case study below).

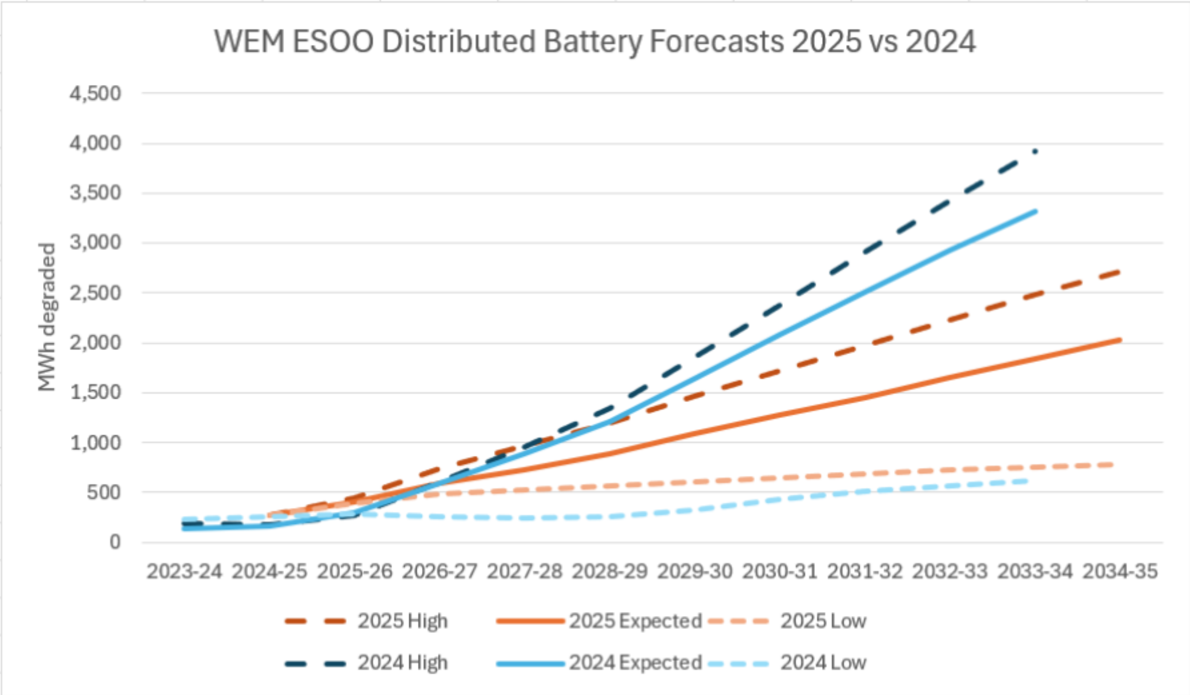
In addition, the complexities regarding these forecasts at a time of fundamental change in the electricity system means that even 'state of the art' forecasting faces challenges with inflexion points in the use of the network, energy transition and technology change.

3 See: Graham, P., Mediwaththe, C. and Green, D. 2025, *Electric vehicle projections 2024*. CSIRO, Australia. Prepared for AEMO.

4 See: Department of Planning, Lands and Heritage, 2025, *Western Australia Tomorrow 12 Population Forecasts*.

Case study: Forecasting uncertainty in the uptake of distributed batteries

In both its 2024 and 2025 WEM Electricity Statements of Opportunities, AEMO has forecast the capacity of distributed batteries in the SWIS, in both cases showing growth over the outlook period.[5]



However, Western Power notes the significant variances between the two sets of forecasts, in particular:

- In the 'expected' scenarios, the 10-year compound annual growth rate dropped from 37% in the 2024 forecast to 22% in the 2025 forecast.
- The difference in the annual forecasts (i.e. between the 2024 forecast and the 2025 forecast) in the 'expected' scenarios starts with increases in the first two years but then decreases, dropping to a 44% fall by the last two years of the shared outlook period (i.e. 2032-33 and 2033-34).

Given the early stage in development, some fluctuation would be expected, but the amount of variability in these forecasts makes long-term investment decision-making very challenging.

AEMO acknowledged the uncertainty, suggesting that the differences recognise cost uncertainty, the higher number of existing installations in 2025, and anticipated rising battery subsidy support, particularly in the 'expected' and 'high' scenarios.

An evolving economic, policy and regulatory environment

Western Power has started a decade of transformative activity highlighted by network expansion activities resulting from decarbonisation, increasing electrification, industry growth and successive growth in peak demand. In addition to network expansion, ongoing maintenance is required to support a highly utilised and aging network, including preparing for network resiliency driven by climate change. Over the next decade,

5 See: AEMO, *2025 Wholesale Electricity Market Electricity Statement of Opportunities*, Appendices, June 2025, A.2.3.2.

Western Power expects to undertake the largest ever capital and operating expenditure program in the network's history.

Much of this expansion is driven from Government policy, as highlighted by the release of the SWIS Transmission Plan in September 2025.[6] This Plan highlights the proposed approach – via the Clean Energy Link (CEL) program – to expand the 'backbone' of the SWIS to enable the integration of large-scale renewable energy to enable the retirement of coal, and establish new transmission corridors to unlock further decarbonisation opportunities across the SWIS. The Plan also highlights the enablement of strategic industrial areas (SIAs) aligned with the Government's Diversify WA policy as a core policy enabler – driving industries like clean energy, advanced manufacturing and critical minerals processing.[7]

Additionally, transformation of the distribution network is being guided by the WA Government's Distributed Energy Resources (DER) Roadmap, including major policy initiatives such as the Residential Battery Scheme. Building on the success of the Project Symphony pilot, Project Jupiter is now underway to provide the platform for scalable integration of customer-owned DER and a pathway for customers to participate in, and benefit from, the energy transition. By 2028, all new DER connecting to the network will have the opportunity to participate in a virtual power plant, marking a shift from passive connections to active, system-integrated customer-owned DER.

The scale of the WA Government's Residential Battery Scheme is significant in this context. With more than $400 million committed to support up to 1 GW of behind-the-meter storage, it represents one of the largest residential battery programs in Australia. By accelerating access to household batteries, the scheme increases the amount of flexible storage interacting with the distribution network.

Concurrently, Western Power is preparing for unprecedented demand growth driven by accelerated housing development, population growth, with emerging medium to large-scale data centre loads also expected to contribute. Western Power is a central partner in WA's housing growth agenda and other priority initiatives delivering critical power infrastructure.

This evolving operating environment is reshaping both our business and cost structures. As we enter the AA6 period, this rapidly changing landscape requires us to address increasing cost uncertainty and adapt our approach to remain responsive and resilient.

There are several examples of how this changing operating environment has impacted Western Power from both a cost and delivery perspective in the recent past. These include:

- Traffic management regulations obligations: Western Power has experienced significant cost increases in relation to traffic management during the AA5 period, driven by changes to the Main Roads WA traffic management scheme. These changes were unknown at the time of AA5 submission and were not something Western Power could have reasonably foreseen and forecasted in AA5. The corresponding cost increases have been priced into competitive market rates for traffic management services. The financial impact to Western Power of the changes is material, estimated at $6.4M up to financial year 2025 (FY25), and is beyond Western Power's ability to manage or control.
- Housing: In the 2024-25 Mid-year Review, the WA Government committed $400 million for enabling infrastructure for housing, to help deliver thousands of new homes by investing in water, wastewater and electricity infrastructure in priority locations in Perth and regional WA.[8] This funding is in addition to significant funding by the Federal and WA Government across a range of initiatives to increase housing in WA, which will contribute to the growing levels of new connections to the Western Power

[6] Department of Energy and Economic Diversification, *South West Interconnected System Transmission Plan, Powering our State's Future*, September 2025.

[7] Department of Energy and Economic Diversification, Diversify WA economic development framework, 2025.

[8] See: WA Government, *$400 million fund to unlock housing and land supply*, 2024-25 Mid-Year Review.

network and associated network development activities. This is expected to have an impact on the overall deliverability of Western Power's capital expenditure program, with works being programmed to ensure delivery in accordance with Government priorities.

- Made in WA: As part of the 2025/26 State Budget, the WA Government announced funding for several "Made in WA" initiatives that Western Power has a role in delivering. These include $25 million for the local manufacture of transmission towers and components, $584 million for the development of Clean Energy Link – North and Regans Ford terminal to enable the connection of more renewable generation north of Perth and several investments to support the development of new economic activity, including in SIAs and the Westport development, which will require additional electricity infrastructure.[9]
- Ministerial Direction for strengthening local industry participation in procurement activities: Western Power is required to prioritise WA suppliers for all procurements above the Western Australian Industry Participation Strategy thresholds, adopt a "value for money" approach beyond lowest cost, and include local content requirements in tenders. It mandates local market testing for contracts over $10 million, quarterly reporting, and an "if not, why not" stance when WA suppliers are not engaged, while working closely with the Department of Energy and Economic Diversification and a Joint Advisory Committee to maximise local sourcing and economic benefits.

Increasing supply chain pressures

Alongside policy changes and changes to the use of the network, there are increasing supply chain pressures impacting the Western Power network. This includes local impacts on key raw materials and construction costs. Western Power's analysis has shown that AA5 unit cost increases exceed the Consumer Price Index.

Analysis has also shown that from FY21 to FY26 there were increases in costs per emergency response incident as well as unit rate costs for distribution vegetation cutting. Unit rates for vegetation inspections and maintenance, which are primarily externally delivered, have increased between 12 and 20 per cent from FY21 – the year used to determine AA5 cost allowances.

These supply chain pressures sit against a backdrop of global supply chain pressures, geopolitical uncertainties and technological change as the global energy transition and demand for the associated materials, technologies and skilled workforce continues. These pressures include those on globally required materials such as electrical-grade steel and skilled technicians such as qualified electricians.

Significant weather events

Extreme weather events also place considerable pressure on the network and generate additional costs. For example, on 16 January 2024 a severe thunderstorm passed over the Western Power network resulting in over 43,000 customers losing power, predominantly in the Wheatbelt and Perth Hills areas. On 17 January 2025 the 220kV transmission line that supplied power to customers in the Goldfields and parts of the Wheatbelt was damaged during lightning activity from a second storm front, resulting in an additional 23,000 customers being without power. The two storm fronts resulted in nearly 70,000 customers without power for an average of nearly 23 hours. The estimated cost of the incident stands at approximately $13.5m.

More recently, between 13 and 15 December 2025 Western Power experienced storms, lightning and bushfire activity around the Midwest and Wheatbelt resulting in damage on the transmission and distribution network. This was the fourth worst event in terms of customer reliability since records began, compounded by Total Fire Ban days, resulting in 168,044 customers without power for an average of nearly 11 hours.

9 See: WA Government, *Made in WA – unlocking future growth*, Western Australia State Budget 2025-26.

Intensifying heatwave conditions across the SWIS are continuing to drive sharp summer peak demand- spikes, for example, due to the growing reliance on air-conditioning during extreme temperature events. The 2024/25 summer period has already demonstrated the scale and pace of this shift. On Monday, 20 January 2025, the SWIS recorded a new maximum operational demand of 4,486 MW during the 18:30 interval, surpassing the previous record of 4,233 MW set in Q1 2024. Earlier that same day, underlying demand reached an unprecedented 5,385 MW at 13:15, eclipsing the December 2024 record of 5,262 MW.

Further policy changes are expected

This rapid economic, policy and regulatory development is likely to continue into, and beyond, the AA6 period. Potential changes for the AA6 period which could have cost, or revenue recovery, implications for Western Power include:

- Further initiatives aligned with the Government's strategic priorities, including housing, decarbonisation and 'Made in WA'.
- A fundamental review of the Access Code identified as part of the Energy Transformation Strategy.[10]
- The proposed new transmission funding mechanism for the connection of new generation and large loads.[11]
- Formalisation of Western Power's role as Distribution System Operator, enabled by the *Electricity Industry Amendment (Distributed Energy Resources) Act 2024*.
- Changes to roles, responsibilities and standards for power system security and reliability, including proposed system strength obligations, arising from the ongoing review by the Coordinator of Energy.[12]
- An increasingly complex regulatory environment, such as recent changes to federal environmental laws (*Environment Protection and Biodiversity Conservation Act 1999* (Cth)).

Customer uncertainty and cost pressures

As noted in the issues paper, Western Power's customers are also experiencing uncertainty in the energy transition. Many consumers are embracing new energy technologies but remain uncertain about how they can best be used and are seeking further information from Western Power and retailers about their options. Energy price levels and their predictability are also primary concerns – both for businesses who are experiencing increasing energy costs, and households facing a range of cost-of-living pressures.

In community working groups being conducted by Western Power in support of the AA6 submission, over 30 per cent of customers ranked affordability as their top priority and over 50 per cent of customers had affordability in their top three priorities overall.

Notwithstanding these concerns, the community expressed support for reasonable bill increases where the benefits are clear and meaningful, including in cases where those benefits accrue to others.

In preparing for AA6, Western Power has a strong focus on ways to manage uncertainty and its impacts on both Western Power and customers, and on directing investment to customer identified- priority areas where the benefits are clear, particularly in light of the ever-present concern about affordability for customers, as discussed below.

10 Energy Policy WA, Leading Western Australia's brighter energy future, Energy Transformation Strategy, 2021, pp. 16 to 21.
11 Energy Policy WA, New and improved transmission funding model to support Western Australia's energy transition, 2025.
12 Energy Policy WA, Power system security and reliability standards review, 2025.

1.2 These changes present significant risks under the existing access arrangement

The current application of the regulatory framework does not provide Western Power with effective tools to manage this level of change and uncertainty without impacting the financial sustainability of the organisation or impacting outcomes for customers. There are two key issues:

- a risk that Western Power is unable to recover the revenue allowed in the access arrangement
- cost recovery gaps that manifest when costs that are unforeseen or discounted at the time of the most recent access arrangement review arise.

In practice, Western Power is unable to recover its allowed revenues

The current revenue recovery mechanism contained in the access arrangement does not allow Western Power an opportunity to recover in full the target revenue that it is permitted.

Under this revenue recovery mechanism, tariffs are set each year at levels designed to allow for the recovery of that year's allowed revenue. However, under the terms of the access arrangement, the customer numbers, energy volumes and other charging parameters used in tariff setting must be consistent with forecasts approved by the ERA in the access arrangement decision.

As explained further in section 2.1, it is increasingly challenging to accurately forecast customer numbers, energy volumes and splits across different customer groups over a five-year period, particularly when these forecasts must be prepared around two years in advance of the five-year regulatory period to support the access arrangement revision process. In addition, there is no adjustment for any under-recovery or over-recovery of actual revenue compared with target revenue from previous years. Therefore, to the extent that revenue is under-recovered in one year as a result of forecasting challenges, it is permanently foregone.

This has been borne out in practice, with Western Power suffering a sustained under-recovery across the AA5 period, which currently stands at around $217 million (cumulative, present value as of 2027). This is in addition to an under-recovery of $176 million over the AA4 period.

While these risks have always been present, the growing uncertainty in Western Power's operating environment is intensifying them and their consequences. Western Power therefore considers that the current revenue-recovery mechanism is no longer fit-for-purpose in providing a reasonable opportunity to recover allowed revenues.

The access arrangement does not adequately allow for unexpected costs to be recovered

The current access arrangement can also lead to cost recovery gaps arising when costs that were unforeseeable or were foreseeable but not allowed for at the time of the access arrangement review (due to insufficient certainty), eventuate. There are insufficient mechanisms in the access arrangement to allow for Western Power's revenues to be adjusted over the course of the access arrangement period given the range of increasing uncertainties set out in section 1.1, above.

These additional costs can manifest as both capital expenditure and operating expenditure, although Western Power is currently experiencing a broader range of issues associated with operating expenditure in terms of both:

- increasing volumes and/or unit costs related to foreseeable costs, where there is no mechanism to recover the additional costs; and

- new obligations with operating expenditure implications where there is no effective way to pass these new costs on.

As an illustration, Western Power has experienced a substantial increase in operating costs, with four key drivers:

- Primary fault response – where faults have increased through heightened numbers of bushfires, storms, heatwaves and cyclones, and where unit costs have also increased as a result of policy changes and supply chain pressures. Network fault responses are reactive in nature and therefore difficult to predict in terms of volume, timing and severity.

- Emergency response generators – due to the deployment of additional emergency response generators to mitigate the risk of long supply interruptions in the worst performing regional areas of the network.

- Vegetation management – where allowed operating expenditure did not include sufficient funds to cover an increase in unit rates and a volume of works, beyond what had been allowed.

- Silicone treatment – where the volumes used in the baseline year in the access arrangement were lower than usual following a safety incident. A return to more usual volumes, following a safety investigation, presents an ongoing, and unavoidable cost pressure for Western Power.

These issues are not unique to Western Power and are being experienced across Australia and globally. The Australian Energy Regulator (AER) has highlighted significant increases in operating expenditure for both distribution and transmission network service providers in the National Electricity Market. Rising operating expenditure has been a consistent theme across recent AER transmission and distribution revenue determinations, reflecting a combination of climate related events, higher input costs and the growing complexity of operating modern networks.

The AER's analysis shows that these higher operating costs are directly contributing to lower measured productivity across the sector. In 2024, productivity in the electricity distribution industry fell by 3.8 per cent compared with the previous year, with increased operating expenditure contributing – 3.9 percentage points to the result (partially offset by a +0.1 percentage point- contribution from other inputs and outputs).[13]

Similarly, transmission industry productivity fell by 3.2 per cent in 2024 as compared to the previous year. Increasing operating expenditure was again the primary driver of the productivity decline, although the AER noted that a range of different pressures impacted on operating expenditure for different transmission businesses.[14]

The ERA set Western Power's current revenue allowance using an assumed annual operating expenditure productivity improvement of 2 per cent. By contrast, in recent determinations for electricity distribution and transmission networks, the AER has applied a materially lower benchmark of 0.5 per cent. The application of this higher productivity factor reduced Western Power's operating expenditure for AA5 by approximately $100 million.

Importantly, the impact of this reduction is not static. The tightened operating expenditure will reduce the carryover amounts under the gain sharing mechanism, which will adjust allowable revenue for the AA6 period.

While these productivity trends suggest a longer-term shift towards upward cost pressures on operating expenditure, it does also demonstrate the need for the access arrangement to be capable of adjustment mid-

13 AER, *Annual Benchmarking Report*, Electricity distribution network service providers, November 2025, p. 7.

14 AER, *Annual Benchmarking Report*, Electricity transmission network service providers, November 2025, p. iii.

period to allow for the recovery of uncontrollable and unforeseen (but prudently and efficiently incurred) costs.

1.3 Improvements can be made to the AA5 arrangements to manage the uncertainty

There are tools and mechanisms available that could be incorporated into the access arrangement to mitigate and reduce the risks highlighted above, to ensure that customers get the service they tell us they want while ensuring the ongoing financial sustainability of Western Power.

Western Power is proposing a holistic suite of measures to address the risks identified both in relation to revenue recovery and in response to unexpected cost changes. These proposals are informed by regulatory approaches in Australia and in other jurisdictions.

