# Access Arrangement Information

## Access Arrangement revisions for the fifth access arrangement period

1 February 2022

**An appropriate citation for this paper is:**

Access arrangement information

**Western Power**

363 Wellington Street
Perth WA 6000
GPO Box L921 Perth WA 6842

T: 13 10 87 | Fax: 08 9225 2660
TTY 1800 13 13 51 | TIS 13 14 50

Electricity Networks Corporation
ABN 18 540 492 861

enquiry@westernpower.com.au
westernpower.com.au

Enquiries about this report should be directed to:

**AA5 Project Team**

Email: AA5@westernpower.com.au

# What our AA5 proposal delivers for our community and customers

### Continued focus on safety

- Maintain safety performance
- Replace ~37,000 wood poles, underground 875 km of urban network, improve substation security, reduce electric shocks and enhance cyber security

### Reliable supply

- Maintain overall network reliability and improve underperforming hotspots
- Utilise standalone power systems, microgrids and undergrounding
- Modernise protections, control and visibility of network operation and performance

### Facilitating more renewables

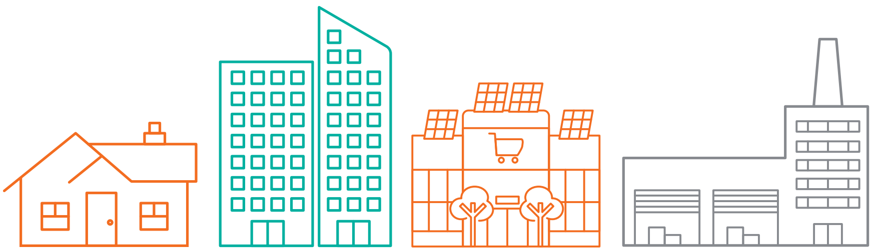
- Support more renewable connections including 3 GW of rooftop solar by the end of the AA5 period
- Enhance voltage management
- Full deployment of advanced metering infrastructure

### Affordable price outcomes

- Price rises of less than inflation for the average network bill
- New services and tariffs that increase customer choice and control of bills

### enabled via the transition to a modular grid

Improve resilience to extreme climate events
Adopt new technology that better supports customers
Improve use of technology to support two-way energy flows, remote supply, storage, and communication



**Our customers**

Residents, Generators, Retailers, Local Government, Large, small & medium businesses, Land development & industry, Electrical service

# Highlights

| | |
|---|---|
| **Increase in the average network bill is less than inflation** | Our proposal provides price decreases for customers (in real terms). This means nominal price increases for the average network bill will be lower than the rate of inflation. For the AA5 period, the average network bill rise is 50 per cent lower than the price increase in the AA4 period. |
| **Customer and community engagement shaped our AA5 proposal** | Customers and the community tell us they expect electricity to be there when they need it. They expect safe, reliable, and increasingly renewable energy, delivered at an affordable price. Our proposal is a measured and cost efficient approach to meeting the increasing challenges associated with the changing use of our network, such as connecting new technologies, and supporting the decarbonisation of the Western Australian economy whilst continuing to maintain a safe, reliable, and affordable energy service. |
| **Safety will continue to be a key focus** | Our assets co-exist with the community. Safety is considered critical by customers and by Western Power. We will continue to use our risk-based approach and experience to continuously seek ways to reduce the cost of maintaining safety for our customers, our people, and the community. |
| **Reliability performance will be maintained** | Reliability is front of mind for our customers and Western Power. Our investment plan for the AA5 period is aimed at maintaining overall reliability levels and managing the technical challenges associated with the integration of distributed energy resources. Customers have reiterated their support for further investments to improve network resilience in response to extreme climate events through undergrounding and ensuring there are sufficient staff to restore supply when outages occur. |
| **We are supporting the energy transformation** | Western Australians are embracing renewable energy technologies in homes and businesses at one of the highest rates in Australia. More than one in three homes serviced by our network has rooftop solar PV. The installed capacity of grid connected rooftop solar is forecast to reach almost 3 GW by the end of the AA5 period, representing a 60% increase from the end of the AA4 period. We have responded to our customer preferences by introducing new services and network tariffs which will provide customers with greater choice. |
| **A proposal that balances customer needs and affordability** | Our proposal delivers on customer needs and responds to the challenges of a changing energy environment, while balancing the cost of delivering safe and reliable services from an ageing network. Our investments over the coming decade will be both transformational; modernising the electricity delivery system to meet the changing needs of our stakeholders, and traditional; maintaining the core of the grid which underpins supply. Our investment is greater than in the AA4 period but the price impact on customers will be offset by market conditions that reduce the cost of financing the investment. |

# How our AA5 proposal compares to AA4

| Outcomes | AA5 Proposal | Changes from AA4 |
|---|---|---|
| **Safety** | Continued strong focus | No change (maintain performance) |
| **Reliability** | Maintain with improvements in underperforming areas and crew availability | No change (maintain performance) |
| **Services** | Introduce new tariffs that provide strong incentives to use the network efficiently and to recognise emerging technologies such as batteries, energy storage and electric vehicles. | Increasing pace of changing customer behaviour requires a more proactive response to support new services and improve efficient use of the network. |
| **Prices** | Prices rise by less than inflation | Prices rose above inflation |
| **Compliance** | Maintain existing compliance levels and meet new obligations. | New technologies and energy reform has increased functions and obligations |

| Key Financial Elements[1] | AA5 Proposal | Changes from AA4 |
|---|---|---|
| **Revenue** | $7.5 billion | 10% reduction primarily driven by a lower rate of return |
| **Capital expenditure** | $5.4 billion | 30% increase to address the challenges associated with the changing use of the network and improve technology and communication to support new services and markets. |
| **Operating expenditure** | $2.2 billion | Small reduction achieved despite managing new obligations, functions and growth in the network and labour costs. |
| **Rate of return** | 4.73% | A reduction of nearly 20% due to changes in market conditions. |

1 Financial metrics presented in $ real as at 30 June 2022.

# Executive Summary

1. Electricity is essential to our modern way of life – so much of the Western Australian lifestyle and productivity depends on safe and reliable electricity supply 24 hours of every day. Western Power is committed to ensuring the community can continue to enjoy this lifestyle and is strongly focused on adapting our business to meet the changing energy needs of Western Australians. This includes understanding community expectations, and testing and integrating new technologies to provide an optimum outcome for customers.

2. The rapidly changing energy landscape and technology, coupled with a move towards decarbonisation and increasing electrification of industry, is seeing a significant change in customer behaviour and expectations of Western Power's networks and how we plan for the future.

3. This Access Arrangement Information and supporting documents presents our plan for delivering services to customers over the next five years that will provide an important platform for our future network. This plan reflects extensive customer engagement that has sought to understand the requirements and priorities of our customers whilst managing the current state of our network and the necessary steps to meet future expectations.

4. In developing this proposal, we engaged with a broad range of consumers and stakeholders in the community to capture and incorporate their views into our planning processes for the fifth access arrangement period (referred to as the **AA5 proposal**).

5. Customers and the community tell us they expect electricity to be there when they need it. They expect safe, reliable, and increasingly renewable energy, delivered at an affordable price. Importantly, the community is voting with its wallet and investing in ever greater amounts of renewable generation and expects Western Power to enable a renewable-powered future.

6. The AA5 proposal supports our Corporate Strategy (refer Figure ES.1) to meet these needs by efficiently and effectively transitioning to a modular grid that will support the decarbonisation of the Western Australian local economy and meet our customers' needs, whilst maintaining an affordable energy delivery service reflected in our network tariffs.

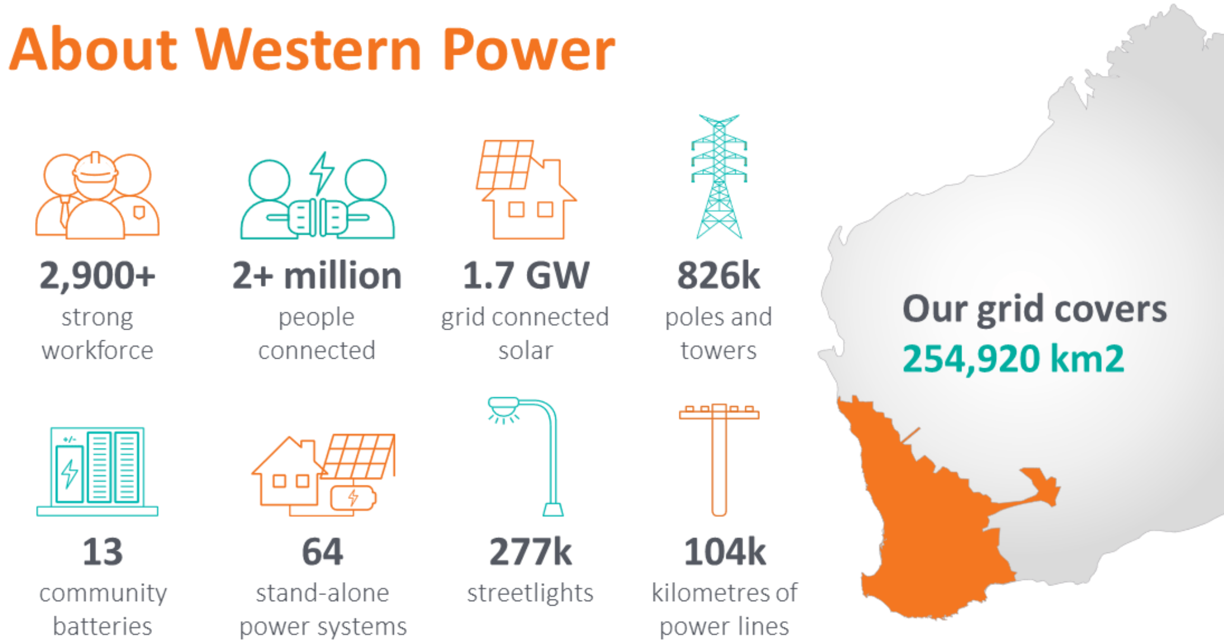
**Figure ES.1: Western Power Corporate Strategy 2021-2031**


7. The modular grid refers to a move from a purely traditional network towards one which incorporates a mix of new energy solutions, such as standalone power systems (**SPS**), microgrids and battery energy storage systems (**BESS**), that can potentially plug into or out of the grid as needed.

## Our customers and network

8. Western Power connects more than 2 million Western Australian homes, businesses and essential community infrastructure through our geographically vast network that covers the south west corner of our state.

**Figure ES.2: Western Power's network**




9. Western Australians are embracing renewable energy technologies on homes and businesses at one of the highest rates in Australia. Combined with growing levels of utility-scale renewables being connected, this is transforming the way that electricity is generated for, delivered to, and used by, customers.

10. These changes are largely driven by customer behaviour, government policy, decarbonisation of the electricity system and technological advancement in the energy sectors. In particular:

- more than one in three homes serviced by the Western Power Network have rooftop solar PV and customers are connecting over 4,000 new installations each month
- the installed capacity of grid connected rooftop solar is increasing by more than 20 MW each month and is forecast to reach almost 3 GW by the end of the AA5 period
- applications for large-scale renewable energy projects (wind, solar and waste-to-energy) to connect to the Western Power Network continues to increase, with almost 1 GW currently under development
- the times demand is peaking on the network has shifted from an afternoon interval to the evening, due to the growth in PV, which is also exacerbated by significant load volatility during times of unusual weather patterns and cloud cover
- there are now more than 3,500 approved battery applications for residential customers on the Western Power Network, with a combined storage capacity of over 34 MWh
- new technologies such as SPS and batteries are being installed to support or replace network infrastructure in areas where it addresses a network need and is financially prudent to do so
- an increasing uptake of electric vehicles (**EVs**) within WA

- a low carbon electricity system is critical to the State Government's commitment to net zero greenhouse gas emissions by 2050
- other recent technological advancements including behind the meter solutions offer our customers more choices to optimise their generation, storage and use of electricity.

## Our growing challenges and opportunities

11. The pace of change in the energy market, presents Western Power with a number of growing challenges and opportunities. Western Power has been addressing these challenges over recent years and must continue to proactively respond throughout the AA5 period.

***Significant new renewable connections***

12. For decades, Western Power transported electricity directly to homes and businesses through poles and wires from traditional gas, diesel, and coal-fired generators. The electricity system is now in an unprecedented transformation, driven by widespread uptake of customer owned rooftop solar photovoltaic (**PV**) systems and changes in the utility-scale generation mix towards more renewables, both displacing utility-scale fossil fuelled generators. More than one in three homes in the South West Interconnected System (**SWIS**) now have rooftop solar PV, contributing to 1.7 GW of grid connected solar. This compares to 4 GW of Western Power's network capacity. In addition, Western Power has recently connected a further 460 MW of utility-scale renewable energy projects to our network, including the Yandin Wind Farm, Warradarge Wind Farm, and the Merredin Solar Farm.

***Transformation from historical one-way power flows to two-way power flows***

13. 'Minimum operational demand' (at times of peak rooftop solar PV generation) and the associated impact on system stability represents a growing challenge for Western Power to maintain a reliable supply. It is anticipated that customer behaviour, increasing decarbonisation of the electricity system, and ongoing technological advancement in the energy sector will continue to push the capacity of the network to keep up with the community's expectations and requirements.

***Increasing proportion of ageing assets with deteriorating performance***

14. These changes are occurring while Western Power's existing network is experiencing increased deteriorating performance from a large portion of ageing assets and security of our critical infrastructure becomes more important to protect our physical and digital assets against potential incidents. This causes further challenges in managing our assets, while planning for, and starting to transition into, the network of the future.

***Increasing extreme climate events***

15. In recent times, Western Power has seen extreme climate events have a significant impact on the network, including severe storms in May 2020 stretching from Quinns Rock in the north through to Albany in the south; the Wooroloo, Wundowie and Red Gully bushfires in January, February and March 2021; storm related flooding in Northam and surrounding areas in March 2021; Tropical Cyclone Seroja in April 2021; and heatwave conditions in December 2021 with four consecutive days above 40 degrees celsius. Compared to any prior climate event, many of these events caused the most significant widespread damage to Western Power's network and impacted the largest number of our customers.

***Significant energy reforms***

16. Western Power has been working closely with Energy Policy WA and the Australian Energy Market Operator (**AEMO**) in the development and implementation of the Government's Energy Transformation

Strategy[2]. To meet these expectations, Western Power is planning and implementing the network of the future, which will facilitate decarbonisation, enable benefits for the community from their investments in distributed energy resources (**DER**) and ensure an energy supply which is more resilient to extreme climate events for future generations. This will support Western Australia's (**WA**) economy and is backed by reforms under the Energy Transformation Strategy.

17. These challenges are having a combined effect of lowering minimum demand levels during the middle of the day, followed by steep ramping to an evening peak compared to a decade ago. This is exacerbated by significant load volatility at times of unusual weather patterns and cloud cover and voltage and network stability issues from the changing generation mix. However, it also presents our business, and customers, with opportunities.

***Providing greater choice to customers through network tariffs***

18. In consultation with customers and end-users, we have developed network tariffs which will provide greater choice to customers in response to changing customer behaviour and influence future network investment needs. Designing a package of tariffs that encourages customers to use less electricity at peak times and greater electricity at times of minimum demand, whilst promoting affordability and fairness across our customer base, is an important part of our proposal. Our new time of use tariff introduces a 'super off-peak' component from 9am-3pm, with a variable price per kilowatt hour (**kWh**) close to zero, to encourage usage when the network is experiencing minimum demand.

19. This proposal for our AA5 period focuses on delivering on customer needs and responding to the challenges of a changing energy environment, while balancing the cost of delivering safe and reliable services. Electrification is expected to play a key role in the industry and communities' decarbonisation plan. The network must be able to facilitate decarbonisation and renewable connections and integrate new technologies into the grid to enable Western Power to continue to provide an essential service for customers 24 hours of every day now and into the future.

## How we are responding to what our customers told us

20. Western Power reached out to more than 2,000 members of the community, including users, end-use customers, generators, retailers, industrial businesses, small to medium sized businesses, local governments, industry associations and residential customers (including urban, regional, vulnerable, and culturally and linguistically diverse customers).

21. The key insights from this extensive research program are summarised in the table below.

**Table ES.1: Key insights from customer engagement program**

| | | |
|---|---|---|
| | **Safety is considered critical by customers.** | Should the level of service surrounding safety decline, it would be detrimental to customer experience. Customers see safety as being a core value of profound importance. |

[2] Government of Western Australia, Energy Transformation Strategy, 2019 https://www.wa.gov.au/sites/default/files/2019-08/Energy-Transformation-Strategy.pdf

| | | |
|---|---|---|
| | **Reliability of supply is critical to customers.** | There are different service experiences across our network. The frequency and duration of outages is considerably greater and longer amongst customers in regional areas in comparison with urban customers. However, any erosion of reliability would have a significant negative impact on customer experience, irrespective of customer segment. |
| | **Customers expect Western Power to integrate more renewables into the grid and to prepare the grid for the future.** | This requires a sustainable approach to DER management, to manage critical minimum demand risks while maximising the opportunity for the community to invest in DER and large-scale renewables. |
| | **Customers expect Western Power to continue to address ageing assets.** | While at the same time facilitating the transition of the network to meet changing customer behaviour and expectations. |
| | **Residential customers are sensitive to price increases and therefore minimising cost increases is a high priority for them.** | However, there is willingness to pay for increased reliability, renewables and potentially a combination of elements, provided the cost impacts range between 1-5 per cent of their current bill. Similarly, small and medium enterprises supported future focused investments, provided cost increases were within the 1-9 per cent range. |
| | **Customers are more sensitive to bill increases than bill reductions.** | A finding which is supported by economic literature. |

22. Our AA5 proposal includes investments aligned with our customers' priorities of safety, reliability, increasing renewable energy generation, investing in new technologies and supporting future demand.

### *Delivering safe electricity to customers*

23. Our assets co-exist with the community. Safety is considered critical by customers and by Western Power – they see safety as being a core value of profound importance.

24. Customers believe there is already significant importance given to safety and do not prioritise additional investment in this area. This is due to a perception that Western Power is performing well in this area. However, there is no willingness to trade-off safety for lower bills, greater reliability, or increased sustainability.

25. During the AA5 period, Western Power will continue to use a risk-based renewal approach to manage safety performance of our network including providing a safe working environment for our people. Specific investments targeted at addressing the deteriorating performance of ageing assets and maintaining the safety of the Western Power Network include:

- replacing and reinforcing poles, towers and conductors to minimise public safety risk from asset failure, for example, bushfires and electric shocks
- investing in SPS and converting overhead network to underground where these options are determined to be lower cost than replacing the overhead network or provide additional capacity, for example from EVs. Investment Snapshot 1 presents more information on Western Power's undergrounding program.
- upgrading substation buildings to minimise risk to public and workforce safety
- updating Western Power's ageing depots to meet current workplace safety practices for our people and ensuring both cyber and physical security protection of our critical infrastructure assets.

26. Importantly, almost 40 per cent of our forecast investment is directed at maintaining safety performance of the network during the AA5 period.

## Investment Snapshot 1 – Undergrounding Program

Our Undergrounding Program involves the targeted conversion of overhead powerlines to underground power. These projects are proposed for areas in the urban network where:

- the overhead assets are deteriorated and require replacement, and
- underground replacement presents the same or lower cost to a like for like replacement.

Western Power will seek to underground the network through financial partnerships with local communities (via the relevant local governments).

A significant part of the metropolitan overhead network will soon need to be replaced. Undergrounding projects are timed to address the largest proportion of overhead assets that require treatment.

The benefits of this investment program are improved safety and reliability, lower maintenance costs, and facilitation of more renewable connections. Undergrounding of existing overhead infrastructure also provides better amenity and streetscapes by allowing the green canopy in urban areas to grow.

Western Power plans to invest $685 million in underground power programs during the AA5 period, including $245 million in capital contributions. This investment will convert approximately 875 km of poles and wires to underground cabling during the AA5 period.

27. Supported by the investments identified above, our AA5 proposal maintains the current level of safety standards in accordance with customer expectations.

28. Importantly, as many of our investments are in long life assets with assets lives of greater than 40 years, these investments will be paid for by customers over the next 40+ years.

### *Providing reliable services for customers*

29. As an essential service, customers expect electricity to be there when they need it, 24 hours of every day. The reliability of our services is perceived as good by most customers, although there are pockets of our regional network where customers value improvements. Customers have reiterated their support for further investments to improve network resilience in response to extreme climate events.

30. We will maintain overall reliability levels over the AA5 period and improve service in hotspots that are underperforming. We will also improve network resilience through undergrounding and ensuring sufficient staff on the ground to restore supply after an outage event

31. In recent times, Western Power has seen extreme climate events have a significant impact on the network, including severe storms in May 2020 stretching from Quinns Rock in the north through to Albany in the south; the Wooroloo, Wundowie and Red Gully bushfires in January, February and March 2021; storm related flooding in Northam and surrounding areas in March 2021; Tropical Cyclone Seroja in April 2021; and heatwave conditions in December 2021 with four consecutive days above 40 degrees celsius. Compared to any prior climate event, many of these events caused the most significant widespread damage to Western Power's network and impacted the largest number of our customers.

32. Investment in the modular grid and the integration of new technologies therein (i.e., SPS and microgrids) will improve the level of reliability and resilience of our network in regional areas and facilitate faster restoration of supply. Investment Snapshot 2 presents more information on Western Power's SPS program.

## Investment Snapshot 2 – Stand-alone power systems

Providing reliable power supply in regional and remote areas of WA is challenging, with distance, complex terrain, diverse landscapes and extreme climate events and bushfires impacting network infrastructure. SPS deliver significant benefits to our customers in these areas, providing a cost-effective alternative to traditional poles and wires that can provide reliable access to power almost regardless of location or conditions.

Each SPS functions as an energy supply unit comprised of a renewable energy source (solar PVs), a battery and back-up generation (if required), operating entirely independently of the main electricity network while still forming part of our service area.

Western Power plans to invest $330 million in SPS during the AA5 period. SPS will be deployed when sections of our overhead network require replacement and an SPS solution is determined to be the same or lower cost over the long term.

SPS will be efficiently deployed based on the optimal balance of asset deterioration and cost efficiency. As this solution is implemented, large geographical areas of overhead network will be decommissioned.

SPS benefits include improve reliability, an inherent reduction in electric shock and bushfire risk, improved network access, lower whole of life costs and supporting decarbonisation. Western Power plans to transition 4,000 existing connection points to either SPS or proactive supply abolishment by 2031. Approximately, 1,860 SPS units or equivalent are forecast to be deployed in the distribution area over the AA5 period. This includes 1,630 SPS equivalents for the SPS program and 230 SPS equivalents to enable microgrids.

*Responding to changing customer behaviour*

33. Customers expect Western Power to continue to address the deteriorating performance of ageing assets, whilst at the same time facilitating the transition of the network to meet changing customer behaviour and expectations.

34. DER are smaller-scale devices that can either use, generate or store electricity, and form a part of the local distribution system, serving homes and businesses. They include rooftop solar, energy storage, EVs, and other technologies that customers can use at their premises to manage their electricity demand. With the rapid uptake of DER, particularly rooftop solar PV systems, customers are increasingly meeting their own electricity demand for certain periods of the day, while still relying on the network at other times. Customers still view Western Power as an essential service.

35. In consultation with customers and end-users, we have developed services and network tariffs which will provide greater choice to customers in response to changing customer behaviour and influence future network investment needs. Designing a package of services and tariffs that encourages customers to use less electricity at peak times and greater electricity at times of minimum demand, whilst continuing to promote affordability and fairness across our customer base, is an important part of our AA5 proposal. Our new time of use service introduces a 'super off-peak' component from 9am-3pm, with a variable price per kilowatt hour close to zero, to encourage the use of our network at times of minimum demand. Changing usage patterns will avoid costly reinforcements to the network to meet the requirements of peak and minimum demand days.

36. We have introduced new reference services for:

- transmission connected storage systems
- distribution connected storage systems
- dedicated EV charging points
- time of use, with time bands to reflect forecast demand patterns.

37. Increased adoption of DER and large-scale renewable systems will contribute to reducing carbon emissions and cost of generation in the system, while providing customers with the benefit of greater control over their energy use and costs. However, the high level of uncontrolled and unpredictable solar PV is making the system harder to manage in the transition away from conventional, controllable generation sources such as coal and gas fired generation.

38. Advanced metering infrastructure (**AMI**) plays a key role in a range of emerging network requirements which require increased visibility (and potentially control) of the distribution network and technology connected to it. AMI is a critical enabler for the effective integration of DER solutions, mitigating risks associated with minimum demand, the introduction of more flexible tariffs and allowing customers to actively participate in the energy market. Investment Snapshot 3 presents more information on Western Power's AMI program.

## Investment Snapshot 3 – Advanced Metering Infrastructure

AMI refers to digital meters with a communication device installed. Advanced meters can automatically and remotely read electricity flows and provide early detection of connection faults and supply issues. They enable a clearer picture of power quality information, including voltage and current levels, and how much renewable energy is being fed into the network.

AMI plays a key role in a range of emerging network requirements which require increased visibility (and potentially control) of the distribution network, including both customer and network, and technology connected to it. AMI is a critical enabler for the effective integration of DER, solutions for mitigating the risk of low load, flexible tariffs and allowing customers to actively participate in the energy market.

Western Power commenced deployment of AMI in 2019, with the deployment aimed for completion in 2027. Almost half a million advanced meters will be installed by June 2022, with a further 795,130 scheduled to be installed during the AA5 period.

Western Power will invest $317 million in advanced meters during the AA5 period.

The implementation of advanced metering delivers immediate benefits to customers from improved fault detection – our service connection condition monitoring program is forecast to provide a 70 per cent reduction in network electric shocks; remote meter reading leading to fewer estimated bills and a reduction in workplace safety risk; usage recordings in 30-minute intervals, allowing for more detailed energy usage information; remote re-energisation, leading to faster reconnections; and improved efficiency in integration of new technologies including community batteries, microgrids, embedded networks and EVs.

*Facilitating more renewables on the network for the benefit of our customers*

39. Overall, there is strong support for further investment that increases the amount of renewable energy in the SWIS, with stakeholders suggesting that renewables are essential to the future of energy in our state. Furthermore, there was strong support for Western Power to proactively lead the way and plan for the future.

40. During the fourth access arrangement (**AA4**), our commitment to a constrained access model to facilitate renewable generation connection, via the commissioning of our Generator Interim Access (**GIA**) tool, has enabled the connection of 460 MW of utility-scale renewable energy projects, including the Yandin Wind Farm, Warradarge Wind Farm, and the Merredin Solar Farm. We are also undertaking work in the Eastern Goldfields region to open up capacity to customers, enabling them to move from site generation to a grid connection thereby accessing renewable energy via our network.

41. During the AA4 period we have made significant progress in transforming our network by leveraging new technologies, developing data-based modelling and connecting renewable energy sources. Technology is evolving rapidly as we continually trial new solutions to test their suitability for the transforming network. SPS and community batteries are now part of our toolkit to manage the network and are being installed to replace or support traditional network infrastructure in areas where it is technically or financially feasible.