This package enables the following:

- **Ensuring customers pay the right amount over time and that Western Power can maintain financial stability**. To achieve this, Western Power proposes changing the revenue-recovery mechanism so any under-recovery (or over-recovery) of revenue is corrected in subsequent years (see section 2.1). This approach is consistent with the regulatory practice both in Australia and internationally.
- **Ensuring Western Power can efficiently expand the network when demand is higher than forecast, and return funds when demand is lower**. Western Power proposes expanding the existing uncertainty management mechanism for capital expenditure, i.e. the investment adjustment mechanism, to include all growth-related (that is, capacity expansion and customer-driven) capital expenditure for both transmission and distribution (see section 2.2).
- **Ensuring operating costs can adjust when circumstances change unexpectedly**. Western Power proposes introducing an equivalent uncertainty management mechanism for operating expenditure, which would include operating expenditure associated with capital expenditure projects that are included within the scope of the investment adjustment mechanism, and potentially other categories of operating expenditure, such as non-network solutions (see section 2.3).
- **Greater certainty about when and how the access arrangement can be updated during the period.** Western Power proposes providing greater regulatory certainty by specifying 'trigger events' for mid-period revisions and limiting any revisions to the consequences of those events (see section 2.4).
- **Maintenance of a stable and effective tariff framework while making targeted improvements**. Western Power proposes retaining its existing technology-neutral and cost-reflective tariff structure. Western Power is initially proposing three changes to reference tariffs for the AA6 period (see section 3.2).
- **Transparent, achievable service performance expectations while maintaining strong incentives for improvement.** To achieve this, Western Power proposes using simple measures of actual service performance, e.g. observed average reliability performance, for use in the service standard adjustment mechanism. This mechanism checks that service quality stays at expected levels while Western Power works to be efficient and adjusts revenues, if service levels fall. Separate compliance checks prevent unreasonable deterioration, and expenditure allowances support creating step changes in performance, where needed – for example to improve regional reliability (see section 3.3).
- **Maintaining fair efficiency incentives while protecting customers and Western Power from excessive risk.** To achieve this, Western Power proposes refining the gain sharing mechanism, which shares efficiency gains (or losses) with customers by carrying forward savings (or losses) for a set

period. Because the current mechanism is affected by cost changes unrelated to efficiency, Western Power proposes capping carry forward- amounts and removing uncontrollable costs from the mechanism (see section 3.5).

These proposals are set out in detail in sections 2 and 3 of this submission.

The adoption of these approaches will strengthen Western Power's ability to manage uncertainty and deliver for customers affordably and sustainably. Greater revenue certainty during the transition is essential to maintaining service delivery and ensuring Western Power can progress its investment program efficiently, without the need for re-sequencing or deferral. This, in turn, supports more reliable and efficient long-term outcomes for customers and the State, and provides Western Power with the flexibility needed to respond to emerging priorities as the energy transition accelerates and in the face of other external factors as discussed above.

The table below summarises Western Power's responses to the eight specific issues highlighted by the ERA and provides guidance as to where further information can be found in this submission.

Table 1. Western Power's responses to the eight issues raised by the ERA

#	ERA issue	Summary of Western Power's response
1.	The ERA is seeking stakeholder views on their expectations for Western Power's AA6 proposal.	Western Power intends to put forward a proposal for an access arrangement that will facilitate the delivery of Western Power's long-term vision and plans for the development of the network. It will be clear and transparent, customer-centric, promote prudency and efficiency in expenditure, and allow Western Power to recover this expenditure in a more robust and flexible manner than at present to deal with the changes inherent in the transformation. More information can be found in section 3.1 and throughout this submission. Western Power supports additional transparency measures for local areas where there is a net benefit for customers. However, as discussed in this paper, this is sufficient as a first step. Any additional transparency metrics must be measured in ways that do not inhibit Western Power responding to new or emerging network issues in an agile manner.
2.	What changes are needed for the current list of reference services and tariff structures to support new technologies and energy models, while providing incentives that will reduce overall costs to consumers.	Western Power has identified two issues with its existing metered demand tariffs for large commercial customers, as well as an error in the pricing structure of its Electric Vehicle charging tariff. Details of the changes proposed by Western Power to address these issues can be found in section 3.2.1.
3.	The ERA is interested in stakeholder views on what changes may be needed to metering services to reflect that most customers have advanced meters.	Western Power would welcome feedback from stakeholders and further discussion and engagement with the ERA on this matter. As many customers move to advanced meters, there will be a decrease in the demand for manual services, which may have consequences for manual-read charges. Further information can be found in section 3.2.3.

#	ERA issue	Summary of Western Power's response
4.	The ERA is interested in stakeholder views on improvements that could be made to the framework for payments for services (including new and upgraded connections) that are not included in network tariffs.	Western Power will seek stakeholder feedback, work with the ERA and develop improvements, where required. Also, as highlighted in our response to issue 6, recent changes have led to greater transparency and improved timeframes in the connections process.
5.	The ERA is interested in stakeholder views on setting disaggregated service standards for reliability and improving service standards relevant to business procedures.	Western Power is proposing refinements to the service standard adjustment mechanism to ensure it operates as intended. Combined with the forthcoming regional reliability plan and the significant transparency already provided – particularly in reporting regional reliability performance – these measures will support customers by maintaining and improving reliability while enhancing visibility of service outcomes. See section 3.3.1 for further discussion.
6.	The ERA is interested in stakeholder views on what improvements could be made to Western Power's connection processes and whether additional mechanisms are needed to incentivise Western Power.	Since mid-2023, Western Power has implemented improvements to its connections process for major customers, and this has resulted in reduced timeframes for new connections. Western Power has also commenced the implementation of improvements to the process for connections by residential and small business customers. Western Power plans to roll out further improvements over the next three years. Western Power would welcome further detail on any options being considered by the ERA. Further detail is included in section 3.4.

#	ERA issue	Summary of Western Power's response
7.	The ERA is interested in stakeholder views on changes to the price control and incentives and adjustment mechanisms that would: • Improve Western Power's accountability for delivering the access arrangement and complying with it. • Deal with uncertainty while maintaining incentives for efficient expenditure and accountability for Western Power to deliver. Ensure the most efficient option is chosen regardless of whether it is a capital or non-capital costs.	Western Power is proposing a suite of changes to deal with uncertainty and promote efficiency, including: • A change to the form of the price control to allow for the correction of prior year under- or over-recovery of revenue. • An expansion of the coverage of the investment adjustment mechanism and introduction of an equivalent mechanism for non-capital costs. • The introduction of caps on the level of surpluses and deficits carried forward to the next access arrangement period under the gain sharing mechanism, to mitigate risks to both consumers and Western Power. More information on these proposed measures can be found in sections 2.1, 2.2, 2.3 and 3.5, respectively.
8.	The current regulatory framework includes a broad range of provisions that Western Power and the ERA can use to manage uncertainties. The ERA is interested in stakeholder views on whether additional guidance about the use of these provisions in needed in the framework and approach.	Western Power considers that the access arrangement should be modified to explicitly identify the circumstances in which it would be appropriate for the process for making mid-period revisions to be instigated. The scope of any revisions made should be limited to only the consequences of the changed circumstances. This issue is discussed in section 2.4.

2. Key matter for AA6

The previous section described the increasingly uncertain operating environment that Western Power is faced with and introduced the developments to the access arrangement that are required to meet these challenges.

This section of the submission covers four key areas where changes could allow Western Power to better manage the uncertainties arising, in the long-term interests of consumers:

- improving revenue certainty through changing the form of price control
- expanding the coverage of the existing uncertainty management mechanism for capital expenditure (the investment adjustment mechanism)
- introducing a new uncertainty management mechanism to mitigate risks associated with uncertain operating expenditure
- bringing greater clarity to the process for the making of mid-period revisions to the access arrangement.

These four areas relate to matters raised by the ERA in its issue 7 (in part) and 8, which are set out below.

Issues raised by the ERA in its issues paper

7. The ERA is interested in stakeholder views on changes to the price control and incentives and adjustment mechanisms that would:

- *Improve Western Power's accountability for delivering the access arrangement and complying with it.*
- *Deal with uncertainty while maintaining incentives for efficient expenditure and accountability for Western Power to deliver.*
- *Ensure the most efficient option is chosen regardless of whether it is capital or non-capital costs.*

8. The current regulatory framework includes a broad range of provisions that Western Power and the ERA can use to manage uncertainties. The ERA is interested in stakeholder views on whether additional guidance about the use of these provisions is needed in the framework and approach.

2.1 Improving revenue certainty through changing the form of price control

Western Power proposes that the form of price control in the access arrangement should be amended, as follows:

- A 'standard' revenue cap form of price control should be applied, such that reference tariffs would be set to recover the target revenue in a given year, with a correction made for the under or over-recovery of target revenue in prior years.
- To manage the potential impact on customers, a 'side constraint' should be introduced, which in broad terms, would constrain the annual change for each tariff to be no more than an agreed percentage.

The reasons for making these proposals are explained below.

2.1.1 Risks associated with the current modified revenue cap

Under the access arrangement that applies in the AA5 period, Western Power is subject to a 'modified' revenue cap. When Western Power updates its tariffs each year, it aims to ensure that the forecast revenue from those tariffs is equal to the target revenue determined through the price control formula.

There is no adjustment for any under-recovery or over-recovery of actual revenue compared with target revenue from previous years. In addition, the customer numbers, energy volumes and other charging parameters used in tariff setting must be consistent with forecasts approved by the ERA in the access arrangement decision – that is, up to five years in advance of the pricing process.

The effect of the current mechanism is to expose Western Power to demand, and hence revenue, risk rather than providing Western Power with a more certain level of revenue.

In the view of the ERA, this exposure to demand risk "provides incentives for Western Power to develop more efficient tariffs, encourage the connection of new customers and offer services that meet user requirements and benefit Western Power through increased revenue, reduced costs or a combination of both".[15]

While Western Power acknowledges the intent for the incentive properties of the current revenue cap to encourage the connection of new customers, it considers that a range of factors undermine these intended outcomes and create significant risks, with the potential for adverse impacts on customers.

Western Power's revenue recovery is largely driven by the volumes of energy transported across its network. However, its costs are primarily linked to peak demand conditions. While forecasts can be developed to estimate the balance of costs, energy volumes, demand and demand profiles over customer segments, and services and tariffs over a five-year period, Western Power's underlying cost structure does not relate in a simple, uniform and predictable way to either energy volumes or customer numbers in a way that would support the ERA's logic.

In reality, as outlined below, forecasting future energy volumes and customer growth involves a high degree of uncertainty. The timing and scale of new connections or changes in consumption patterns are largely outside Western Power's control, making any revenue uplift from higher-than-expected volumes more akin to chance than a reliable planning assumption. This uncertainty significantly complicates efforts to ensure that target revenues can be recovered over the regulatory period.

As noted above, the ERA has also suggested that the modified revenue cap should incentivise Western Power to develop more efficient tariffs. Over time, Western Power has been developing tariffs that are more reflective of costs and customers have been transitioning onto these tariffs where their retailer elects to do so. This, however, is necessarily a gradual, evolutionary process, with 57 per cent of Western Power's customers still remaining on flat volumetric tariffs at the present time.

It should be noted that Western Power does not have a direct relationship with customers and can only attempt to influence retailers to set efficient retail tariffs. There is no requirement that retailers pass on the signals given by efficient network tariffs to encourage behaviour change.

Western Power's ability to recover its target revenue each year is further constrained by the requirement in the access arrangement to set tariffs using parameters consistent with the forecasts of customer numbers and energy volumes approved by the ERA in the access arrangement at the start of the five-year period.

While the accuracy of these forecasts has tended to be relatively good over time, it is intrinsically difficult to forecast customer numbers and energy volumes to this level of detail over a five-year period. Customers' energy demand will be affected by several factors, including the installation and usage of sources of demand

15 ERA, *Framework and approach for Western Power's sixth access arrangement review*, issues paper, 1 December 2025, p. 14.

(such as air conditioners and electric vehicle chargers) as well as of potential substitutes to network-supplied electricity (such as solar PV panels and insulation). With various factors driving energy consumption up (e.g. population growth, electrification, continued installation of air conditioning) and down (e.g. price pressures, installations of rooftop PV and batteries along with energy efficiency improvements), the uncertainty in forecasting demand is only increasing.

In recent years, the approved energy volume and customer number forecasts have tended to slightly under-estimate actuals. However, the distribution of this across the customer groups defined in the forecast has not been even, with the growth being primarily in the residential customer segment, offset by lower than forecast consumption by industrial and commercial customers. With no mechanism for shifting volume across customer groups, the overall effect has been a sustained under-recovery.

Western Power is also of the view that the risk is likely to be asymmetrical. Any sustained over-recovery above Western Power's target revenues (and above any associated additional costs), would likely attract regulatory and political scrutiny, and may prompt potential intervention. Western Power is not compensated for this asymmetric risk through its allowed cost of capital.

Taken together, these factors mean that, in practice, the modified revenue cap does not provide Western Power with an appropriate opportunity to recover its target revenues. Where revenue recovery falls short while the cost base remains fixed or continues to rise, the result is reduced dividends and, ultimately, an increase in debt. Over time, this will produce a compounding effect, where revenue shortfalls drive increased costs (in the form of the increased costs of servicing debt), which then further reduce the funds available to Western Power to deliver essential work.

Over time, these pressures translate into real impacts for customers. Persistent revenue shortfalls and growing gaps in cost recovery constrain Western Power's financial capacity and operational flexibility. This, in turn, results in diminished safety, reliability, and service performance, less efficient investment sequencing, and higher long-term costs for both customers and the State.

2.1.2 Moving to a revenue cap would reduce risk and support the transition

To address the risks set out above, Western Power is proposing that the form of price control for the AA6 period should be a standard revenue cap. Under this approach, reference tariffs would be set to recover the target revenue each year, with a correction made for the under or over-recovery of target revenue in prior years.

A standard revenue cap would provide greater certainty to Western Power as to the level of revenue that could be recovered over the course of the access arrangement period. This would provide certainty over the financial deliverability of the planned investment program and avoid pressures being put on Western Power's cashflows and debt levels.

This certainty would be in the long-term interests of consumers, in that it would allow Western Power to appropriately invest in, and maintain, its network in order to provide reliable and secure supply. By allowing Western Power to efficiently finance its business, unnecessary future costs of servicing debt can be avoided.

Western Power notes that the AER has applied standard revenue caps for distribution and transmission businesses in the National Electricity Market (NEM) for over 10 years (see box, below).

Case study: The use of revenue caps in the National Electricity Market (NEM)

Distribution and transmission businesses across the NEM (and in the Northern Territory) are regulated by the AER.

Under the National Electricity Rules, the AER is required to regulate transmission businesses through the use of revenue caps. In contrast, the AER is granted discretion in relation to distribution businesses being permitted to regulate them using a variety of control mechanisms, as follows:[16]

- a schedule of fixed prices
- caps on the prices of individual services
- caps on the revenue to be derived from a particular combination of services
- tariff basket price control
- revenue yield control
- a combination of any of the above.

However, despite this permitted flexibility, the AER has standardised its regulation of distribution businesses to also make universal use of revenue caps. New South Wales, South Australia and Victoria were formerly regulated using tariff basket price controls (weighted average price caps), and transitioned to revenue caps from 2014, 2015 and 2016, respectively. The Australian Capital Territory was formerly regulated using a revenue yield cap (average revenue cap), transitioning to a revenue cap from 2019.

In explaining this shift, the AER noted its view "that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient cost, better incentives for demand side management, less reliance on energy forecasts and further alignment with the development of efficient prices".[17]

Furthermore, the AER considered that what it saw as the possible detriments of a revenue cap – within period pricing instability and weak pricing incentives – were able to be mitigated.

Western Power further considers that a revenue cap form of price control will be more consistent with the required characteristics of a form of price control in the context of the energy transition. In particular, it is questionable whether a form of price control, such as the modified revenue cap, which incentivises the network operator to grow volume is appropriate in circumstances where:

- Customers' energy demands are reducing through energy efficiency.
- There is increasing use of DER by customers, potentially reducing volumes (although noting that overall volumes may increase if electric vehicle penetration becomes significant).
- Electricity consumption is subject to time shifting, for example, where underlying consumption is increased in the middle of the day (when there is excess solar energy being generated) due to the rebound effect.[18]

Under the current form of modified revenue cap, there is no incentive on Western Power to encourage behind-the-meter investment and reductions in demand. The opportunity to increase revenue would act to incentivise Western Power to keep maximum demands high at times when tariffs are at their greatest levels.

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16 See NER clause 6.2.5(b).

17 AER, *Framework and approach for Victorian distributors 2016-2020*, May 2014, p. 20.

18 When users install rooftop solar, the lower effective cost of electricity often leads them to use more energy than before. This is referred to as 'rebound effect'.

This is unlikely to be in the long-term interests of consumers, or consistent with a range of other policy initiatives, for example the objective of the demand management innovation allowance.[19]

While there are likely to be significant benefits from electrification of demand and potentially therefore, in the long term, a substantial increase in energy volumes, it is not clear whether it is appropriate to be encouraging growth in either peak demand or overall energy consumption at this stage of the transition, when approximately two-thirds of electricity generated in the SWIS is still supplied by gas and coal-fired generation. Consequently, a revenue cap that is delinked from energy volumes is likely to be more consistent at the present time with the limb of the SEO relating to environmental outcomes, including the reduction of greenhouse gas emissions.

2.1.3 Risks to specific customer groups can be mitigated

Acknowledging the uncertain environment during the AA6 period, a potential effect of a move to a revenue cap might be a risk of greater volatility in tariffs. Where there is an under-recovery in a given year, this will be transferred to the following year, which would tend to place upward pressure on tariffs in that year – even if the underlying target revenue was the same across the two years. Equally, an over-recovery in one year might lead to lower tariffs the following year.

Western Power considers that any such concerns can be mitigated through the introduction of a 'side constraint'. In general terms, this would restrict the annual change for each tariff to be no more than a specified level above the change in overall expected weighted average revenue. This would help avoid more significant price 'shocks' and is consistent with practice in the distribution sector in the NEM.[20]

Further, customers would have reasonable notice of any forthcoming changes in tariffs. Since the time that the modified revenue cap was introduced into the access arrangement, the Access Code has been amended to require Western Power to publish – and update on an annual basis – a reference tariff change forecast which sets out, for each reference tariff, the service provider's forecast of the weighted average annual price change for that reference tariff for each pricing year of the access arrangement period.[21] Western Power must also explain any material departures from forecast tariff changes over time.[22]

Finally, although Western Power acknowledges the case previously articulated by the ERA that the modified revenue cap should provide stronger incentives for Western Power to encourage the connection of new customers, the case for this in practice appears to be limited. Most drivers of new customer connections are outside of Western Power's control. For example, residential growth and new connections are constrained by land releases, and broader economic and decarbonisation policies.

2.1.4 A revenue cap better meets the price control objectives

Under section 6.1 of the Access Code, an access arrangement may contain any form of price control, provided it meets the price control objectives (and otherwise complies with chapter 6 of the Access Code).

The price control objectives are set out in sections 6.4(a)-(c) of the Access Code. They are that the price control in an access arrangement must have the objectives of:

a. giving the service provider an opportunity to earn revenue for the access period from the provision of covered services;[23]

19 See section 6.32C of the Access Code.
20 As required under NER clause 6.18.6(c)(1), which specifies a "permissible percentage" of two per cent.
21 As required under section 7.1D, which was inserted into the Access Code on 18 September 2020.
22 As required under section 8.12(e) of the Access Code.
23 Section 6.4(a) additionally contains further detail on the amounts of revenue to be earned.

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

c. minimising, as far as reasonably possible, variance between expected revenue for the last pricing year in the access arrangement period and the target revenue for that last pricing year.

Objective (c) was revised in September 2020, subsequent to the ERA's decision to introduce a modified revenue cap for the AA4 period (which was made in September 2018). The stated rationale for this change was to focus the objective on reducing the incidence of sudden tariff movements between access arrangement periods.[24] Previously, objective (c) referred to "avoiding price shocks (that is, sudden material tariff adjustments between succeeding years)".

In its final decision for the AA4 period, the ERA concluded that a revenue cap would not be consistent with objective (b) or the then-objective (c) and that, instead, the modified revenue cap would – in the view of the ERA – ensure the price control was compliant with those objectives. The ERA also considered that the change would not affect the price control's compliance with objective (a).[25]

However, in the light of practical experience, Western Power considers that moving away from a revenue cap has been detrimental to the price control's compliance with objective (a), as compared to a standard revenue cap. A revenue cap would also better allow for the achievement of the revised objective (c) as compared to the existing modified revenue cap.

A revenue cap would be more consistent with objective (a)

The adoption of a revenue cap would better allow objective (a) to be met, that is giving the service provider the opportunity to earn the target revenue.

As noted, the ERA has previously outlined that, in its view, the change from a revenue cap to the modified revenue cap for AA4 would not affect the price control's compliance with objective (a). The ERA suggested that "Western Power will still have the opportunity to earn revenue to meet its forward looking and efficient costs".[26]

However, the nature of the modified revenue cap, where Western Power is exposed to demand risk, fundamentally affects the nature of this opportunity, to the point that Western Power considers it an untenable opportunity. As previously explained, in practice, revenue risk has manifested in an asymmetric way, such that Western Power has consistently under-recovered as compared to its target revenue under the modified revenue cap.

For the modified revenue cap to offer an equal opportunity to recover target revenue as compared to a revenue cap, the demand forecast approved by the ERA prior to the start of the access arrangement period would need to be perfectly accurate. In the absence of this condition holding, a revenue cap provides a better opportunity to recover target revenue and hence offers a greater degree of consistency with objective (a).

The importance of objective (b) is unclear

Under a revenue cap with an overs and unders mechanism, the suggestion could be made that it would not be as straightforward for users to predict the likely annual changes in target revenue during the access arrangement period (i.e. objective (b)) as compared to under a modified revenue cap. Under the modified

[24] Energy Transformation Taskforce, *Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code*, Consultation Paper, May 2020, p. 30.

[25] ERA, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network 2017/18 – 2021/*22, Submitted by Western Power, 20 September 2018, pp. 28, 32.

[26] ERA, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network 2017/18 – 2021/*22, Submitted by Western Power, 20 September 2018, p. 32.

revenue cap, annual target revenues during the access arrangement period are set in advance for the duration of the five-year access arrangement period, and the need to predict likely annual changes in target revenue is effectively removed. In this respect, the approach may extend beyond what limb (b) envisages, which is to enable users to form reasonable expectations, not to eliminate variability entirely.

Further, the importance of this objective to users is unclear. What is likely to be more directly relevant to them is the ability to predict likely annual changes in reference tariffs. As noted, subsequent to the ERA's September 2018 decision to introduce a modified revenue cap, the Access Code had been amended to require Western Power to publish – and update on an annual basis – a reference tariff change forecast which sets out, for each reference tariff, the service provider's forecast of the weighted average annual price change for that reference tariff for each pricing year of the access arrangement period.[27]

This requirement would be unaffected by a move to a revenue cap, and customers would therefore still be able to predict the likely annual changes in reference tariffs during the access arrangement period. Further, the operation of the 'side constraint' would ensure that each tariff did not increase materially more than the change in overall expected weighted average revenue. The visibility and protection provided by these measures is likely to be of much greater importance to users than the ability to predict likely annual changes in target revenue.

A revenue cap would be more consistent with the revised objective (c)

Western Power considers that, in light of the September 2020 change, it is no longer the case that the current form of price control is compliant with objective (c). A modified revenue cap would not minimise, as far as reasonably possible, the variance between expected revenue for the last pricing year in the access arrangement period and the target revenue for that last pricing year.

Under the modified revenue cap, and given the requirement to use forecast customer numbers, energy volumes and other charging parameters consistent with the demand approved by the ERA in the access arrangement decision, there would generally be a variance between expected revenue for the last pricing year in the access arrangement period and the target revenue for that last pricing year. This might be quite significant given the limitations of demand forecasting accuracy and potential for unforeseen events over an approximately five-year period.

There might therefore be a substantial under-recovery in the last year of an access arrangement under a modified revenue cap. One impact of this could be to exacerbate the size of the 'step change' going into the following access arrangement period (as the step would be compounded by the under-recovery in the last year of the outgoing access arrangement).

In contrast, a revenue cap with an overs and unders mechanism that extends across access arrangement periods (with the balance of that account being kept as close to zero as possible in each pricing year) would best allow for target revenue to be recovered in every pricing year, including the last pricing year in an access arrangement period. This would therefore best facilitate the achievements of objective (c).

This approach would also likely better allow for the incidence of sudden tariff movements between access arrangement periods to be reduced, as there would be less likely to be a step change between actual revenue recovery in the last pricing year of one access arrangement period and that in the first pricing year of the next access arrangement period if the level of under (or over) recovery in the last pricing year of the outgoing access arrangement period can be reduced.

[27] As required under section 7.1D, which was inserted into the Access Code on 18 September 2020.

On balance, therefore, Western Power considers that a revenue cap better meets the price control objectives overall than the existing modified revenue cap, which is inconsistent with objective (c) and performs poorly in respect of objective (a).

To the extent that there are any perceived drawbacks with a standard revenue cap in respect of objective (b), these are addressed by the reference tariff change forecast and the operation of the side constraint, and would not, in any event, outweigh the benefits associated with the other two objectives.

2.2 Expanding the coverage of the existing uncertainty management mechanism for capital expenditure

The access arrangement contains an investment adjustment mechanism to allow for the management of uncertainty in relation to certain categories of capital expenditure. It provides for an adjustment to be made to target revenue in the following access arrangement period to correct for any economic loss or gain due to differences between forecast and actual capital expenditure for these expenditure categories.

Western Power proposes that the existing categories of capital expenditure covered by the mechanism should be retained:

- the underground power program for both the transmission and distribution systems
- the standalone power systems (SPS) program for the distribution system
- the transmission network expansion projects identified by Government to support the announced closures of coal-fired generation
- allowances for a plan to address regional reliability.

Western Power further proposes that the coverage of the investment adjustment mechanism should be expanded to include all growth-related (that is, capacity expansion and customer-driven) capital expenditure for both transmission and distribution.

Western Power has not yet finalised the forecast of capital expenditure for AA6, so may propose further categories of expenditure for this mechanism in future.

The reasons for making these proposals are explained below.

2.2.1 Including growth-related capital expenditure in the investment adjustment mechanism

In general, the approach taken under the access arrangement is for Western Power to keep the benefit of any out-performance of cost forecasts and incur the cost of any under-performance. This is consistent with the objectives of incentive regulation, which aims to incentivise the service provider to minimise costs but not at the expense of service quality.

However, in certain circumstances, this usual incentive structure may be ineffective or result in perverse outcomes. This can be the case when there is uncertainty around the need for or timing of capital expenditure programs.

Where there is uncertainty around the need for or extent of a program, or there is uncertainty around the timing of a program, there is the possibility either that customers may ultimately fund a windfall gain to Western Power or, alternatively, that Western Power may not be able to recover its efficient costs.

Western Power considers that it would be appropriate, for the AA6 period, to include additional categories of capital expenditure within the scope of the investment adjustment mechanism, namely all growth-related (capacity expansion and customer-driven) capital expenditure for both transmission and distribution.

This would be consistent with a move to a revenue cap form of price control, where Western Power's revenue recovery would not change as demand changes. Hence, inclusion of the type of capital expenditure in the investment adjustment mechanism would provide protection from the capital cost risk of additional investment needed to meet demand in excess of forecast or less investment needed if demand was less than forecast. This would allow for the ex post true-up of costs once the need for, and cost of, them was known, reducing risks to both Western Power and to customers.

For context, at the time of the ERA's final decision on AA5, growth-related transmission capital expenditure over the AA5 period was forecast to be around \$230m out of total transmission capital expenditure program of around \$800m. Growth-related distribution capital expenditure was forecast to be around \$300m out of a total distribution capital expenditure program of nearly \$2.5bn.[28] These are material amounts but only formed a minority of overall capital expenditure, at the time. These numbers are expected to grow substantially but be highly uncertain and beyond Western Power's control.

As discussed in section 2.1.1, while the accuracy of Western Power's forecasting has tended to be relatively good over time, it is intrinsically difficult to forecast customer numbers and demand over a five-year period. This is particularly the case in the current environment, as the pace of change in technology adoption, customer behaviour and government policies and priorities accelerates. Consequently, Western Power considers that it would not be prudent to 'lock in' allowances for growth-related capital expenditure for the duration of the AA6 period. The use of an adjustment mechanism would allow risks for Western Power and for consumers alike to be better managed.

Under the existing access arrangement, the modified revenue cap itself can act, to some extent, as a form of revenue adjustment mechanism. Western Power will tend to receive more revenue if demand is greater than forecast and less revenue where demand is lower than forecasts. However, there is no direct linkage between revenue recovery and costs. For example, it is possible for Western Power to over-recover without any change in costs.

The current approach therefore works only imperfectly as a revenue adjustment mechanism. As also discussed in section 2.1.1, Western Power's growth-related capital expenditure program is driven primarily by changes in peak demand, whereas changes in revenue recovery are driven primarily by changes in overall energy volumes. In recent years, peak demand has been growing to a much greater extent than energy volumes. Under these circumstances, any revenue growth will tend to be outpaced by increased costs associated with the need for capacity expansion and customer-driven capital expenditure.

Consequently, Western Power considers that including this category of capital expenditure in an explicit adjustment mechanism will be a more effective method of managing the inherent uncertainty, as opposed to the variations in revenue recovery that would result from changes in energy volumes as is the case in the access arrangement at present.

[28] All figures are nominal at 30 June 2023.

2.3 A new uncertainty management mechanism to mitigate risks associated with operating expenditure

The investment adjustment mechanism provides an important tool for managing uncertainty associated with capital expenditure. However, there is currently no equivalent for operating expenditure.[29]

Western Power proposes that the access arrangement should be amended to introduce a new operating expenditure adjustment mechanism. This would operate in a similar manner to the investment adjustment mechanism, providing for an adjustment to be made to target revenue in the following access arrangement period to correct for any economic loss or gain due to differences between forecast and actual expenditure for certain classes of operating expenditure.

Western Power currently envisages that the new mechanism would be applied to two classes of operating expenditure for the AA6 period, as follows:

- Operating expenditure relating to non-network solutions (including non-co-optimised essential system services or NCESS), with forecast operating expenditure for these services being included as an expenditure category provided for in the determination of target revenue for the first time.
- Operating expenditure associated with capital expenditure projects that are included within the scope of the investment adjustment mechanism.

Western Power has not yet finalised the forecast of operating expenditure for AA6, so may propose further categories of expenditure for this mechanism in future.

Classes of operating expenditure covered by the operating expenditure adjustment mechanism would be excluded from the operation of the gain sharing mechanism (see section 3.5 for further information).

The reasons for making these proposals are explained below.

2.3.1 Approach for non-network solutions

The term 'non-network solutions' is used in this submission to refer to demand management or generation solutions that can be a substitute for network augmentation. It is also intended to encompass NCESS. NCESS are supply or demand-side services contracted by Western Power that help manage or solve localised network constraints pursuant to section 3.11B of the Electricity System and Market (ESM) Rules.

To date, no explicit allowance for forecast operating expenditure on non-network solutions has been made in the determination of target revenue in the access arrangement for any access arrangement period.

Instead, the costs associated with these services have been managed through the 'D-factor' mechanism. Under this mechanism, an amount is added to Western Power's target revenue for the following access arrangement period such that Western Power is in a financially neutral position as the result of:

(a) any additional operating expenditure incurred by Western Power as a result of deferring capital expenditure projects during the access arrangement period, net of any amounts included in the target revenue in relation to the deferred capital expenditure projects: and

(b) any other additional operating expenditure incurred by Western Power in relation to non-network solutions.

29 Note that both the Access Code and access arrangement refer to 'non-capital costs'. The term 'operating expenditure' is used here for ease of comprehension.

In all cases, there must be an approved business case for the relevant expenditure, which must be submitted to the ERA along with supporting evidence and which must demonstrate that the expenditure meets the requirements of sections 6.40 and 6.41 of the Access Code in relation to cost minimisation and benefit maximisation.

Greater use of non-network solutions (both in terms of the number of services procured and the size of these services) has driven a steady increase in the amount of expenditure on non-network solutions over time – and this is projected to grow further over the AA6 period. Over the period FY23 to FY25, expenditure on non-network solutions has more than doubled each year, reaching $40m in total over the three years.

To the extent that non-network solutions are procured as an alternative to capital expenditure projects included in the forecast of new capital expenditure projects for the access arrangement period, then some funding will be included as part of the target revenue in that access arrangement period. However, the revenue allowed for forecast capital expenditure would generally be less than required to fund non-network solutions. In addition, for any other non-network solutions, including NCESS, funding is not available until the subsequent access arrangement period.

Consequently, Western Power now considers that it would be appropriate to treat forecast operating expenditure associated with non-network solutions in a manner consistent with other forecast operating expenditure. That is to say that forecast operating expenditure for these services with an approved business case should be provided for in the determination of target revenue for the access arrangement period in which the expenditure is projected to be incurred.

Continuing to recover much of the expenditure associated with non-network solutions in the following access arrangement period would result in larger increase in tariffs in subsequent years if not addressed now and further impact on Western Power's cashflow and debt levels in the short term.

2.3.2 Need for an uncertainty management mechanism

While the change in treatment of operating expenditure for non-network solutions set out above would address the issues associated with cashflow and debt levels, there is also a need for an uncertainty management mechanism to be introduced in relation to this expenditure.

Actual expenditure during the access arrangement period will generally differ from the forecast of expenditure made when the access arrangement was approved. These differences could result from changed requirements for non-network solutions, or from differences in timing and/or costs as compared to forecasts. In particular, when procuring NCESS, Western Power must take into account the impacts of any payments received by the tendering facility in relation to capacity credits, introducing further uncertainty.

As discussed in the preceding sub-section, differences of this nature relating to capital expenditure are managed through the investment adjustment mechanism. There is, however, currently no equivalent mechanism for operating expenditure in the access arrangement. Western Power therefore proposes that an operating expenditure adjustment mechanism should be introduced into the access arrangement and that expenditure on non-network solutions should be one of the classes of operating expenditure subject to the mechanism.

This operating expenditure adjustment mechanism would provide for an adjustment to be made to target revenue in the next access arrangement period to correct for any economic loss or gain due to differences between forecast and actual operating expenditure, taking into account inflation and the time value of money.

This type of adjustment mechanism is appropriate where there is uncertainty around the need for or timing of expenditure programs. These are relevant considerations in the case of non-network solutions, particularly

NCESS where the triggers for these projects are decisions made by the Coordinator of Energy under section 3.11A of the ESM Rules and are therefore external to Western Power. Subjecting the forecast costs of this expenditure to an operating expenditure adjustment mechanism will avoid any windfall loss to Western Power in the event that more services are procured than forecast.

Western Power further proposes that forecast expenditure associated with the procurement of non-network solutions should be excluded from the derivation of the efficiency and innovation benchmarks and therefore not subject to the gain sharing mechanism.[30] It would not be appropriate for Western Power to benefit from or to be penalised for any gains or losses in actual operating expenditure as compared to forecast operating expenditure for classes of expenditure that was sufficiently uncertain so as to be made subject to an adjustment mechanism of the type proposed.

A new uncertainty mechanism would complement the existing D-factor mechanism

Western Power envisages that a new operating expenditure adjustment mechanism would act as a complement to, rather than a replacement for, the existing D-factor mechanism.

As highlighted above, the D-factor mechanism has two limbs. The first limb relates to any additional operating expenditure incurred by Western Power as a result of deferring capital expenditure projects during the access arrangement period. Operating expenditure incurred as an alternative to capital expenditure projects included in the forecast of new capital expenditure projects for the access arrangement period should not be included within the scope of the new operating expenditure adjustment mechanism and should continue to be covered by the D-factor mechanism.

Continued use of the first limb of the D-factor mechanism is also likely to be the most practical way of addressing the types of scenarios raised by the ERA in respect of categories of expenditure that might include capital expenditure and operating expenditure e.g. augmentations that could be addressed by additional network investment or a non-network solution.[31] In this case, forecast expenditure would initially be allowed for as capital expenditure, but the D-factor mechanism would facilitate the substitution of operating expenditure, if this was a more efficient option overall.

The second limb of the D-factor mechanism should also be retained and could continue to apply to those additional non-network solutions arising over the course of an access arrangement period that were not included in forecast operating expenditure and were not an alternative to forecast capital expenditure over the access arrangement period. For the avoidance of doubt, there would be no ‘double recovery’ of costs through both the D-factor and operating expenditure adjustment mechanisms.

2.3.3 Application for operating expenditure associated with investment adjustment mechanism capital expenditure projects

Western Power proposes that operating expenditure that is associated with capital expenditure projects subject to the investment adjustment mechanism should be covered within the scope of the new operating expenditure adjustment mechanism.

The investment adjustment mechanism provides a means of managing uncertainty for capital expenditure programs, for instance where the need for or timing of the program is uncertain. However, any change in operating expenditure associated with the capital expenditure program is not covered by the mechanism.

As an example, the investment adjustment mechanism covers transmission network expansion projects identified by Government to support the announced closures of coal-fired generation, including the Clean

30 See section 3.5 for further information on the gain sharing mechanism.

31 ERA, *Framework and approach for Western Power’s sixth access arrangement review*, Issues Paper, 1 December 2025, p. 18.

Energy Link (CEL) program. Western Power has incurred significant additional operational costs relating to project management office costs and general ongoing CEL support.

Western Power considers that the same rationale for the application of an adjustment mechanism would apply to operating expenditure as to capital expenditure, where this change in operating expenditure is associated with capital expenditure programs covered by the investment adjustment mechanism.