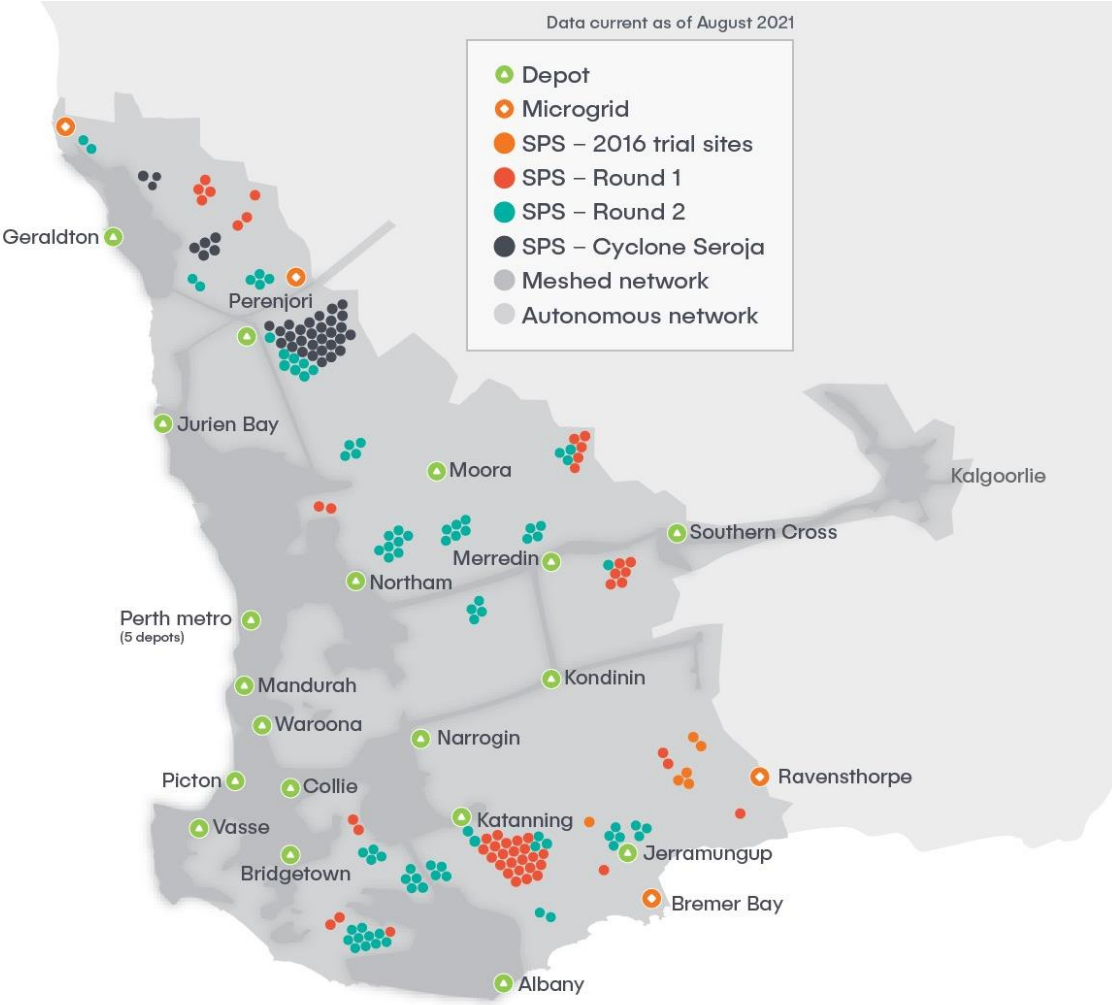
42. Our Grid Strategy is based on long-term scenario planning for evolving customer preferences and needs, which identifies the right technology to use at the right place and time. This approach provides a roadmap which minimises whole of life cycle costs and regrettable investment.

43. Our proposed capital expenditure (**capex**) plan for the AA5 period is designed to enable increased levels of renewable generation connection to our network and implement the Energy Transformation Strategy Stage 1 outcomes.

44. To best meet the needs of our community, now and into the future, we need to move as safely, and as affordably as possible to the modular version of the network. This needs transformational investment in existing assets and new technology. The modular grid will consist of three zones:

- a tightly meshed urban network of increasingly underground assets servicing most of our customers for decades to come
- a hybrid network of mostly overhead assets, complimented by new technologies such as SPS
- an autonomous stand-alone network of remote power systems such as SPS and microgrids (see Figure ES.3).

**Figure ES.3: Illustrative network zones and assets of Western Power's modular network**




45. Our undergrounding program will play a key role in supporting the future uptake of EVs by enhancing capacity on our distribution network to accommodate EV charging services.

46. We continue to support the State Government's Energy Transformation Strategy to identify the right policy, regulation and investments that will allow us to manage the rising challenges and embrace the right solutions, while remaining efficient and delivering on customer expectations.

47. Our proposed capex plan includes investments to:

- enable customers to keep connecting renewable generation to the transmission network
- allow customers to continue to connect rooftop solar by addressing emerging grid stability issues caused by the high penetration of renewable resources in the distribution network
- implement new capability to manage and enable the connection of DER.

48. Western Power's strategy to move as safely and as affordably as possible to a modular network will support our ability to tackle climate change impacts and connect more renewables to the network. Western Power will continue to evolve our network to safely accommodate renewable generation and innovate by developing products and services that support the electrification of the transport, industrial and processing sectors.

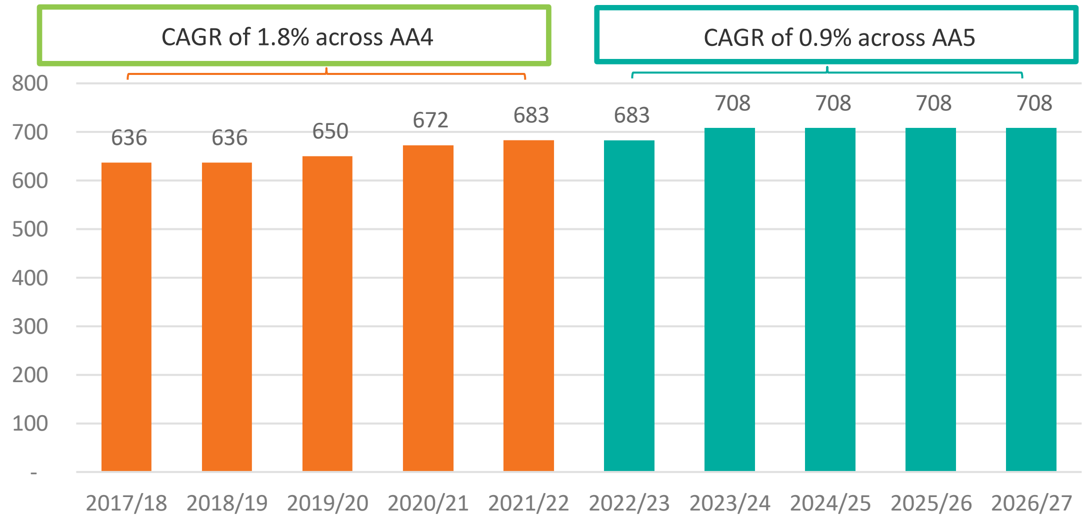
*Ensuring affordability for our customers*

49. Ensuring affordable price outcomes is a high priority for our customers. Our AA5 proposal considers the price impact on customers, particularly residential and small and medium business customers.

50. Residential customers are sensitive to price increases, so keeping costs low is a high priority for them. Our AA5 proposal results in price decreases for customer (in real terms). This means nominal price increases for the average network bill will be lower than the rate of inflation. For the AA5 period, the average network bill outcome represents a compound annual growth rate (CAGR) of 0.9 per cent per annum which is 50 per cent lower than the AA4 period CAGR of 1.8 per cent per annum.

51. If passed on to regulated retail customers, the proposal would result in a one-off increase of approximately $25 in 2023/24 to the retail bill of an average consumption customer, then flat for the remainder of AA5 (up to the end of 2026/27).

**Figure ES.4: Estimated average network price movements (2018 - 2027)**[3]



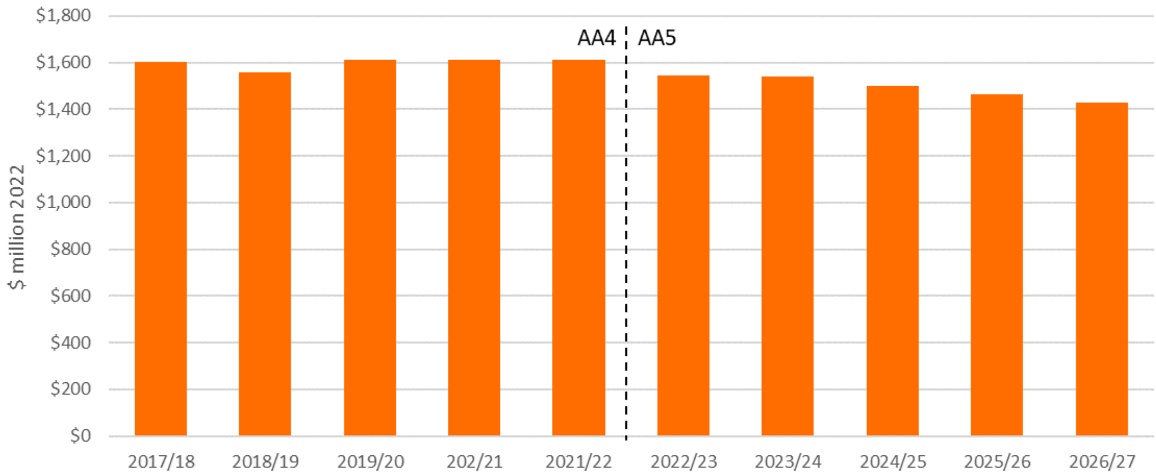

## Revenue required to deliver on customer expectations

52. Western Power's proposed revenue requirement for the AA5 period is $7,473 million (smoothed $ real 2022). This is the revenue required to recover the prudent and efficient costs of transforming the network to meet our customers' expectations, treat ageing assets and address the challenges of the changing energy landscape.

53. Target revenue for the AA5 period ($ million real) is 6.5 per cent lower than the target revenue for the AA4 period ($7,992 million), as shown in Figure ES.5.

[3] $683 in 2022/23 being the network component of an average residential bill, excluding tariff equalisation contribution (TEC) ($762 including TEC). Final pricing will be subject to updated information as it becomes available prior to final determination.

**Figure ES.5: Target revenue (smoothed), $ million real at 30 June 2022**

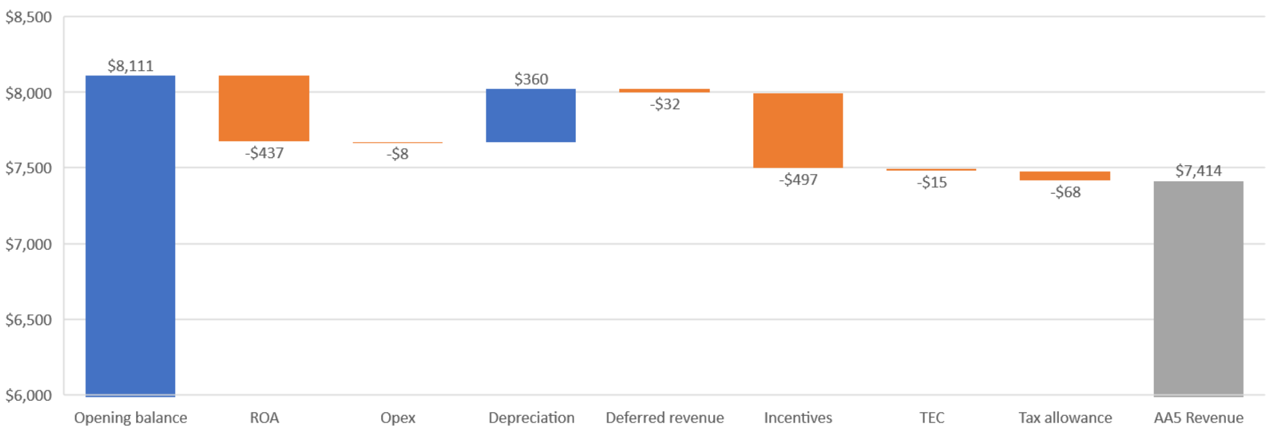



54. The target revenue allowance comprises the following building blocks:

- return on assets (**ROA**), which is a function of the capital investment and rate of return (or weighted average cost of capital (**WACC**)) on those assets
- operating expenditure (**opex**)
- depreciation
- deferred revenue recovery
- incentive scheme adjustments
- tariff equalisation contribution
- tax allowances.

55. The reduction in revenue for the AA5 period is driven primarily by reductions in the return on assets and adjustments for incentive schemes, as shown in Figure ES.6.

**Figure ES.6: Changes in revenue (unsmoothed) from AA4 to AA5, by building block, $ million real at 30 June 2022**



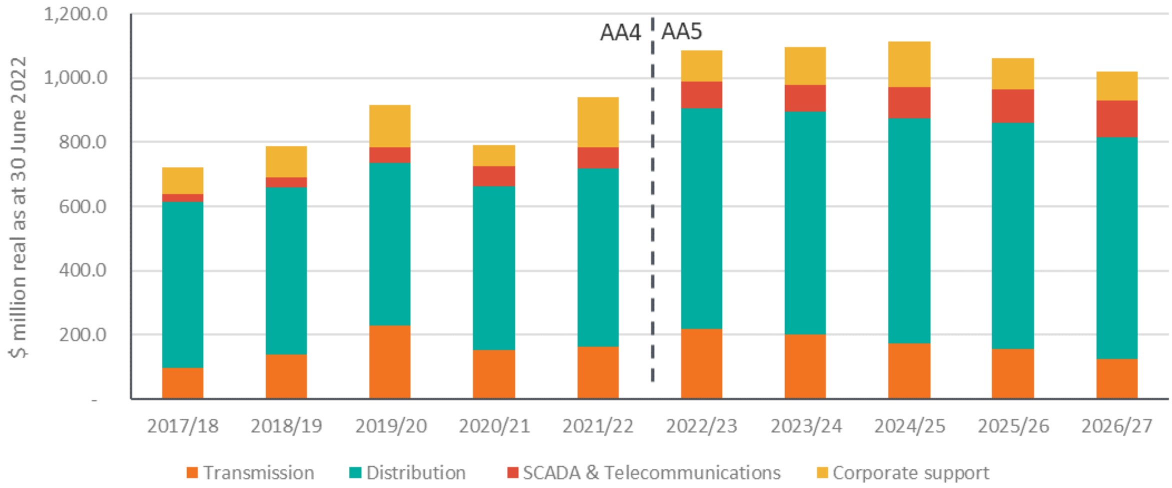

56. The WACC generally has the greatest impact on Western Power's financial sustainability. The WACC is the rate of return that Western Power earns on its investment in the electricity network. The proposed WACC for the AA5 period is estimated at 5.05 per cent in 2022/23, falling to 4.49 per cent in 2026/27, resulting in

an average WACC of 4.73 per cent across the AA5 period. This is considerably lower than the WACC of 5.87 per cent that applied during the AA4 period.

### *Capital expenditure*

57. During the AA5 period, Western Power proposes to invest $5,376 million of capital to deliver covered services. From this, approximately $1,035 million will be recovered directly from customers in the form of either capital contributions or gifted assets. We forecast $4,341 million will be added to the regulated asset base (**RAB**) and recovered through reference and non-reference tariffs.

**Figure ES.7: AA4 actual and AA5 forecast capex, including indirect costs and escalations, $ million real at 30 June 2022**




58. Our proposed capex plan for the AA5 period is designed to move as safely and as affordably as possible to the modular version of the grid during a period of energy transformation. Western Power is developing the modular grid as it affords the least cost technology to meet the requirements of the differing customer groups served by Western Power. At the same time, the proposed investment will allow us to continue to manage the existing network, treat the deteriorating performance of ageing assets and maintain safety and reliability, while we transform into the future.

59. We are forecasting increases in capex for our transmission, distribution, and Supervisory Control and Data Acquisition (**SCADA**) and telecommunications networks to treat the deteriorating performance of ageing assets, meet our customers' expectations and address the challenges of the changing energy landscape. Corporate capex is forecast to remain steady relative to the actual expenditure incurred in the AA4 period. The increases in capex reflect the following factors:

- **Transmission network:** forecast capex is expected to increase by around 11 per cent (compared to the actuals for the AA4 period) driven primarily by Western Power's ageing asset base and to facilitate additional capacity for customer connection (including connection of renewable generation and load to meet their carbon reduction requirements) and rationalise voltages, whilst improving network utilisation. Asset life extension techniques such as refurbishment, digital asset management and delivery optimisation have underpinned our proposed capex investment plan to ensure current levels of network performance are maintained
- **Distribution network:** forecast capex is expected to increase by around 34 per cent (compared to actuals for the AA4 period) driven primarily by the need to manage the deteriorating performance of ageing assets, facilitate the transformation of the network and support future customers' needs, such

as EVs, whilst managing minimum demand risks and maximising the opportunity for the community to invest in DER. Key investment programs include maintaining safety performance of our network (including addressing ring main unit safe operating risk issues), undertaking the AMI deployment, installation of SPS and significant undergrounding programs

- **SCADA and Telecommunications:** forecast capex is expected to increase by around 110 per cent (compared to the actuals for AA4 period) driven primarily by asset obsolescence, management of cyber security risk, compliance requirements and requirements to implement the outcomes of the Energy Transformation Strategy (e.g. five-minute settlement and DER integration). Western Power will uplift its largely obsolete SCADA and Telecommunications network during the AA5 period to support the digital network and enable the integration of DER. This investment will enable a secure transformation to a modular grid by improving our foundational cyber security controls and adopting a 'secure by design' approach to the introduction to new and emerging technologies.

60. We are cognisant of the emerging delivery challenges presented by the current world climate, including competition for local resources and global supply chain disruption, and have developed workforce strategies and supply chain plans to mitigate these potential challenges accordingly.

### *Operating expenditure*

61. Opex reflects activities and costs that are ongoing and recurring. We are forecasting opex of $2,183 million to safely operate and maintain our networks over the AA5 period, which is $11 million lower than the opex incurred in the AA4 period. Our opex forecast for the AA5 period only includes non-capital costs that would be incurred by a service provider efficiently minimising costs.

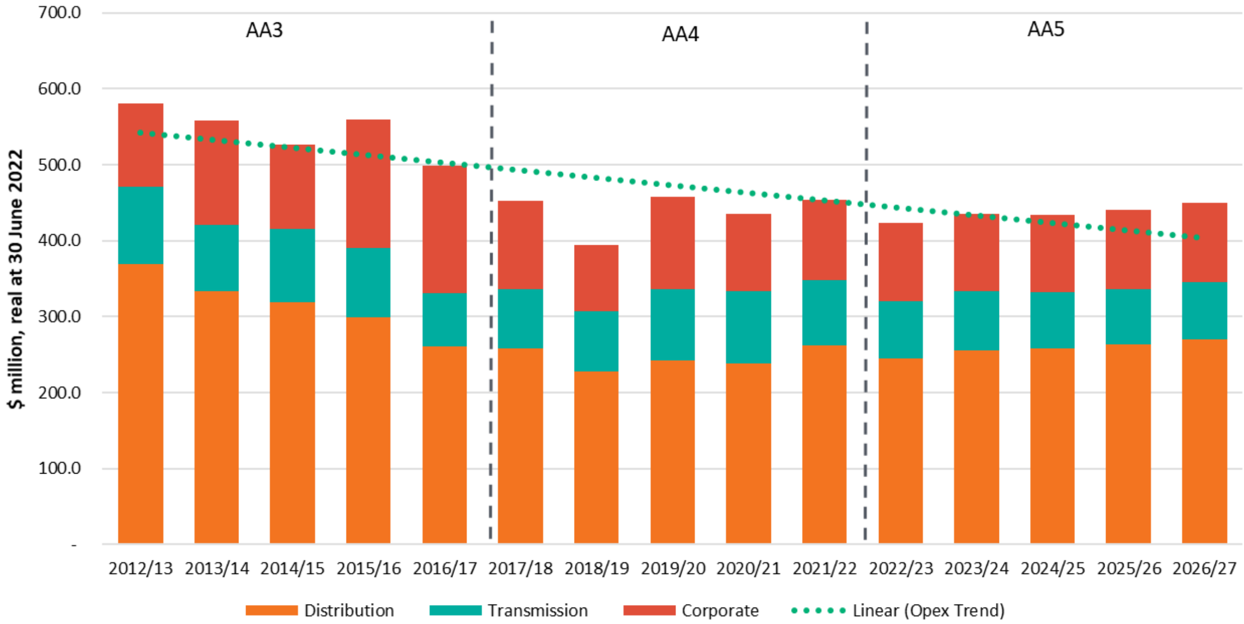
62. We have developed our AA5 opex forecast using the base-step-trend method, which has the following benefits:

- it is simple and transparent
- it has been applied in recent regulatory decisions in Australia, including Western Power's AA4 decision
- it embeds efficiency gains made by Western Power during the AA4 period.

63. We consider our proposed opex is efficient for the following reasons:

- our proposed base year is in line with the approved opex for 2020/21 and the approved base year opex for 2016/17 in the AA4 Further Final Decision
- the forecast opex embeds opex savings resulting from improvements to Western Power's work practices and processes, asset strategies, procurement processes and organisational structure implemented during the AA3 and AA4 periods. These improvements have ensured that our proposed base year remained efficient, and we will sustain these efficiencies into the AA5 period
- proposed step changes in the AA5 period are required to meet substantial new obligations; support and improve the integration of DER, AMI and SPS on the Western Power Network; support the transformation of the network to meet future needs; and improve fault response and condition monitoring capabilities to maintain the reliability of supply, which is critical to customers.

Figure ES.8: AA3 and AA4 historical and AA5 forecast opex, including indirect costs and escalations, $ million real at 30 June 2022




### *Western Power's AA5 proposal*

64. Western Power considers this proposal for the fifth access arrangement review period best serves the long-term interests of our customers and the community.

65. Customers have told us what they expect, and we have developed a plan to meet those expectations whilst balancing the need to keep prices affordable. We consider our proposed access arrangement, as described in this proposal, complies with the requirements of the *Electricity Networks Access Code 2004* (**Access Code**), reflects an optimum investment profile which keeps prices affordable and meets the current and future expectations of customers and the community now and into the future.

# Contents

## List of tables

## List of figures

# Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

| Term | Definition |
|---|---|
| AA3 | Third access arrangement |
| AA4 | Fourth access arrangement |
| AA5 | Fifth access arrangement |
| AA6 | Sixth access arrangement |
| AAI | Access arrangement information |
| Access Code | Electricity Networks Access Code 2004 |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| AESCSF | Australian Energy Sector Cyber Security Framework |
| ALARP | As low as reasonably practicable |
| AMI | Advanced metering infrastructure |
| AMS | Asset management system |
| AOD | Average outage duration |
| AQP | Application and Queuing Policy |
| ARENA | Australia Renewable Energy Agency |
| CAG | Competing Applications Group |
| CAGR | Compound annual growth rate |
| capex | Capital expenditure |
| CAPM | Capital asset pricing model |
| CBD | Central business district |
| CCTV | Closed circuit television |
| CEP | Customer and community engagement program |
| CMS | Customer management system |
| CNMS | Communications Network Management System |
| CPI | Consumer Price Index |
| CSIS | Customer Service Incentive Scheme |
| Depot Program | Depot Optimisation and Consolidation Program |
| DER | Distributed energy resources |
| DFES | Department of Fire and Emergency Services |
| DGM | Dividend growth model |

| Term | Definition |
|---|---|
| DLVCHS | Distribution low voltage connection headworks scheme |
| DMIA | Demand management innovation allowance |
| DMO | Distribution market operator |
| DRP | Debt risk premium |
| DSLMP | Dedicated streetlight metal poles |
| DSO | Distribution system operator |
| Dx | Distribution |
| EMS | Energy management system |
| ENSMS | Electricity network safety management system |
| ERA | Economic Regulation Authority |
| ERP | Enterprise resource planning |
| ESP | Economic Stimulus Package |
| ESS | Essential system services |
| ETAC | Electricity Transfer and Access Contract |
| EV | Electric vehicle |
| FCESS | Frequency co-optimised essential system service |
| GIA | Generator Interim Access |
| GSM | Gain sharing mechanism |
| GSMR | Gain sharing mechanism revenue |
| GTEng | Grid Transformation Engine |
| GW | Gigawatt |
| HV | High voltage |
| IAM | Investment Adjustment Mechanism |
| IGF | Investment Governance Framework |
| IT | Information and communications technology |
| ITOMS | International Transmission Operations and Maintenance Study |
| kms | Kilometres |
| kWh | Kilowatt hour |
| LED | Light-emitting diode |
| LiDAR | Light Detection and Ranging |
| LoSEF | Loss of supply event frequency |
| LV | Low voltage |
| MFA | Multi-function assets |

| Term | Definition |
| --- | --- |
| MIL | Maturity Indicator Level |
| MRL | Mean replacement life |
| MRP | Market risk premium |
| MW | Megawatt |
| MWh | Megawatt hour |
| MVAr | Megavolt ampere (reactive) |
| NCESS | Non-co-optimised essential system service |
| NEM | National Electricity Market |
| NFIT | New Facilities Investment Test |
| NPV | Net present value |
| NQRS | Network Quality and Reliability of Supply |
| NRUP | Network Renewal Undergrounding Program |
| OCSC | Overhead customer service connection |
| opex | Operating expenditure |
| PV | Photovoltaic |
| RAB | Regulated asset base |
| RF | Radio frequency |
| RMU | Ring main unit |
| RoCoF | Rate of change of frequency |
| RTU | Remote terminal unit |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | Supervisory Control and Data Acquisition |
| SSCM | Service connection condition monitoring |
| SEQT | Safety, Environment, Quality & Training |
| SF6 | Sulphur hexafluoride gas |
| SLA | Service level agreement |
| SME | Small and medium enterprise |
| SPS | Stand-alone power system |
| SSAM | Service Standard Adjustment Mechanism |
| SSB | Service Standard Benchmarks |
| SST | Service Standard Targets |
| STPIS | Service target performance incentive scheme |

| Term | Definition |
| --- | --- |
| SUPP | State Underground Power Program |
| SVC | Static Var Compensator |
| SWIN | South West Interconnected Network |
| SWIS | South West Interconnected System |
| TAB | Tax asset base |
| Taskforce | Energy Transformation taskforce |
| TEC | Tariff Equalisation Contribution |
| TFB | Total fire ban |
| TRIFR | Total recordable injury frequency rate |
| TSS | Tariff structure statement |
| Tx | Transmission |
| UFLS | Under frequency load shedding |
| URD | Underground residential distribution |
| VCR | Value of customer reliability |
| VESDA | Very early smoke detection apparatus |
| VPP | Virtual power plants |
| WA | Western Australia |
| WACC | Weighted average cost of capital |
| WEM | Wholesale electricity market |
| WOSP | Whole of system plan |
| ZSS | Zone substation |

# 1. About this submission

66. This chapter outlines the structure of our AA5 proposal, its relationship to the Western Power access arrangement for the regulated or 'covered' Western Power Network, and how the proposed revisions to the access arrangement in the AA5 proposal were developed.

**Key Messages**

- Our AA5 proposal is a credible, sustainable and future focused plan. It has been developed to meet the changing energy needs of our community and customers while considering the deteriorating performance of ageing assets, the rapidly changing energy landscape, and balancing the cost of delivering safe and reliable services
- To best meet the requirements of our customers, our proposal focuses on moving as safely, and as affordably as possible, to the required future version of the grid, investing in both existing assets and new technologies
- Our proposal covers the five-year period from 1 July 2022 to 30 June 2027. The proposal meets the Access Code objective and has regard to the requirements of the new Framework and Approach published by the Economic Regulation Authority in August 2021

## 1.1 Overview

67. Every five years Western Power undertakes a process known as an access arrangement review. This is our opportunity to engage with the community to understand what energy services and solutions they value and need – now and into the future. Customers are expecting more from us, and we are responding – we incorporated the insights and feedback from our customers into our thinking on the services we will provide and the technology solutions we will invest in. We have revised the services we offer and updated the network tariffs to accurately reflect the safe, reliable and efficient delivery of these services under our access arrangement for the Western Power Network[4].

68. We submit our plans to the Economic Regulation Authority Western Australia (**ERA**), who decide how much revenue we are allowed to recover from customers to enable us to efficiently operate and invest in the network for the next five years. The ERA also reviews the terms and conditions for accessing our network.

69. Our submission for the fifth access arrangement period (referred to as the AA5 proposal) is due on 1 February 2022 and covers the five-year period from 1 July 2022 to 30 June 2027 **(AA5 period**). This proposal outlines our key activities and investments over the AA5 period, and the network tariffs that will reflect the safe, reliable and efficient delivery of our services. It also discusses and reviews what we have delivered over the previous access arrangement period (**AA4 period**).

70. This chapter provides:

- an overview of the key Access Code provisions relevant to producing access arrangement information (**AAI**) and how the amendments to the Access Code to support the delivery of the State Government's Energy Transformation Strategy have been addressed[5]
- a summary of the approach Western Power adopted, and its key considerations when developing this AA5 proposal

[4] The Western Power Network is defined in the Electricity Networks Access Code 2004 and is the portion of the South West Interconnected Network that is covered under the Access Code.

[5] https://www.wa.gov.au/government/announcements/amendments-the-access-code

- a revisions submission date and targeted revisions commencement date for the following access arrangement period (**AA6**)
- a summary of the document structure and the information contained in each chapter.

## 1.2 Access Code provisions

71. In accordance with section 4.48 of the Access Code, this document comprises the AAI for consideration by the ERA. The AAI is the supporting information required by the ERA to assist in understanding our AA5 proposal, and the underlying assumptions of that proposal.

72. As required by sections 4.2 and 4.3 of the Access Code, the AAI has been written to enable the ERA, our customers, and other interested stakeholders to:

- understand how we derived the elements that make up the AA5 proposal and
- form an opinion on whether the AA5 proposal complies with the Access Code.

73. The AAI includes information on the form of price control, pricing methods, total costs, capacity and volume assumptions, service standards, incentive mechanisms, and other evidence that demonstrates how the AA5 proposal complies with the Access Code.

### 1.2.1 Access Code objective

74. Western Power operates the Western Power Network in accordance with the Access Code objective[6], which is:

> *to promote efficient investment in and efficient operation and use of, services of networks in Western Australia for the long-term interests of consumers in relation to:*
>
> *a) price, quality, safety, reliability and security of supply of electricity;*
>
> *b) the safety, reliability and security of covered networks; and*
>
> *c) the environmental consequences of energy supply and consumption, including reducing greenhouse gas emissions, considering land use and biodiversity impacts and encouraging energy efficiency and demand management.*

75. The Access Code objective was changed as part of the amendments to the Access Code in September 2020 to support the delivery of the State Government's Energy Transformation Strategy. This is the first time we have submitted an access arrangement review proposal under the new objective.

76. The AA5 proposal is designed to ensure we continue to satisfy the Access Code objective. To do this, we believe Western Power, supported by community expectations, must:

- ensure network tariffs are kept to the lowest sustainable level for an efficient business
- deliver a level of service that meets our customers' needs
- provide services that are safe, reliable and efficient
- adapt tariffs and services to the changing energy landscape
- reflect the investment required to address the challenges arising from the rapidly changing energy landscape.

6 Section 2.1, *Electricity Networks Access Code 2004.*

77. We have provided evidence to demonstrate how our proposal will deliver these outcomes over the AA5 period and beyond.

78. While the Access Code objective guides the overall AA5 proposal, there are also specific obligations that apply to certain elements of the AAI. To assist the reader, we have referenced relevant sections of the Access Code throughout the AA5 proposal.

### 1.2.2 Regulatory reforms influencing the AA5 submission

79. In September 2020, the Access Code was amended to support the delivery of the State Government's Energy Transformation Strategy. The objectives of the strategy relevant to this AA5 proposal are to[7]:

- maintain a secure and reliable electricity supply
- ensure affordable electricity for households and businesses
- reduce energy sector emissions
- promote local jobs and growth.

80. As part of the Energy Transformation Strategy, the State Government is looking at a range of options to evolve WA's power system and markets. These options include introducing whole of system planning as well as progressing changes to our arrangements for network connection and the provision of essential system services. Further information about the energy market reforms, and how they are impacting our network is provided in Chapter 3.

81. As a result of the amendments to the Access Code, the ERA is required to develop a framework and approach and new guidelines that will apply to our AA5 proposal.

#### *Framework and approach*

82. The ERA published the framework and approach final decision in August 2021.[8] The matters covered by the framework and approach are:

- the form of price control that will set our target revenue
- a list of, and classification of, services, including whether services are reference services or non-reference services
- the method for setting the service standard benchmarks for each reference service
- the incentive mechanisms for the access period, including the investment adjustment mechanism, the gain sharing mechanism, the service standards adjustment mechanism, and a new demand innovation management allowance.

83. The objective of the framework and approach is to streamline the access arrangement review process and facilitate early public consultation on these key matters.

84. The AA5 proposal has regard to the framework and approach final decision and Western Power has adopted all the required amendments included in that final decision.[9]

---

[7] Government of Western Australia, 2019, Energy Transformation Strategy, https://www.wa.gov.au/sites/default/files/2019-08/Energy-Transformation-Strategy.pdf

[8] https://www.erawa.com.au/electricity/electricity-access/western-power-network/western-powers-network-access-arrangements/framework-and-approach-2022-to-2027

[9] https://www.erawa.com.au/cproot/22112/2/Western-Power-AA5-Review---Framework-and-approach---Final-decision.PDF

### *Excluded Services Determination*

85. As part of the framework and approach, it was determined that services provided by batteries owned by Western Power would be an excluded service. The ERA subsequently published an excluded services determination in October 2021 to bring that decision into effect[10].

86. The ERA considers that network support services provided by batteries are contestable and meet the requirements for an excluded service. Under this approach, the capital cost of the battery sits outside the regulated business and is not included in Western Power's regulated asset base. The efficient costs of any network support service provided to the regulated network business by a Western Power owned battery can be charged to the regulated business and this operational expenditure is assessed by the ERA as part of its determination of the efficient costs of providing covered services.

87. The AA5 proposal has regard to the excluded services determination and Western Power has implemented the required amendments to reflect that determination.

### *Guidelines*

88. Since the last access arrangement review, the ERA has published the following guidelines:

- Demand management innovation allowance (**DMIA**) guideline: published on 14 September 2021 – to provide guidance on the upfront annual allowance for research and development in demand management projects that have the potential to reduce long term network costs
- Multi-function asset (**MFA**) guideline: published on 15 October 2021 – to guide the development of Western Power's MFA Policy that covers Western Power's approach to sharing additional revenue from using regulated assets for unregulated purposes with customers through lower tariffs
- New facility investment test and net benefits guidelines: published on 20 December 2021 – to provide guidance on the factors the ERA will consider when making a new facilities investment determination and acceptable methods for valuing net benefits

89. Western Power has endeavoured to comply with the guidelines in this submission, notwithstanding the timing of their publication. Our AAI supporting forecast new facilities investment was prepared prior to the publication of the new facilities investment test and net benefits guideline and may not fully reflect the requirements of the new guideline.

## 1.3 Preparing a balanced and reasonable proposal

90. Our aim is to submit a balanced and reasonable proposal that meets the Access Code objective and manages the price impact on customers. Our AA5 proposal is a credible, sustainable and future focused plan that has been developed to align with our customers' expectations, ongoing energy market reform supported by our asset management systems and our investment governance framework. As such, the proposed changes to our access arrangement are focused on meeting the changing energy needs of our community while considering the deteriorating performance of ageing assets, the rapidly changing energy landscape, and ensuring ongoing financial sustainability of the business.

91. The Western Power Network is in a period of transition. Our existing network assets are ageing and approaching end of life. At the same time technological progress is rapidly reducing the cost of non-wires alternatives. To best meet the needs of our customers, our proposal focuses on moving as safely, and as affordably as possible to the required future version of the grid, investing in both existing assets and new technology. This will facilitate the transition of the network while ensuring ongoing financial sustainability

[10] https://www.erawa.com.au/cproot/22206/2/Classification-of-services-provided-by-batteries-owned-by-Western-Power---Determination.PDF

and connection of more renewable sources of energy. Further information about the changing energy landscape, and how it is impacting our network is provided in Chapter 2.

### 1.3.1 A proposal that is credible, sustainable and future focused

92. Our AA5 proposal is a credible, sustainable and future focused plan:

- Credible - our proposed investment plan is necessary, deliverable in the access arrangement period, achieves an affordable network tariff outcome and is supported by customers.
- Sustainable - our AA5 proposal maintains our safety and reliability outcomes, whilst addressing ageing assets and technology risks[11], facilitating transition of the Western Power Network and ensuring ongoing financial sustainability.
- Future focused - our proposal will enable energy transformation and digitisation through incorporating the requirements of the changing energy landscape, having regard to climate change impacts and facilitating opportunities for customers.

### 1.3.2 AA5 Community and Customer Engagement

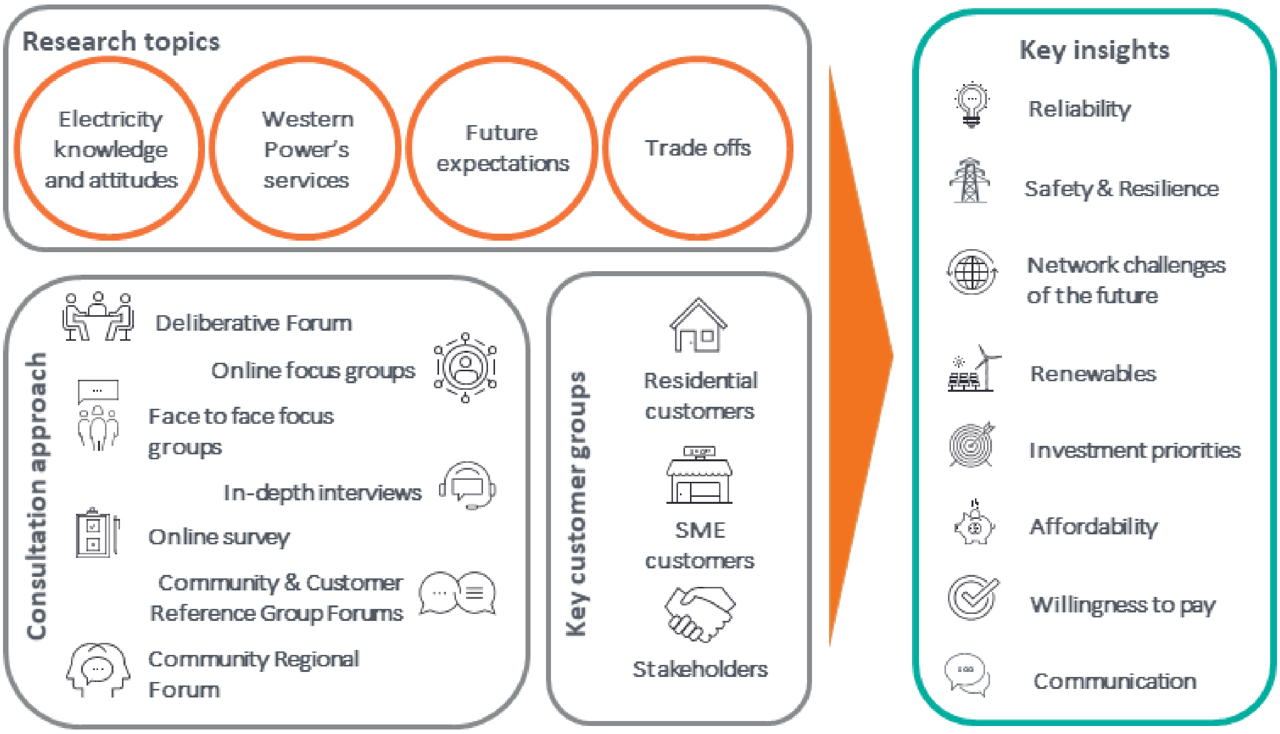
93. The access arrangement review is an opportunity for us to gain an understanding of what our diverse range of customers value in relation to the services we offer and deliver, both currently and into the future. We have engaged with a broad range of our customers and stakeholders in the community including, residents, energy retailers, local governments, small to large businesses, land developers, generators, government agencies and electricians, to incorporate their views into our AA5 proposal.

94. The core focus of our customer engagement was to understand our community's attitudes towards electricity, network performance and safety, network tariff preferences, affordability of services, future opportunities, new technologies, climate change and access to renewables.

95. We have used several different measures including large quantitative surveys, focus groups, interviews and a community reference group. Our direct engagement with customers started in early 2021, and included samples of regional communities in Geraldton, Kalgoorlie, Bunbury, Albany, and smaller regional communities. The engagement has provided valuable insights that have been incorporated into our proposal. Detailed information on the customer engagement program is provided in Chapter 4. Figure 1.1 summarises our engagement approach.

[11] Technology risks include both the network impact of greater PV penetration and cyber security impacts.

**Figure 1.1: Customer engagement program overview**

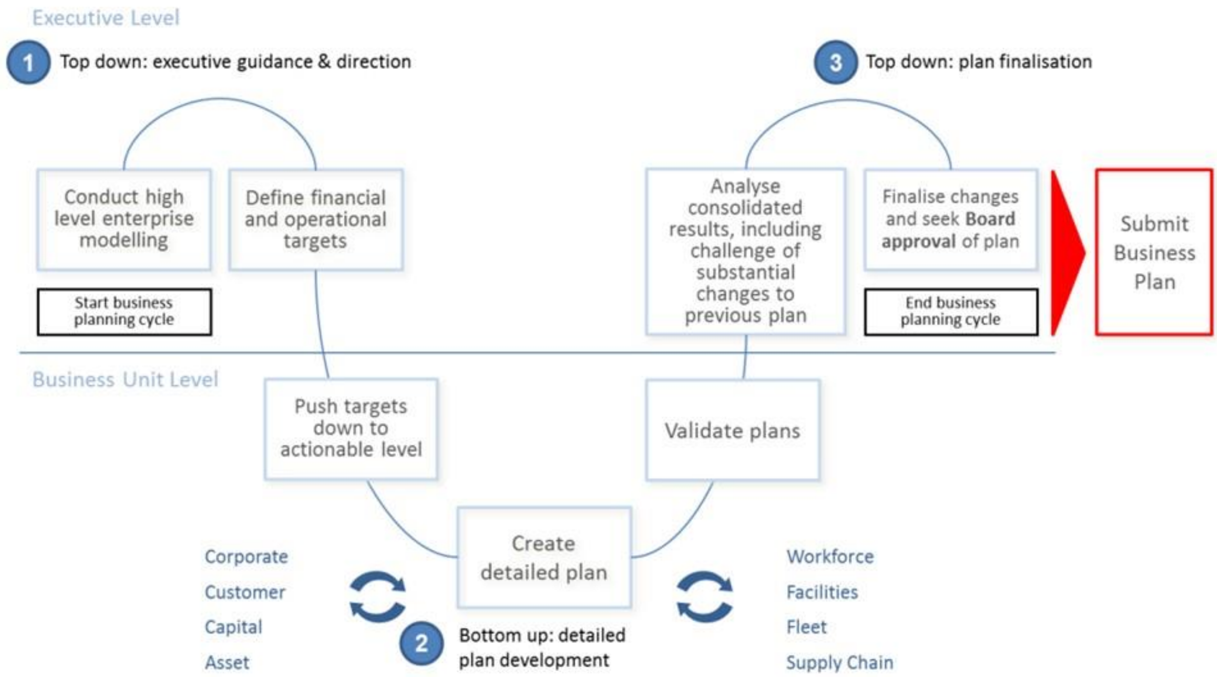



96. Insights from the customer engagement program have shaped our AA5 proposal on the services we will provide and the technology solutions we will invest in over the AA5 period. Commentary on how customer feedback has influenced our expenditure is provided throughout the opex and capex proposals outlined in the AA5 proposal.

### 1.3.3 A proposal subjected to rigorous challenge

97. The information, estimates and forecasts used in this AA5 proposal have been subject to a rigorous verification process. For example, the expenditure forecasts in this proposal were drawn from Western Power's annual business planning process, which generates a rolling 10-year business outlook. Figure 1.2 summarises our business as usual approach to business planning and investment governance.

**Figure 1.2: Western Power's business planning approach**




98. Our business as usual business planning process is informed by our asset management systems, and a suite of strategic documents which are refined and scrutinised regularly, which means the information in this AA5 proposal has already been subject to considerable internal challenge.

99. In addition to our business as usual business planning and governance practices, our AA5 proposal has been subjected to additional review. Key features of this include:

- forecasts and historical expenditure are based on robust business cases[12], which have been reviewed for compliance with the Access Code
- all relevant drivers of a particular forecast have been taken into account, and the underlying data used to derive forecasts is provided with this proposal
- a wide range of regulatory requirements, for example, safety regulations, environmental regulations and cyber security regulations are considered
- we have leveraged key experience in the industry to inform our proposal and used independent expert advice to prepare some of our forecast information including for the WACC proposal and demand forecasts.

### 1.3.4 Information used in this proposal

100. The historical information used in this AA5 proposal is the most recent actual information available at the time of developing the proposal.

101. A summary of the key assumptions used in this AA5 proposal is listed below:

- opex base year is set using audited full year 2020/21 actuals

[12] For those that have reached this point in the investment governance process.

- capex forecasts, network growth factor forecasts and indicative average price movements have been developed using Western Power's 2020 peak demand, energy consumption and customer number forecasts[13]
- AA4 capex and opex is reported as audited full 2017/18 to 2020/21 actuals and 2021/22 forecast
- expenditure forecasts are expressed in real dollars at 30 June 2022 unless otherwise stated
- all revenue amounts are expressed in nominal dollars unless otherwise stated
- labour input costs are as per the independent expert report, prepared in September 2021
- material cost escalation is assumed at zero per cent
- average labour and embedded contractor component is based on the Australian Energy Regulator **(AER)** benchmark methodology to determine the proportion of labour costs of a benchmark efficient business
- network metric forecast assumptions are from 2022/23 to 2026/27, for use in opex output growth calculations
- shared network and corporate costs are allocated as per the cost and revenue allocation method
- where the WACC parameters require an averaging period to be used, we have used the 20 days to 30 June 2021.

102. Some tables may not add due to rounding.

103. This proposal has been based on information available at the time of submission. There are a number of ongoing energy and industry reforms and legal proceedings which may influence the forecast investment included in this proposal. These include, but are not limited to:

- Stage 2 of the Energy Transformation Strategy to be implemented over the period 2021 to 2025
- assessing the full impact of recently enacted and proposed amendments to the *Security of Critical Infrastructure Act 2018* (Cth)
- the requirement for Western Power to inspect private poles directly connected to the network following the WA Supreme Court's judgement relating to the Parkerville fire
- responding to the *Work Health and Safety Act 2020* and related regulations.

Where new obligations on Western Power arise prior to submitting our response to the ERA's draft decision, updated information will be included as part of that response (currently expected in late 2022).

## 1.4 Length of access arrangement period

104. Under section 5.31 of the Access Code, the length of the forthcoming access arrangement period is established by Western Power proposing a revisions submission date and a targeted revisions commencement date for AA6.

105. Western Power proposes the revisions commencement date for the revisions set out in the AA5 proposal be 1 July 2023.

13 The National Institute of Economic and Industry Research (NIEIR) reviewed the Energy and Customer Numbers Forecasts 2020 provided at Attachment 7.5 in the NIEIR Report on Western Power's Forecasting Methodology for Western Power's 2022-27 Regulatory Period provided at Attachment 7.7. Peak demand, energy consumption and customer number forecasts are updated annually. Western Power will include the impact of any material changes to these forecasts in our response to the draft decision.

106. Western Power proposes that the AA6 revisions submission date is 1 February 2026, and the access arrangement targeted revisions commencement date is 1 July 2027.

107. This results in a five-year AA5 period from 1 July 2022 to 30 June 2027.[14]

108. The start date for the AA5 period is 1 July 2022. However, the revised access arrangement will not take effect until the ERA has completed its AA5 review. This means that we have what is referred to as a 'gap year', because the expected finalisation of the review of the AA5 proposal is one year later than the nominated end date of the AA4 period. This means we will continue to have a five-year access arrangement period for AA5, with forecast opex and capex for all five years to be approved as part of the access arrangement determination process. However, it will be necessary to agree up front certain key principles, such as tariffs, to apply in the gap year only, as the AA5 determination process will not be finalised prior to 1 July 2022.

109. In its Final Decision on the framework and approach to apply for the AA5 period[15], the ERA published a number of decisions that will apply for the 2022/23 financial year (the gap year). These include:

- the AA5 decision will determine total target revenue for the five-year period from 1 July 2022. Western Power's current price list will apply until the revised access arrangement comes into effect
- the ERA will take account of revenue received for the period between 1 July 2022 and the commencement date of the revised access arrangement when determining target revenue for the remaining AA5 period
- the current service standard benchmarks will apply until the commencement date of the revised access arrangement
- a service standard adjustment mechanism will not apply between 1 July 2022 and 30 June 2023.

110. The proposed revisions submission date for AA6 of 1 February 2026 allows 17 months to conduct the access arrangement review process for the AA6 period. This should provide sufficient time for the ERA and Western Power to complete the review and implement any changes in preparation for the commencement of AA6.

## 1.5 Structure of this proposal

111. The structure and content of this proposal is informed by the ERA's *Guidelines for Access Arrangement Information*. Capex and opex forecasts were developed in accordance with section 4.4.1, 4.4.3 and 5.5 of the ERA's guidelines.

112. This AA5 proposal (which, along with the attachments and associated expert reports, forms the AAI) should be read in conjunction with the proposed access arrangement itself.

14 The end date of the AA4 period is 30 June 2022.

15 ERA, 2021, *Framework and approach for Western Power's fifth access arrangement review – Final Decision*, https://www.erawa.com.au/cproot/22112/2/Western-Power-AA5-Review---Framework-and-approach---Final-decision.PDF

**Table 1.1: Structure of this proposal**

| Chapter # | Summary of content |
|---|---|
| 1. About this submission | Chapter 1 provides:<br>• an overview of the key Access Code provisions relevant to producing AAI<br>• a summary of the approach Western Power adopted, and its key considerations when developing this AA5 proposal<br>• a revisions submission date and targeted revisions commencement date for AA6<br>• a summary of the document structure and the information contained in each section |
| 2. About Western Power and the changing energy landscape | Chapter 2 provides an overview of Western Power, our services, and Western Power Network. It also provides an overview of the recent changes in the WA energy landscape (largely driven by customer behaviour, decarbonisation of the electricity system and technological advancement in the energy sector), and how the changes have impacted Western Power and informed our AA5 proposal. |
| 3. Energy Market Reform | Chapter 3 provides an overview of the energy market reforms in WA, and how the changes have impacted Western Power and informed our AA5 proposal. |
| 4. Customers, stakeholders, and community engagement | Chapter 4 provides an overview of the customer and community engagement program and stakeholder engagement that Western Power has recently conducted and how it has informed our AA5 proposal. |
| 5. Performance during AA4 | Chapter 5 sets out how Western Power performed over the five years of the AA4 period (2017/18 to 2021/22). It summarises the key customer outcomes and the investment undertaken to achieve these outcomes. This chapter also highlights a number of service improvements made during the AA4 period, as well as improvements to processes and governance. |
| 6. Services and service standards | Chapter 6 lists the reference services to be delivered by Western Power in the AA5 period. This chapter also provides an overview of Western Power's service standards proposed for the AA5 period including an explanation for any changes compared to the AA4 period arising from the Access Code changes, ERA's Final Decision on the framework and approach, and any changes Western Power proposes. |
| 7. Forecast operating expenditure | Chapter 7 provides the methodology used to determine the forecast opex required by Western Power over the AA5 period. It also provides an overview of the opex forecasts, including the rationale for any changes from the AA4 period. |
| 8. Forecast capital expenditure | Chapter 8 provides an overview of Western Power's forecast capex over the AA5 period, including the forecasting approach and key investment drivers. |
| 9. Expenditure incentives and adjustment mechanisms | Chapter 9 provides an overview of the incentive mechanisms to apply to Western Power over the AA5 period. It details the methodology for calculating expenditure incentives, the investment adjustment mechanism and demand management innovation allowance mechanism and explains how they represent the interests of customers. |
| 10. Weighted average cost of capital | Chapter 10 outlines Western Power's proposed estimate of the WACC for the AA5 period. |
| 11. Annual revenue requirement | Chapter 11 describes how Western Power has calculated its revenue requirement for the AA5 period. It includes the forecast target revenue and outlines the form of price control and revenue components, including calculation of Western Power's RAB, tax asset base (**TAB**), adjustments under regulatory incentive/adjustment mechanisms, and other revenue items. |

| Chapter # | Summary of content |
|---|---|
| 12. Price path and network tariffs | Chapter 12 outlines Western Power's tariff structure statement (**TSS**), providing an overview of network tariffs and average price path for the AA5 period. It also includes discussion of reference services and the corresponding reference tariff changes as well as the introduction of new tariffs. |
| 13. Policies and contracts | Chapter 13 summarises proposed changes to the standard electric transfer access contract and three policies that form part of Western Power's proposed access arrangement, being the Applications and Queueing Policy, Contributions Policy and MFA Policy. |
| 14. Supplementary matters | Chapter 14 covers the supplementary matters required by the Access Code, and how they relate to Western Power. |

# 2. Western Power and the changing energy landscape

113. This chapter provides an overview of Western Power, our services and the Western Power Network. It also provides an overview of the recent changes in the WA energy landscape (largely driven by customer behaviour, decarbonisation of the electricity system, and technological advancement in the energy sector), and how the changes have impacted Western Power and influenced our AA5 proposal.

114. The energy market reform program in WA, and how these reforms are being addressed by Western Power are discussed in Chapter 3.

**Key Messages**

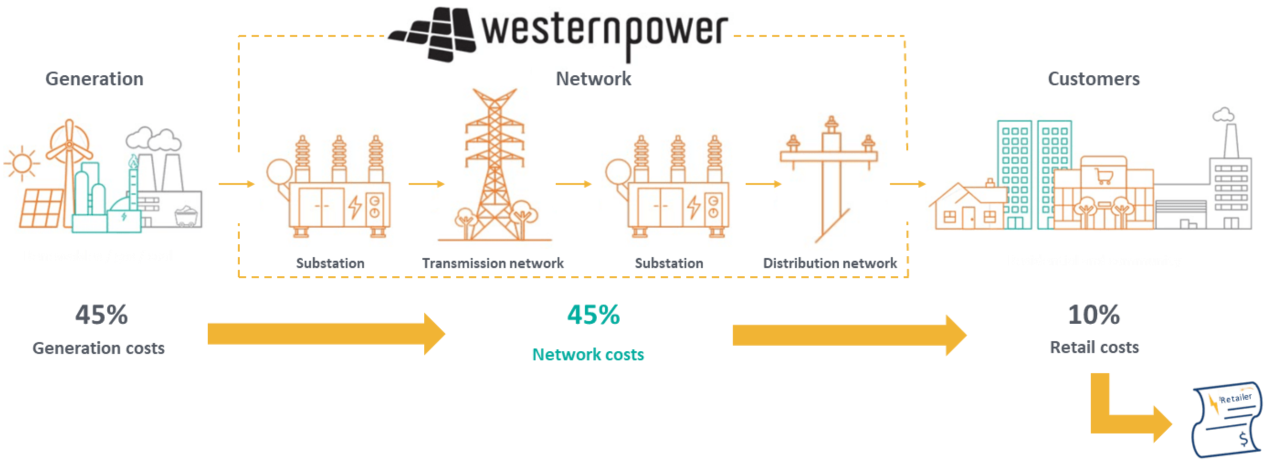
- Western Power is responsible for building, maintaining and operating an electricity network that connects 2.3 million customers' homes, businesses and essential community infrastructure to an increasingly renewable energy mix
- New technologies are giving our customers more choices on how they access and use electricity. The rapid rise in uptake of technologies such as solar PVs, energy storage and electric vehicles, known collectively as Distributed Energy Resources, has accelerated Western Power's need to respond to this changing environment
- These new technologies are changing the traditional approach of delivering electricity one way across a centralised network. The increase in these more dynamic bi-directional flows, has increased the complexity of planning and operating these networks for efficiency, power quality and reliability requirements

## 2.1 What we do

115. Western Power is responsible for building, maintaining and operating an electricity network that connects our 2.3 million customers' homes, businesses and essential community infrastructure to an increasingly renewable energy mix. We are focused on adapting our business to meet the changing energy needs of West Australians. This includes the trial and adoption of new technologies to ensure we continue to supply safe, reliable and affordable energy. What we do supports the economic activity of WA and is backed by robust regulatory reform.

116. We transport electricity from place to place – this is called transmission and distribution of electricity. Our services connect generation sources to deliver electricity to customers (see Figure 2.1). We do not generate electricity and we do not sell electricity.

**Figure 2.1: Western Power's role in the electricity supply chain and average electricity costs**




Source: adapted from ERA, https://www.era.com.au/electricity/switched-on-energy-consumers-guide, Accessed 12 July 2021. Network costs include the cost of the Tariff Equalisation Contribution.

117. The transmission network is like a freeway – it transfers electricity from where it is generated across long distances at higher voltages to maximise network efficiency. When electricity arrives closer to its destination (e.g. cities and towns), the electricity is stepped down to lower voltages and this is where the distribution network begins. The distribution network supports flows from customer generation to customer load and transfers electricity between the transmission network and our customers' homes, businesses and essential community infrastructure.

118. That electricity is bought by electricity retailers from the generators and sold to end-use customers by the retailers. The retailers are responsible for administering customer accounts and issuing electricity bills to customers.

119. Increasingly, customers are also generating their own electricity from solar PV, which is changing the traditional approach of delivering electricity one way across a centralised network. The increase in these more dynamic bi-directional flows, has increased the complexity of planning and operationally managing these networks for efficiency, power quality and reliability requirements. This is discussed further in section 2.4.2.