Under the current access arrangement, Western Power is unduly penalised for any increases in operating expenditure associated with capital expenditure programs covered by the investment adjustment mechanism. Instead of being able to recover the increased operating expenditure in the following access arrangement period, Western Power is exposed to the loss within the access arrangement period and further penalised through the operation of the gain sharing mechanism in the following access arrangement.

Western Power therefore considers that operating expenditure should be treated equivalently to capital expenditure where an increase in operating expenditure is associated with capital expenditure programs covered by the investment adjustment mechanism.

This outcome could be facilitated through the inclusion of this type of operating expenditure in the operating expenditure adjustment mechanism outlined in the previous section. As with operating expenditure associated with non-network solutions, forecast operating expenditure associated with capital expenditure programs covered by the investment adjustment mechanism should be excluded from the derivation of the efficiency and innovation benchmarks and therefore not subject to the gain sharing mechanism.[32]

2.4 Greater clarity in the process for the making of mid-period revisions to the access arrangement can mitigate risk

In the issues paper, the ERA highlighted that, during periods of significant change and uncertainty, additional measures may be needed to allow for changes within the regulatory period. The measures available include provisions that allow Western Power to apply for its access arrangement to be amended prior to the target revisions commencement date.

Western Power agrees that these provisions are likely to become increasingly important and proposes that, for the AA6 period, the access arrangement should be modified in order to explicitly identify circumstances in which it would be appropriate for the process for the making of mid-period revisions in this way to be instigated.

It would also be helpful for the ERA to provide additional guidance in the access arrangement information guidelines in relation to the information that would be required to be submitted to the ERA in relation to mid-period proposed revisions.

The reasons for making these proposals are explained below.

2.4.1 Definition of trigger events under the current access arrangement

The Access Code recognises that Western Power should have the opportunity to earn revenue to meet the efficient costs of providing covered services. However, the increasing uncertainties described in section 1 make setting fixed target revenues for five-yearly access periods more challenging than ever.

Consequently, there is an increasingly important role for uncertainty management mechanisms that recognise and allow for revenue adjustments to address material divergences between forecast and actual

32 See section 3.5 for further information on the gain sharing mechanism.

expenditure. In particular, there is a need to mitigate potentially adverse exogenous events that can adversely affect Western Power's network and increase the cost of supplying network services.

Section 4.37 of the Access Code provides that an access arrangement may specify one or more trigger events. A trigger event is a set of circumstances, the occurrence of which requires the service provider to submit proposed revisions to the access arrangement during an access arrangement period. In general, these mid-period revisions will seek to address the financial impacts of the event that has occurred.

The current access arrangement contains a single, generic trigger event which is defined as being any significant unforeseen event which has a materially adverse impact on Western Power, and which is:

a) outside the control of Western Power; and

b) not something that Western Power, acting in accordance with good electricity industry practice, should have been able to prevent or overcome; and

c) so substantial that the advantages of making a variation to this access arrangement before the end of this access arrangement period would outweigh the disadvantages of doing so, having regard to the impact of the variation on regulatory certainty.

Were an event to occur and these criteria to be met, Western Power would need to notify the ERA by the 'designated date' (currently defined in the access arrangement as 90 business days after the trigger event has occurred) and submit to it proposed revisions to be made to the access arrangement. The ERA must then consider the proposed revisions in accordance with a modified version of the provisions used to consider a proposed access arrangement.

Western Power believes that the proposed revisions would not necessarily constitute "an application to re-open the entire access arrangement before the end of the access arrangement period and undergo a full access arrangement review".[33] None of the provisions in the Access Code regarding proposed revisions explicitly require the review of every aspect of an existing access arrangement.

In particular, because, in the circumstances being contemplated here, there would already be an otherwise fully functioning access arrangement, including a price control for revenue target services, in place and valid until the next target revisions commencement date, Western Power does not consider that there would be any requirement for it to propose – or for the ERA to consider – any revisions to the access arrangement beyond those directly resulting from the occurrence of the trigger event.

The Access Code also contains three other mechanisms by which the access arrangement could be revised or varied during the course of an access arrangement period, as follows:

- Section 4.38 allows the ERA to vary the price control or pricing methods in an access arrangement if:
  - its approval of the access arrangement contains a material error or was based on materially false, misleading or deceptive information; or
  - significant unforeseen developments have occurred;
- Section 4.41 allows the ERA to vary the access arrangement if the Access Code is amended; and
- Section 4.41A allows the ERA to vary the access arrangement if Western Power proposes revisions other than when it is required to do so under the Access Code and in circumstances where sections 4.38 and 4.41 do not apply.

[33] ERA, *Framework and approach for Western Power's sixth access arrangement review*, issues paper, 1 December 2025, p. 14.

2.4.2 Objectives of an effective mid-period revisions mechanism

Western Power is of the view that an effective mechanism for mid-period revisions forms a critical part of the access arrangement. An effective mechanism should:

- cover both events that were unforeseeable and those that were foreseeable but uncertain;
- to the extent possible, be based around a pre-defined test, which is capable of objective assessment, in order to provide regulatory certainty; and
- result in a revisions process that is limited in its scope to only the direct impacts of the event in question.

The purpose of a mid-period revisions mechanism is to allow amendments to be made to the access arrangement should circumstances change. In some cases, this change in circumstances may have been completely unforeseeable. However, in others, the change in circumstances may have been foreseen as a potential scenario but the likelihood or timing of the scenario eventuating may have been uncertain. Alternatively, the impacts resulting from the change in circumstances may be hard to forecast. An effective mid-period revisions mechanism needs to be able to cater for all these different scenarios. Including the impacts of foreseen but uncertain events in target revenue would not be the most prudent approach to protect consumers' interests.

It is also important that all parties are clear on whether a relevant change in circumstances has occurred. Ideally, potential scenarios should be identified in advance and an objective test defined, so that it can be unambiguously determined if, and when, the change in circumstances has occurred. This would support regulatory certainty, which the ERA is required (under section 5.36(a) of the Access Code) to consider when determining whether to include a trigger event in the access arrangement.

To limit transaction costs and to avoid creating further uncertainty, the scope of any revisions made to an access arrangement in response to changed circumstances should be limited to only the consequences of those changed circumstances. If an event, such as a severe weather event, has led to additional costs being incurred by Western Power, the consideration of revisions to the access arrangement undertaken by the ERA should be limited to assessing the extent to which these additional costs should be allowed for through a revised access arrangement.

2.4.3 Improvements can be made to the access arrangement to help meet these objectives

The current access arrangement does not meet the objectives outlined above. In particular, the single trigger event contained in the access arrangement relates only to a significant unforeseen event. Events that are foreseeable, but which are uncertain in their likelihood or timing, are not included. Further, the trigger event currently included in the access arrangement is generic in its nature and therefore is not capable of objective assessment through a pre-defined test, resulting in a lack of regulatory certainty.

Western Power considers that improvements can be made to the access arrangement to help meet these objectives and through the provision by the ERA of additional guidance. Principally, this should be done by including a number of defined trigger events in the access arrangement, in addition to the current generic trigger event. Greater specificity in the definition of trigger events will lessen the need for the ERA to apply regulatory discretion regarding the occurrence of an event.

Western Power's current view is that five new trigger events should be included in the access arrangement, as follows:

- **Regulatory change event:** A change in obligations arising from any regulatory or legislative change which impacts the way services must be provided or materially impacts the cost of delivering services.

- **Service standard event:** A change in obligations arising from any regulatory or legislative change which impacts the nature or scope of a covered service, its minimum standard, the manner in which it must be delivered or materially impacts the cost of delivering services.
- **Cyber security event:** A change in federal or state government cyber security legislation that imposes new obligations on Western Power in the provision of covered services.
- **Severe weather event:** A weather event or natural disaster including, but not limited to, cyclone, fire, flood or earthquake, which increases the cost of providing covered services in the access arrangement period.
- **Tax change event:** A change in the relevant tax rate, the interpretation or calculation of tax rates or the imposition of relevant taxes which materially affects the cost of providing covered services in the access arrangement period.

If an event listed above was to occur, Western Power would notify the ERA and submit to it proposed revisions to be made to the access arrangement in accordance with section 4.37 of the Access Code. The revisions proposed by Western Power would be limited to the impacts of the event (for example, additional costs that may have been incurred).

Given that the mid-period revisions proposed by Western Power would be limited to only those matters directly related to the consequences of the event, there would be no need for the ERA to consider any wider revisions, such as would be considered prior to the start of each new access arrangement period.

Western Power considers this approach to be consistent with the relevant provisions of the Access Code. The proposed revisions submitted by Western Power would need to be considered by the ERA in accordance with sections 4.46 to 4.52 of the Access Code, which in turn refer to sections 4.2 to 4.36.

Under section 4.2, the access arrangement information that must be submitted to the ERA by Western Power must enable the ERA, users and applicants to understand how the elements of the proposed revisions were derived. Section 4.3 sets out the requirements of access arrangement information, but the operation of section 4.2 means that not all elements of access arrangement information need to be amended through proposed revisions.

Section 4.5 provides that the ERA may, from time to time, publish guidelines setting out in formation what information must be included in access arrangement information in order for the access arrangement information to comply with sections 4.2 and 4.3, either generally or in relation to a particular matter or circumstance.

In the issues paper, the ERA asked whether additional guidance about the use of provisions in the Access Code to manage uncertainties is needed. Western Power considers that it would be helpful for the ERA to provide guidance in the access arrangement information guidelines in relation to trigger events and, specifically, the information that would be required to be submitted (and the information that would not be required to be submitted) to the ERA in the particular circumstance of a trigger event occurring.

2.4.4 The approach proposed is consistent with best practice in other jurisdictions

The proposed approach to mid-period revisions outlined above in consistent with the practice in other comparable jurisdictions.

National Electricity Market

The National Electricity Rules (NER) that govern network regulation undertaken by the AER in the NEM on the east coast provide for cost pass-through mechanisms for both distribution and transmission businesses.

The NER define the following as “pass through events”:

- a regulatory change event;
- a service standard event;
- a tax change event;
- a retailer insolvency event (distribution only);
- an insurance event (transmission only); and
- any other event specified in a distribution / transmission determination.

Events specified in various distribution and transmission determinations include:

- an insurance coverage event;
- an insurer’s credit risk event;
- a natural disaster event; and
- a terrorism event.

If such an event occurs, the relevant Network Service Provider (NSP) can seek the approval of the AER to pass through additional costs incurred as a result. The NSP must submit to the AER, within 90 business days of the event occurring, details of the event, the proposed pass-through amount (and in which regulatory years these should be recovered), together with evidence of the cost increase.

In general, however, NSPs are limited to claiming additional costs only where these are considered ‘material’ – that is, they exceed or are likely exceed one per cent of the annual revenue requirement for the NSP for the relevant regulatory year.

Where the AER determines that a pass-through event has occurred and that the NSP’s claim is valid, it must determine the approved pass-through amount and in which regulatory years the pass-through amount should be recovered.

The process outlined in the NER is broadly consistent with that proposed by Western Power for the AA6 period, as set out above. Western Power does not consider that a materiality threshold such as that applied in the NEM is necessary – the transaction costs associated with the process for proposing mid-period revisions will act to prevent any revisions being proposed where cost increases are immaterial.

New Zealand

The Input Methodologies (IMs) that govern the determinations of price-quality paths undertaken by the Commerce Commission in New Zealand allow for the mid-period reconsideration of price-quality paths for both electricity distributors and for Transpower, the transmission business.

Under the IMs for electricity distribution services, price-quality paths may be reconsidered where:

- a catastrophic event has occurred
- a change event (relating to new or revised legislative or regulatory requirement) has occurred
- there has been an error event (relating to incorrect data or the incorrect application of data)

- a major transaction has occurred (relating to an acquisition or disposal of assets affecting the number of customers supplied)
- false or misleading information has been provided, or
- an unforeseeable major capex project is required.

There are also provisions relating to major capex projects that were foreseeable but that were not provided for in the original determination, although the arrangements vary between those distributors using the general default price-quality path framework and those with a customised price-quality path.

The Commerce Commission is not permitted to amend the price path more than is reasonably necessary to take account of the effects of the event, net of any insurance or compensatory entitlements. Similarly to the NEM, events are generally not triggered unless the cost impact is equivalent to at least one per cent of the net allowable revenue in the relevant year.

The arrangements for Transpower, the transmission business, are largely aligned with those for the distribution sector, with the Transpower IM allowing for the reconsideration of Transpower's price-quality path where:

- a catastrophic event has occurred
- a change event (relating to new or revised legislative or regulatory requirement) has occurred
- there has been an error event (relating to incorrect data or the incorrect application of data), or
- false or misleading information has been provided.

There are also provisions that address projects which were unforeseeable, as well as those that were foreseeable but not included in the original determination. Materiality thresholds apply for most events.

Great Britain

The electricity market in Great Britain is regulated by Ofgem, the Office of Gas and Electricity Markets. The energy network price controls are known as RIIO (Revenue = Incentives + Innovation + Outputs). The next price control period for gas transmission (GT), electricity transmission (ET) and gas distribution (GD) will run from 2026 to 2031 (for electricity distribution (ED), the period will run from 2028 to 2033).[34]

Ofgem published its RIIO-3 draft determinations for the ET, GT and GD sectors in July 2025. There was a significant step up in spending in RIIO-ET3 compared to RIIO-ET2, following a clear mandate from UK Government for this increase in spending, with its December 2024 Clean Power (CP) 2030 Action Plan[35] noting that the level of deployment required to meet the CP2030 trajectory will require an estimated £40bn on average per year between 2025-2030, much of which will be private investment, and £10bn of which is investment in transmission network assets.

Consistent with the significant scale of expenditure sitting outside baseline, as part of the ET draft determinations, Ofgem has proposed an extensive package of uncertainty mechanisms (UMs) comprising re-openers, indexation, volume drivers, and pass-through items. Some of these are common to all sectors, others are specific to the challenges faced by each sector. In total Ofgem has defined 25 UMs that apply to the ET networks – 13 of these are cross-sector, but 12 are sector-specific. These include the key sector-specific reopeners and other uncertainty mechanisms focused on:

34 Energy network price controls | Ofgem

35 Clean Power 2030: Action Plan: A new era of clean electricity

1 **Pre-construction funding:** A reopener valued at £237.6m to enable companies to progress early-stage project development associated with large load-related investments.

2 **Load reopener:** To enable companies to take forward agreed load-related investments with a value of £25m+.

3 **Load Use-It-Or-Lose-IT (UIOLI):** c. £690m to enable companies to progress load-related projects of less than £25m with reduced regulatory scrutiny.

4 **Non-load reopener:** A UM has been created, which will allow companies to apply for funding for non-load investment, where there was previously a load driver that has fallen away.

5 **Connections volume driver:** To enable companies to invest in the network in response to unplanned for demand or generation connections.

6 **Re-opener for the Centralised Strategic Network Plan financial outcome delivery incentive (CSNP-F):** When triggered by the Authority (Ofgem), this will ensure that companies are funded to deliver CSNP projects, which arise over the period.

All re-opener applications to Ofgem must include a needs case. These must contain information on the alignment with overall business strategy and commitments, a demonstration of the needs case/problem statement, a consideration of options and methodology for selecting the preferred option, and a clear description of the preferred option. Cost information must also be provided.[36]

Under these re-openers, potential qualifying events or criteria are known in advance, and often indicative total levels of funding available are also known in advance.

[36] Re-opener Guidance and Application Requirements | Ofgem

3. Response to issues highlighted by the ERA

This section of our submission responds to the issues highlighted by the ERA for consultation that were not covered in the previous section. Its ordering matches that of the ERA's issues paper, being structured as follows:

- general approach and content of Western Power's AA6 proposal
- services offered and payments for those services
- service standards
- connecting customers
- price control, incentives and adjustment mechanisms.

As noted previously, some of the matters raised by the ERA in its section on price control, incentives and adjustment mechanism have already been covered in the previous section, as have the matters discussed in the ERA's final section on uncertainty.

3.1 General approach and content of Western Power's AA6 proposal

In the first section of the issues paper, the ERA described the challenges faced by Western Power at the time of the AA5 decision and those that are expected over the AA6 period and beyond. The ERA discussed likely areas of focus for the AA6 and set out some specific expectations for the AA6 proposal, before seeking stakeholder feedback.

Issue raised by the ERA in its issues paper

1. *The ERA is seeking stakeholder views on their expectations for Western Power's AA6 proposal.*

Within this section Western Power covers the following areas regarding the general approach and content of the AA6 proposal:

- a plan for the long-term
- a clear, transparent and customer-centric proposal
- greater geographic disaggregation in planning
- delivering efficiently, including through the use of alternative solutions.

Managing uncertainty and the potential for geographical disaggregation of service standards are considered separately in sections 2.2 to 2.4 and 3.3.1, respectively.

3.1.1 A plan for the long-term

Western Power acknowledges the importance of taking a long-term view in its planning and, in turn, as part of the AA6 framework and approach. Planning for the long term is both important and challenging under the increasingly uncertain environment outlined in section 1.

Western Power is already implementing long-term planning in several ways.

Western Power prepares and publishes key annual plans for its network – the Transmission System Plan (TSP) and Network Opportunities Map (NOM).[37] Together, the TSP and NOM provide a comprehensive picture of the state of the network, how and where issues are being addressed, and identify opportunities for non-network solutions.

- The TSP, developed under section 4.5B of the ESM Rules, considers the future development of the transmission network over the coming decade and beyond. It provides a summary of Western Power's proposed plan for development of the transmission network to address power system security and reliability, while maximising the long-term interests of customers.
- The NOM, developed under Chapter 6A of the Access Code, provides a snapshot of the opportunities, challenges, risks and constraints emerging for the network in the planning period (five years) and in the foreseeable long term (ten years). The primary purpose of the NOM is to provide opportunities to businesses to become involved in providing non-network solutions to the network, such as demand management, battery storage options or an alternative option.

In addition to these annual planning processes for the network, Western Power contributes to various periodic and one-off planning processes, in collaboration with other entities.

This includes contributing to the development of the Whole of System Plan (WOSP), developed by the Coordinator of Energy under section 4A of the ESM Rules. The WOSP is an integrated assessment of the future development of SWIS. It provides for a detailed, long-term analysis of power system needs under various scenarios and seeks to identify the lowest-cost mix of generation, storage and transmission infrastructure for the SWIS. Based on this assessment, a key purpose of the WOSP is to identify the network investments required to support the lowest-cost supply of electricity in the SWIS over the next 20 years. Under the ESM Rules, the next WOSP is due to be published by September 2027.

Western Power also contributes to other planning processes and publications, for example:

- the comprehensive 'Perth and Peel @ 3.5 million' framework published in 2018, to guide the development of the Perth and Peel regions over the period to 2050;[38]
- the SWIS Demand Assessment published in 2024, which collated industry data to understand the potential change in electricity demand over the next 20 years, considering the requirements of existing industrial users on the SWIS and potential growth in new industries;[39] and
- the SWIS Transmission Plan published in 2025, which provides a plan for the expansion of the transmission network in the SWIS to support the State's clean energy transition to 2035 and beyond.[40]

These planning processes and documents inform, and in turn are informed by, Western Power's engagement with retailers, consumers and other stakeholders. This includes engagement with consumers undertaken in preparation for an access arrangement review, discussed in the following section.

Western Power welcomes further engagement with the ERA and other stakeholders on planning for the long term.

[37] Information on the TSP and NOM is available on the Western Power website.
[38] Information on the Perth and Peel @3.5 million framework is available on the WA Government website.
[39] Information on the SWIS Demand Assessment is available on the WA Government website.
[40] Information on the SWIS Transmission Plan is available on the WA Government website.

3.1.2 A clear, transparent and customer-centric proposal

Western Power agrees that its proposal should be clear, transparent and focussed on positive outcomes for its customers. The interests of customers, including opportunities to improve transparency, are priorities for Western Power in all of its activities, and have been considered by Western Power throughout this response.

Western Power is already providing significant transparency regarding its performance and future proposals, both on an ongoing basis and as part of targeted consumer engagement.

Western Power provides transparency of its plans and performance in several ways. For example:

- The plans outlined in section 3.1.1 above.
- Information on Westen Power's website about the network and network improvements.
- Regulatory reporting submitted to the ERA and published on the ERA's website including service standard performance reports,[41] demand management initiatives under Demand Management Innovation Allowance[42] and Annual Monitoring Report[43].
- Reporting under its distribution license, which is also published on the ERA's website, on a range of measures such as outages, connections, complaints management and call centre performance.

Western Power also actively engages customers through multiple formal and informal communication channels to ensure customer preferences inform service levels, performance and investment decisions.

Improving transparency for regional and remote customers remains a priority and initiatives such as our Regional Connect program facilitate clear engagement pathways, better visibility of project status and tailored support that reflects the unique challenges of regional communities.

To support our ongoing engagement, Western Power has rolled out Social Pinpoint as a key digital engagement platform to enable transparent, accessible and inclusive consultation with customers and stakeholders. Through this platform, customers have been able to provide us feedback on proposals, raise concerns, and contribute ideas in a way that is visible and responsive – helping to enable meaningful engagement and ensure customer voices are reflected in decision-making.

In preparing for AA6 Western Power is undertaking a program of community and stakeholder engagement. As part of this engagement, Western Power has convened four Community Working Groups (CWGs), representing each of Western Power's network regions (Metro, North, East, and South), to gather consumer insights and inform the development of Western Power's AA6 expenditure plans.

Engagement with the CWGs so far has highlighted that overall affordability is the major concern for consumers. However, CWG participants highlighted that minimising outage frequency and duration is also important; ensuring that services are dependable. Overall, CWG participants have indicated some willingness to pay for uplifted regional reliability and resilience. Customers are generally supportive of a bill increase where there is a clear benefit – even if they are not direct recipients.

The engagement with CWGs indicates that consumers in different regions may have different preferences for the approach to investment (proactive or reactive, including the use of non-network solutions).

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[41] As part of its annual service standard performance reports, Western Power provides additional reporting on estimated System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) performance by feeder and by Local Government Authority (LGA) area.

[42] Refer to Demand Management Innovation Allowance - Economic Regulation Authority Western Australia.

[43] Refer to Access arrangement AA5 (2022 to 2027) - Economic Regulation Authority Western Australia

This engagement with consumers also reinforces that consumers value transparency and the ability to engage with Western Power on local reliability and potential investments. Consumers also indicate the importance of effective communication during outages. Despite these clear preferences, CWG participants indicate that consumers are generally not willing to pay for uplifted customer experience.

This engagement with the CWGs is ongoing as Western Power prepares its submission for the AA6 period.

Western Power welcomes further engagement with the ERA and the outcomes it is looking to deliver in this area. Western Power considers that there is a careful balance to take into account between the benefits of reporting and/or publication requirements for the users of this published information, against the additional administrative regulatory and cost burden this places on Western Power and ultimately consumers.

3.1.3 Greater geographic disaggregation in planning

In the issues paper, the ERA indicated it is considering introducing additional transparency requirements to strengthen the delivery of customer outcomes. One option under consideration is requiring Western Power to submit proposals that are geographically disaggregated. While the ERA has not developed a specific proposal, the issues paper indicates this could involve local area plans aligned with the Local Government Area zones.

Western Power recognises the importance of providing transparency to customers in its future plans and the associated costs, and supports customer visibility and providing transparency. As outlined in sections 3.1.1 and 3.1.2 above, we already provide substantial information relating to planning and network performance. Western Power supports providing additional transparency, if there is a clear customer-identified gap and demonstrated value in providing additional information – but is concerned that trying to disaggregate plans to a greater extent will be complex and costly, and may have unintended consequences.

The access arrangement is determined at a point in time to provide sufficient revenue for managing the network over the access arrangement period. Western Power manages the network using a risk-based approach that adapts to emerging issues. Binding Western Power to local targets will reduce flexibility, ultimately to the detriment of customers. In the current environment of heightened uncertainty, adaptability and flexibility will be required to ensure expenditure on the network is prudent, efficient and responsive to changing conditions.

Western Power also notes that there are existing mechanisms for sharing information about local plans. For example, the WA Government is advancing local-area economic plans, including for Strategic Industrial Areas and priority housing growth locations. Western Power will be presenting a Regional Reliability Plan as part of the AA6 process.

Western Power further acknowledges the ongoing work of the WA Government on the Power Systems Security and Reliability (PSSR) Review, with the recent consultation outlining proposed reforms aimed at establishing a consistent, single, end-to-end PSSR framework for the SWIS, including updated PSSR standards and a centralised governance framework. Western Power notes that a paper on this is expected to be published and which will inform future network planning.

Recent experience in Great Britain also indicates caution in introducing disaggregated planning requirements, which is proving to be a complex exercise.

Learnings from regional planning in Great Britain

The National Energy System Operator (NESO) was established under the 2023 Energy Act as the independent system planner and operator in Great Britain. NESO became operational in 2024 and has taken on several key functions, including overseeing the reformation of the connections queue. Another key role NESO has is to prepare GB's Regional Energy Strategic Plans, or RESPs, and for the Electricity Distribution price control (RIIO-ED3) 'transitional' RESPs (tRESPs).

The purpose of the RESPs is to help ensure that local areas get the energy infrastructure needed to meet local net zero and growth ambitions, and help communities to access reliable, clean and affordable energy. These will be published in January 2026 and will be used by Distribution Network Operators to develop their plans for RIIO-ED3, but also on an ongoing basis for the electricity transmission and gas network companies in their planning.

The regional planning process is both highly ambitious and highly complex. NESO is looking at whole systems planning, considering a range of vectors and how these trade off with one another to form regional plans. The process has already faced delays for a number of reasons, however ultimately the complexity of the process means that regional planning requires a significant amount of time and engagement with a range of stakeholders such as local authorities and industry groups.

Another element of complexity is introduced when considering the regional boundaries for regional planning and target setting. Under the RESP program, there are 11 regions across England, Scotland and Wales, however these regions do not correspond to the equivalent regions owned by the energy network operators. Regional boundaries selected and the criteria for doing this will be a key consideration for the ERA.

3.1.4 Delivering efficiently, including through the use of alternative solutions

In line with its requirements under the Access Code, Western Power is focussed on delivering outcomes efficiently, including where possible through the use of alternative options.

Under the access arrangement framework, Western Power is incentivised to minimise costs, through the opportunity to retain the benefits of any outperformance of cost forecasts and the requirement to incur the costs of any under-performance during the access arrangement period. For forecast operating expenditure only, the gain sharing mechanism increases the incentive to achieve efficiencies by ensuring that Western Power retains any savings for a five-year period, regardless of which year during the access arrangement period the efficiency was made.

Additionally, the D-factor mechanism provides for the recovery, in the next access arrangement period, of additional expenditure incurred as a result of deferring a capital expenditure proposal or for non-network solutions. Facilitating the retrospective recovery of non-capital costs in this way means that any potential short-term incentive on Western Power not to choose the overall least cost option is avoided.

The success of this mechanism has been demonstrated over the AA5 period to date through the delivery of non-network solutions, including those for the Eastern Goldfields, North Country, Ravensthorpe and Bremer Bay. Collectively, expenditure on these projects has totalled $40m (nominal) of non-network costs over the three years up to FY25.

Western Power has also recently implemented a pilot project under the Regional Reliability Initiative (RRI) involving the installation of a Static High Voltage Injection Unit (HVIU) in Lancelin, which has already delivered measurable improvements in outage duration and customer experience.

Finally, following determinations made by the Coordinator of Energy, Western Power is currently procuring several NCESS projects, as follows:

- Network Support Services for Metropolitan Capacity Expansion
- Reliability and system strength services for the Eastern Goldfields region
- Network Support Services for Geraldton Minimum Demand Services
- Network Support Services for Byford Peak Demand Services.

As noted in earlier sections of this document, greater use of non-network solutions (both in terms of the number of services procured and the size of these services) over time has driven a steady increase in the amount of expenditure on non-network solutions – and this is projected to grow further over the AA6 period. A key element of Western Power's proposal for AA6 is a move to treat forecast operating expenditure associated with non-network solutions in a manner consistent with other forecast operating expenditure.

3.2 Services offered and payments for those services

As noted in section 1 above, the F&A must include a list of and classification of services. This includes:

- whether services are reference services or non-reference services
- the eligibility criteria for each reference service
- the structure and charging parameters for each distribution reference tariff
- a description of the approach to setting each distribution reference tariff.

In the issues paper, the ERA is seeking stakeholder feedback on the following three issues.

Issues raised by the ERA in its issues paper

2. What changes are needed to the current list of reference services and tariff structures to support new technologies and energy models, while providing incentives that will reduce overall costs for consumers.

3. We are interested in stakeholder views on what changes may be needed to metering services to reflect that most customers have advanced meters.

4. We are interested in stakeholder views on improvements that could be made the framework for payments for services (including new and upgraded connections) that are not included in network tariffs.

Western Power's comments on issues relating to services and tariffs are provided in the following subsections, which cover:

- reference services and tariffs (issue 2)
- metering services (issue 3)
- services recovered by charges other than network tariffs (issue 4).

3.2.1 Reference services, tariffs and the classification of services

Western Power acknowledges the need for network tariffs and reference services to be fit for purpose for the changing usage of the network, including the use of new energy technologies and the need to ensure tariffs incentivise energy use that minimises costs for consumers.

Approach to evaluation of services and tariffs

Western Power developed a structured evaluation framework to guide its consideration of, and engagement with stakeholders on, services and tariffs. We have identified the following four principles, which are aligned with the SEO:

- Cost reflective – is the tariff structured to be able to accurately reflect the costs of serving applicable customers?
- Effective – is the tariff effective in meeting customer needs in sending up-to-date pricing signals and minimising customer bill impacts?
- Understandable – do customers on the tariff understand the structure of the tariff and how charges will change with usage?
- Maximises opportunities – does it allow Western Power and customers to take advantage of evolving and emerging opportunities?

Consistent with these principles, Western Power considers that technology-neutral tariffs should be preferred, to ensure that costs are signalled on an equivalent basis and do not distort customers' decisions to generate, store or otherwise manage their energy use.

Reference tariffs – eligibility criteria, structure and charging parameters

Western Power currently offers the following reference services:

- 23 exit services as reference services
- 3 entry services as reference services
- 24 bi-directional services as reference services
- 9 services at a connection point as a reference service (ancillary)
- 20 metering reference services.

Consistent with the evaluation framework outlined above, Western Power proposes three potential changes to reference tariffs for the AA6 period, namely:

- new or amended tariffs to address concerns with the existing metered demand tariffs for commercial customers
- revision of the distributed generation discounting mechanism
- correction of the EV charging tariff.

In light of the ongoing uptake of DER and move to greater DER coordination, Western Power has considered whether new DER tariffs would be beneficial.

These are discussed in the following sections.

Metered peak demand tariff

Westen Power has identified two issues with its existing metered demand tariffs for large commercial customers (RT5 and RT6):

- **The tariff structure does not reflect the network cost structure, which is driven by peak demand**. The current metered demand tariffs are based on a customer's anytime maximum demand. They do not include a peak period, and therefore do not provide any effective incentive for the customer to shift consumption away from peak periods of demand on the network, which are the key driver of network costs. They only incentivise a customer to save by minimising its annual peak demand anytime, even when it occurs away from network peak times.

- **The discount framework is complex and also not linked to the key driver of network costs**. These tariffs include a complex discount framework that is intended to encourage customers to flatten their load. Specifically, it applies a discount to the fixed and variable rolling 12-month demand charges calculated by reference to the ratio between off-peak and peak consumption. In their current form, these tariffs do not provide effective signals to customers about the forward-looking costs of providing the service, which is the means by which tariffs promote efficiency and, for this reason, is a requirement of the Access Code.[44]

These tariffs also do not perform well against the principles we have identified – their cost reflectivity is limited, they are not effective at incentivising consumers to reduce demand at peak times, and their complexity reduces the extent to which they will be readily understood by customers.

Feedback from the Expert Consumer Panel has highlighted the mismatch between the 'anytime' demand incentive and peak demand periods, which drive network costs. This mismatch means these tariffs currently act as a disincentive to investment in batteries by commercial customers as the best time for charging a battery from a network perspective (the middle of the day when solar output is high) is likely to coincide with the customer's maximum demand in the middle of the business day leading to higher network charges. Further, while discharge from the battery in the evening will benefit the network, the customer receives no benefit for this.

Western Power agrees with this assessment. Ideally, irrespective of their anytime rolling 12-month maximum demand, large commercial customers would be presented with an incentive to reduce their use of the network when it is constrained and to invest in technologies to support this where efficient.

Western Power considers that amending or replacing these tariffs, to ensure commercial customer tariffs reflect network cost drivers and incentive the efficient use of the network, is a priority. Western Power would welcome the opportunity to work with retailers to develop a solution which is fit-for-purpose, cost-reflective and is likely to be used by a significant portion of the market.

Distributed generation discounting mechanism

Tariffs to facilitate distributed generation and other non-network solutions were introduced into the access arrangement for the AA4 period. The concept remains relevant, but the existing tariff mechanism has not been utilised effectively since its introduction. When assessed against the principles above, the tariff is not very easy to understand, which contributes to its lack of effectiveness.

The existing calculation of the discount is complex, and the onus is on users to demonstrate a reduction in costs. In addition, the potential size of the discount is not transparent to users or retailers. The discount is calculated as the annualised present value over 15 years of the forecast savings in network costs resulting from the distributed generating plant being located in a particular part of the covered network.

Western Power proposes to revise the tariff calculation and discount definitions to include an annual adjusted discount that is linked to the distribution network constraints and alternative opportunities

[44] Section 7.3G of the Access Code.

identified through the annual Network Opportunities Map (NOM). The discount would be available for distribution generation or exit tariffs.

The NOM and alternative options framework have evolved in recent years and now include a process to publish costs associated with network augmentation and locations where feeder utilisation is greater than 80 per cent. This process can be leveraged for the discount calculation, which would improve transparency. It would also allow the discount to be adjusted annually to reflect expected future costs as feeder utilisation changes, including to reduce to zero when there is no longer an issue at a particular feeder.

Correction of the EV charging tariff

Western Power proposes to revise the pricing structure for the EV charging tariff to reflect an error in the existing approach.

The existing EV charging tariff has a tiered pricing structure based on network utilisation bands, defined as:

$$\frac{30\ minute\ intervals\ with\ demand\ above\ 10kW\ between\ 3pm\ and\ 9pm}{30\ minute\ intervals\ in\ a\ billing\ period}$$

The network utilisation bands are:

- Band 1: 0 to <15%
- Band 2: >/= 15% and < 30%
- Band 3: >/= 30%

Since there are six hours per day in the peak times, utilisation greater than 25% is impossible.

Western Power proposes to simplify the utilisation pricing to two bands:

- Band 1: <15%
- Band 2: >/= 15%

Distributed energy resources

Determining the most efficient way to service the energy needs of Western Australians using either traditional network solutions ('poles and wires') or emerging technologies such as DER is essential to delivering services in the long-term interests of consumers. Over the AA6 period, Western Power anticipates consumers will continue to invest strongly in DER including solar PV systems and, increasingly, batteries and electric vehicles.

The expected designation[45] of Western Power as DSO represents a significant change to its role. As the DSO, Western Power will have expanded responsibilities for actively managing and monitoring the distribution network to support the continued adoption of DER by consumers and establishing conditions that enable active participation by DER.

Similar to SPS systems in the AA5 period, DER and Western Power's role as DSO are elements of the fundamental change underway in the way electricity is supplied. The increased deployment and coordination of DER offer significant potential to help achieve a reliable, more affordable and lower emissions power supply, and give consumers greater control over their energy costs and use. This emerging, enhanced ability

45 Amendments are proposed to the Electricity System and Market Rules to designate Western Power as the DSO. Refer to Energy Policy WA's consultation on Electricity System and Market Rules – Distributed Energy Resources – Roles and Technical Requirements.

to coordinate distributed, small-scale systems should be supported by policies and operational capability to optimise use of our existing poles-and-wires infrastructure.

While these developments are significant, the coordination of DER in the South-West Interconnected System is at an early stage. Western Power's engagement with customers indicates that customers generally support continued DER uptake and coordination of DER through VPPs, however customers are seeking more information about how participation works, what the value of participation is and how to ensure equity across the community.

To enable greater coordination, Western Power's current priorities are the development of dynamic operating envelopes (DOEs) and technical requirements. DOEs are the dynamic export and import limits (determined by the network operator) that apply at the customer's connection point. An export limit determines the maximum amount a customer can export into the network from their onsite generation, while an import limit is the maximum that can be consumed from the network. Historically, fixed export and import limits have applied at all times, however 'dynamic' limits mean the limits can vary, such as at different times of the day, reflecting the capability of the network. DOEs are typically implemented through real-time communication between the network or retailer and the meter or inverter at the customer's connection point. DOE capability is an important foundational step in the transition towards DSO capabilities and may enable greater use of flexible tariffs in the future.

Project Jupiter, which will be completed during the AA6 period, is designed to accelerate the integration of DER across the Western Power network. In addition to developing technical settings such as DOEs, Project Jupiter will consider the customer pathways, value frameworks and regulatory settings for the integration and coordination of DER at scale. The learnings from Project Jupiter are expected to inform future services and tariffs.

Western Power considers the existing reference services remain sufficient and appropriate for consumers with DER over the AA6 period. An additional DER tariff is not likely to deliver any significant benefit and, with DER coordination at an early stage, risks unintentionally favouring specific technologies and distorting price signals to customers. The existing reference services should continue to cater for both un-coordinated and coordinated DER over the AA6 period.

This can be reviewed again as part of future access arrangement processes as the coordination of DER matures over time.

Other tariffs

Western Power proposes working closely with the ERA to ensure any drafting updates to eligibility criteria appropriately take into account impacts on other elements of the access arrangement, including relevant contracts and policies.

Consistent with the principles above, Western Power proposes to continue with adjustments:

- to the price of grandfathered tariffs; and
- to rebalance fixed and variable charges

to gradually provide customers with tariffs that are more cost-reflective.