120. Our team of engineers and network controllers manage these dynamic electricity flows through the network, creating a balance and harmony that is essential to a secure, reliable and quality power supply at all hours of the day and night.

121. Western Power's services are paid for via electricity network tariffs, which forms part of the overall tariff charged by retailers. Western Power's costs account for around 45 per cent of the average residential customers' electricity bill.[16]

122. When customers use or connect to the Western Power Network, they expect electricity to be available when they need it. They also expect it to be delivered safely and reliably, regardless of where they are located (e.g. very remote areas, or in cities). Our customers have also stated their preferences for more of their energy supply to be renewable, while we tackle climate change impacts and the deteriorating performance of our ageing assets.

16 Economic Regulation Authority, https://www.era.com.au/electricity/switched-on-energy-consumers-guide, Accessed 12 July 2021. Network costs include the cost of the Tariff Equalisation Contribution.

123. Meeting our customers' needs in the future requires us to transform our network into a modular grid that will better serve these needs affordably, sustaining or improving their supply experience. Technology advances are making these alternative means of providing access to supply possible.

124. The modular grid refers to a move from a purely traditional network towards one which incorporates a mix of new energy solutions that can potentially plug into or out of the grid as needed. New solutions forming the modular grid include:

- SPS which combines solar, storage and potentially a generator, allowing a customer to be disconnected from the main grid
- microgrids which are small scale power grids providing power to an entire community, which may be used as backup connections if the main supply goes down, or entirely disconnected
- battery energy storage systems (**BESS**), which can be used for local communities to store excess solar power, or to be used as a temporary backup if the main grid goes down.

125. Our traditional assets will continue to remain a significant part of our business. However, new technologies are giving our customers more choices on how they access and use electricity. The rise in technologies such as PV, energy storage and EVs (known collectively as DER), and the emergence of new business models such as virtual power plants (**VPP**), microgrids and SPS, has accelerated Western Power's need to respond to this constantly and quickly changing environment. Further information on the changing energy market is provided below.

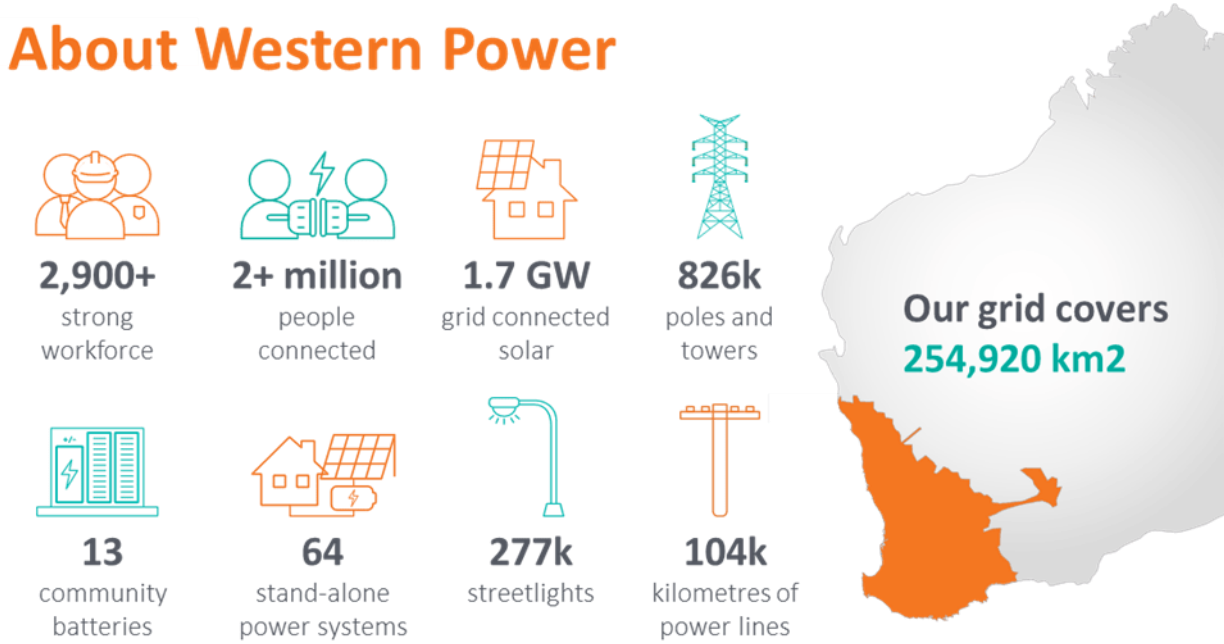
126. While forecasts show overall electricity consumption from the Western Power Network has flattened, there are still areas where demand (electricity usage) forecasts exceed current network capacity, or a network expansion is needed to support large customer driven projects. Additionally the reduced demand and increase in customer PV generation has introduced new challenges in managing reverse power flows during the middle of the day.

127. As critical community infrastructure, the potential impact of increasingly sophisticated cyber-attacks on the operation of the Western Power Network has come into sharp focus. In response to the increasing threat landscape, Western Power has adopted the Australian Energy Sector Cyber Security Framework (**AESCSF**) as the maturity framework and related reference frameworks to implement necessary controls to manage the cyber risks against our business and the Western Power Network.

## 2.2 Our network

128. The Western Power Network comprises both transmission and distribution assets and is one of the world's largest stand-alone networks. The Western Power Network makes up almost all of the South West Interconnected Network (**SWIN**), which together with electricity generators, makes up the SWIS. The Western Power Network reaches as far north as Kalbarri, east to Kalgoorlie and south to Albany (see Figure 2.2).

**Figure 2.2: Western Power's network**




129. The vast majority of Western Power's 2.3 million customers are located in the Perth metropolitan area.

130. Our networks cover a service area of 254,920 km². It is bigger than the United Kingdom and contains 103,069 km of circuit wire. That's two and a half times the Earth's circumference (40,075 km).[17]

## 2.3 Changing energy landscape

131. For decades, Western Power transported electricity to our customers' homes and businesses via one-way flow of electricity through poles and wires from traditional gas, diesel and coal-powered generators. The electricity landscape is in the midst of an unprecedented transformation, driven by widespread uptake of customer owned rooftop PV systems and changes in the large-scale generation mix towards more renewable generation (displacing fossil fuelled generators) which is likely to transpire into an increasing uptake of EVs.

132. It is important to note that the changes are largely driven by customer behaviour, government policy, decarbonisation of the electricity system, and technological advancement in the energy sectors. In particular:

- more than one in three homes serviced by the Western Power Network have rooftop solar PV and customers are connecting over 4,000 new installations each month
- the installed capacity of grid connected rooftop solar is forecast to reach almost 3 GW by the end of the AA5 period
- applications for large-scale renewable energy projects (wind, solar and waste-to-energy) to connect to the Western Power Network continues to increase, with almost 1 GW currently under development
- the time of peak demand on the network has shifted from an afternoon interval to the evening, due to the growth in PV, which is also exacerbated by significant load volatility during times of unusual weather patterns and cloud cover

---

[17] Western Power's Annual Planning Report 2020, p. 5

- there are now more than 3,500 approved battery applications for residential customers on the Western Power Network, with a combined storage capacity of over 34 MWh
- new technologies such as SPS and batteries are being installed to support or replace network infrastructure in areas where it addresses a network need and is financially prudent to do so
- an increasing uptake of EVs within WA
- a low carbon electricity system is critical to the State Government's commitment to net zero greenhouse gas emissions by 2050
- other recent technological advancements including behind the meter solutions offer our customers more choices to optimise their generation, storage and use of electricity.

133. The West Australian electricity system, including the Western Power Network, is uniquely positioned to both experience and benefit from the impacts of the changing energy landscape:

- the Western Power Network is a large, isolated network, with no interconnectors, which means any impacts of the changing energy landscape (such as minimum demand, voltage and frequency instability) must be managed within the Western Power Network
- WA has a plethora of renewable energy sources, with solar and wind power in abundance. Renewable generators are taking the opportunity to increase generation capacity with coal and gas retirements and Western Power is evolving our network to safely accommodate up to 50 per cent renewable generation in the next 10 years
- the major metropolitan area is built on sand, which means we have a low cost avenue to gaining the benefits of underground networks.

134. We are supporting the State Government's Energy Transformation Strategy to identify the right policy, regulation and investments that will allow us to manage the arising challenges and embrace the right solutions, while remaining efficient and delivering on customer expectations. More information on the Regulatory Reform Program is provided in Chapter 3.

### 2.3.1 Considerations

135. Uncertainty in the current environment is challenging for Western Power. However, it has also created opportunities to proactively investigate options to deal with these challenges, as well as having the potential to better meet customers' needs and community expectations in the long term. The following considerations inform the way we plan our network operations and investments.

#### *Minimum demand and impacts on voltage and frequency*

136. The changing customer behaviour (such as adoption of PV and technological advancement) are creating several challenges in planning and operating the power system, such as voltage and frequency stability.

137. Western Power has developed the network to support typically high customer demand during the evening peak (between 5pm and 8pm), with evening demand of over 4 GW currently experienced during peak intervals.

138. The large increase in rooftop PV is causing a significant shift in the patterns of high and low demand on the network. Many consumers' energy needs, particularly during daylight hours, are now being met by their own PV, resulting in low demand for energy from the grid. As such minimum demand now typically occurs in daytime, typically between 11:30am and 2:30pm. However, PV has only had a small impact on peak demand, which typically occurs between 6:30pm and 7:30pm, when PV produces very little, leading to a widening gap between minimum and maximum demand that the network is expected to serve.

139. EV charging may increase this gap, as consumers may charge EVs during the evening peak, however, uncertainty as to customer adoption rates and charging behaviour is introducing uncertainty into customer demand forecasting.

140. Managing a network to support the minimum demand while also facilitating peak load a few hours later poses a range of planning and operational challenges. While these challenges occur for a short time (e.g. ramping up of load during the afternoon as solar PV generation reduces) it is occurring more frequently.

141. Long term solutions are being developed to better integrate DER into the network. In the meantime, we need interim solutions to manage minimum demand and the integration of DER. We will improve DER integration and co-ordination with our AMI deployment, modernised connection standards for DER, and greater amounts of grid-connected storage to help balance periods of minimum demand and intermittent supply.

142. Energy market reforms are currently underway to assist in addressing these issues. Further information on the energy market reforms to integrate DER into the network is provided in Chapter 3.

#### *Customers have excess energy*

143. As noted above, the large increase in rooftop PV is causing a significant shift in the patterns of energy flow on the network. Many consumers with rooftop PV are producing more than they consume, adding to the challenges of minimum demand discussed above.

144. Grid storage has a critical role to play for supporting load and generation management for the community in a high DER future. For example, large scale distributed community batteries can be used as a 'solar soak' to store excess PV generation for later use during the evening peak.

145. Western Power has been trialling community power banks and other grid-connected community batteries to better manage demand by adding another level of support to local networks. They allow us to delay network enhancement costs and customers benefit from a shared battery at a lower cost. Thirteen community batteries have been deployed across the Western Power Network during AA4.

#### *Cost to maintain the network continues to grow*

146. The changes in the energy landscape are occurring alongside our network assets ageing and approaching end of life. This provides opportunities and additional challenges to manage our existing assets, while planning for and starting to transition the network.

147. As the network ages, the costs to maintain and replace the network are also increasing. However, the age profile of our asset base provides opportunities to adopt new technologies and transition the network in locations where the assets are ageing, which we are leveraging for the benefit of our customers. For example, we are transitioning ageing regional networks to SPS to reduce rebuild and maintenance costs which will also result in improved reliability for our customers over the life of the assets.

#### *Climate change impacts*

148. Climate change is presenting both physical and transitional risks for Western Power. Responses to climate change are already driving new connections to the network as renewable generators see the opportunity with coal and gas retirements, and major loads seek to reduce their carbon footprint by connecting to the Western Power Network.

149. Climate change will see a need for greater emphasis on disaster preparedness, resilience and increase the challenge of protecting grid infrastructure and supply to communities vulnerable to the impacts of climate change.

150. We are now piloting solutions such as microgrids and rolling out SPS in low density parts of our network to improve both reliability and network resilience to our customers mitigating the risks of climate change on the more remote parts of the Western Power Network. In addition, with the majority of the Perth metropolitan area being "meshed", an underground meshed grid is envisaged when shown to be economic, rather than rebuilding the overhead grid, which is prone to environmental conditions, when assets reach end of life.

### 2.3.2 How Western Power is responding to the changing energy landscape

151. The range of future energy scenarios considering macro-economic factors, macro-demographic factors and customer uptake of different technologies (including PV, storage and EVs) is resulting in increased complexity of the planning process. Western Power has developed and implemented decision support tools, such as the Grid Transformation Engine (**GTEng**), that presents a range of possible future energy scenarios, and how the transition pathway to the future state across these different scenarios could look to maximise efficiency and benefits.

152. When planning our network, Western Power carefully considers the impacts of change on our network that will likely evolve significantly in the coming decades. That's why we economically consider options for non-network solutions such as managing demand or structuring tariffs in a way that optimises the use of our network alongside options for conventional network management (i.e. poles and wires).

153. Technology is evolving rapidly as we continually pilot new solutions to test their suitability as part of the transforming network. Examples of how we do this are SPS which are now considered part of our toolkit to manage the network, after significant trial. These new tools are being installed to replace or support traditional network infrastructure in areas where it is technically and financially feasible.

154. Western Power has been planning for the transforming network for some time now. We have made significant progress in transforming our network by leveraging new technologies, developing data-based modelling and connecting renewable energy sources.

155. We need to ensure our AA5 proposal maintains our safety and reliability outcomes, whilst facilitating transition of the network to meet changing customer behaviour and expectations. Our AA5 proposal details our plans to address ageing assets, technology risks and ensure ongoing financial sustainability of the business so we can continue to deliver benefits to the communities in which we operate.

156. The AA5 investment plan applies a combination of traditional and new technologies to manage and address the challenges resulting from the energy transformation. Further information on our specific investment programs is provided in Chapter 8.

## 2.4 Our vision

157. Our vision is to power the lives of our community by transitioning to a modular version of the network. This is consistent with the outlook for the energy sector identified in the Infrastructure WA State Infrastructure Strategy.[18] We have been delivering electricity safely, reliably and efficiently for more than 70 years, and this will continue to be our focus today and in the future.

158. In a quickly changing energy landscape, our customers' energy needs are evolving, and we intend to keep them connected every step of the way. Whether it's charging a smart phone, powering home WiFi, running an air-conditioner, powering schools and hospitals, helping to drive our economy by connecting developers

[18] Infrastructure Western Australia, *Foundations for a Stronger Tomorrow – State Infrastructure Strategy*, Draft for public comment, July 2021

building shopping centres or a stadium hosting a sporting event, or powering an EV, we are there to deliver energy.

159. Our community expects Western Power to safely maintain reliability of supply, keep costs low, support new renewable technology and future jobs and growth. In response, our strategy to deliver for the community focuses on five key areas:

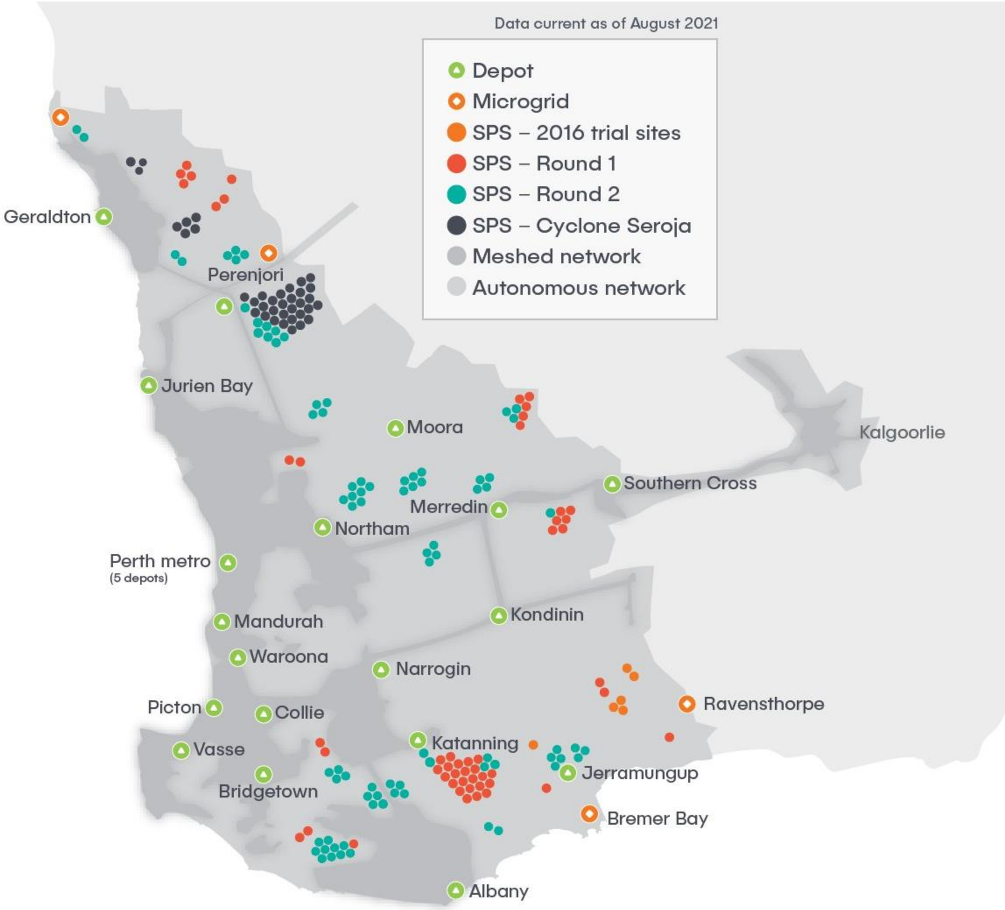
1. optimising the modular grid transition
2. integrating DER into the network
3. delivering outcomes for customers
4. driving financial sustainability
5. decarbonising our community.

### 2.4.1 Optimising the modular grid transition

160. Western Power's network is in a period of transition. To best meet the needs of our community, we need to move as safely, and as affordably as possible to the modular version of the network. This needs transformational investment in existing assets and new technology. The modular grid will consist of three zones:

- a tightly meshed urban network of increasingly underground assets that will service the majority of our customers for decades to come
- a hybrid network of mostly overhead assets but new technologies such as SPS and connected microgrids where possible
- an autonomous stand-alone network of remote power systems such as SPS and disconnected microgrids (see Figure 2.3).

**Figure 2.3: Illustrative network zones and assets of Western Power's modular network**




161. Our largest customer base will always be in the urban population areas. For metropolitan customers, we are focusing on undergrounding assets, and facilitating more renewables and DER to connect to the Western Power Network – everything from rooftop solar panels to storage and EVs.

162. For regional customers, the modular network will mean new ways of delivering power like SPS and microgrids. Although much of our rural network is ageing, there will still be many poles and wires to maintain, and we'll still need to respond to faults and outages as safely and reliably as we do now. Our depot network will remain, supporting regional communities.

163. The modular network will improve the resilience of the Western Power Network. Resilience is of increasing importance as we face impacts of climate change driving up the frequency of extreme climate events and bushfire potential. Maintaining electricity supply through major events enables essential services such as communications and water supply to continue uninterrupted.

164. Our strategy requires balanced decisions between investing in traditional and new technology assets. Western Power is committed to proactive and ongoing trials of alternative solutions that will deliver better outcomes for customers, where they are financially and technically feasible, as demonstrated by our proven record in SPS, batteries and AMI.

165. AMI will play a key role in the delivery of our strategy as it is a critical enabler for the effective integration of DER, flexible tariffs and allowing customers to actively participate in the energy market. Further information about AMI and the role it plays under the Energy Transformation Strategy is outlined in Chapter 3.

166. SPS are a key part of delivering on our strategy. SPS improve reliability for our customers using more efficient and flexible technology. This technology results in a cost-effective, innovative solution that replaces ageing infrastructure in low density parts of our network which conventionally would be a like for like replacement.

167. Under the WA Recovery Plan, Western Power is supporting the Government's commitment to drive the local manufacturing industry and jobs of the future by deploying SPS units built in WA over AA5 (almost 900 in the first three years as part of the Government's election commitment). Further information on the reforms to the regulatory framework enabling the use of SPS as technology option in the Western Power Network is provided in Chapter 3.

### 2.4.2 Integrating DER into the network

168. The rise in DER connected to electricity networks is fundamentally changing the energy value chain and driving increasingly complex consumption and production patterns. DER gives our customers more choice in generating, storing and using energy.

169. However, it is also challenging the traditional approach of delivering electricity one way across a centralised network. The rapid uptake of DER has already started causing Western Power technical challenges in managing the network (such as voltage management and frequency issues), that will continue to escalate and require intervention and planning as PV penetration levels increase. If DER are not coordinated effectively it poses system security risks. This highlights the importance of the proposed distribution system operator (**DSO**) role and associated investments in undertaking this coordination. Further information on the proposed regulatory reforms to effectively integrate DER is provided in Chapter 3.

170. The integration of DER into the Western Power Network (and all Australian electricity networks) creates opportunities and challenges:

- It creates opportunities to improve the safety and reliability of existing services while lowering future costs by leveraging new technologies and providing new products to our customers and the electricity market. We will continue to integrate DER into our network as we have been for some time with batteries, EVs, microgrids and managing solar PV uptake.
- The challenges to coordinate DER integration include having visibility to balance network demand and generation in order to maintain the right network voltage and system stability. We will continue to work with stakeholders to develop capabilities to manage these issues while still meeting customer choices.

171. The proposed introduction of a DSO role is expected to assist with managing the integration of DER. Further information on the proposed DSO model and integrating DER into the network is provided in Chapter 3.

172. We are enabling an increasingly renewable future for the community by improving DER integration and coordination with the help of things like AMI, modernised connection standards for DER and greater amounts of grid-connected storage to help balance periods of low demand and intermittent supply. This will also help us plan for more EVs, without overinvesting in the technology before their broad adoption.

### 2.4.3 Delivering outcomes for customers

173. Our customers are becoming more informed, more active and more engaged in the production and consumption of electricity. They will make investment decisions (such as installing a battery storage system in their homes or buying an EV) that will impact Western Power's network investment decisions and change the way we need to operate the network. Our customer engagement program found that customers are

supportive of us investing to plan and build for the evolving network. Further information on the findings of the customer engagement program is provided in Chapter 4.

174. The costs of technological alternatives compared against conventional networks, to supply electricity such as solar PV and batteries will continue to fall, and these alternative supply options will increasingly make more economic sense for some customer groups. This results in the expectation that customers will continue their investment into these alternatives to lower their electricity costs. As traditional roles in the energy sector transform and new participants emerge, Western Power will have the opportunity to create new relationships that add value to our customers, the community and our network. This will also challenge our existing operating model and requires us to adapt. It is driving a new way of thinking on how customers can benefit from a modernised electricity network.

175. We need to ensure we can support customers' equitable access to our network and optimise their supply alternatives. That's why we are looking towards the future with value-add services like AMI, SPS for regional areas and collaborating with retailers to provide additional offerings such as battery storage.

176. To do this effectively we need the relevant capabilities to operate and deliver outcomes for customers in this more complex future environment without losing focus on continuing to get the basics right such as delivering a level of service that meets our customers' needs and providing services that are safe, reliable and affordable.

177. While customers are supportive of our future focus, customers have also told us that the following hygiene factors are fundamental to maintain:

- safety is critical – customers see this as being a core value of Western Power and appreciate the importance it is given
- service reliability is important for all customers – any erosion of reliability would have a significant negative impact on customer perceptions, irrespective of customer type.

178. So, we still need to focus on keeping our core strong to ensure we maintain safety and reliability standards, which gets harder to do over time with an ageing network and increased frequency and severity of inclement weather events. Further information on our ageing network, and our specific investment programs are provided in Chapter 8.

### 2.4.4 Driving financial sustainability

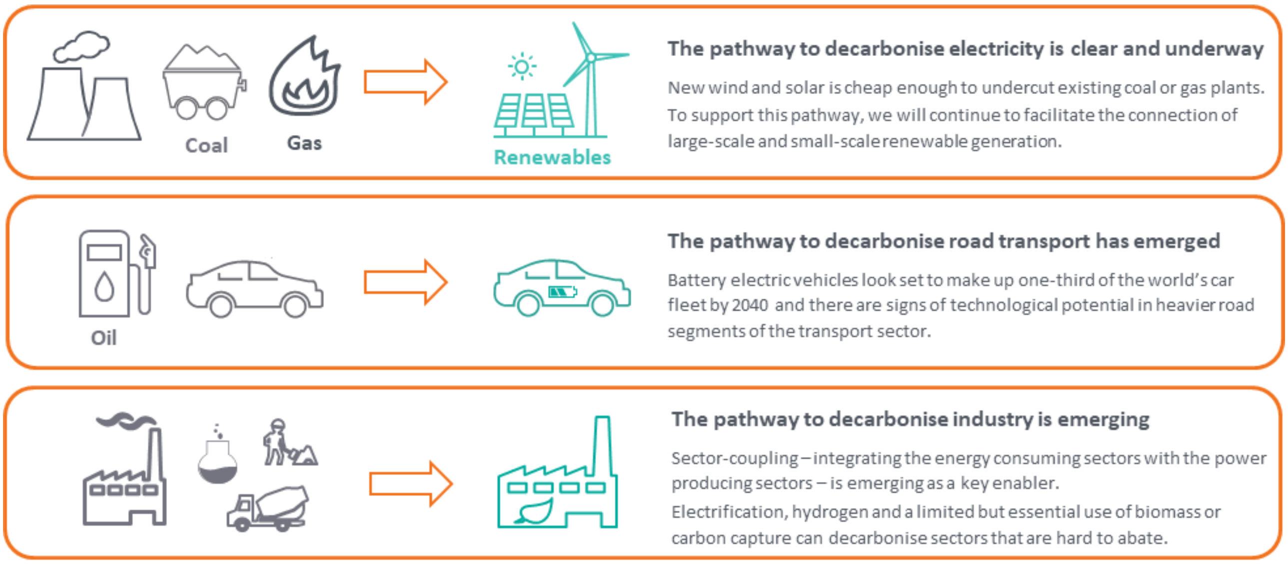
179. A sustainable business model for Western Power is critical to the investment the community has made in the network for future generations. We remain committed to driving efficiency to support the affordability of electricity supply to all our customers.

180. The transforming energy sector – lower demand forecasts and the need for investment to transition the network to the modular grid – means Western Power must be innovative in the way we operate and manage our business and network while delivering an optimum outcome for the community. We will continue to identify ways to leverage our network assets and workforce to drive financial sustainability and deliver efficient solutions for customers. We have also developing network tariffs to encourage customers to use less electricity at peak times and greater electricity at times of minimum demand, therefore influencing future network investment needs.

### 2.4.5 Customer choice driving decarbonisation

181. The government is committed to achieving net zero emissions by 2050.[19] At Western Power, we too are taking action to address climate change by supporting the decarbonisation of the economy. There are three key decarbonisation pathways for various sectors that impact on the Western Power Network, each at different development stages. These pathways are summarised in Figure 2.4.

**Figure 2.4: The three decarbonisation pathways impacting the Western Power Network**




182. Western Power will continue to evolve our network to safely accommodate increased renewable generation and innovate by developing products and services that support the electrification of the transport, industrial and processing sectors. To build climate change resilience, Western Power is placing a greater emphasis on disaster preparedness, resilience and protecting network infrastructure which supplies vulnerable communities.

183. In addition, Western Power is taking the following actions to support decarbonisation:

- implementing Western Power's 2050 net-zero transition plan by 2023
- ensuring that Western Power can support greater than 50 per cent of all electricity needs being met by renewable sources by 2031
- transitioning greater than 25 per cent of Western Power's light passenger fleet to EVs by 2025
- developing standards for the optimised charging of EVs by 2025
- replacing all streetlights with light-emitting diodes (**LEDs**) by 2029.

## 2.5 Recognition for Western Power

184. Western Power strives to deliver the best outcomes for our community via our willingness to learn, change and act.

185. During the AA4 period our efforts in adoption of new technologies and developing innovative solutions have been recognised with state, national and international awards.

[19] Department of Water and Environmental Regulation, Western Australian Climate Policy, November 2020

186. Our people have been the driving force behind our success. The value and expertise of our workforce has been also recognised with several awards received for individual achievement, and ongoing commitment and contributions to the energy sector as shown in Table 2.1

**Table 2.1: Western Power industry recognition**

| 2021 | | |
|---|---|---|
| WA Australian Institute of Energy | Women in Energy | Winner - Margot Hammond, SPS Program Manager |
| WA Australian Institute of Energy | WA Energy Professional of the Year | Finalist - Zahra Jabiri, Head of Regulation and Investment Assurance |
| Australian Workplace Health & Safety Awards | Large Enterprise Excellence Awards | Finalist - Health & Wellbeing Program |
| Australian Workplace Health & Safety Awards | Large Enterprise Leadership and Culture | Finalist - Health & Wellbeing Program |
| Energy Networks Australia | Industry Innovation Awards | Finalist - Flexibility Services Pilot |
| Energy Networks Australia | Industry Contribution Award | Winner - Nigel Wilmot |
| Peak Load Management Alliance 2021 | | Winner - 100 MW Challenge - Flexibility Services Pilot |
| CIPS Australia & New Zealand Excellence in Procurement Award | Sustainable procurement project of the year | Finalist – Western Power, SPS procurement framework |
| Healthier Workplace WA | | Gold Recognition – Western Power |
| ISO Certification | Network Operations accredited to ISO9001:2015 | |
| **2020** | | |
| Digital Utility of the Year | Energy | Winner - Digital Substation Pilot |
| Itron Innovator Award | | Winner - Smart City Lab |
| WA Australian Institute of Energy | Women in Energy | Winner - Western Power |
| **2019** | | |
| Australian Financial Review Most Innovative | Industry: Agriculture, Mining & Utilities | Winner - Pole Top Fire Modelling |

| | | |
|---|---|---|
| WA Australian Institute of Energy | Young Energy Leader | Winner - Genevieve Simpson, Manager Government Relations |
| WA Australian Institute of Energy | Energy Professional of the Year | Winner - Matt Cheney, Head of Grid Transformation |
| Clean Energy Council | Innovation Award | Finalist - PowerBank trial |
| WA Records and Information Management Professionals Australasia (RIMPA) | Black Swan Award for individual achievement | Winner - Frank Flintoff, Senior Information Compliance Specialist |
| Asset Management Excellence Award | Information Management | Winner - Pole Top Fire Prediction Model |
| Chartered Institute of Procurement and Supply (CIPS) | CIPS Advance Platinum Award | Highest Level of Certification – Western Power |
| ISO Certification achieved | Asset Management System achieved ISO 55001 | |
| **2018** | | |
| Australian Marketing Institute | Best in the West - Awards for Marketing Excellence | Winner - "Make the Safe Call" safety marketing campaign |
| Energy Networks Australia | Consumer Engagement | Highly Commended - Kalbarri Microgrid |
| WA Training Awards | WA Apprentice of the Year category | Finalist - Emily Davis, Lineworker Kalgoorlie Depot |
| WA Training Awards | WA Trainee of the Year category | Finalist - Beth Hodder, Business Trainee, Change and Innovation |
| WA Training Awards | WA Apprentice of the Year category | Finalist - Megan Feaver, Electrical Tradesperson, Kewdale |

# 3. Energy market reform

187. This chapter provides an overview of the energy market reform program in WA, and how these reforms are being addressed by Western Power and have therefore informed this proposal.

**Key Messages**

- We are supporting the State Government's Energy Transformation Strategy to identify the right policy, regulation and investments that will allow the right solutions for managing the arising challenges, while remaining efficient and delivering on our customer expectations
- Many elements of our proposal are enabled by and build on the work done under the Energy Transformation Strategy. These include changes made to the regulatory framework in Stage 1 to support standalone power systems and the work to come in Stage 2 looking into the introduction of microgrids, both of which facilitate Western Power's transition to a modular grid
- Our AA5 proposal has been prepared based on the regulatory framework in its current form, including the reforms that have been completed under Stage 1 of the Energy Transformation Strategy, as intended

## 3.1 Energy Transformation Strategy

188. The WA Government launched the Energy Transformation Strategy in March 2019 in response to the changing energy landscape and changing customer behaviour. The objective of the strategy is to deliver cleaner, affordable and more reliable energy for decades to come that supports a sustainable market that meets customer needs.[20] This is the WA Government's strategy to enable the transmission to low-emissions and distributed energy sources, and to plan for the future of our power system.

189. Stage 1 of the strategy implementation was developed by the Energy Transformation Taskforce (the **Taskforce**) over 2019 to 2021 across three streams:

- **Distributed Energy Resources**: including the development and release of the DER Roadmap in April 2020, which sets out 36 actions over a five-year period to integrate DER into the energy system. Of the 36 actions, Western Power was assigned 22.
- **Whole of System Planning**: including the development and release of the inaugural whole of system plan (**WOSP**) in October 2020, which sets out four future scenarios for the SWIS in order to inform the energy and network needs over the next 20 years
- **Foundation Regulatory Framework**: focusing on changes to the regulatory framework and energy market requirements to facilitate the transformation, and improving the access arrangement process, such as the framework and approach process and the tariff structure statement.[21]

190. Stage 2 of the Energy Transformation Strategy will be led by Energy Policy WA and be implemented over 2021 to 2025. It will focus on four key themes:

- **Implementing the Taskforce decisions**: focusing on continuing the implementation of the DER Roadmap initiatives and development of the next WOSP, which will include climate policy targets and potential new projects such as hydrogen

20 Government of Western Australia, *McGowan Government launches Energy Transformation Strategy*, Media Statement, 6 March 2019

21 Energy Policy WA, *Energy Transformation Strategy 2019-2021*, https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy-2019-2021, Accessed 28 July 2021.

- **Integrating new technology into the SWIS**: continuing the technology trials, preparing for EVs and tariff reform to support the transformation
- **Keeping the lights on through the transition**: focusing on maintaining network security, reliability and sustainability while the system transitions away from coal and to a lesser extent gas
- **Regulating for the future**: which will establish governance frameworks to facilitate the energy transformation.[22]

191. Western Power has been working closely with Energy Policy WA, AEMO and the Taskforce in the development and implementation of the Western Australia Government's Energy Transformation Strategy. Many elements of Western Power's strategy, discussed in the previous chapter, are enabled by and build on the work done under the Energy Transformation Strategy. For example, a move towards a modular grid wouldn't be possible without the changes made to the regulatory framework in Stage 1 to support SPS and the work to come in Stage 2 looking into the introduction of microgrids in the SWIS.

192. Our AA5 proposal has been prepared based on the regulatory framework in its current form, including the proposed reforms that have been completed under Stage 1 of the Energy Transformation Strategy, as intended. Table 3.1 sets out the relevant versions of the regulatory instruments which our proposal is based on.

**Table 3.1: AA5 proposal regulatory instruments and relevant versions**

| Regulatory instrument | Version and/or date |
|---|---|
| Access Code | No. 134, 30 July 2021 |
| *Electricity Industry Act 2004* | No 186, 5 November 2021 |
| *Electricity Corporations Act 2005* | Version 03-a0-01, as at 07 June 2019 |
| *Electricity Industry (Metering) Code 2021* | No 145, 19 August 2021 |
| *Electricity Industry (Network Quality and Reliability Supply) Code 2005* | No 186, 5 November 2021 |
| Technical Rules | Revision 3, 1 December 2016 |
| *Wholesale Electricity Market Rules* | No 96, 28 May 2021 |

193. These versions of the regulatory instruments include the following reforms:

- introduction of the framework and approach process
- introduction of the tariff structure statement
- changes to recovery of deferred revenue
- changes to the Access Code objective to include a focus on the long-term interests of consumers and an environmental objective
- changes to allow the recovery of costs incurred in respect to the Government's reforms to network access, to the extent that these costs are prudent and efficient
- codifying building block for AMI expenditure in AA4
- enabling the inclusion of SPS and storage solutions (e.g. batteries) as a technology option in the SWIS.

---

22 Energy Policy WA, *Leading Western Australia's brighter energy future*, Energy Transformation Strategy, Stage 2: 2021-2025, July 2021.

- five-minute intervals for market dispatch and settlement
- publication of opportunities for third parties to provide network services, for example the Network Opportunity Map.

194. Many of the proposed reforms in the Energy Transformation Strategy are still subject to further consideration as part of Stage 2. Some of the key decisions yet to be resolved include the impact of constrained access and the final form of the DSO role. Where changes to the regulatory framework are yet to be made, Western Power proposes to address the issue as follows:

- where a change will be made prior to submitting our response to the ERA's draft decision, updated information will be included as part of that response (currently expected in late 2022)
- where changes are made after the response is submitted and will impact Western Power during the AA5 period, Western Power will work with the ERA and assess whether the change requires the re-opening of the access arrangement (as per the processes set out in Subchapter 4.3 of the Access Code)
- changes that do not warrant the re-opening of AA5 can be dealt with by 'truing up' for expenditure differences in the AA6 period.

## 3.2 Key reforms and their implications

195. The following sections provide further details on the key reform outcomes and how they are incorporated into our AA5 proposal.

### 3.2.1 DER and the Distribution System Operator role

196. The introduction of a DSO role is included in the 36 actions set out in the DER Roadmap, specifically actions 24 through to 30. It identified the need for a DSO who has visibility of the distribution network and could be responsible for:

- enabling connection and operation of active DER on the Western Power Network whilst ensuring that the network operates within its technical limits
- identifying and managing network technical issues as they arise, engaging DER providers to mitigate these issues where it is the most efficient solution.[23]

197. The DSO is a key part of the 'new' integrated DER world with aggregators and a distribution market operator (**DMO**) that will both rely on a functioning DSO capable of supporting what may become a significant market and complex aggregator DER control and dispatch delivering value for the overall system through the wholesale electricity market (**WEM**).

198. The DER Roadmap identified the DSO as a natural evolution of Western Power's role:

> *"In the high-DER future, the Distribution System Operator is a natural evolution of Western Power's role as a network service provider."*[24]

199. The Taskforce proposed the responsibilities of the DSO could include:

- determining technical arrangements for the connection of DER
- reviewing and approving connection applications for DER assets

---

[23] Energy Transformation Taskforce, *DER Roadmap: Distributed energy resources orchestration roles and responsibilities*, Issues Paper, 14 August 2020

[24] Energy Transformation Taskforce, *Distributed Energy Resources Roadmap*, December 2019, p.44.

- collating information on DER and providing it to AEMO for the purposes of establishing, maintaining and updating a DER register
- providing a dynamic operating envelope to aggregators/retailers for all active DER
- creating and/or administering systems, such as a DSO platform, to enable the visibility of power flow across the distribution network, and to provide visibility of, and means of managing, issues on its network in real time when they emerge
- developing processes within the DSO platform that allow the DSO to request network support services where needed and available to meet network support requirements
- providing information on the deployment of network support services to allow the DMO to consider the impact of these services on the broader power system
- planning network investments that deliver economic benefit.[25]

200. The expanded role of a DSO is expected to commence in 2023. The DSO is likely to be vested with responsibilities for identifying alternative options to network investments and procuring suitable services from a range of possible providers including contestable customers and DER aggregators by means of bilateral contracts.

201. The DSO format and scope is evolving, and lessons learned through current market, system and network trials will inform the final format and scope of the DSO role. Notwithstanding this, we are further developing required capabilities for DSO during the AA5 period, for example by undertaking the following activities:

- release of Distribution Storage Opportunities Information Paper in December 2020 (as part of Action 5b of DER Roadmap), as a precursor to the release of the inaugural Network Opportunities Map in October 2021 (Action 21 of DER Roadmap)
- updating Western Power's DER connection guidelines in May 2021 to mandate enhanced ride-through capability of customer DER in advance of AS/NZS 4777:2020 taking sole effect in December 2021
- proposing updates to the Technical Rules to improve distribution network visibility to enable enhanced DSO role (Action 14 of DER Roadmap)
- working with businesses to build network support services into commercial and industrial customer solutions as part of the Flexibility Services Pilot
- updating Western Power's DER connection guidelines in December 2021 to enable Distributed PV management.

202. An active DER demonstration project, Project Symphony, is underway as a collaboration project between Western Power, AEMO and Synergy, with funding from the Australia Renewable Energy Agency (**ARENA**). Project Symphony will further inform the development of the DSO role alongside the proposed DMO and DER Aggregator roles, contributing to the requisite capability build within Western Power.

203. Project Symphony aims to build industry capability by developing and testing the end-to-end customer, market and technical capabilities and functions required to safely and reliably integrate DER within the SWIS. It is considering DER integration issues across three key areas:

- **Technical:** focusing on how DER can be used to manage security and reliability issues on the SWIS
- **Customer**: focusing on understanding customer preferences around DER products and services
- **Market:** focusing on DER participation in the wholesale market and how it can reduce system costs.[26]

---

25 Energy Transformation Taskforce, *DER Roadmap: Distributed energy resources orchestration roles and responsibilities*, Issues Paper, 14 August 2020

26 Energy Policy WA, *Leading Western Australia's brighter energy future*, Energy Transformation Strategy, Stage 2: 2021-2025, July 2021.

204. The Project Symphony pilot, which will create a VPP by aggregating customer rooftop solar, battery energy storage systems and other controllable appliances, has been under development since early 2020. The pilot study commenced in mid-2021 and is due to run until mid-2023. More information on our proposed investment in Project Symphony and potential DSO enabling solutions is provided in Chapter 8.

205. Western Power will need to assess the implication of the outcomes of the DER Roadmap on both network and non-network investments such as increased network monitoring requirements to improve distribution network visibility, and workforce or technology impacts. It is expected the impacts will be greater towards the end of the AA5 period as more of the reforms are implemented. Where these impacts are known, they have been included in Chapter 7 and Chapter 8 of our AA5 proposal.

206. Where impacts are not yet known, as the changes to the regulatory framework have not yet been finalised, Western Power will deal with this uncertainty through one of the three approaches identified in section 3.1.

### 3.2.2 Whole of System Planning

207. The WOSP is a detailed study of how the SWIS may evolve over the next 20 years. The first WOSP was delivered by the Taskforce in October 2020 and presents four scenarios of how the SWIS could evolve through to 2040.[27] Western Power was a key contributor to the modelling and assessment of the four scenarios for the first WOSP, working closely with Energy Policy WA, AEMO and industry.

208. The Access Code was amended in September 2020 to enable Western Power to recover costs that it incurs in respect to the Government's reforms to network access, to the extent that these costs are prudent and efficient.[28] This includes the recovery of Western Power's expenditure related to the development of the first WOSP. We incurred costs of $0.5 million during the AA4 period in relation to this access reform work. Further information is provided in Chapter 11.

209. The next WOSP is expected to be developed by Energy Policy WA within the AA5 period and will include a review of potential projects in the Mid-West, climate policy targets and new projects such as hydrogen. It may identify 'priority projects', at which time Western Power will determine the network impacts and any required investment. If investments are required during the AA5 period, we will need to assess whether it necessitates the re-opening of the access arrangement (as per the processes set out in Subchapter 4.3 of the Access Code). Investment changes that do not warrant the re-opening of AA5 can be dealt with by 'truing up' for expenditure differences in AA6.

### 3.2.3 Foundational Regulatory Framework

210. As noted above, the Energy Transformation Strategy included changes to the regulatory framework, markets and operations to facilitate the energy transformation and improve the access arrangement process. These changes are discussed further in the sections below.

***Reforms to Regulatory Frameworks***

211. Changes have been implemented to regulatory frameworks to facilitate energy transformation and improve the access arrangement process through:

- introduction of the framework and approach process
- introduction of the tariff structure statement
- amendments to model policies and contracts

27 Energy Transformation Taskforce, *Whole of System Plan 2020*, August 2020.
28 Sections 6.81, 6.82, and 6.83, Electricity Networks Access Code 2004

- changes to recovery of deferred revenue
- changes to the Access Code objective
- codifying a building block for AMI
- changes to Technical Rules
- enabling the inclusion of SPS and storage solutions (e.g. batteries) as a technology option in the SWIS.

212. Each of these is discussed below.

*Framework and approach*

213. The Access Code was amended in September 2020 to require that, prior to Western Power submitting the AA5 proposal, the ERA to produce a framework and approach document, which sets out the ERA's decision on the following matters:

- classification of services, including whether services are reference or non-reference services, and the eligibility criteria for each reference service
- the structure and charging parameters for each reference tariff and the approach to setting the reference tariffs
- incentive mechanisms, including the investment adjustment mechanism, gain sharing mechanism, service standards adjustment mechanism and demand management innovation allowance
- form of price control
- method for setting service standards benchmarks.[29]

214. The objective of the framework and approach process is to facilitate early public consultation on these matters, which would otherwise be determined as part of the ERA's consideration of any proposed access arrangement revisions, thereby reducing the time pressures during the access arrangement approval process.[30]

215. The ERA released its Final Decision on the framework and approach in August 2021. The key decisions set out in the framework and approach include:

- changes and additions to service classifications relating to SPS, batteries and multifunction assets
- changes to the definition and / or proposed eligibility criteria of certain reference services
- the introduction of new reference services for storage systems and EV charging points
- that benchmarks for service standards will continue to be based on the 97.5$^{th}$ percentile of actual performance over the previous period
- changes to certain measures for benchmark service standards
- retention of the current price control, but with a single price control for the transmission and distribution network, and the removal of the side constraint on the movement in tariffs
- changes to the application of existing incentive schemes and the application of a demand management innovation allowance mechanism in the AA5 period.[31]

29 Subchapter 4.A, Electricity Networks Access Code 2004.

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

31 ERA, *Framework and approach for Western Power's fifth access arrangement review*, Final Decision, August 2021.

216. Western Power's AA5 proposal is consistent with the decisions set out in the ERA's framework and approach. There have been no material changes in circumstances since the framework and approach was released.

217. Further information about Western Power's services and service standards is provided in Chapter 6 and further information on the application of incentive schemes is provided in Chapter 9.

### *Tariff structure statement*

218. The Energy Transformation Taskforce determined that Western Power should be required to develop a tariff structure statement, as one of several measures to ensure appropriate price signals are provided to customers. It acknowledged that retailers ultimately determine the tariffs for customers and noted that *"adopting network tariffs that encourage efficient utilisation is a necessary first step for those signals to be passed through to end-use customers"*.[32]

219. Amendments made to the Access Code in September 2020 require Western Power to submit a tariff structure statement with our AA5 proposal. The tariff structure statement must set out:

- our pricing methods
- the structure and charging parameters for each reference tariff
- our approach to setting each distribution reference tariff.[33]

220. The tariff structure statement must also comply with the pricing principles in Chapter 7 of the Access Code and the ERA's framework and approach.[34] Through the framework and approach, the ERA has determined that Western Power's tariff structure statement is to address:

- the transition to the revised time periods for time of use tariffs proposed by the ERA
- price differentiation between the time periods for the time of use tariffs.[35]

221. Western Power is also expected to consider the use of flexible network pricing to facilitate the integration of DER and demonstrate that its proposed tariffs are cost reflective.[36]

222. Further information on Western Power's proposed tariff structure statement is provided in Chapter 12. A copy of the proposed tariff structure statement is provided at Appendix F.1 – Tariff Structure Statement Overview and Appendix F.2 – Tariff Structure Statement Technical Summary.

### *Amendments to model policies and contracts*

223. Changes to the Access Code were made in September 2020 as part of the Energy Transformation Strategy to increase opportunities for new technologies and maximise utilisation of existing network infrastructure. Further changes were made to the Access Code in July 2021 to support the introduction of the constrained network access regime (described further below).

224. Energy Policy WA led a stakeholder consultation that resulted in consequential changes to model policies and contracts to complete the implementation of the constrained network access regime, including the Standard Access Contract, Applications and Queueing Policy (**AQP**) and Electricity Transfer Access Contract (**ETAC**).[37] These amendments also resulted in the Transfer and Relocation Policy being absorbed into the

---

32 Energy Transformation Taskforce, *Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code*, Consultation Paper, May 2020, p.28

33 Section 7.1A, Electricity Networks Access Code 2004

34 Section 7.1B, Electricity Networks Access Code 2004

35 ERA, *Framework and approach for Western Power's fifth access arrangement review*, Final Decision, August 2021.

36 ERA, *Framework and approach for Western Power's fifth access arrangement review*, Final Decision, August 2021.

37 Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code - Improving access to the Western Power network

AQP[38] and a new requirement was placed on Western Power to develop a Multi-function Asset Policy as part of its access arrangement.

225. Key changes to each of the model policies and contracts are summarised in the following table.

**Table 3.2: Changes to the model policies and contracts**

| Model policy or contract | Key changes |
|---|---|
| Transitional ETAC | • Amendments to provide increased certainty to Western Power and AEMO under a constrained access regime<br>• New schedule for negotiated generator performance standards<br>• New provisions requiring compliance to the Technical Rules, generator performance standards and monitoring plan<br>• Permitting Western Power to immediately suspend a user due to breaches of the generator performance standards, or if the connection threatens power system reliability or supply of electricity<br>• Removal of the concept of bare transfers and assignment, which is not relevant under a constrained access regime |
| Transitional AQP | • New confidential information and publication of information relating to projects to provide more visibility of generation projects, facilitate transparency and increase investment confidence<br>• Changes to remove the concept of spare network capacity, as this has limited relevance to generators and entry services in a constrained access regime<br>• Modified the concept of competing application groups to be relevant for a constrained access regime<br>• Amended applicant specific solutions to be relevant for a constrained access regime<br>• Expanded the definition of Technical Rules to include generator performance standards under WEM rules<br>• Other changes to improve clarity of AQP |
| Transitional Contributions Policy | • Change to reflect generator performance standard requirements<br>• Changes to definitions to ensure consistency with the Access Code |
| Multi-function asset policy | • New requirement for Western Power to develop a Multi-function Asset Policy as part of its access arrangement.<br>• The Access Code also outlines the requirements of the Multi-function Asset Policy[39] and a list of principles that Western Power must take into consideration in developing the Multi-function Asset Policy[40] |

226. The updated policies and contracts will apply as transitional documents until the commencement of Western Power's fifth access arrangement. Western Power's proposed amendments to policies and contracts are outlined in Chapter 13.

38 The concept of bare transfers and relocations has been removed as a result of the introduction of the constrained network access regime. Amendments were made to clauses 2.2 and 2.2(e) in the Applications and Queuing Policy to reflect this. Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code - Improving access to the Western Power network, pg. 35.

39 Access Code, section 5.37

40 Access Code, section 6.86

### *Deferred Revenue*

227. In our second access arrangement, the regulatory treatment of capital contributions was changed, resulting in an increase in our revenue, the majority of which was deferred. During our third access arrangement, the recovery period for the deferred revenue was set to 42 years for distribution revenue and 50 years for transmission revenue.

228. The Access Code was amended on 30 July 2021[41] to allow for the recovery of this deferred revenue over the AA5 period, so long as the recovery of the deferred revenue does not result in an increase in network price when compared with the AA4 period. Further information on how we are proposing to recover this deferred revenue is provided in Chapter 11.

### *Changes to the Access Code objective*

229. As part of the changes made to the Access Code in September 2020, the Access Code objective was changed with a focus on the long-term interests of consumers. The new Access Code objective also includes consideration of the environmental consequences of energy supply and consumption, including reducing greenhouse gas emissions, considering land use and biodiversity impacts and encouraging energy efficiency and demand management.

### *AMI building block*

230. AMI refers to digital meters with a communication device installed connected to a communications network. AMI can automatically and remotely read electricity flows and provide early detection of connection faults and supply issues. They can also remotely disconnect and reconnect electricity supply. AMI have the ability to provide a clearer picture of the power quality data, including the voltage and current levels, and how much renewable energy is being fed back into the network.

231. AMI will play a key role in a range of future scenarios requiring increased visibility (and potentially control) of the distribution network, including customers and technology connected to it. It is a critical enabler for the effective integration of DER, flexible tariffs and allowing customers to more actively participate in the energy market. It also enables the development and targeting of new retail products and services based on customer demand profiles.

232. Western Power commenced the AMI deployment in 2019[42], and it is due for completion in 2027. It is expected that 92 per cent of customer will have AMI installed once the deployment is completed.[43] An estimated half a million advanced meters will be installed by June 2022.

233. The Access Code was amended in September 2020[44] to enable cost recovery of AMI expenditure relating to communications and IT during the AA4 period. The amendments allow recovery of AMI expenditure through a separate building block, similar to how deferred revenue is recovered. Further information on the cost recovery of AA4 period AMI expenditure is provided in Chapter 11.

234. The AMI deployment will continue during the AA5 period, with a further 795,130 scheduled to be rolled out. Importantly, a number of the key actions and reforms under the Energy Transformation Strategy, such as the DER Roadmap outcomes, are dependent on AMI to realise the proposed benefits. Further information on the AMI deployment in AA5 is provided in Chapter 8.

---

41 https://www.wa.gov.au/sites/default/files/2021-07/Tranche-2-amendments-to-the-Access-Code.pdf

42 The AMI deployment has been implemented on a new and replacement basis.

43 AMI penetration is not expected to reach 100% as some premises are not suitable for AMI due to locational and physical factors which prevent mobile signals reaching the meter location.

44 https://www.wa.gov.au/government/electricity-networks-access-code-tranche-1-amendments

### *Technical Rules*

235. Western Power commenced a review of the existing Technical Rules in January 2020 to support the State's transition to a renewable future, improve technical communications to our customers and improve network reliability. The objectives of the review were to:

- align the Technical Rules with the requirements of WEM Rules amendments and government policy decisions by Energy Policy WA
- provide improved clarity on roles and responsibilities for Western Power, AEMO and Users (loads and generators connected to the Western Power Network)
- provide improved clarity on system performance standards
- improve network investment planning principles and criteria
- introduce performance standards for microgrids and SPS
- facilitate easier connection of inverter-based generators, loads and energy storage systems through the introduction of clearer and more suitable performance standards and technical requirements
- improve operational planning and coordination of efforts with AEMO.

236. Western Power submitted the proposed Technical Rules amendments to the ERA on 30 July 2021. The submission completes key actions and milestones under the DER Roadmap, providing draft rules for battery storage and the finalisation of network visibility requirements.

237. The ERA decision on the proposed amendments is expected in 2022.

238. The impact of the revised Technical Rules on Western Power's existing processes and future investments has not yet been assessed and is not included in our AA5 proposal. Once the ERA decision on the proposed amendments has been released, we will review the impact of the revised Technical Rules on our processes and may propose investments related to this in our response to the draft decision.

### *Stand-alone power systems*

239. Stage 1 of the Energy Transformation Strategy reforms enabled the implementation of SPS, which are now being installed as a lower whole-of-life cost solution to renewing end-of-life network assets.

240. SPS are off-grid power systems that operate independently from the main electricity networks.[45] Each SPS consists of a renewable energy supply (such as solar panels), battery storage, an inverter and, where necessary, a backup generator. Each SPS typically supplies electricity to a single property. With 40 per cent of our overhead distribution network serving less than 1 per cent of our customers, there are significant opportunities to deploy SPS.

241. Access Code amendments delivered by the Taskforce have enabled the inclusion of SPS as a technology option in the SWIS[46], where they are adjunct to the network. This delivers better reliability outcomes for customers and lowering system costs, particularly for long power lines servicing very few customers.

242. SPS is now one of the solutions available alongside conventional poles and wires to provide a safe and reliable supply of electricity where it is economically efficient to do so, in particular in regional and remote communities.

---

[45] SPS are defined in s3 of the *Electricity Industry Act 2004*
[46] Sections 1.3 and 3.2A, Electricity Networks Access Code 2004

243. SPS represents a critical transformational solution required to move towards a modular grid and incorporating higher levels of renewable generation. Further information on our proposed investment in SPS during the AA5 period is provided in Chapter 8.

### *Reforms to the Market and Operations*

244. In addition to the reforms to regulatory frameworks, changes to the energy market and operations have been introduced to facilitate the energy transformation. These are discussed below.

#### *Constrained access*

245. Security constrained economic dispatch (constrained access) under the WEM is due to commence in October 2022.

246. The amendments made to the Access Code[47] to support constrained access reforms enable generators to connect to the grid irrespective of the available network capacity in their location. A generator's real time export to the network will be determined by AEMO's dispatch engine to give effect to the principle of security constrained economic dispatch.

247. The definition of relevant reference services will be amended for the AA5 period to facilitate the implementation of constrained access. In the framework and approach final decision, the ERA determined that Western Power must amend entry reference services and capacity allocation swap services to reflect the introduction of constrained access.[48]

248. In July 2021, Energy Policy WA made consequential changes to the following documents to better reflect constrained access:

- AQP, which sets out the processes and procedures for access to the Western Power network
- ETAC, which is the standard access contract for reference services
- Contributions Policy, which details how Western Power determines the contributions required to obtain access to our network.