Technology-neutral, cost-reflective tariffs are a key element of Western Power's approach to services and tariffs, which aims to ensure efficient management of the network. Tariffs that provide accurate, cost-driven signals related to use of the network help promote efficient network usage and reduce overall costs by minimising the need for network investment.

3.2.2 Metering services

The impact of advanced metering infrastructure (AMI) meter rollouts is an area Western Power welcomes further discussion and engagement with the ERA on in the development of the AA6 framework and approach and subsequent determinations. Clarity on the direction and intention for any amended/new services should be provided as soon as possible to enable efficient implementation for AA6.

In any event, it is likely that a review of some metering tariffs may be required, as there will likely be a significant decrease in the demand for manual services over the AA6 period, as most Western Power meters become advanced meters. This will likely put upward pressure on the price for manual services.

Nevertheless, Western Power's current view is that the current services should be retained, given the potential for meters that do not consistently communicate on a remote basis and the number of customers that have already opted out of AMI communications.

Compliance testing of instrument transformers

Western Power also considers that the issue of compliance testing for current transformers and voltage transformers (together "instrument transformers") should be considered when reviewing metering services.

Western Power has an obligation to ensure that compliance testing is carried out every 10 years on instrument transformers on its network. However, it is not explicit in the Metering Code[46] that testing must be undertaken by Western Power specifically.

Non-compliance by customers can lead to risks that energy data provided by metering installations is inaccurate, and this can expose Western Power and customers to risks (i.e. undercharging or overcharging).

Western Power is exploring potential options to ensure compliance and mitigate these risks, and would welcome further engagement with the ERA and customers on this matter.

3.2.3 Services recovered by charges other than network tariffs

The issues paper notes concerns from stakeholders about "a lack of transparency and long timeframes to receive quotes from Western Power" for services such as new connections.[47] The issues paper identifies new connections as an example, but does not provide any information on the specific services that may be of concern.

Western Power is committed to enhancing transparency and improving the timeliness of its services to customers, where it can do so safely and efficiently. During the AA5 period, Western Power has implemented a program of work to improve the process for new connections by major users such as large loads and generation facilities.[48] These improvements have resulted in greater transparency and reduced time in the connections process. We are also working to improve connection timeframes for smaller customer connections. Connections are discussed further in section 3.4.

Western Power notes that the Western Australian Government has recently commenced consultation on a new transmission funding model,[49] to provide greater certainty for new generation, storage and large user projects.

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46 The *Electricity Industry (Metering) Code 2005*.

47 ERA, *Framework and approach for Western Power's sixth access arrangement review*, issues paper, 1 December 2025, p. 10.

48 Refer to Western Power website: Major customer connection review, 2025.

49 Department of Energy and Economic Diversification, 4 December 2025, Fixed Capital Charge: Consultation Paper

Western Power welcomes any further feedback on opportunities to improve transparency and the timeliness of its processes.

3.3 Service standards

As highlighted by the ERA in the issues paper, each reference service must have a service standard benchmark (SSB) specified in the access arrangement. SSBs are important for setting the level of reliability customers can expect to receive.

The access arrangement must also contain a service standard adjustment mechanism (SSAM), which is designed to ensure that cost efficiencies are not achieved at the expense of service standards. Variations in performance are assessed against baseline performance measures to provide incentives for maintaining or improving reliability.

This section covers all the issues identified by Western Power in relation to SSBs and the SSAM. It relates to two issues highlighted by the ERA in its issues paper, as follows.

Issues raised by the ERA in its issues paper

5. The ERA is interested in stakeholder views on setting disaggregated service standards for reliability and improving service standards relevant to business process

7. The ERA is interested in stakeholder views on changes to the price control and incentives and adjustment mechanisms that would:

- *Improve Western Power's accountability for delivering the access arrangement and complying with it.*
- *Deal with uncertainty while maintaining incentives for efficient expenditure and accountability for Western Power to deliver.*
- *Ensure the most efficient option is chosen regardless of whether it is capital or non-capital costs.*

The following subsections firstly consider issues associated with regional reliability and the specific concept raised by the ERA in relation to potentially setting more geographically granular SSBs for reliability.

It then outlines Western Power's proposals that several other amendments should be made to the SSBs specified in the access arrangement and to the SSAM, as follows:

- SSBs for transmission and distribution network reference services should be set based on the 97.5th (or 2.5th) percentile of actual performance over the previous period and separate measures should be introduced for use in the SSAM, consistent with the approach taken in the AA3 and AA4 periods.
- The SSBs for distribution network reference services related to the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI) should be amended to sustained interruptions longer than 3 minutes, as opposed to one minute currently.
- The exclusions associated with the call centre performance SSB should be amended to additionally include the day following a 'major event day' and force majeure events more generally.

Western Power is developing and testing potential revised approaches to measuring customer service performance through its community engagement program. Consequently, Western Power may propose new

SSBs in this regard as part of the AA6 proposal, which have the potential to replace the current call centre performance SSB.

3.3.1 Disaggregated service standards for reliability

The ERA has requested views from stakeholders on the setting of disaggregated service standards for reliability and improving service standards relevant to business processes.

Western Power considers the current industry-standard four-segment system reliability benchmarks to remain the most effective and balanced way to provide transparency and drive reliability performance across the network. These benchmarks operate alongside a broader suite of regulatory tools, including the SSAM, expenditure allowances, and compliance measures, to deliver reliability outcomes. These mechanisms must be assessed collectively rather than in isolation. Further disaggregation of service standard benchmarks into more granular categories risks creating unintended consequences and is unlikely to achieve the objectives being pursued.

For example, the existing CBD, urban, rural short, and rural long categories reflect structural differences in network design, customer density, and environmental exposure. These categories are large enough to produce stable, statistically meaningful performance data, ensuring that incentives under the SSAM reward genuine improvements rather than random variation. This stability is essential for a scheme that carries financial consequences for both customers and the network.

By contrast, a highly disaggregated approach would fragment the customer base into smaller groups, increasing year-to-year volatility and reducing the reliability of performance signals. This raises the risk of windfall gains or penalties unrelated to actual service quality, undermining the effectiveness of the incentive framework.

The ERA's issues paper notes that aggregate reporting does not always provide a complete picture of actual reliability performance across the network.

Western Power agrees that transparency is important; however, this can be achieved through separate reporting measures rather than by disaggregating the service standard benchmarks themselves. This approach provides visibility where needed while avoiding the adverse outcomes associated with fragmenting the service standards benchmark framework.

Western Power is already providing significant transparency and reporting regarding its regional reliability and performance, and has outlined its position regarding reliability standards in general in the following subsection and therefore requests that these positions also be considered in response to the ERA's question regarding disaggregated service standards.

Western Power considers that this is primarily an area which sits within the remit of the ERA, and progressing changes relating to disaggregated service standards for reliability cannot be achieved by Western Power in isolation without clear criteria provided by the ERA.

Western Power welcomes further engagement with the ERA on these areas, and requests that the following areas are given careful consideration in this context as well as 'disaggregated network planning' discussed in section 3.1.3:

- Fairness and equity of level and allocation of costs (for example, to address spillover effects from an investment that benefits multiple areas other than the area that drives the need for the investment).
- Where and how benefits are realised, both on a standalone basis and in the context of where and how costs are allocated.

- The Western Australia Government's local planning such as Strategic Industrial Areas and $400 million Housing Enabling Infrastructure Fund, and how these have been used to date (and intend to be used in future) in local planning.

Western Power looks forward to receiving further clarity from the ERA on its intentions for this area.

3.3.2 Method for calculating SSBs for transmission and distribution reference services

Under the Access Code, an access arrangement must include an SSB for each reference service.[50] Section 5.6 of the Access Code provides that an SSB for a reference service must be:

(a) reasonable; and

(b) sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

Further, section 11.1 of the Access Code requires Western Power to "provide reference services at a service standard at least equivalent to the service standard benchmarks set out in the access arrangement".

In the AA3 and AA4 periods, Western Power's SSBs were set at the 97.5th (or 2.5th) percentile of Western Power's actual performance in the previous period. In its F&A final decision document for the AA5 period, the ERA explained its decision to maintain this approach, commenting that: "The service standard benchmarks are the minimum level of service standards customers should receive. As a general principle, recent historical measures of service standards provide an appropriate starting point for determining service standard benchmarks".[51]

However, in its draft decision on the access arrangement for the AA5 period, the ERA modified this approach. The ERA expressed concern that the prevailing practice of including in the access arrangement both SSBs and Service Standard Targets (SSTs) was causing confusion for customers about what level of service Western Power would be expected to deliver.[52] SSTs are measures that, prior to the AA5 period, had been used for the SSAM.

Under this modified approach, confirmed in its final decision, the ERA decided to discontinue the practice of including both SSBs and SSTs in the access arrangement. Instead, it decided that only SSBs should be included. However, rather than setting the SSBs at minimum performance levels, as had been the case, the SSBs were to be set using the method previously used to set the SSTs, that is average performance over the previous five years.[53]

Western Power considers that, for the AA6 period, the method for calculating SSBs should return to the previous approach, that is set at minimum performance levels. The approach adopted for the AA5 period, based on an average measure is not consistent with the intent of the SSBs and makes compliance almost impossible. This arises due to the inconsistency between setting SSBs at the average level of performance and section 11.1 of the Access Code, which requires Western Power to provide reference services at a service standard "at least equivalent" to the SSBs set out in the access arrangement (see above).

Western Power considers that SSBs cannot be both an indicator of average service quality and a minimum service expectation. For SSBs to be an indicator of service quality they need to reflect expected reliability levels, for which using the historical average is an appropriate level. However, for the purpose of compliance,

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50 As required under section 5.1(c).

51 ERA, *Framework and approach for Western Power's fifth access arrangement review*, Final decision, 9 August 2021, pp. 27-28.

52 ERA, *Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, Attachment 9: Service standard benchmarks and adjustment mechanism, 9 September 2022, p. 14.

53 ERA, *Final decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, Attachment 9: Service standard benchmarks and adjustment mechanism, 31 March 2023, p. 16.

SSBs need to be reasonable in the sense that they allow Western Power a reasonable opportunity to be compliant. Many factors outside of Western Power's control affect performance in any given year. It is not appropriate to be held to a compliance standard for a measure that is based on historical average performance. Nor does setting SSBs at a reasonable compliance level (i.e. at the 97.5^{th} (or 2.5^{th})) provide customers with a good understanding of the level of performance they can expect for the applicable reference services.

One way to address this incompatibility would be an amendment to section 11.1 of the Access Code to remove the inference that service standards must be "at least equivalent to" the service standard benchmarks. However, as no change is expected ahead of the AA6 period,[54] Western Power considers that returning to the previous method of setting the SSBs (i.e. at the 97.5^{th} (or 2.5^{th}) percentile of actual performance over the previous period) is the most pragmatic approach to resolving this issue and better achieving the purpose of the SSBs.

Separate measures should be reintroduced for use in the SSAM

Under the SSAM, Western Power earns a financial reward if it exceeds specified levels of performance and incurs a financial penalty if it performs below these. For the AA3 and AA4 periods, the SSAM utilised SSTs to enable the SSAM to work. The SSTs were set based on the average performance achieved in the preceding access arrangement period.

In its F&A final decision for AA5, the ERA decided, consistent with the prevailing practice at the time, to set SSTs to be used in the SSAM based on the average service standard performance for the AA4 period.[55]

This was consistent with the purpose of the SSAM, which is to act as a balance against expenditure incentives. In the absence of a service incentive scheme, such as the SSAM, there would be an incentive to reduce expenditure to achieve rewards, including under the GSM, but this could be at the detriment of service quality. Therefore, a service incentive scheme may be required to ensure that service levels do not decline as a result of efforts to achieve efficiency gains.

However, as already highlighted, in its draft decision on AA5, the ERA modified this approach.[56] The ERA decided to discontinue the use of SSTs, and to instead use SSBs in the SSAM, confirming this position in its final decision.[57] As previously outlined, this has resulted in a situation where SSBs represent a minimum performance benchmark as well as measures of average performance in the SSAM.

Given the Access Code provisions associated with SSBs discussed above and established regulatory practise for service incentive standards, Western Power proposes that two sets of measures should be defined for the AA6 period. These two sets of measures would be:

- SSBs set at a reasonable level allowing Western Power the opportunity to be compliant with the Access Code.
- An alternative set of measures (such as the former SSTs) which would allow the SSAM to work in line the purpose of balancing against expenditure incentives (including the GSM) and provide an

54 Western Power notes that as part of the ongoing Power System Security and Reliability Framework Review, future changes are proposed to the setting of customer service outcome levels in the Energy System and Market Rules, replacing the existing duplicate approaches in Access Arrangements and the Network Quality and Reliability of Supply Code.

55 ERA, *Framework and approach for Western Power's fifth access arrangement review*, Final decision, 9 August 2021, p. 47.

56 ERA, *Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, Attachment 9: Service standard benchmarks and adjustment mechanism, 9 September 2022, p. 14.

57 ERA, *Final decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, Attachment 9: Service standard benchmarks and adjustment mechanism, 31 March 2023, p. 16.

indication of service reliability to customers. The naming of these measures could be updated to provide greater clarity on their purpose and to avoid confusion with SSBs.

A separate measure would be consistent with a regional reliability plan for the AA6 period

In its final decision on the access arrangement for the AA5 period, the ERA adopted a bespoke approach to specifying an SSB for rural long feeders.

The ERA noted that average levels of performance being used as a basis for the SAIDI distribution SSB for the AA5 period for CBD, urban and rural short feeders were well within the limits prescribed under the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (NQRS Code). However, the outage performance for rural long feeders (of 290 minutes) was not. The ERA therefore required the SSB for rural long SAIDI to be set at the level required under the NQRS Code (despite the fact that an SSB of this nature would not provide an indication of expected service reliability as average performance was tracking at 733 minutes).[58]

The ERA noted that, if Western Power was not to meet the rural long SSB set in the final decision, it would be subject to a financial penalty under the SSAM. Given the prevailing level of performance on the rural long feeders, the likelihood was that this would result in significant penalties for Western Power under the SSAM.

To support the development of a plan to address rural long reliability, a capital expenditure allowance equal to the estimated penalty ($88 million) was included in the forecast expenditure for the AA5 period. This allowance was to be used to develop a plan to improve regional reliability, including implementing solutions in pilot areas.

Provided this allowance was invested effectively, the ERA decided that the service standard adjustment penalty relating to the difference between 290 minutes and the SSB that would otherwise have been determined based on the level of average performance in the AA4 period (733.5 minutes) would not be imposed.

Western Power's proposal to reestablish a separate benchmark measure in the SSAM means that there would be no need to treat rural long feeders in the SSAM any differently to any other feeder class. Targets for rural long feeders would be set at the level of average performance in the preceding access arrangement period in line with other feeders.

58 ERA, *Final decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, Attachment 9: Service standard benchmarks and adjustment mechanism, 31 March 2023, p. 2.

Case study: Regional Connect – improving regional reliability

Western Power emphasises its commitment to improving regional reliability outcomes. In the AA5 period, Western Power has progressed its regional reliability initiative – Regional Connect.

Regional Connect is a targeted program to shorten the duration and frequency of unplanned outages for homes and businesses supplied by long feeder lines. Western Power tailors its approach for each feeder line and target area based on the environmental, demand and local context, delivering practical improvements now while planning for what is needed next.[59] While the roll-out of these initiatives is ongoing, in 2024-25 overall SAIDI for long rural feeders was recorded at 675.5, a 21% improvement on the previous financial year.

Western Power is tracking the outcomes in each area to learn and inform future actions. Drawing on these learnings, Western Power will set out a comprehensive regional reliability plan as part of its full AA6 submission, having tested this through community consultation.

Western Power considers this to be the appropriate approach to resolving regional reliability issues, as opposed to attempting to use the SSAM for this purpose. Western Power notes that the AER has previously concluded that incentive schemes, such as the SSAM, are not the right vehicle to drive step changes in reliability should customer engagement reveal this to be necessary.[60]

As previously noted, the purpose of the SSAM is to act as a balance against the incentives for cost minimisation present elsewhere in the access arrangement that might favour a degradation in current performance levels and, in this regard, the appropriate measure for use in the mechanism is the prevailing average level of actual service performance.

Determining appropriate benchmarks for setting SSBs

For AA5, the ERA determined that service standard benchmarks in the access arrangement should not be set below the standard of NQRS Code requirements because it considered the NQRS Code to represent a legislative obligation. Consequently, the ERA determined the AA5 service standard benchmark for rural long feeders should be set at 290 minutes rather than basing it on actual performance during the AA4 period.

Western Power considers the purpose of SSBs under the Access Code must be central to determining appropriate benchmarks. The Access Code requires SSBs to be reasonable and enable a user or applicant to determine the value represented by the reference service at the reference tariff.[61] It does not require SSBs to match or exceed the levels specified in the NQRS Code.

First, setting the reliability SSB for rural long feeders at the level expressed in the NQRS Code is unreasonable, as this level of performance cannot reasonably be achieved in short to medium term, and without substantial costs; expenditure that may not align with customer expectations or willingness to pay.

Second, adopting the NQRS Code reliability level as rural long SSBs would not enable users or applicants to determine the value represented by the reference service for the reference tariff,[62] because it would not reflect the service reliability outcomes that can realistically be delivered.

59 More information on Regional Connect is available on the Western Power website.

60 AER, *Reviewing the Service Target Performance Incentive Scheme and Establishing a new Distribution Reliability Measures Guideline*, issues paper, January 2017, p. 35.

61 Under section 5.6 of the Access Code.

62 As required under section 5.6(b) of the Access Code.

Consequently, Western Power considers that the approach to setting an SSB for rural long feeders should be consistent with that proposed above for other SSBs, that is being set at the 97.5th (or 2.5th) percentile of actual performance over the previous period.

Western Power further considers that the rationale set out above should also apply to SSBs for reference services D1 to D13. In the AA5 final decision, the ERA decided that the SSBs for reference services D1 to D13 must be amended to be consistent with the time periods specified in the Metering Code or Code of Conduct, on the basis that the SSBs should be consistent with any legislative obligations.[63]

As with SSBs for rural long feeders, the approach adopted by the ERA for these ancillary services also does not enable users or applicants to determine the value represented by the reference service for the reference tariff, as required by the Access Code. Consequently, Western Power similarly proposes that SSBs for these reference services should be specified as a percentage of actual performance.

3.3.3 Changes to the definitions of SAIDI and SAIFI

The access arrangement currently includes three types of SSBs for distribution reference services. Of these, two relate to distribution network reliability performance, as follows:

- System average interruption duration index (SAIDI) for urban areas, rural-short and rural-long feeders and the Perth central business district, which measures the average duration of sustained interruptions per customer in a year.
- System average interruption frequency index (SAIFI) for urban areas, rural-short and rural-long feeders and the Perth central business district, which measures the average number of sustained interruptions per customer in a year.

Currently, a sustained interruption is defined as being greater than one minute in duration for each of the SSBs relating to SAIDI and SAIFI.