249. Energy Policy WA made these changes to ensure an appropriate contracting framework was in place prior to the introduction of constrained access that is targeted to commence in October 2022.

250. New requirements to support the move to a constrained access market include the development and provisioning of limit advice to AEMO, to enable calculation of the network's constraints within which dispatch can occur. Limit advice includes both thermal limits (including equipment ratings) and non-thermal limits related to system security and stability that depend on infrastructure specifications (for example, voltage ratings) and network configuration. This advice will need to be regularly updated for any change in the network such as augmentations and retirements to the transmission network, new connections and facility retirements. The changes required to deliver the new WEM outcomes require significant uplift to our processes, systems and capabilities ahead of the commencement of the constrained access market.

251. The Access Code was amended in September 2020 to enable Western Power to recover costs that it incurs in respect to the Government's reforms to network access, to the extent that these costs are prudent and efficient.[49] We have incurred costs of $2.5 million during the AA4 period in relation to this access reform work. Further information on these is provided in Chapter 11.

---

47 https://www.wa.gov.au/sites/default/files/2021-07/Tranche-2-amendments-to-the-Access-Code.pdf

48 ERA, *Framework and approach for Western Power's fifth access arrangement review*, Final Decision, 9 August 2021

49 Sections 6.81, 6.82, and 6.83, Electricity Networks Access Code 2004

### *Essential system services*

252. A key reform of the stage 1 reforms was the development of a new framework for acquiring and providing essential system services (**ESS**, formerly known as ancillary services), to facilitate competition in the provision of these services and enable new technologies to be provided, such as storage. With increasing diversity in generation technology and the introduction of new technologies, competition in the provision of these services is becoming increasingly feasible.[50]

253. The new ESS framework provides for five ESS:

- **Regulation ESS (raise and lower)**: which is the provision of reserve MW to respond upwards (i.e. raise) during a dispatch interval when load is greater than generation and to respond downwards (i.e. lower) when generation exceeds load
- **Contingency Reserve (raise and lower):** which is the provision of reserve MW to respond to a loss of generation (raise) or loss of large load (lower), in order to restore frequency to an acceptable level
- **Rate of Change of Frequency** (**RoCoF**) **Control:** which is a rapid response service to restrict the rate of change in frequency following a contingency.[51]

254. ESS will be procured through real-time markets, in which any facility that is capable and accredited for an ESS is able to participate by making offers and providing the service.

255. ESS will be delivered on a frequency co-optimised or non-co-optimised basis:

- **Frequency co-optimised ESS** (**FCESS**): will be dispatched and managed by AEMO through the Security Constrained Economic Dispatch Engine that they are currently developing as part of the reforms relating to constrained access. FCESS will manage the delivery of ESS that relate to frequency and system level issues.
- **Non-co-optimised ESS** (**NCESS**): are ESS that are procured and dispatched outside of the Security Constrained Economic Dispatch Engine and are typically related to locational issues. It is expected that Western Power will either provide or incur costs for NCESS.

The Taskforce has established a high-level framework and principles for NCESS.[52] However, the detailed design for the operation of the framework is still being developed, and further changes to the regulatory framework will be required to incorporate the NCESS framework. The impact of the new ESS framework on Western Power's existing processes and future investments has not yet been assessed and is not included in our AA5 proposal. Once the detailed design for the NCESS framework has been released, we will review the impact of the NCESS on our processes and may propose investments related to this in our response to draft decision.

### *Five-minute settlement*

256. To ensure that market benefits from the energy transformation can be fully realised, the Taskforce determined that market dispatch and settlement intervals should be aligned to both be at five-minute intervals.[53]

257. The new settlement rules will require five-minute interval energy data and weekly settlements for contestable metering points.

---

50 Energy Transformation Taskforce, *Foundation market parameters – information paper*, August 2019.
51 Energy Transformation Taskforce, *Foundation market parameters – information paper*, August 2019.
52 Energy Transformation Taskforce, *A framework for Non-Cooptimised Essential System Services, May 2021*
53 Energy Transformation Taskforce, *Market Settlement – Implementation of five-minute settlement, uplift payments and Essential System Services settlement*, 1 December 2019.

258. Five-minute settlement will commence on 1 October 2025, to allow time for Western Power and owners of relevant facilities to implement the metering infrastructure and systems required to support five-minute settlement. Western Power has estimated that around 21,000 existing meters will need to be replaced with five-minute meters and around a further 7,600 will be reconfigured to provide five-minute data.

259. These meter replacements are separate to the routine AMI deployment.

260. Drafted amendments to the *Electricity Industry (Metering) Code 2021* are expected to be approved by the Minister in 2021, enabling the recovery of expenditure associated with the implementation of IT system uplifts and meter deployment and reconfiguration. Our forecast of the impact of this reform on our AA5 capex is $25.1 million. This is included in our capex forecast in Chapter 8.

*Physical and Cyber security*

261. In 2020, the Minister for Home Affairs proposed amendments to the *Security of Critical Infrastructure Act 2018* (Cth). Following consideration of recommendations made by the Parliamentary Joint Committee on Intelligence and Security, tabled in late 2021, the proposed amendments were separated into two tranches.

262. The first tranche of amendments, which has now been enacted, expanded coverage of the Act from four to eleven critical infrastructure sectors, introduced Australian Government assistance measures and incident reporting obligations, and expanded reporting requirements. There are no material implications to Western Power to comply with the obligations conferred under the first tranche of amendments over and above our existing processes and reporting.

263. The second tranche of amendments, which is proposed to be taken to parliament in 2022, outlines a framework for risk management programs, covers declarations of systems of national significance and has provisions for enhanced cyber security obligations. These proposed provisions will be the subject of further public consultation in the first half of 2022.

264. We have considered the impact of this proposed reform on our AA5 capex, based on the draft provisions for enhanced security obligations and have included investments to improve our preparedness for security incidents. Further information on these is provided in Chapter 8. Where impacts are not yet known, as the changes to the regulatory framework have not yet been finalised, Western Power will deal with this uncertainty through one of the three options identified in section 3.1.

# 4. Customers, stakeholders, and community engagement

265. This chapter provides an overview of the customer and community engagement program and stakeholder engagement that Western Power has recently conducted and how it has informed our AA5 proposal.

**Key Messages**

- Our customers and the community are core stakeholders in our strategic vision and being customer focused is one of our organisational values.
- We consult with our customers and the community to better understand what services they want and value and how they prioritise outcomes.
- Our AA5 proposal has been shaped by their feedback and our forecast investments are aligned with achieving outcomes that customers and the community value and prioritise
- Our customers and the community consider that the present levels of reliability and safety is generally good, but that any decline would be detrimental
- They are interested in ensuring the network supports renewables and other technologies that can increase and improve service
- Affordability is a priority for customers, and they are willing to pay for increased renewables and new technologies if it means lower price reductions and can be clearly linked to outcomes
- Communication is valued and they prefer increased engagement with digital platforms over improved telephone wait times

## 4.1 Our approach to customer and community engagement

266. Western Power, and its predecessors, has proudly provided a range of services to our customers and the community over the past 70 years. At Western Power we know customers rely on us to power their modern lives, and we are mindful of the impact our assets and the cost to operate and maintain the network have on them. Our customers and the community are core stakeholders in our strategic vision and being customer focused is one of our values. We aim to provide our customers with value for money services that will benefit them in both the short and the long-term. Accordingly, we regularly engage with our customers and the community to understand their expectations of us and what they value.

267. The objective of the Access Code is to promote efficient investment in, and efficient operation and use of network services in WA for the long-term interests of consumers. We consider our customers and the community as 'consumers' for the purposes of the Access Code.

268. Our most recent customer and community engagement program was conducted over the course of 2021. The purpose of Western Power's customer and community engagement program (**CEP**) was to gain an understanding of what our customers and the community prioritise and value in relation to the services we currently provide and potential future services. The CEP builds upon our regular ongoing customer and community engagement as well as the engagement program completed ahead of the AA4 submission. This AA5 program is broader in scope than the AA4 engagement, one example being the establishment of a Community Reference Group. The CEP was designed to deliver insights and feedback that could meaningfully be incorporated into the development of the AA5 proposal.

269. The CEP was designed to deliver insights and feedback that could meaningfully be incorporated into the development of the AA5 proposal.

270. As part of the CEP, we wanted to understand our customers':

- electricity knowledge and attitudes
- knowledge of Western Power's services
- future expectations
- views of trade-offs between different investment options.

271. Development of the CEP approach has been informed by:

- the AER Consumer Engagement Guidelines
- the methodology underpinned by the International Association for Public Participation (IAP2)
- discussions with other Australian electricity network service providers on their recent customer engagement experiences[54]
- reflections on the AA4 CEP and related learnings.

272. We engaged Kantar Public and Synergies Economic Consulting to assist with the design and delivery of the CEP. Their role was to:

- ensure the CEP was conducted in an independent and robust manner
- ensure the findings of the CEP were an accurate reflection of our customers' preferences
- develop and facilitate metropolitan and regional community forums and focus groups with support from Western Power subject matter experts
- undertake in-depth interviews with a representative sample of Western Power's residential and non-residential customers
- design a large scale representative survey to understand residential and small and medium business customers' preferences, willingness to pay and trade-offs they are willing to make regarding various investment options
- establish and facilitate ongoing Community and Stakeholder Reference Groups.

273. The key engagement principles that underpinned the design and delivery of the CEP are summarised in Table 4.1.

**Table 4.1: CEP engagement principles**

| Engagement Principle | Description |
|---|---|
| Accessible and inclusive | • Engagement should be representative of our customer and community base<br>• Customers and community should be aware of engagement activities and know how to access and contribute<br>• Sustainable decision making will be promoted by recognising and communicating the interests of all participants, including decision makers |
| Transparent and open | • Adequate information will be made available to customers and the community so they can provide informed responses<br>• Options that are available to customers and the community will be clearly articulated, including constraints |
| Measurable | • Evidence of how input has affected decision making will be provided |

54 Discussions were held with AusNet Services, Jemena and Energy Queensland on their recent customer engagement experiences

274. We sought to hear from a broad range of our customers and included representation across all nine Western Power customer segments (see Figure 4.1). Overall, more than 2,000 customers were engaged through the CEP, reflecting over 800 hours of engagement.

**Figure 4.1: Western Power customer segments**


275. Insights were gathered from each of Western Powers' customer segments, and summarised across three groups of customers, with similar characteristics, as described in Table 4.2.

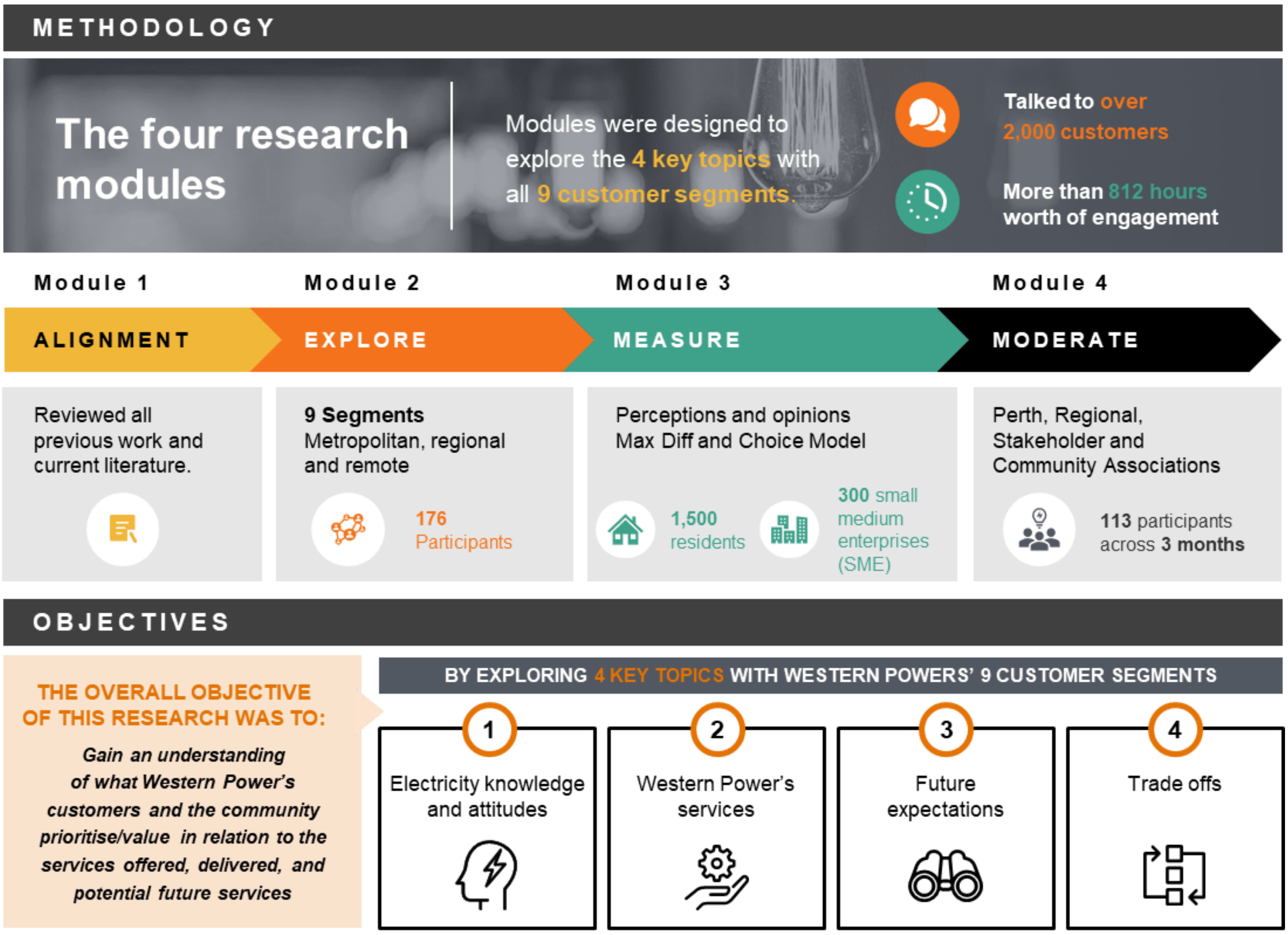
**Table 4.2: Characteristics of customer research groups**

| Customer research grouping | Customer segments represented | Characteristics of customer research group |
|---|---|---|
| Residential Customers |  | • Rely on electricity<br>• Have an emotional connection to power<br>• Fundamental part of day to day life |
| Small and Medium Enterprises (**SME**) |  | • Important component of business<br>• Impacts operations, products and services<br>• High expectations of Western Power due to Government support<br>• Have very high benchmark expectations regarding service delivery and performance |

| Customer research grouping | Customer segments represented | Characteristics of customer research group |
|---|---|---|
| Stakeholders | Generators; Local government; Large businesses & government; Land development & industry; Retailers; Electricians & service providers; Electrical consultants | • Stakeholders represent remaining seven customer segments<br>• Motivated by industry progress<br>• Focus on innovative solutions |

276. The CEP consisted of four research modules (see Figure 4.2). The modules were designed as a step-by-step process to engage customers and assist in providing an iterative process to develop, explore and re-test the various investment and service offerings for all segments.

**Figure 4.2: Customer engagement approach and objectives**




Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

277. The methodology for each research module is summarised in the following sections. Further details on the CEP are set out in the Kantar Public *Community and Customer Engagement Program Report* (Attachment 4.1).

### 4.1.1 Module 1: Alignment

278. Module 1, the 'alignment' stage, provided the base for developing and designing the CEP. This stage involved undertaking a review of previous Western Power, and other electricity networks' customer research programs, including a review of the robustness of methodology. The review of previous engagement programs and customer engagement guidelines informed the development of a detailed engagement strategy, which defined the core aspects of the engagement strategy, including:

- research and customer engagement methodology and approaches (including qualitative and quantitative approaches)
- sampling and target markets for customer engagement
- discussion guide content
- design of online survey
- risk management
- expected stage outcomes.

279. To ensure customer feedback was collected in a coordinated and consistent format, four research topics were selected to inform the structure of the customer engagement. The topics are presented in Table 4.3.

**Table 4.3: Customer engagement program research topics**

| Research topic | Description |
|---|---|
| Electricity knowledge and attitudes | • Attitudes towards electricity<br>• How customers see reliability, security, safety<br>• How do different customers see certain topics e.g. climate change, current Western Power initiatives |
| Western Power's services | • Western Power's services, including connecting renewables and new technology, customer servicing and field crews<br>• Western Power's communication, including media campaigns |
| Future expectations | • Future network opportunities such as new technology, future services, tariff structures<br>• Expectations around safety, reliability and security of supply |
| Trade-offs | • Customer views of trade-offs between safety, reliability, investment in innovation and cost |

### 4.1.2 Module 2: Explore

280. Module 2, the 'explore' stage, was where key hypothesis points developed in module 1 were tested with our customers. The focus of this module was to explore customers' electricity knowledge and attitudes, perceptions of Western Power services, future expectations and trade-offs.

281. Kantar Public undertook qualitative research to provide deeper insights and context about customers' views and preferences. The qualitative research covered a representative sample of all nine of Western Power's customer segments, and included:

- a four-hour Deliberative Forum conducted at Western Power's office
- in-depth phone interviews with residential customers for a duration of 30 – 45 minutes
- face-to-face focus groups with Small and Medium Enterprise (**SME**) customers, conducted at the Kantar Public offices for a duration of 90 minutes

- online mini focus groups, conducted over videoconference for a duration of 90 minutes
- paired in-depth interviews with culturally and linguistically diverse customers, held virtually for a duration of 45 – 60 minutes
- face-to-face mini focus groups with Aboriginal and Torres Strait Island customers in Perth conducted by Cultural Partners for a duration of 90 minutes.

282. The forums, focus groups and interviews were all structured around the four research themes developed in module 1.

### 4.1.3 Module 3: Measure

283. Module 3, the 'measure' stage, quantitatively measured perceptions amongst residential and SME customers. This module was designed to assist in gaining an understanding of:

- the choices customers make related to usage, demand management and new technologies
- customers' energy priorities and support for different options
- the value of different aspects of the product and price offering to different customer groups.

284. Module 3 involved an online survey with residents and business representatives, as outlined in Table 4.4.

**Table 4.4: Quantitative engagement method and customer segments**

| Research theme | | Residents | Businesses |
|---|---|---|---|
| Definition of customer segment | | Residents over 18 years who are solely or jointly responsible for the payment of their household's electricity bill | SME representative who is solely or jointly responsible for the payment of the business's electricity bill of a business that has spent less than $75,000 on electricity in the last 12 months |
| Sample size | | 1,538 | 301 |
| Method | | 20 minute online survey | 20 minute online survey |
| Dates | | 28 April to 12 May 2021 | 29 April to 21 May 2021 |
| Average interview length | | 17 minutes | 21.4 minutes |
| Network Location | Urban | 934 customers | 200 business representatives |
| | Rural Short | 431 customers | 62 business representatives |
| | Rural Long | 173 customers | 39 business representatives |

Source: Kantar Public, 2021, Community and Customer Engagement Program Report

285. The survey questions included a choice model and maximum difference analysis to measure price and product trade-offs that our customers were willing to make.

*Assessing willingness to pay using choice modelling*

286. It is important for Western Power to understand its customers' willingness to pay for various investment options, and the trade-offs they are willing to make for potential investments in and services provided by the Western Power Network. Specifically, we sought to understand our customers' preferences regarding supply reliability, safety, new technologies and customer service metrics and the trade-offs they make for

cost savings or increases. The online survey measured customers' willingness to pay through a choice model.

287. Choice models are used to determine the underlying preference structures and decision rules used by a person to choose and, if a price attribute is considered, willingness to pay or willingness to accept for concepts, outcomes and product / service attributes.

288. Choice models work by presenting customers with a series of scenarios. Each scenario presents the customer with a range of options to choose between. These options require the customer to make a trade-off between them. The options presented during the CEP were based on:

- duration of outages
- frequency of outages
- investment in new technologies
- investment in customer notifications and service
- investment in underground power
- investment in vegetation management
- impact on annual electricity bill.

289. By asking respondents to make choices between similar situations, customer preferences can be ascertained.

290. Within the survey, respondents were provided with a series of 12 hypothetical scenarios. Each scenario consisted of three packages of seven attributes with a random combination of features of that service or a 'none of these' option. Having reviewed the features of each package, the respondent was asked to select their preferred package. In order to provide realistic scenarios to customers, prohibitions were also set so particular scenarios were not shown to customers if that option was significantly outside the current reliability standards.

291. An example choice model question from the survey is shown in Figure 4.3.

**Figure 4.3: Example choice model question from online survey**

## An example of choice options appears below:

Below are 3 possible ways Western Power can manage investment into the electricity network over the next 10 years.
Change to the investment can results in changes to safety, reliability and your bill size.
Given the level of investment and outcomes shown, please indicate which ***one*** you would most prefer.

| Attribute | Offer 1 | Offer 2 | Offer 3 | None |
|---|---|---|---|---|
| Change on your electricity bill | $21 price decrease | $21 price increase | $21 price decrease | I would not choose any of these |
| Average number of unplanned outages (blackouts) per customer | 1 outage every 3 years | 1 outage every 3 months | 1 outage every 3 months | |
| Average outage (blackout) length | 24 hours | 24 hours | 60 minutes | |
| New technologies (incl Solar, SPS, etc.) | No change to investment in enabling renewable energy or new technologies in the network | Increasing investment in enabling renewable energy or new technologies in the network | No change to investment in enabling renewable energy or new technologies in the network | |
| Communications & Customer | Increasing investment in improved outage notifications and customer service | Decreasing investment in improved outage notifications and customer service | Increasing investment in improved outage notifications and customer service | |
| Underground power | No change to underground power protocols | No change to underground power protocols | No change to underground power protocols | |
| Tree trimming / vegetation management | No change to tree trimming protocols | Increasing investment in tree trimming | Increasing investment in tree trimming | |
| | ☐ | ☐ | ☐ | ☐ |

Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

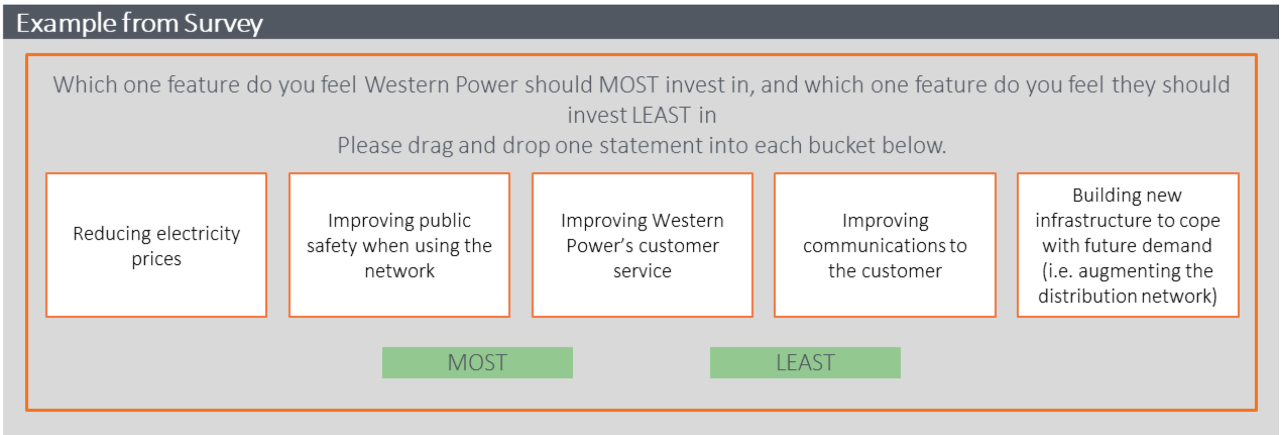
### *Identifying customers' priorities using maximum difference analysis*

292. It is also important for Western Power to understand its customers' preferences for various investment options. The online survey measured customers' preferences for 12 different priority areas using maximum difference analysis.

293. Maximum difference analysis is a ranking exercise which is applied when there is a need to understand the relative priority between a large number of items. Respondents are shown a number of cards and are asked to select the "best" and "worst" items from a subset on each card.

294. As part of an online survey, customers were asked a series of questions where they were to select the feature Western Power should most and least invest in. An example maximum difference question from the survey is shown in Figure 4.4.

**Figure 4.4: Example maximum difference analysis question from online survey**




Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

### 4.1.4 Module 4: Moderate

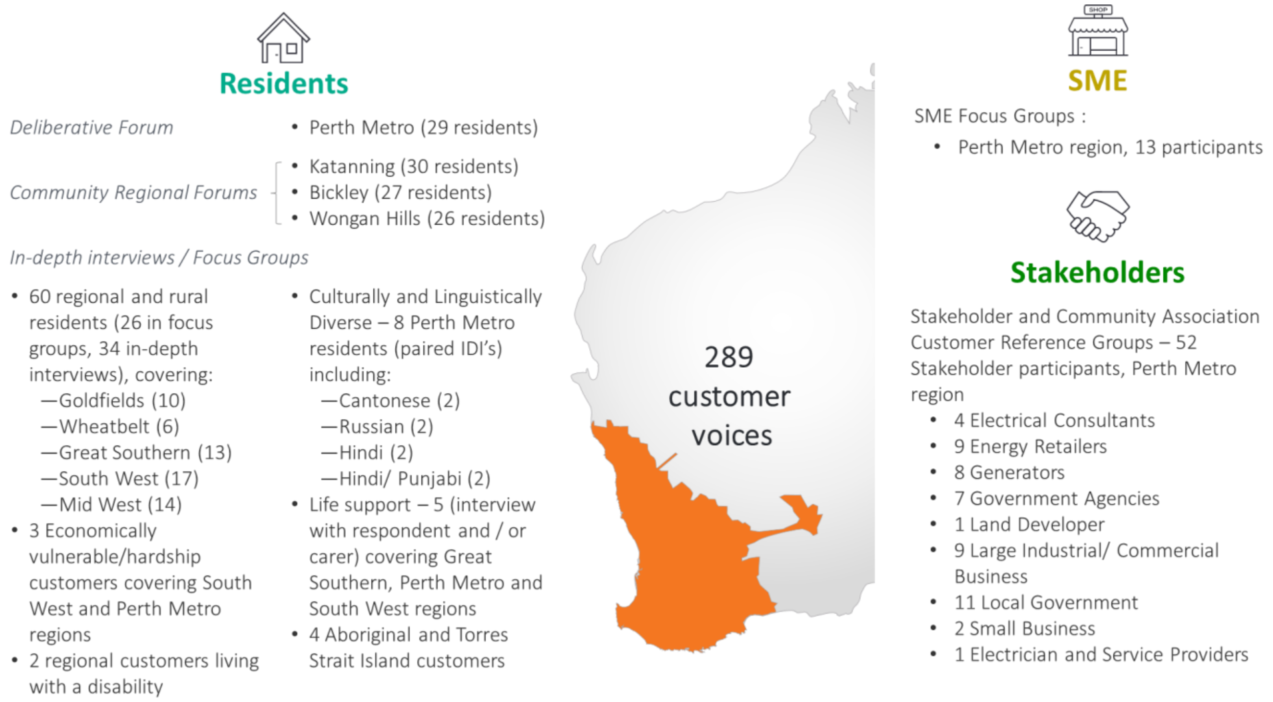
295. Module 4, the 'moderate' stage, established Community Regional Forums and Community and Customer Reference Groups to test reactions and perceptions of potential future Western Power initiatives for the AA5 period. The Community Regional Forums provided opportunities for further re-testing of the insights gained in the previous two modules.

296. Kantar Public conducted qualitative research over several months with the following groups:

- Community Regional Forums were held monthly between March and May 2021 and ran for three hours, with communities from Katanning to Bickley to Wongan Hills. All were held in the evening
- Community and Customer Reference Groups were held monthly across three sessions in the Western Power offices and ran for one and a half hours. All were held in the evenings
- Stakeholder and Community Association Reference Groups were held six weeks a part for a period of two hours. All were held during the day.

297. In total, the qualitative research undertaken as part of modules two and four of the CEP resulted in 289 customers being engaged, as shown in Figure 4.5.

**Figure 4.5: Qualitative engagement methods and customer segments**

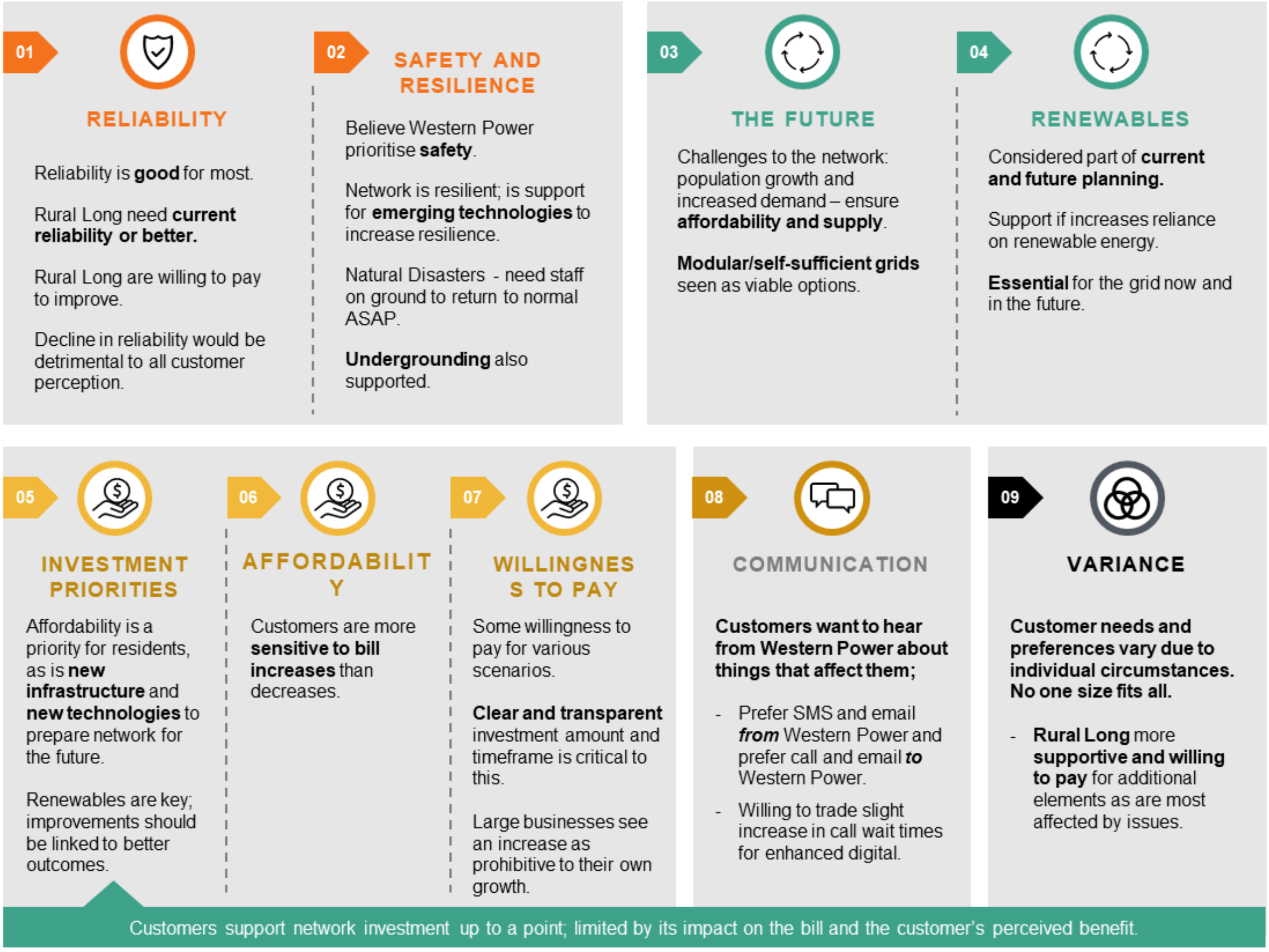



Source: Kantar Public, 2021, Community and Customer Engagement Program Report

## 4.2 Summary of customer insights

298. The key findings of the CEP are summarised in Figure 4.6. Overall, customers told us that while hygiene factors (such as safety and service reliability) need to be maintained, there is strong support for Western Power to adapt the Western Power Network to accommodate new technologies and prepare for the future.

**Figure 4.6: Summary of key findings from CEP**




Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

299. Findings were grouped into seven key themes, summarised in the sections below. The CEP also made findings around communication from Western Power. These findings have been included in the discussion on investment priorities. A copy of Kantar Public *Community and Customer Engagement Program Report* is provided in Attachment 4.1.

### 4.2.1 Safety and Resilience

300. Safety is considered critical by customers. Should the level of service surrounding safety decline, it would be detrimental to customer perceptions of Western Power. Customers see safety as being a core value of profound importance.

301. Customers believe there is already significant importance given to safety and do not prioritise additional investment in this area. This is due to a perception that Western Power is performing well in these areas and therefore no further investment is required. However, there is no willingness to trade-off safety for cheaper bills, greater reliability or increased sustainability.

302. There is in-principle support for further investments to improve network resilience, such as investments in:

- undergrounding
- having ample staff on the ground to restore supply as soon as possible after an outage event.

### 4.2.2 Reliability

303. Reliability of supply is critical to customers.

304. There are different service experiences across the network. The frequency and duration of outages is considerably longer amongst Rural Long customers in comparison with Urban customers. However, any erosion of reliability would have a significant negative impact on customer perceptions, irrespective of customer segment.

305. All customer segments agreed that the reliability of Western Power's network is generally quite good. Evidence of this from customers comes from very few outages and outages typically lasting for only a short period of time.

306. There are differing views between customer segments as to the cause of outages. Generally, residential customers believe that outages are caused by weather or storms more so than infrastructure faults or age. Other stakeholders acknowledge the age and maintenance needs of infrastructure as potential causes.

307. There is support for improvement to reliability across the network. Amongst Rural Long customers there is a strong preference for reduced outage duration.

308. A decrease in reliability for all would be detrimental. There is strong support from both residential and SME customers towards improvements that would increase reliability of the Western Power Network against outages.

### 4.2.3 Network challenges of the future

309. There was strong support among customers for Western Power to proactively lead the way and plan for the future. Given the desire for Western Power to take a leadership role, there is broad support across stakeholders for Western Power communicating its long-term strategy.

310. While a 5-year plan is important, some stakeholders (such as land developers, large businesses and government agencies) plan for the next 10-20 years. They would value insight into Western Power's long-term strategy for better alignment.

311. There is common appreciation across customer groups that modular or self-sufficient grids are potentially the way of the future, and that the key benefits of these are:

- fewer customers would be affected when there are outages
- if there are outages, a smaller geographical area would be affected
- less pressure on the grid.

312. Stakeholders largely agree that microgrids have a role to play in the network of the future, particularly in poor access areas, and that a smaller grid system should be a credible option as part of Western Power's scenario planning.

313. Investment in infrastructure and new technologies to prepare the network for the future was ranked highly by all customers, with Urban and Rural Long customers prioritising this more (see Figure 4.7).

314. Customers noted their concerns as to how power will be maintained with the increasing population and energy demand (e.g. due to increased use of electrical devices such as iPad and laptops at schools and homes, and multiple phones etc.). They feel that new technologies and multiple sources of power will alleviate any current concerns around our network coping with future demand.

315. It is clear that customers all expect Western Power to continue to address ageing assets, whilst at the same time facilitating the transition of the network to meet changing customer behaviour and expectations.

**Figure 4.7: Residential customer prioritisation**

Maximum Difference Analysis (Index)

Urban and Rural Long customers prioritise new technologies to prepare for the future.

| | | Urban | Rural Short | Rural Long |
|---|---|---|---|---|
| Reducing electricity prices | 100 | 100 | 100 | 87 |
| Supporting renewable energy and management of solar connections to the electricity network | 100 | 100 | 96 | 100 |
| Investing in new technologies to prepare the network for the future | 95 | 97 | 87 | 97 |
| Building new infrastructure to cope with future demand (i.e. augmenting the distribution network) | 90 | 89 | 86 | 97 |
| Maintaining the existing reliability of the network (i.e. the poles and wires) | 89 | 88 | 87 | 100 |
| Maintaining Western Power's outage response capability (i.e. storm or emergency response) | 87 | 85 | 90 | 99 |
| Improving network resilience to minimise the impact of a natural disaster | 69 | 66 | 70 | 81 |
| Improving public safety when using the network | 43 | 44 | 39 | 38 |
| Collaborating with customers to solve localised energy supply problems | 27 | 26 | 27 | 36 |
| Improving Western Power's customer service | 20 | 20 | 19 | 25 |
| Community initiatives (i.e. community safety, energy literacy and community events / participation) | 20 | 20 | 17 | 24 |
| Improving communications to the customer | 19 | 18 | 19 | 23 |

Source: Kantar Public, 2021, Community and Customer Engagement Program

### 4.2.4 Renewables

316. Overall, there is strong support for further investment that increases the amount of renewable energy in the SWIS, with stakeholders suggesting that renewables are essential to the future of the Western Power Network.

317. Residents understood that Western Power is taking steps to prepare for and mitigate against climate change. There was some support for more action on climate change, with several residents stating they believed the network was not as prepared as it could be.

### 4.2.5 Affordability

318. Residential customers are sensitive to price increases, so minimising cost increases is a high priority for residential customers. When discussed further, although customers prefer bills not to increase, they do recognise the need for increased spending to deliver some of their other key priorities. As such, customers, have some there is willingness to pay increased reliability, renewables and potentially a combination of elements, provided the cost impacts range between 1 and 5 per cent of the current bill for residential customers and 1 and 9 per cent of the current bill for SMEs, and are future focused investments.

319. Customers are more sensitive to bill increases than bill reductions, which is supported by economic literature. Rural Long customers are less sensitive to bill changes given their issues with reliability and are willing to pay to secure improved service levels.

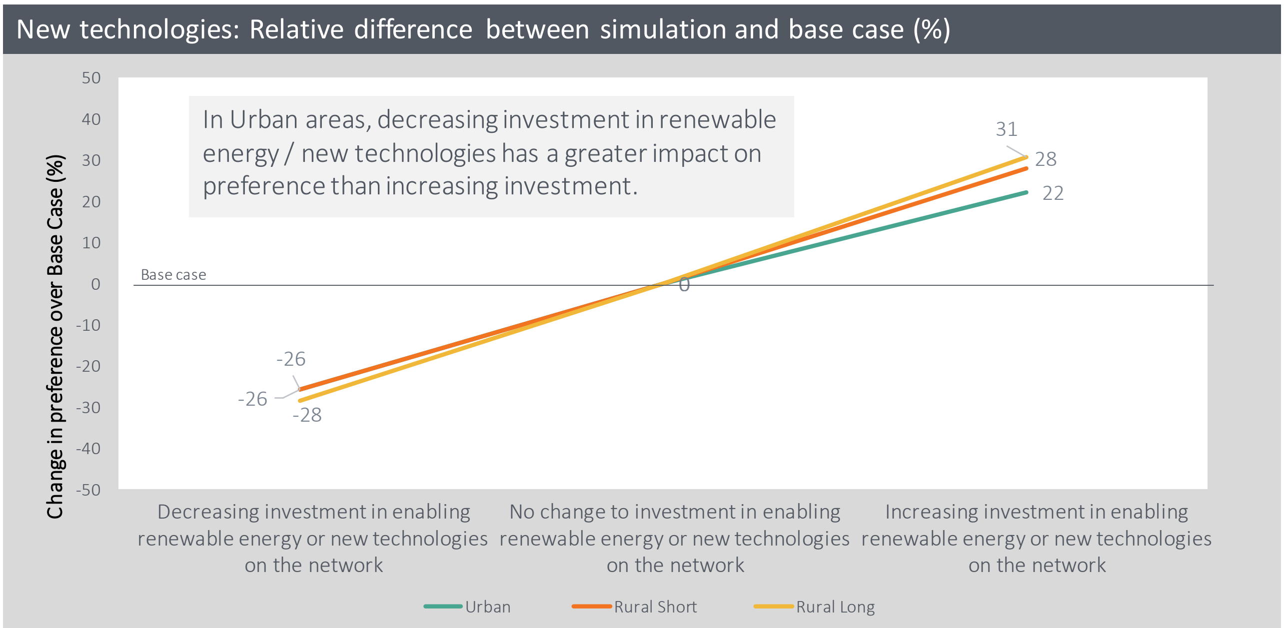
### 4.2.6 Willingness to pay

320. Despite the preference for keeping bills low, customers have some willingness to pay more for investments they see as a priority for the Western Power Network. This willingness differed between customer groups:

- Residential customers are open to paying more for:
  - further investment in renewables
  - further research into the best options for WA
  - active investment in renewables and community batteries
  - rolling out more SPS.
- Residential customers experiencing financial hardship were concerned about increases to prices
- Large businesses were reluctant to bear increased costs in relation to upgrades or service levels. These customers feel that they already pay a high amount for electricity.

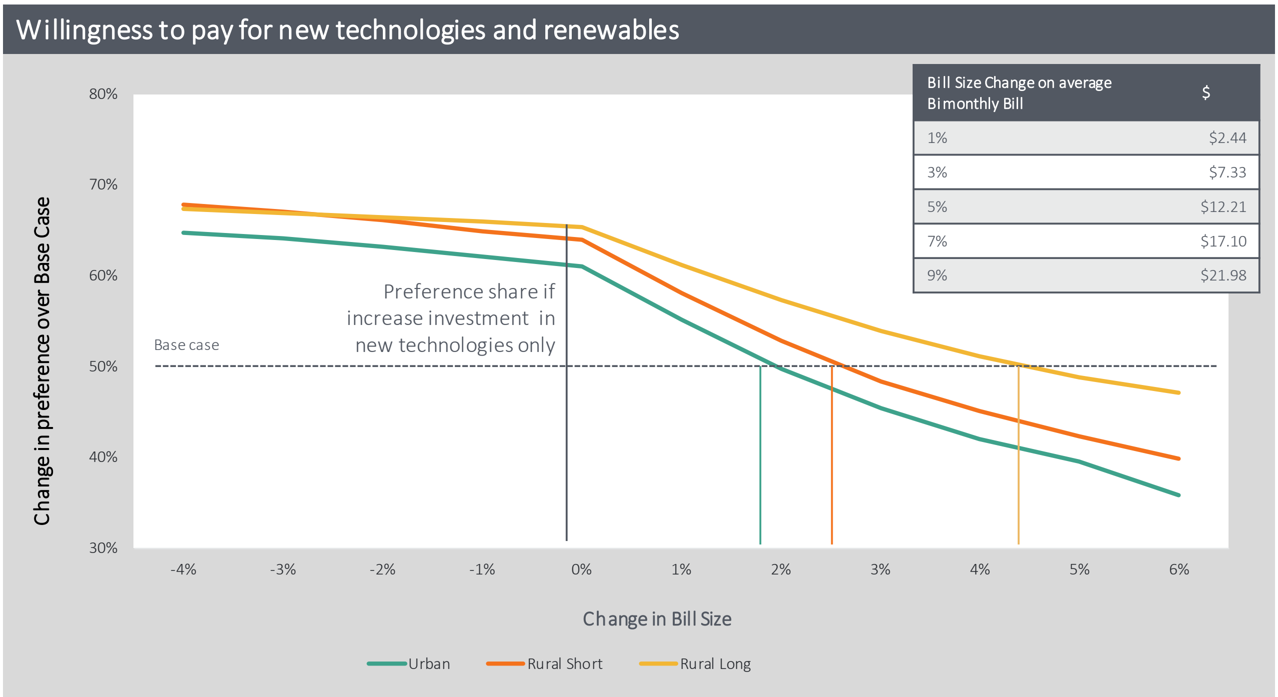
321. Figure 4.8 shows that increasing investment in enabling renewable energy or technologies on the network is strongly preferred by customers, as tested in the module 3 quantitative surveys. Rural Long customers are willing to pay more than both Urban and Rural Short customers to increase investment in new technologies and renewables (see Figure 4.9).

**Figure 4.8: Customer preference for changed investment in renewable energy or technologies**




Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

**Figure 4.9: Willingness to pay for renewable energy or technologies on the network**




Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

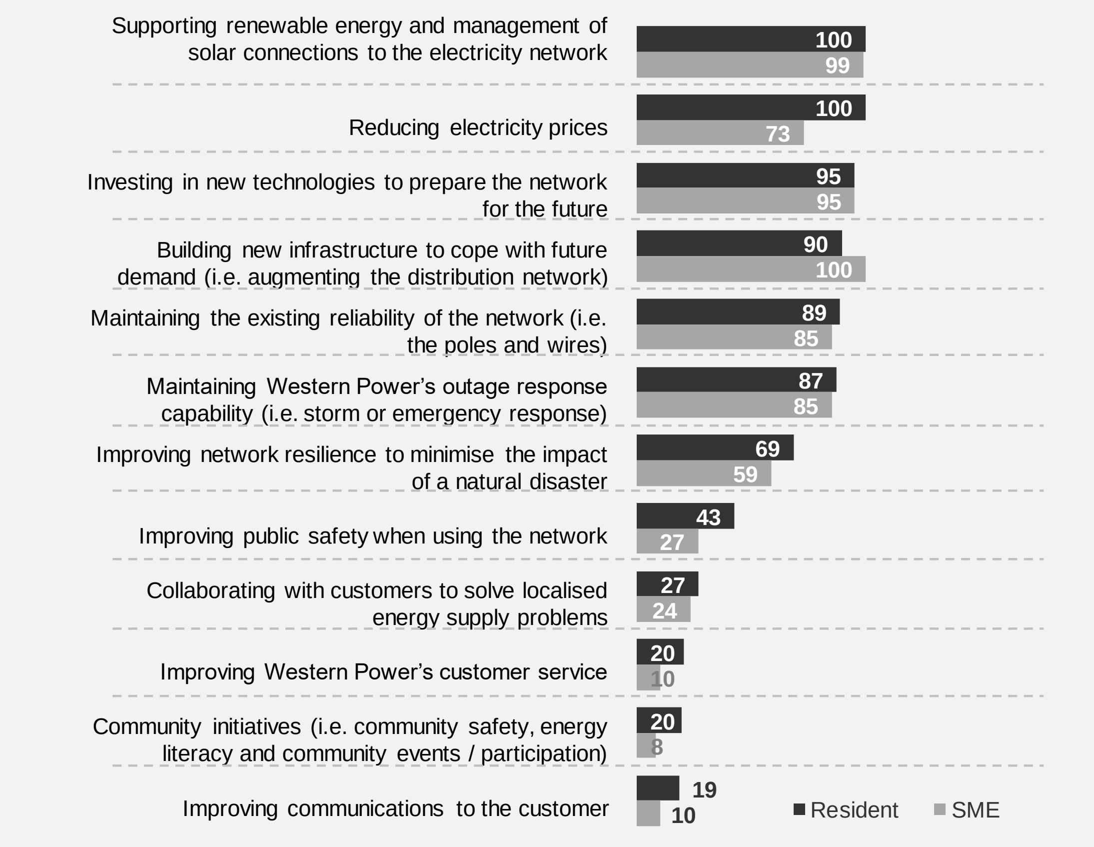
322. Customers support specific investment options, provided bill increases are minimal (e.g. <$5/annum). However, customers need to clearly understand the bill impact of multiple investments (with each attracting their own additional investment).

### 4.2.7 Investment priorities

323. The priority areas tested in the CEP, and the relative importance residential customers and SMEs placed on each, are shown in Figure 4.10. This shows there is broad consistency between different customer segments. At a high level, customers' main priorities are:

- support of renewables
- affordability
- future focus
- maintenance of reliability standards.

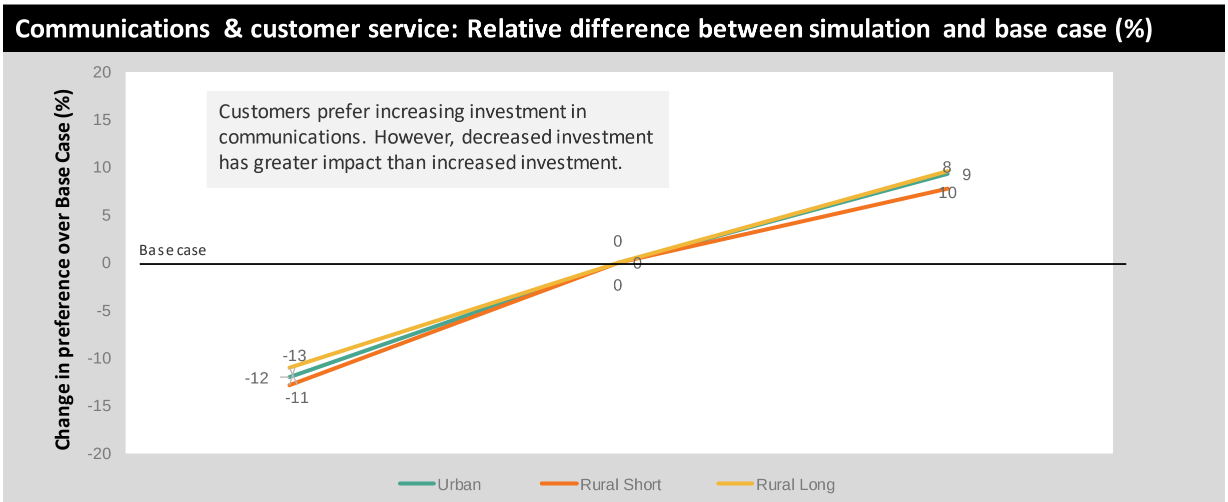
**Figure 4.10: Customer prioritisation**




Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

324. At an overall level, less priority was given to vegetation management, undergrounding and communication. While these areas were still considered important by customers, they were given a lower priority due to a belief that Western Power is performing well in these areas and therefore no additional investment is required. However, should the levels of service surrounding these decline, it would likely be detrimental to customer satisfaction. For example, the results indicate that customers are not willing to pay for increased levels of customer service (e.g. improved response times) but are highly sensitive to any erosion of existing levels (see Figure 4.11).

**Figure 4.11: Customer preference for changed investment in communications and customer service**




Source: Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

### 4.2.8 Variance between customer segments

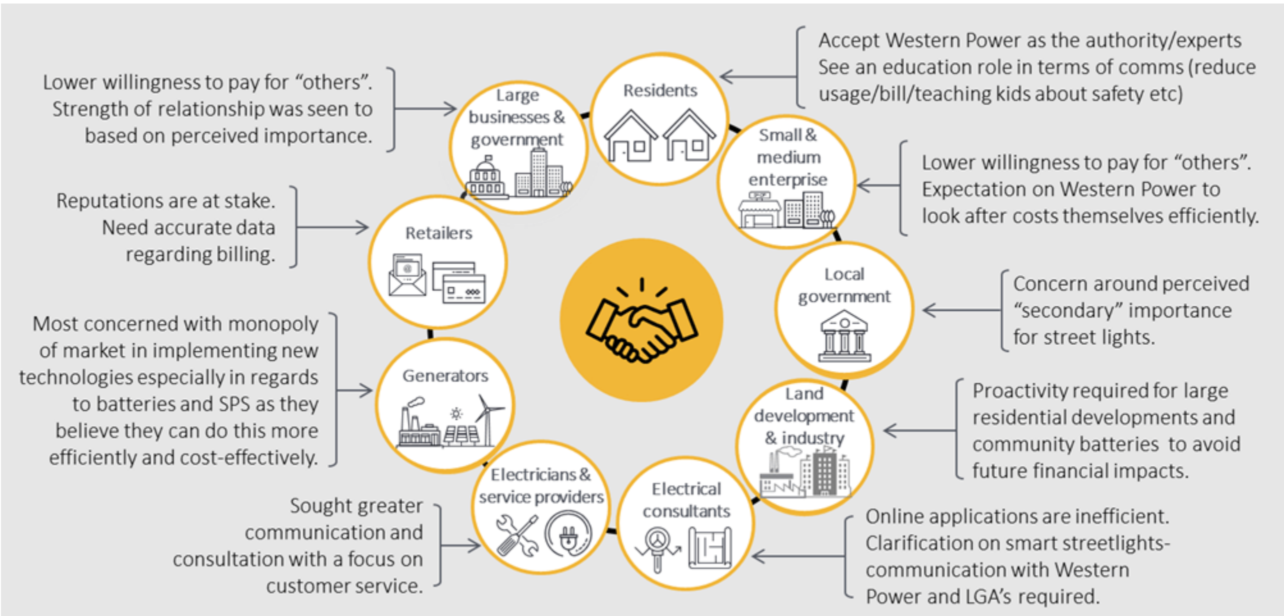
325. Customer needs and preferences vary due to their individual circumstances.

326. While there are many similarities between SME and residential customers in their responses to potential future investments, there are differences between and within these two groups. For example, customers in Rural Long areas of the network are more supportive and willing to pay for renewables, decreasing in outage frequency/duration as well as new technologies, as they are affected the most by these issues.

327. Vulnerable customers amongst both SME and residential customers also have different reactions based on their own circumstance.

328. Figure 4.12 provides a summary of what is important to each of the nine customer segments, demonstrating the differences between customer segments.

**Figure 4.12: Summary of what is important to each customer segment**




Source: Kantar Public, 2021, *Community and Customer Engagement Program Report*

## 4.3 Incorporating customer feedback into our AA5 proposal

329. Western Power has used the outcomes of the CEP to guide development our AA5 proposal including our proposed expenditure and service level. Table 4.5 summarises how we have incorporated customer insights into our plans for the AA5 period.[55]

**Table 4.5: Summary of how customer insights have been incorporated in the AA5 proposal**

| Insight | How have we incorporated this in our AA5 proposal |
|---|---|
| *Safety and Resilience*<br>Safety is seen as critical. Should the levels of service surrounding safety decline, it would likely be detrimental to customer satisfaction.<br>Customers believe there is already significant importance given to safety and do not prioritise additional investment to improve safety.<br>• This is due to a belief that Western Power is performing well in these areas and therefore no further investment is required.<br>• However, there is no willingness to trade-off safety for cheaper bills or greater reliability or increased sustainability.<br>There is in-principle support for further investments to improve network resilience | Forecast expenditure is designed to maintain the current level safety risk associated with our network assets. Western Power will continue to use a risk-based renewal approach that accounts for asset condition, criticality and lifecycle strategy to manage the condition of as many assets as possible for the optimum amount of investment.<br>Specific investments targeted at maintaining the safety of the Western Power Network include:<br>• replacement and reinforcement of poles and towers to minimise public safety risk from asset failure and maximisation of reliability performance'<br>• substation building upgrades to maintain buildings and workforce safety<br>• service connection condition monitoring using AMI to monitor and manage the electric shock risks posed by service connections<br>Further information on our risk-based approach to asset maintenance, and our proposed investment in the network is provided in Chapter 8. |
| *Reliability*<br>Service reliability is critical to all customers<br>• There are different service experiences across the Western Power Network.<br>• Rural Long customers experience longer frequency and duration of outages.<br>• Residential and SME Rural Long customers are most open to future investment options that may deliver them improved reliability.<br>• Any erosion of reliability would have a significant negative impact on customer perceptions, irrespective of customer type. | In line with customer feedback, our proposed investment during the AA5 period is designed to maintain current overall reliability levels rather than incur additional costs to improve reliability across the network.<br>We have targeted reliability investment at pockets of the network that have the poorest reliability and have high network security risks. For example, the investment in the modular grid and the technologies therein (i.e. SPS and microgrids) will significantly improve the level of reliability and resilience and this will be delivered with a lower cost technology than traditional poles and wires (due to the long rural feeders required to service customers dispersed over large distances).<br>Further information on our reliability investments is provided in Chapter 8 |

55 Customer insights and how they have informed specific items of expenditure are also discussed in the relevant sections of the operating and capital expenditure chapters of this document.

| Insight | How have we incorporated this in our AA5 proposal |
|---|---|
| *Network challenges of the future*<br>There was strong support for Western Power to proactively lead the way and plan for the future. | Our proposed investment will ensure the Western Power Network is future focused to enable the most flexible connection and operation of DER and large-scale renewables possible, for the benefit of all Western Australians.<br>Our proposed capex plan includes investments to:<br>• deliver commitments made in the DER Roadmap and ensure an efficient grid which is fit for customer needs and emerging technology trends, including investments in two disconnected microgrids<br>• inform the evolution of the DSO role through Project Symphony (an active DER demonstration project)<br>• develop Western Power's capability to meet DER and DSO integration requirements<br>Further information on our proposed investment in the network is provided in Chapter 8. |
| *Renewables*<br>Strong support for further investments that increases the amount of renewable energy in the system | Our proposed capex plan during the AA5 period is designed to enable increased levels of renewable generation connection to our network and implement the Energy Transformation Strategy Stage 1 outcomes.<br>Our Grid Strategy is based on long-term scenario planning for evolving customer preferences and needs, which identifies the right technology to use at the right place and time. This approach provides a vision and roadmap to the grid vision which minimises whole of life cycle costs and regrettable investment.<br>Our proposed capex plan includes investments to:<br>• enable customers to keep connecting more generation to the transmission network (e.g. improvements to planning capability), as well as to address emerging grid stability issues caused by the high penetration of renewable resources in the distribution network<br>• implement new capability to manage DER to enable greater DER penetration<br>Further information on our proposed investment in the network is provided in Chapter 8. |

| Insight | How have we incorporated this in our AA5 proposal |
|---|---|
| *Affordability*<br>Minimising cost increases is a high priority for residential customers<br>• Residential customers are sensitive to price increases.<br>• There is willingness to pay for key elements, provided they range between 1 and 5 per cent of the current bill for residential customers and 1 and 9 per cent of the current bill for SMEs | The price impact on customers, particularly residential and SME customers, has been considered when developing the AA5 proposal. All expenditure forecasts have been subject to top down review and assessment to ensure they represent a network business efficiently minimising costs.<br>Western Power's WACC proposal, which typically has the greatest impact on revenue (and therefore prices) has been tested and moderated to reduce the impact on customers where possible.<br>Further information on our WACC proposal is provided in Chapter 10 and further information about our pricing proposal is provided in Chapter 12. |
| *Willingness to Pay & Investment priorities*<br>SME and residential customers prioritise sustainability, investing in new technologies and building new infrastructure to cope with future demand<br>• Customers consider it important to plan and build for the future of the network.<br>• They are open to investment in community batteries, SPS and microgrids but remain cautious as to how much additional cost they are willing to absorb.<br>• Customers support specific investment options, provided bill increases are minimal (e.g. <$5/annum) and the cumulative impact of additional investments are 1 and 5 per cent of the current bill for residential customers and 1 and 9 per cent of the current bill for SMEs.<br>• Customers gave lower priority to increasing investment in communication than other areas, due to a belief that Western Power is performing well and therefore no additional investment is required. However, should the levels of service surrounding this decline, it would likely be detrimental to customer satisfaction | Technology is evolving rapidly, and we are trialling new solutions to test their suitability as part of the future network, such as SPS and community batteries. These are now being installed to replace or support traditional network infrastructure where it is cost effective to do so. Some of these solutions, such as AMI and SPS are focussed at reducing overall network cost in the longer-term.<br>When managing our network, Western Power considers options for non-network solutions such as managing demand or structuring tariffs in a way that optimises the use of our network.[56] Further information on our proposed network tariffs is provided in Chapter 12.<br>Western Power will invest in improved SCADA and Telecommunications technology to improve remote monitoring and control of the network, maintain reliability and safety of services, and implement additional necessary controls to manage cyber security risks.<br>Further information on our investments in new technology is provided in Chapter 8.<br>The range of ways in which Western Power communicates with its customers has increased significantly over recent years. However, the increased number of communication channels to be serviced by Western Power call centre staff whilst maintaining existing service levels can add costs to customers' bills. One solution Western Power is considering to overcome this challenge is to slightly increase the response times in some channels in order to service customer enquiries or issues via other more interactive channels (e.g. online chat) with the intent of not putting upward pressure on customer bills. The CEP found three quarters of respondents would support this approach. |

56 As per Section 6.41 of the Access Code.

# 5. Performance during AA4

330. This chapter sets out how Western Power performed over the five years of the AA4 period (2017/18 to 2021/22). It summarises the key customer outcomes and the investment undertaken to achieve these outcomes. This chapter also highlights a number of service improvements made during the AA4 period, as well as improvements to processes and governance.