Western Power proposes that, for both SAIDI and SAIFI, the definition of a sustained interruption should be amended to being greater than three minutes in duration.

This is because it can take longer than 60 seconds for relevant communications systems to send fault signals back to the master station. This impacts on Western Power's ability to restore power within the one-minute window even where 'immediate' restoration can and does successfully occur.

Changing the definition to exclude interruptions of less than three minutes in duration would incentivise further automation, which might not be appropriately rewarded under the current approach. It would also bring Western Australia into alignment with other jurisdictions, including the NEM (see box, below) and Great Britain.

In Great Britain, Ofgem's Interruptions Incentive Scheme (IIS)[64] for electricity distribution covers the number and duration of customers interrupted for three minutes or more.[65] Interruptions of less than three minutes are classed as 'Short Interruptions' and are not included in the IIS.

63 ERA, *Final decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, Attachment 9: Service standard benchmarks and adjustment mechanism, 31 March 2023, pp. 18, 23.

64 The ISS, like the SSAM, is an incentive scheme which sets target levels of performance for distributors to achieve; rewards are provided to distributors who beat their targets, and penalties apply for distributors who fail to achieve their targets.

65 Ofgem, *RIIO-ED2 Regulatory Instructions and Guidance – Interruptions*, 1 January 2024, p. 40.

Case study: Definitions of SAIDI and SAIFI in the NEM

In 2014, the Australian Energy Market Commission (AEMC) conducted a review of distribution reliability measures, with the objective of developing common definitions that could be applied across the NEM (including by the AER when developing incentive schemes).

One of the review's key recommendations was to change the definition of a momentary interruption from less than one minute to less than three minutes and, consequently, that the duration of a sustained interruption would be defined as greater than three minutes.

The AEMC concluded that, as compared to a duration of one minute:[66]

> *"Allowing the duration of momentary interruptions and momentary interruption events to extend to three minutes would allow the distributors greater flexibility in the design of their distribution automation systems. For the majority of networks, where distribution automation systems have not yet been deployed in scale, this change would provide the potential to reduce the cost of implementing distribution automation systems. In conjunction with an effective incentive scheme, the increased flexibility and potential for reduced cost of distribution automation systems would be likely to promote greater investment in distribution automation systems. This increased investment in distribution automation would be expected to reduce the number of sustained interruptions by automatically restoring supply to more customers, thus improving reliability performance."*

The AER agreed that the 3-minute threshold would encourage the introduction of distribution automation systems and accepted the AEMC's recommendation. Accordingly, the AER updated the distribution service target performance incentive scheme with effect from December 2018.[67]

3.3.4 Call centre performance exclusions

The customer service SSB in the current access arrangement relates to call centre performance, measuring the percentage of calls responded to within 30 seconds or less.

This measure is subject to a limited number of exclusions, one of which is all telephone calls received on a 'major event day'. A major event day is one which is excluded from calculations of SAIDI and SAIFI, and the threshold for what constitutes a major event day is specified in the access arrangement.

Western Power proposes that the exclusions associated with the call centre performance SSB should be amended to additionally include the day following a major event day.

This is because the high volumes of calls to the Western Power call centre that would typically be associated with a major event day can extend beyond the period captured by the major event day definition.

For example, on the night of 29 March 2025, the SWIS experienced a significant transmission outage as a result of a severe weather event. Calls received by the Western Power call centre on 29 March were excluded from measurement against the relevant SSB as the day was classified as a major event day. However, the high volume of calls (4,468) received between 1AM and 4AM on 30 March were not similarly excluded.

Western Power therefore considers that it would be appropriate for the day following a major event day to also be excluded from measurement against the SSB, due to the fact that call volumes would not be at usual levels, instead more closely following the pattern associated with a major event day.

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[66] AEMC, *Review of Distribution Reliability Measures*, Final Report, 5 September 2014, p. 12.

[67] AER, *Amendment to the Service Target Performance Incentive Scheme (STPIS)*, Final decision, November 2018, p. 15.

Western Power also considers that it would be appropriate to include force majeure events more generally in the exclusions associated with the call centre performance SSB, to ensure that events with multi-day impacts, beyond the defined major event day, are appropriately accounted for. All SSBs aside from those for distribution reference services already include force majeure.

In practice, this could be implemented by incorporated the concept of force majeure into the last of the existing exclusions as follows:

> *"**A force majeure event affecting call centre performance, including** 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."*

3.3.5 Potential for new customer service performance measures

Western Power is investigating the potential to develop other measures of customer service through its customer engagement program, if this is deemed viable then it will be presented in the AA6 submission.

This would be consistent with developments in the NEM. Historically, the AER's service target performance incentive scheme (STPIS) has penalised or rewarded distributors based on the proportion of fault line telephone calls they answer within 30 seconds (in a similar manner to Western Power's current SSB).

However, engagement with customers by distributors suggested that this incentive might not best reflect customer preferences, and this was confirmed through consultation undertaken by the AER. Consequently, the AER developed a Customer Service Incentive Scheme (CSIS), with the AER stating that it "is designed to encourage electricity distributors to engage with their customers and provide customer service in accordance with their preferences".[68]

The CSIS is a flexible 'principles based' scheme that can be tailored to the specific preferences and priorities of a distributor's customers. This flexibility is designed to allow for the evolution of customer engagement and adapt to the introduction of new technologies. The principles of the scheme target customer preferences and provide safeguards to ensure penalties/rewards under the scheme are commensurate with improvements/detriments to customer service.

The CSIS has now been applied to distributors in New South Wales, Victoria and Tasmania. Where the CSIS has been applied, the AER has opted not to apply the telephone answering parameter in the STPIS, maintaining the overall level of revenue at risk.[69]

Following the current community engagement program, Western Power may look to propose new SSBs relating to customer service as part of the AA6 submission. It should be noted that these measures may – as under the AER approach – have the potential to replace the current call centre performance SSB (referred to in the previous section).

3.4 Connecting customers

In the issues paper, the ERA discussed the experiences of parties seeking to connect to the network at the time of the AA5 review and highlighted the process changes subsequently made by Western Power to reduce connection times.[70]

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68 AER, *Customer Service Incentive Scheme*, Explanatory Statement, July 2020, p. 4.

69 That is, the 0.5 per cent of total annual revenue at risk through the CSIS replaces the 0.5 per cent of total annual revenue that would have been at risk under the telephone answering parameter of the service target performance incentive scheme.

70 ERA, *Framework and approach for Western Power's sixth access arrangement review*, issues paper, 1 December 2025, pp. 12-13.

Nevertheless, as the number of connection applications continue to increase and technological advances are leading customers to increasingly seek to install equipment behind the meter that requires the approval of Western Power, the ERA is considering whether additional mechanisms are needed in the access arrangement to manage the higher levels of complex customer connections Western Power is experiencing and will likely continue to receive for the foreseeable future.

The ERA has specifically requested feedback as follows.

Issue raised by the ERA in its issues paper

6. The ERA is interested in stakeholder views on what improvements could be made to Western Power's connection processes and whether additional mechanisms are needed to incentivise Western Power.

3.4.1 Improvements to connection processes

During the AA5 period, Western Power has been working to improve its connection processes to reduce connection timeframes and improve transparency for customers.

The issues paper notes that Western Power has implemented improvements to its connections process for major customers, such as large loads and generators. Western Power commenced the roll out of these improvements in mid-2023 and has experienced significant improvements in the timeframes for new connections in recent years.

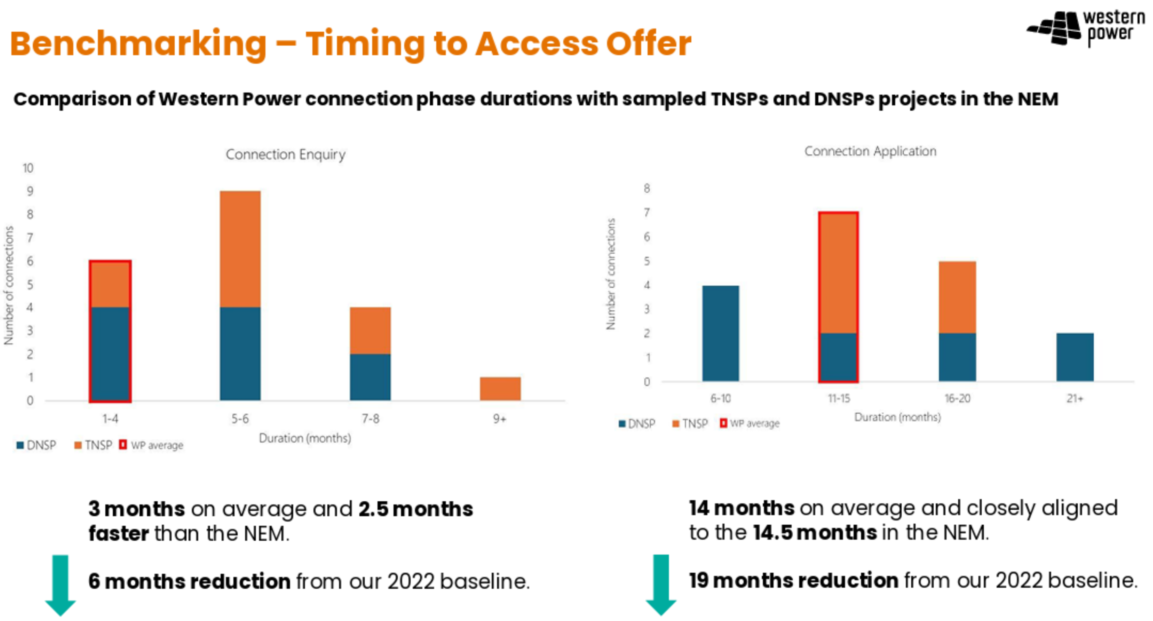
In 2022, Western Power's major customers experienced an average connection time (from connection enquiry to access offer) of 3.5 years. Over the period to September 2025, this had reduced to just under 1.5 years for projects progressing through the new improved connection process:

- Connection enquiry stage – has reduced by 6 months (from 9 to 3 months)
- Connection application to access offer (initiation, scoping and planning stages) – has reduced by 19 months (from 33 to 14 months).

Western Power's connection process timeframes now compare favourably against peers in the NEM, as summarised in the figure below.[71]

[71] Western Power publishes further information on project work being undertaken, average timeframes and data relating to project type, industry and region in the quarterly Major Customer Connection Insights Report.

Figure 2. Change in Western Power connection process timeframes



In 2022, Western Power determined that only five per cent of all connection enquiries were reaching final investment decision and receiving an access offer to move into execution. In FY24, Western Power issued access offers for 1.5 GW. Western Power's current 12-month rolling forecast has about 23 per cent of all connection enquiry reaching access offer and its FY26 access offer forecast is on track to deliver 5.1 GW.

More recently, in June 2024, Western Power implemented the Critical Project Framework to ensure that Western Australia's critical projects can proceed, in line with the State's commitment to achieving a reduction in emissions and to keep pace with the unprecedented uplift in demand for major customer network connections.

The Critical Project Framework identifies and supports projects that clearly demonstrate their readiness to connect. It ensures that customers meet essential criteria for successful delivery, including strategic alignment and overall customer readiness. This has enabled more efficient access to the network, ensuring customers benefit from improved connectivity and service reliability by providing right of way to Western Power resources.

Western Power is continuing work to improve elements of these processes and offer further customer self-serve options (design & construct and dynamic studies) to enable scalability in line with increased connection application demand from industry.

In recent years, Western Power has experienced sustained year-on-year growth in applications for connections to the distribution network.[72] In 2024-25, Western Power commenced several strategic initiatives aimed at improving both commercial and residential customer connections. Alongside reducing connection timeframes, these initiatives seek to improve customer service by adopting a holistic, customer-centric approach from application to energisation, supported by proactive customer management and prioritisation.

Early implementation of these initiatives has focussed on the application and design stages of the connection process, with the focus now shifting toward scheduling and construction. The initiatives also include improvements to management systems and reporting to better identify process constraints, support

[72] Applications increased 7% in 2024-25, with a similar growth level expected for 2025-26.

solutions development, and strengthen performance monitoring. Time-to-connect improvements are measured against corporate key performance indicators for the strategic portfolio segments comprising residential, land development, commercial and asset relocation.

These portfolio segments allow us to maintain focus on government priorities such as housing. Performance for each segment is reported to the Western Power Executive and Board, with current performance illustrated in Figure 3 to Figure 6.

Figure 3. Average processing length – Residential

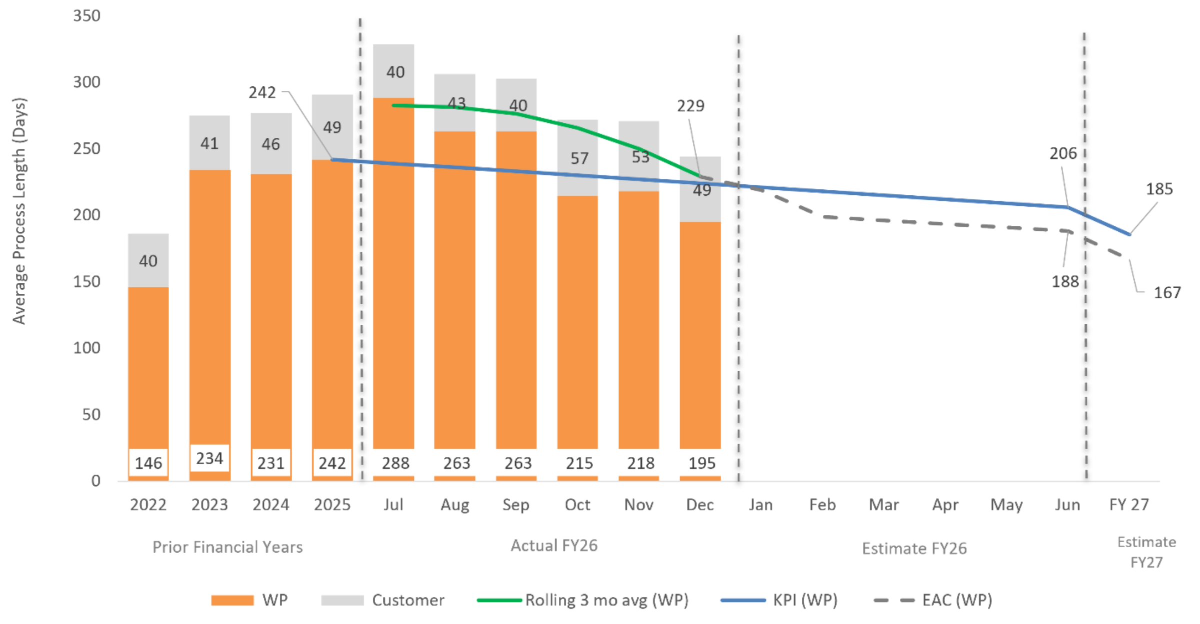


Figure 4. Average processing length – Land development

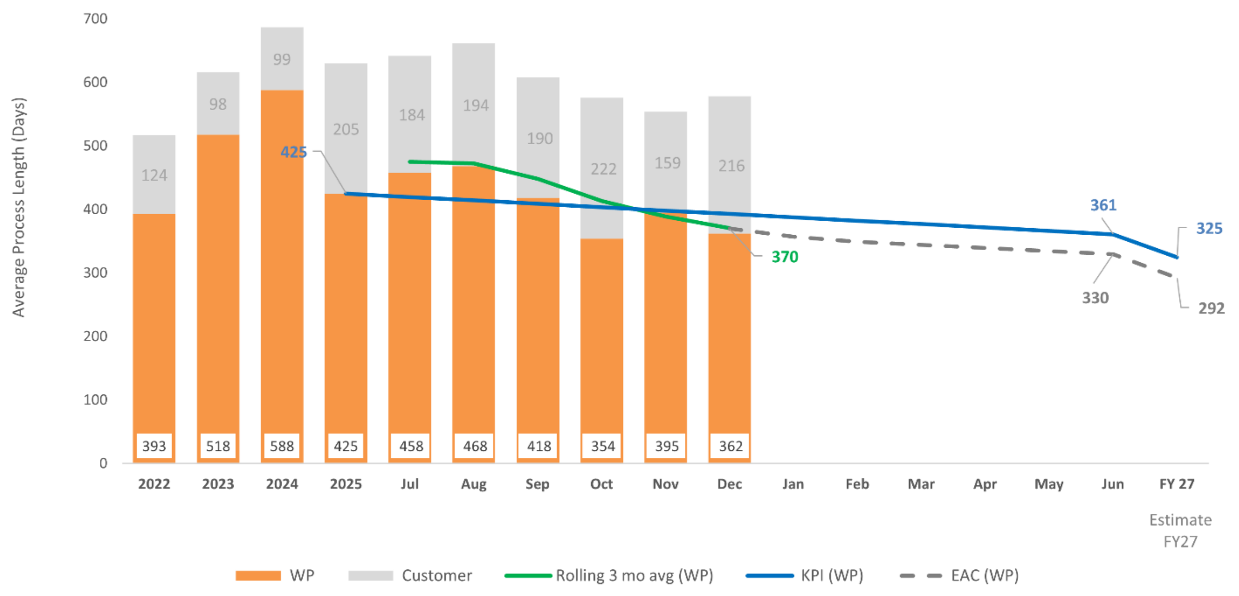


Figure 5. Average processing length – Commercial

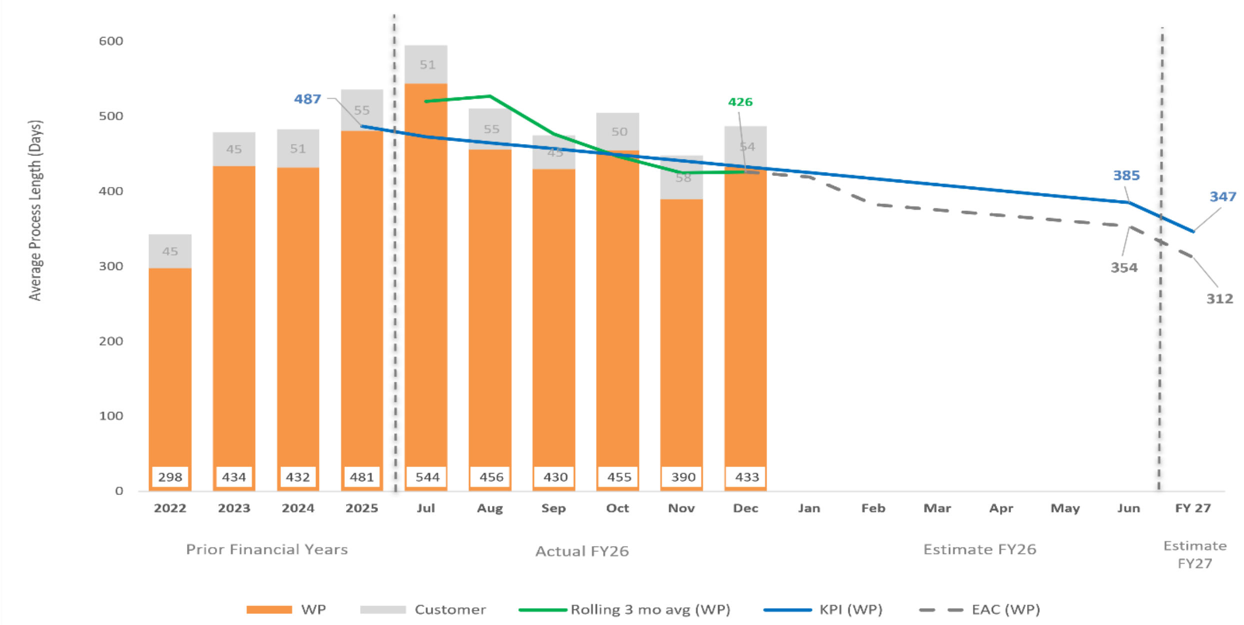
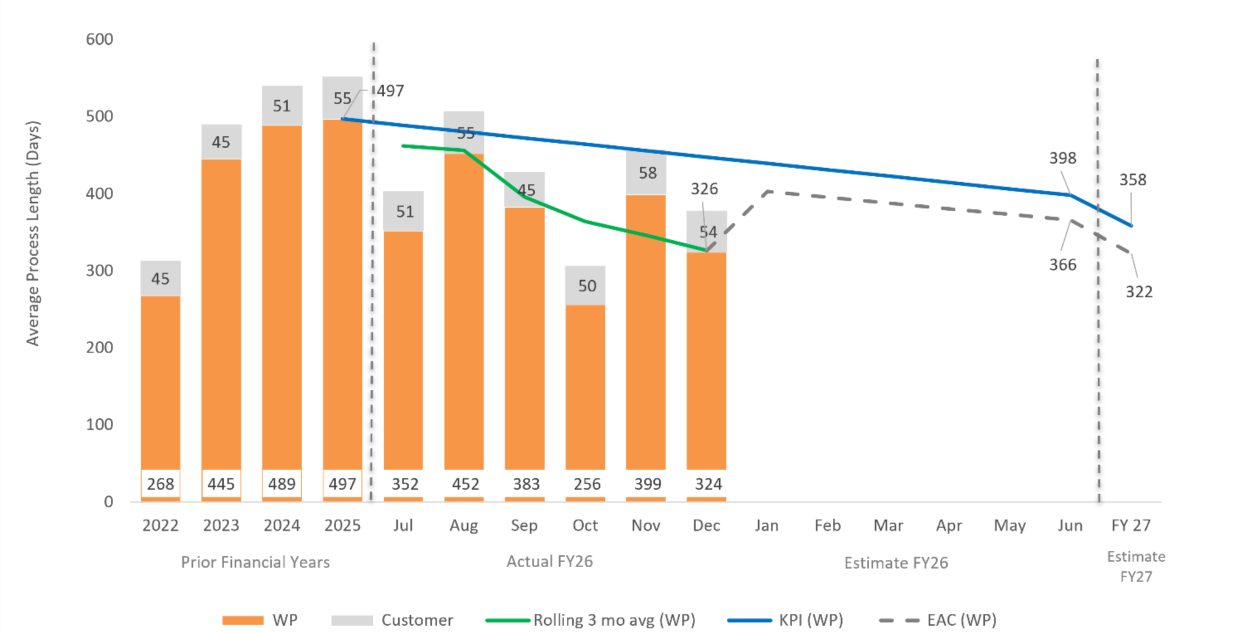


Figure 6. Average processing length – Asset relocations



We note that our reporting maintains visibility of customer average timeframes. Our key performance indicators and our performance are measured based on the time Western Power takes to complete its activities. Our reporting also incorporates our forecast estimate at completion (EAC), which reflects expected future performance based on the most recent rolling average of actual results.

Current reporting indicates sustained improvement through to the end of FY27. Recent highlights from our performance initiatives include:

- a 46 per cent reduction between April and November 2025 for residential design
- a 39 per cent reduction between June and November 2025 for commercial design

- an 80 per cent reduction for design information packages and 49 per cent reduction for design conformance reviews in November 2025 compared to 2024-25 for subdivisions
- implementation of a quality control framework, including an accelerated design review for lower complexity projects.

Customers are now able to access improved information about the likely timeframes and costs of a new connection via the Western Power website.[73]

Western Power has also established the MyWP Projects Portal – a centralised, self-service platform where customers can manage and track projects in real time. It improves transparency through clear milestones, consolidated project views and 24/7 access, enabling customers to update details, manage permissions, share projects and streamline enquiries, submissions and file uploads in one place.

Over the next two to three years, Western Power is working to implement improvements in the other steps in the connection process. This includes developing a web-based customer self-serve tool allowing options analysis, project planning, design and quote generation, tools to optimise Western Power's workflows, and proposed partnerships with vendors to deliver customer-funded projects. These initiatives seek to improve the timeliness of the process, ensure construction capacity and provide greater transparency.

3.4.2 Possible incentive mechanisms

Western Power acknowledges that incentives can play a constructive role, for example, by providing required funding to improve resourcing and processes. However, it would be premature to introduce a new incentive mechanism for customer connections at this stage.

The performance challenges observed during AA5 were not indicative of a sustained or systemic issue across multiple access arrangements. They reflected a temporary period of unprecedented application volumes and short-term resourcing constraints. Western Power has since implemented targeted process improvements that have already delivered material performance gains.

As described above, Western Power is making ongoing improvements to its processes for new connections across different customer groups and notes that these have already delivered significant improvements. In general, Western Power considers that a continued focus on process improvements of this nature would form the most appropriate response to the challenges that the ERA has suggested.

In particular, transparency measures such as the quarterly Major Customer Connections Insights Report referred to above and the special focus area in the ERA's AA5 annual progress reports already provide a high level of visibility over Western Power's performance and progress. These mechanisms give stakeholders clear insight into how connection activities are tracking, which in turn supports accountability and continuous improvement.

That being said, Western Power is committed to receiving feedback from stakeholders and developing improvements to its processes, and is open to further engagement on these matters.

3.5 Gain sharing mechanism and demand management innovation allowance

In the issues paper, the ERA discusses several of the matters it is required to decide on at the F&A stage in a single section relating to the price control, incentives and adjustment mechanisms.

[73] See for example the information available for a single residential connection and a medium commercial connection.

Western Power's proposals in relation to a number of these matters have already been covered in this response:

- the form of price control in subsection 2.1
- the investment adjustment mechanism in subsection 2.2
- the D-factor mechanism in subsection 2.3
- the service standard adjustment mechanism in subsection 3.3.

This final subsection considers the remaining matters raised by the ERA in this area, which relate to:

- the gain sharing mechanism; and
- the demand management innovation allowance.

The ERA has specifically requested feedback as follows.

Issue raised by the ERA in its issues paper

7. The ERA is interested in stakeholder views on changes to the price control and incentives and adjustment mechanisms that would:

- *Improve Western Power's accountability for delivering the access arrangement and complying with it.*
- *Deal with uncertainty while maintaining incentives for efficient expenditure and accountability for Western Power to deliver.*
- *Ensure the most efficient option is chosen regardless of whether it is capital or non-capital costs.*

3.5.1 Gain sharing mechanism

Western Power proposes that several amendments should be made to the operation of the gain sharing mechanism (GSM) as specified in the access arrangement, as follows:

- Caps should be introduced on the level of overall surpluses and deficits under the GSM.
- An explicit determination of the surpluses or deficits resulting from the mechanism should be made by the ERA under section 6.25 of the Access Code.
- Certain additional categories of operating expenditure, including uncontrollable costs, the cost impacts of unforeseen events and items forecast on a bottom-up basis (as opposed to using the Base-Step-Trend methodology), should be excluded from the operation of the GSM.

These proposals are outlined below.

Capping the overall adjustment resulting from the GSM

Consistent with the objectives listed under section 6.21 of the Access Code, the purpose of the GSM is to equalise the power of the incentive on Western Power to minimise operating expenditure across the duration of the access arrangement period. To achieve this, it provides for an adjustment to target revenue in the next access arrangement period so that Western Power retains the benefit of operating cost efficiencies for five years, regardless of which year the efficiency was made. This occurs because operating expenditure is forecast using the Base-Step-Trend (BST) method. Under this approach, the operating expenditure allowance is set with reference to observed costs. As a result, without a mechanism such as GSM, any realised efficiency gains (cost savings) are removed from the allowance in the next period, meaning Western Power does not retain the benefit of those efficiencies, especially toward the end of a regulatory period.

For example, without the GSM, efficiency savings made in year one would be retained for five years but savings in year five would be retained for only one year. Consequently, there would be less of an incentive to make efficiency savings in the latter years of an access arrangement period.

The annual surpluses and deficits to be carried forward into the next access arrangement period are calculated by reference to an annual efficiency and innovation benchmark (EIB) specified in the access arrangement. Prior to the AA5 period the mechanism only applied to surpluses – that is underspends as compared to the EIB – although such surpluses were disregarded if the SSB (set at the 97.5th (or 2.5th) percentile of Western Power's actual performance in the previous period) was not met. With effect from the AA5 period, the requirement to achieve the SSB has been removed, and the mechanism was made symmetrical – that is, deficits as well as surpluses are carried forward.

Western Power considers that the level of total revenue adjustment that can be made as a result of the surpluses and deficits achieved under the GSM should be subject to a cap. In a dynamic operating environment, over or underspend can happen due to factors beyond the reasonable control of a prudent and efficient service provider.

Capping the size of the GSM adjustment would give the clear benefit of mitigating risks for both consumers and Western Power while retaining a strong incentive for efficiency. The cap could be expressed as a percentage of operating expenditure.

Case study: Ofgem's approach to managing risk for Electricity Transmission Operators

In Great Britain, Ofgem has acknowledged the uncertainty and pace of change facing the electricity transmission sector by amending its Totex Incentive Mechanism (TIM), which aims to ensure that Transmission Operators (TOs) and consumers share the risk of overspending and share any cost efficiencies that can be achieved.

The revised TIM introduced as part of its December 2025 final decision on RIIO-3 has a stepped structure, including three bands:[74]

Band 1: On the first 5% of any overspend or underspend TOs would pay 25% of any overspend on that first 5%, and similarly receive 25% of any underspend on that first 5.

Band 2: In addition to Band 1, which will continue to apply for the first 5% of spend variance, under Band 2 when totex spending falls between 5% and 20% (up or down) of agreed price control allowances TOs would pay 10% of any overspend over 5% and up to 20%, and receive 10% of any underspend below 5% and up to 20%.

Band 3: In addition to Band 1 which will continue to apply for the first 5% of spend variance, and Band 2 which will continue to apply for the next 15% of spend variance, Band 3 will apply when totex spending exceeds 20% (up or down) of agreed price control allowances. Under Band 3, TOs would pay 5% of any overspend above 20%, and receive 5% of any underspend below 20%.

Previously, under the RIIO-2 arrangements, there were single rates that varied by TO, ranging from 33% for NGET to 49% for SPT. Ofgem considered that, while maintaining rates at this level would have kept a strong incentive on TOs with regards to cost efficiency, with the volumes of capex expected in the RIIO-3 period, these would place too much risk on TOs (and on consumers, if costs were set too high).[75]

Notably, Ofgem now considers that the TIM should primarily focus on managing the risk of cost forecasting inaccuracy and/or overspends, with the aim of driving TO behaviours to achieve cost efficiency now forming a secondary focus.

Explicitly determining surpluses and deficits under section 6.25 of the Access Code

As set out above, under the current approved access arrangement, GSM surpluses and deficits are effectively calculated as the difference between actual and forecast operating expenditure (in the form of the EIB). There are some relatively minor exclusions, as discussed in the following section.

However, Western Power considers that the Access Code requires the ERA to make an explicit determination of surpluses and deficits arising under the mechanism, rather than being able to simply rely on a mechanistic approach.

For the AA6 review, Western Power must apply the GSM to calculate the above-benchmark surplus or the below-benchmark deficit for the AA5 period, using the EIB set out in section 7.4.2 of the access arrangement.

These calculations will need to be submitted as part of the AA6 access arrangement proposal. The calculations are not binding on the ERA as they are subject to the ERA's subsequent review and determination. Section 6.25 of the Access Code requires that:

> "The Authority [the ERA] must determine how much (if any) of the surplus results from efficiency gains or innovation by the service provider in excess of the efficiency and innovation benchmarks

[74] Ofgem, *RIIO-3 Final Determinations – Electricity Transmission*, 4 December 2025, p. 202.

[75] Ofgem, *RIIO-3 Draft Determinations – Electricity Transmission*, 26 August 2025, pp. 169-171.

> in the previous access arrangement ('above-benchmark surplus') or how much of the deficit results from a failure of the service provider to meet the efficiency and innovation benchmarks in the previous access arrangement ('below-benchmark deficit')."

The ERA must therefore review the surplus or deficit as calculated by Western Power and, if necessary, adjust the amount of the surplus or deficit to the extent that the under-spend or over-spend is not attributable to Western Power's efficiency or innovation gains or losses. This is supported by section 5.26(a), which provides that:

> "Efficiency and innovation benchmarks must… if the access arrangement contains a gain sharing mechanism, be sufficiently detailed and complete to permit the Authority [the ERA] to make a determination under section 6.25 at the next access arrangement review…".

Having made this determination, the ERA will then apply that adjusted figure to Western Power's target revenue for the AA6 period, as provided for in section 6.27:

> "The Authority [the ERA] must apply the gain sharing mechanism to determine how much (if anything) is to be added to or removed from the target revenue for one or more coming access arrangement periods under section 6.4(a)(ii) in order to enable the service provider to continue to share in the benefits of the efficiency gains or innovations which gave rise to the above-benchmark surplus or to penalise the service provider for the failure to meet the efficiency and innovation benchmarks which gave rise to the below-benchmark deficit."

Western Power therefore considers that these provisions require the ERA to make an explicit determination at an access review as to the amounts that should be recovered or returned through the GSM in the following access arrangement period. This would be appropriate, in that it would allow for a more nuanced assessment to be made as to whether surpluses (or deficits) arise as a result of efficiency gains (or losses) or not. In the absence of a formal and detailed determination being made, there is a risk that the GSM is applied for cost differences that are unrelated to changes in efficiency.

Undertaking a formal determination in this manner could effectively also provide an alternative approach to the capping of the overall adjustment made through the GSM. Instead, the ERA could cap the surpluses or deficits adjudged to have arisen each year, prior to these amounts being included in the GSM, as opposed to capping the overall returns and losses resulting from the GSM.

Additional categories of operating expenditure should be excluded from the GSM

Under the GSM, as it currently specified in the access arrangement, certain exclusions apply, including operating expenditure incurred:

- in accordance with the D-factor scheme (providing that the expenditure has been approved by the ERA)
- in accordance with the demand management innovation allowance (see section 3.5.2, below)
- in relation to force majeure events
- in relation to any adjustments made to target revenue for technical rule changes
- in relation to non-revenue target services.

Western Power considers that these exclusions should be expanded to cover several additional categories of operating expenditure, such that the GSM should not take into account: costs which are uncontrollable, the cost impacts of unforeseen events, and items forecast on a bottom-up basis (as opposed to using the Base-Step-Trend methodology). These categories proposed for exclusion are detailed in Table 2, below.

Table 2. Categories of operating expenditure proposed for exclusion from the GSM

Categories of operating expenditure for exclusion from the GSM		Existing or proposed new exclusion
Uncontrollable costs	Energy Safety Levy	Proposed new (excluded prior to AA5)
	ERA fees	Proposed new (excluded prior to AA5)
Unforeseen events	Force majeure	Existing
	Adjustments associated with technical rule changes	Existing
	Specified trigger events	Proposed new
Items not forecast using Base-Step-Trend	Expenditure under the D-factor scheme	Existing
	Expenditure under the DMIA	Existing
	Expenditure related to non-network solutions	Proposed new
	Operating expenditure associated with capital expenditure covered by the IAM	Proposed new
	Non-revenue target services	Existing

By their very nature, uncontrollable costs are not ones that Western Power can seek to reduce through efficiency or innovation. Consequently, there are no benefits in including these costs in incentive schemes such as the GSM. The intended incentive properties serve no purpose, and any seeming over or under-performance by Western Power carries only risks – either of customers funding windfall gains or, alternatively, of challenges being created to Western Power's financial position.

Western Power further considers that operating expenditure associated with other uncertainty measures should not be included in the operation of the GSM, so as to avoid duplication. In particular, operating expenditure not forecast using Base-Step-Trend – including the proposed building block forecasts of operating expenditure related to non-network solutions and operating expenditure associated with capital expenditure covered by the IAM – should be excluded from the GSM, as they will be subject to reconciliation through another uncertainty mechanism.

3.5.2 Demand management innovation allowance

Western Power proposes that the demand management innovation allowance mechanism contained in the access arrangement should continue to operate on a broadly unchanged basis for the AA6 period.

Under section 6.32B of the Access Code, the demand management innovation allowance is an annual, ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each pricing year of an access arrangement period.

The objective of the demand management innovation allowance, as set out in section 6.32C of the Access Code, is to provide funding for research and development in demand management projects that have the potential to reduce long term network costs.

For the AA5 period, the ERA decided that target revenue would include an annual demand management innovation allowance based on 0.08 per cent of approved target revenue (excluding the allowance) for each pricing year.[76] This represents an annual amount of $1.4m, although no annual cap applies, so the amount can be accumulated up to the value of $7.1m over the AA5 period (in nominal terms).

The mechanism operates as follows:

- The allowance can be used during the access arrangement period for projects that meet the eligibility requirements set out in the Access Code and in the ERA's demand management innovation allowance guidelines.
- Western Power is required to provide annual compliance reports to the ERA in accordance with the ERA's guidelines.
- Expenditure claimed against the allowance will be reviewed at the next access arrangement review. Any allowance that has not been used will be returned to customers through an adjustment to target revenue at the next access arrangement period.

In Western Power's view, the mechanism has operated well over the course of the AA5 period to date. Five eligible projects have been progressed, representing a claim under the allowance of $7.55m (in nominal terms).

The initiatives undertaken include research and development projects with the intention to reduce or shift customer demand, avoid or defer network augmentation, or target a reduction in peak or broad-based demand. The research and development projects funded under the allowance are essential to Western Power's efforts to balance sustainability and long-term affordability as peak demand continues to be a principal driver of network augmentation costs. Further information can be found in Western Power's most recent demand innovation allowance compliance report.[77]

On this basis, Western Power is of the view that the mechanism should continue into the AA6 period on a broadly unchanged basis. Western Power intends to consider stakeholder feedback provided directly and in response to the issues paper in informing its view on the detailed design of the mechanism, including the extent to which there is any appetite for increased incentives for demand management. In the coming months, Western Power planning may also identify the need for additional allowances.

[76] This is broadly comparable with the allowances applying in the NEM, which are 0.075 per cent of target revenue for distribution businesses and 0.1 per cent of target revenue for transmission businesses.

[77] Western Power, *Demand Management Innovation Allowance Report 2022/23 to 2024/25*, 31 October 2025.