**Key Messages**

- Western Power has delivered on our AA4 proposal promise of maintaining network safety and reliability whilst keeping costs lower than expected and transforming to meet the increasing and emerging energy industry and environmental challenges
- We were able to achieve efficiencies during the AA4 period delivering our capital expenditure program for less than forecast. However due to increasing risks and costs arising from energy industry changes (including the shift to renewable energy, energy transformation regulatory reforms and asset obsolescence) and unprecedented extreme climate events, our actual operating expenditure during the AA4 period was higher than forecast. Nevertheless, our AA4 operating expenditure remained 19% lower than in the AA3 period.
- We were able to achieve the majority of our minimum service standard levels over the period, with the 58 out of 62 met over the period[57]

## 5.1 Overview of AA4 performance

331. During the AA4 period, the WA energy sector has experienced significant changes, driven by the widespread uptake of customer owned rooftop PV systems, a shift towards renewable generation displacing fossil fuelled generation, and the uptake of new technologies such as energy storage solutions and SPS. The past five years has seen an unprecedented transformation from historical one-way power flows to two-way power flows which gives rise to growing challenges for Western Power and its industry stakeholders to transform the way we deliver a service that safely, reliably and affordably meets the needs of our customers.

332. Key achievements during the AA4 period include:

- **Meeting customers' needs:** we have connected new customers and delivered electricity in a safe, reliable and affordable manner. We have complied with safety obligations and delivered against most of our key reliability measures. We have responded to customers' investment in solar PV and have identified opportunities to better meet customers' needs through transformation to a modular network and enhancement in our systems and processes. We have:
  - connected 425 MW of rooftop PV to the Western Power Network
  - connected 89,147 new homes and businesses to the distribution network
  - implemented a customer management system **(CMS)** to enhance our customers' experience, including providing more accurate 24/7 information via their preferred communication channels
  - significantly improved our Net Promotor Score, a key performance indictor with respect to customers across our nine customer segments.

57 Based on the number of service standard benchmarks met during the AA4 period to date, 2017/18 to 2020/21, as shown in Figure 5.4.

- **Delivery of major network projects:** we have continued to address the highest priority safety concerns while still maintaining the overall level of public safety risk associated with our network. We have:
  - replaced or reinforced more than 137,000 distribution poles and replaced 1,627 km of conductor, treating 8,200 streetlight poles
  - replaced the 'out of support' Communications Network Management System **(CNMS)** with a capable, expandable, reliable system
  - Installed 415,783 meters. Of these, 73,686 were AMI capable, and 316,805 were AMI ready, progressing the AMI deployment
  - refurbished six switchboard in the central business district (**CBD**) Hay and Milligan substations to reinforce supply
  - installed 350 MVAr of reactors to address reactive power issues across the Western Power Network due to minimum demand
  - replaced obsolete SCADA and telecommunication assets, enabling a range of services critical to the operation of the Western Power Network
  - continued the State Underground Power Program (**SUPP**) in partnership with the State Government and local governments to replace overhead power lines with underground power infrastructure
  - extended the network capacity in the Eastern Goldfields region
- **Exploring innovative solutions:** we have identified and tested new and innovative ways to manage our asset performance to find more cost-effective approaches and options to maintain network reliability and meet our customers' needs. We have:
  - installed AMI across the Western Power Network which will improve the ability to detect faults remotely as planned with 490,000 advanced meters expected on our network by 2022
  - identified opportunities to better deliver our services to customers using modular network solutions such as SPS instead of traditional network rebuilds of poles and wires following Cyclone Seroja and Wooroloo bushfires
  - installed a total of 197 SPS units across the Western Power Network
  - implemented a 5 MW microgrid in Kalbarri (one of Australia's largest microgrids) to run in complete renewable mode, which means it can draw energy solely from the connected wind farm and feed-in from residential rooftop PV, serving a 1,500 people community
  - installed 13 community batteries in areas with high PV penetration and allowed customers to maximise their investment in solar and participate in battery storage solutions. The batteries are installed in areas where the network would otherwise need upgrading to maintain power quality.
  - Conduct digital substations trial at two metropolitan locations; Midland Junction and Southern River intended to improve condition information of critical transmission
  - used Light Detection and Ranging (**LiDAR**) to take 3D images of assets to quickly identify damaged poles and wires
  - used helicopter patrols to conduct initial surveys of damage following Tropical Cyclone Seroja to identify and bring forward maintenance work that could be carried out alongside repair work bypassing the need for future planned outages for this work

- introduced various initiatives to improve productivity, for example, robotic process automation in support areas and digital dispatch and data capture for field, planning and scheduling optimisation, streetlight fault process, customer connection services design and estimating
  - undertaken various trials of new technology targeting productivity improvements including Work Order Risk Prediction algorithm, machine learning, and robotic platform.

- **Responding to unforeseen events:** during the AA4 period unforeseen events challenged our business and impacted the delivery of our planned investments and resulted in lower expenditure than planned:
  - Extreme weather and fire events, such as the Yarloop and Wooroloo bushfires, and tropical cyclone Seroja, significantly damaged extensive parts of our network infrastructure. During the AA4 period we had 84 level 3 emergency event days[58], 18 of which were bushfire emergencies.
  - Increased pole inspections in response to the Parkerville fire and subsequent court case.
  - The COVID-19 pandemic had immense health, social and economic impacts for Western Australians. As an essential service to most Western Australians, we took quick and decisive action to ensure the Western Power Network was able to maintain reliable and safe supply to our customers and keep the lights on.

  Western Power is cognisant of the continued impact of COVID-19 on competition for resources and supply chain issues. We continue to plan for and mitigate these impacts on both the Western Power Network and our customers.

58 A network level 3 emergency is when an event (bushfire, storm, cyclone or network issue) has had, or is having a significant impact on employee or public safety and wellbeing, business performance or normal customer related activities, network security or transmission trip (multiple feeder trips).

**Figure 5.1: Overview of key AA4 achievements**

2017/18 — AA4 period — 2021/22

**Meeting customers' needs**

- 89,147 new homes and businesses connected
- 425 MW of rooftop PV connected
- Implemented a customer management system to enhance our customers' experience
- Customer calls: at least 90% answered within 30 seconds
- Maintained reliability of electricity supply despite performance being under pressure due to increasing environmental and energy industry changes

**Delivery of major network projects**

- More than 137,000 poles replaced / reinforced
- 1,627 km of overhead conductor replaced
- 197 SPS units installed across the Western Power Network
- Installed 415,783 meters and provided Service Connection Condition Monitoring for 77% of the network
- Replaced obsolete SCADA and telecommunication assets
- Continued the SUPP
- 23% improvement in electric shock performance

**Exploring innovative solutions**

- Used Light Detection and Ranging to take 3D images of assets to identify damaged poles and wires
- Conducted initial damage surveys following Tropical Cyclone Seroja using helicopter patrols to bring forward maintenance work
- Installed 13 community batteries
- Implemented a 5MW microgrid in Kalbarri to run in complete renewable mode

333. Further detail on AA4 expenditure and service performance is provided in the following sections.

## 5.2 Expenditure during the AA4 period

334. Western Power invested $4,098.2 million in capital costs and incurred $2,025.1 million in operating costs to provide safe, reliable and affordable connection to, and services from, the network during the AA4 period. The total expenditure is a 29 per cent reduction in expenditure compared to the AA3 period and a 1 per cent decrease in total expenditure compared with what was forecast in the AA4 final determination (see Table 5.1).

335. The actual expenditure undertaken during the AA4 period is consistent with the Access Code requirements as a result of:

- responding to customer needs, for example investing in grid transformation to optimise future energy generation, and enable the connection of more renewable energy
- efficiently minimising costs through our works optimisation process and our procurement practices (including the competitive tendering of materials and work delivered by external parties)
- delivering network management savings through our risk-based approach to asset management which reflects industry best practice

- optimising investment solutions by considering alternative options instead of 'like-for-like' asset replacement of existing network assets, such as network reconfiguration enabling load transfer
- continuously improving our governance procedures via several policies, strategies, and frameworks to ensure all investment decisions are prudent and delivered efficiently.

**Table 5.1: Comparison of forecast and actual expenditure during the AA4 period, $million real at 30 June 2022[59]**

| Expenditure type | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22[60] | Total |
|---|---|---|---|---|---|---|
| **Operating expenditure** | | | | | | |
| Opex forecast | 393.7 | 388.7 | 388.3 | 395.5 | 389.5 | 1,955.8 |
| Opex actual | 390.8 | 364.5 | 425.8 | 409.0 | 435.1 | 2,025.1 |
| $ variance | -3.0 | -24.2 | 37.5 | 13.5 | 45.6 | 69.3 |
| % variance | -0.8% | -6.2% | 9.6% | 3.4% | 11.7% | 3.5% |
| **Capital expenditure** | | | | | | |
| Capex forecast | 846.6 | 929.7 | 938.1 | 750.3 | 756.4 | 4,221.1 |
| Capex actual | 721.5 | 786.2 | 914.8 | 790.8 | 884.9 | 4,098.2 |
| $ variance | -125.1 | -143.5 | -23.3 | 40.5 | 128.5 | -123.0 |
| % variance | -14.8% | -15.4% | -2.5% | 5.4% | 17.0% | -2.9% |
| **Total expenditure** | | | | | | |
| Total forecast | 1,240.4 | 1,318.4 | 1,326.3 | 1,145.9 | 1,145.9 | 6,176.9 |
| Total actual | 1,112.3 | 1,150.7 | 1,340.6 | 1,199.8 | 1,320.0 | 6,123.3 |
| $ variance | -128.1 | -167.7 | 14.2 | 53.9 | 174.1 | -53.6 |
| % variance | -10.3% | -12.7% | 1.1% | 4.7% | 15.2% | -0.9% |

336. The total expenditure during the AA4 period was on par with the forecast. Some components varied as a result of:

- lower levels of investment in capacity expansion and customer driven work during the AA4 period due to weakened economic conditions and a significant slowdown in the growth of the mining sector in WA, although this has started to accelerate again in 2021/22
- a conscious effort to implement alternative solutions where more cost effective to do so including SPS, undergrounding, asset refurbishment or LiDAR
- the response to events such as major bushfires, cyclone events and COVID-19

337. Further commentary on opex and capex savings is provided in the following sections.

59 Total expenditure excluding non-revenue cap services and TEC.

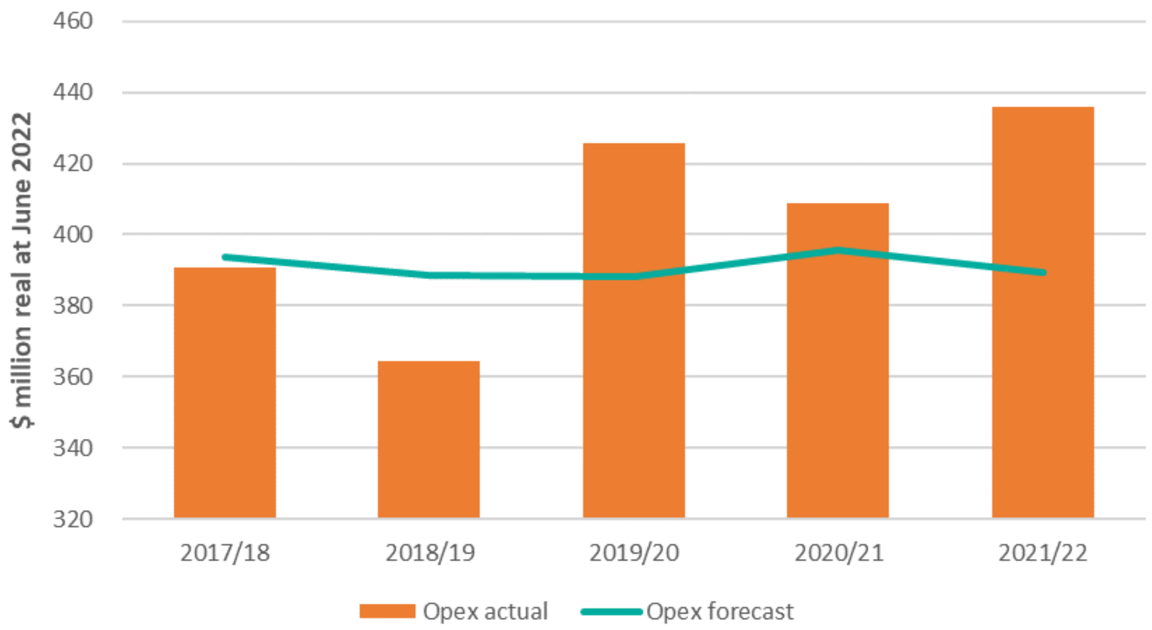
60 2021/22 is forecast expenditure.

### 5.2.1 AA4 operating expenditure

338. Western Power spent $2,025.1 million in operating costs to provide safe, reliable, and affordable connection to, and services from, the network during the AA4 period which is a 19 per cent reduction in comparison to the AA3 period. This was due to productivity improvements to Western Power's work practices and processes, asset strategies, procurement processes and organisational structure undertaken towards the end of AA3 and embedded during the AA4 period. Western Power was also subject to the gain sharing mechanism during the AA4 period, which provided incentives to improve productivity over the access arrangement period.

339. Operating costs during the AA4 period were around $69.3 million or 3.5 per cent higher than forecast (see Figure 5.2).

**Figure 5.2: Comparison of AA4 forecast and actual opex, $ million real at 30 June 2022**[61]




340. The slightly higher than forecast expenditure during the AA4 period is a result of the combination of:

- changes to distribution maintenance practices, including:
  - an increase to SCADA and Communication maintenance costs due to the measures supporting cyber security efforts and continued deployment of AMI
  - an increase in distribution preventative condition maintenance driven mainly by an increase in line easement vegetation management, overhead line maintenance and overhead switchgear maintenance. These increases were a result of a combination of factors including increase in hazard tree management, defect find rates, and costs for overhead maintenance activities
  - an increase in corrective emergency maintenance due to responses to natural events such as bushfires and cyclones
  - a decrease in distribution preventative routine maintenance mainly due to reduced siliconing activities during a review of work practices

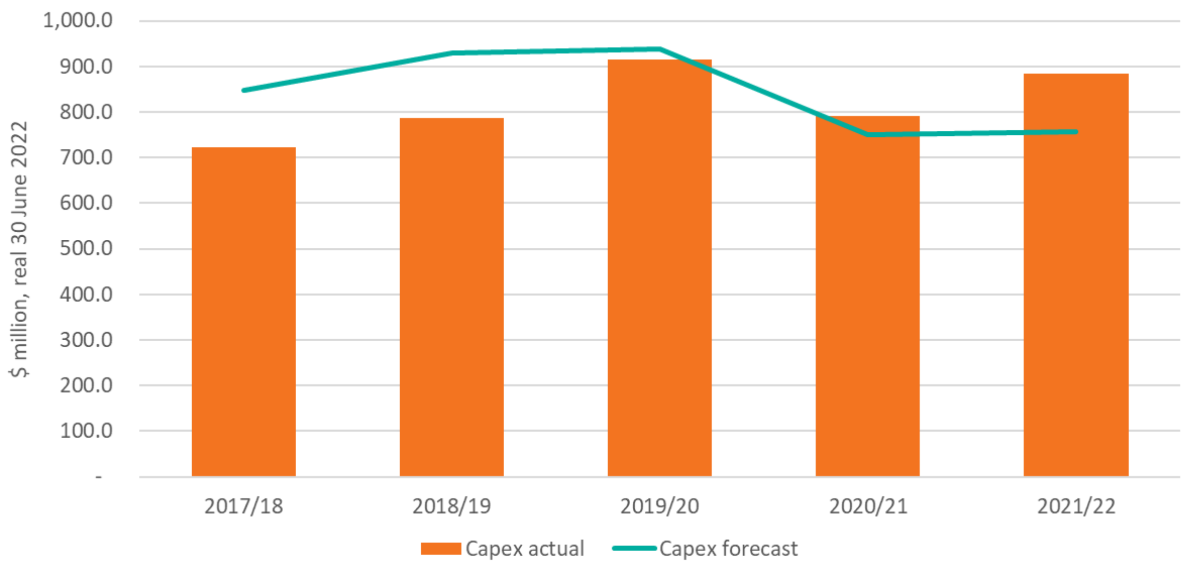
61 Note, 2021/22 is forecast opex.

- a reduction in distribution corrective deferred maintenance due to process improvements that enabled transfer of operating expenditure to capital expenditure and lower priority faults to be deferred
  - a decrease in holistic inspections due to a reduction in scope as a result of the implementation of LiDAR
- increased transmission preventative routine maintenance. Over the AA4 period, the risk of network instability has been steadily increasing because of the impact of the industry transformation (move to renewable energy), which has put additional pressure on opex as more complex switching and contingencies are required to be in place during routine maintenance.
- increased distribution SCADA system expenditure to respond to a large number of obsolete assets which exhibited higher failure rates, which is also reflected in the increased capex delivered during the AA4 period, and additional SCADA maintenance due to the implementation of mobile radio and AMI technologies
- increased metering opex as a result of an increase in the AMI installation rate over the AA4 period
- higher than expected extended outage payments and call centre costs as a result of an unprecedented increase in significant natural events such as bushfires, storms and cyclones during this period
- increased network operations costs as a result of:
  - implementation of the Generator Interim Access which allowed large scale renewable generation to connect to the network before constrained access (note, constrained access is now being implemented as part of the regulatory reform program (see Chapter 3 for further details on constrained access))
  - significant reviews of the system restart plans in the new low network demand context. This work was done in conjunction with AEMO and Energy Policy WA to ensure there are up to date plans and procedures to restart or power up the network in the event of a system black scenario
- an increase in Western Power's costs to respond to industry transformation, specifically the support of the regulatory reform program
- an uplift in the cyber security capability aligned to the further implementation of SCADA systems and changes to regulatory obligations during the AA4 period.

### 5.2.2 AA4 capital expenditure

341. Over the AA4 period, Western Power invested $4,098.2 million in capex compared to a forecast $4,221.1 million. Figure 5.3 provides a comparison of actual and forecast capex over the AA4 period.

**Figure 5.3: Comparison of AA4 forecast and actual capex, $ million real at 30 June 2022**[62]




342. Total capital investment for the AA4 period is 2.9 per cent less than that included in AA4 target revenue and reflects:

- 113.6 per cent more SCADA capex than forecast
- 20.3 per cent more transmission capex than forecast
- 14.3 per cent less distribution capex than forecast
- 13.9 per cent more corporate capex than forecast.

343. This lower level of capital investment has been driven by:

- a slowdown in the growth rate of peak demand following eight years of reasonably strong growth
- a reduction in customer driven work compared to forecast due to weakened economic conditions and a significant slowdown in the growth of the mining sector in WA, although this has started to accelerate again in 2021/22
- the development and implementation of our innovative risk-based renewal methodology for distribution overhead assets enabling the achievement of the optimal balance between risk reduction and efficient delivery. This approach to asset management reflects industry best practice[63] and has delivered network management savings across several capex categories.

344. Further detail about the actual expenditure undertaken during the AA4 period, the outcomes associated with the AA4 capex program and the reasons for the variances are provided in Attachment 5.1 – AA4 Capital Expenditure Report.

345. Notably, we spent $281 million less than forecast for expenditure categories subject to the Investment Adjustment Mechanism (**IAM**) in the AA4 period. This mechanism ensures that where Western Power does not spend as much as forecast in these expenditure categories, the revenue associated with this amount is

62 Note, 2021/22 is forecast capex.

63 Western Power's Asset Management System is audited by an independent review as a condition of Western Power's electricity transmission and distribution licence. The most recent AMS review concluded in September 2020 and observed that Western Power has developed a sophisticated, well-structured and disciplined Asset Management System (AMCL+, Western Power 2020 Asset Management System Review, November 2020).

returned to customers in the next access arrangement period.[64] Through the IAM we will return $39.2 million (in net present value terms as at 30 June 2022) to customers during the AA5 period.

346. Table 5.2 shows actual capital investment compared to forecast by regulatory category

**Table 5.2: AA4 total capex – major capital projects and programs, $million, real at 30 June 2022**

| Expenditure category | AA4 Forecast | Actual | $ variance | % variance |
|---|---|---|---|---|
| **Transmission** | | | | |
| Asset replacement and renewal | 265.2 | 234.5 | -30.8 | -11.6% |
| Growth | 186.3 | 405.7 | 219.4 | 117.8% |
| Compliance | 183.4 | 122.0 | -61.4 | -33.5% |
| Improvement in service | 78.2 | 130.6 | 52.3 | 66.9% |
| **Transmission Total** | **713.2** | **892.8** | **179.6** | **25.2%** |
| **Distribution** | | | | |
| Asset replacement and renewal | 1,489.8 | 1,428.0 | -61.8 | -4.1% |
| Growth | 1,313.4 | 937.3 | -376.1 | -28.6% |
| Compliance | 201.6 | 199.0 | -2.6 | -1.3% |
| Improvement in service | 32.9 | 105.8 | 72.9 | 221.5% |
| **Distribution Total** | **3,037.7** | **2,670.0** | **-367.7** | **-12.1%** |
| **Corporate total** | **470.2** | **535.4** | **65.1** | **13.9%** |
| **AA4 total capex** | **4,221.1** | **4,098.2** | **-123.0** | **-2.9%** |

### *Transmission network investments*

347. Western Power invested $405.7 million in transmission growth projects to expand the capacity of the transmission network to facilitate meeting growth in demand and connecting new customers. This represented 45 per cent of the total AA4 transmission capital investment and included:

- extending the network capacity in the Eastern Goldfield region including:
  - providing 43 MW of reference-service capacity in the Eastern Goldfield region load area to overcome network constraints, and connecting major customer loads and additional generation capacity across the Western Power Network
  - developing an Eastern Goldfields Load Permissive Scheme which will allow prospective customers in the Eastern Goldfields to access non-reference power. There are a number of customers progressing connection under this arrangement
- completion of the West Kalgoorlie Static Var Compensator (**SVC**) Replacement project. The SVC Replacement project 'maintains' existing network capacity

[64] The IAM adjustment accounts for the return on asset and depreciation that had been included the revenue, and therefore prices over the AA4 period for expenditure categories subject to the IAM.

- installing 350 MVAr of reactors to address system low issues at priority zone substations (Henley Brook, Clarkson, Wanneroo, Yanchep, Southern River, Joondalup, Neerabup Terminal, Guildford Terminal, Northern Terminal, Southern Terminal)
- installing additional transformers in existing substations to accommodate demand in specific areas and creating additional feeder capacity to allow for load growth, additional distribution transfer capacity, and connection of new large customers
- installing a 490 MVAr transformer at Kemerton terminal to address asset condition issues and cater for the forecast uplift in customer load.

348. We also invested $487.0 million in transmission non-growth activities. This represents 55 per cent of the total AA4 transmission capital investment related to maintaining the provision of covered services to existing customers to ensure the ongoing safe and reliable operation of transmission assets. Examples of outcomes achieved from this investment included:

- replaced 2,530 and reinforced 8,008 transmission poles
- replaced five 132/22 kV transformers in various locations, including Wagerup and Mullaloo where condition monitoring identified a number of anomalies on the condition of these units
- refurbished 27 power transformers of various voltages
- replaced and refurbished the switchboards at Hay Street substation and Milligan Street substation in Perth Central Business District
- replaced failed and poor condition primary plant[65] assets comprising 66 outdoor circuit breakers (plus two indoor circuit breakers), 263 instrument transformers, 297 disconnectors and disconnectors with earth switches, 90 surge arresters, 15 reactors and other assets (one station transformer, one earthing compensator and 18 relays) in zone and terminal substations
- replaced 209 protection relays, including 71 obsolete relays
- replaced obsolete and/or non-compliant SCADA and telecommunication assets, enabling a range of services critical to the operation of the Western Power Network
- upgraded the energy management system (**EMS**) to address an ageing hardware platform and the end of support of those systems. This was assessed as posing a high operational risk, as not maintaining supported operating systems and software releases may lead to software malfunction with possible major impact on reliant system interfaces. Failures in the EMS could lead to reduced ability to operate and maintain the electricity network, with direct impact to a large number of connected customers from more frequent and extended outages, a safety incident or unacceptable levels of power quality
- invested in the corporate master station technology operating the electricity network, including real-time monitoring, control and management of electrical and telecommunications networks
- rectified structural and building services defects at multiple substations where defects were identified during structural inspections and assessed as having potential to cause a workforce or network reliability risk
- removed all asbestos containing materials from three substations (Rockingham, Kwinana and Northern Terminal) where these materials could be removed without the need for network modification.

65 Some primary plant assets such as circuit breakers can be replaced phase by phase or as whole units. The volumes referred in this document relate to whole units. Volumes reported in AA3 outcomes are expressed in phases (1 unit = 3 phases)

### *Distribution network investments*

349. During the AA4 period, Western Power invested $937.2 million on distribution growth projects to expand the capacity of the distribution network to meet growth in demand and connect new customers. This represented 35 per cent of the total investment in distribution capital activities and included:

- connected 34,595 new customers to the distribution network increasing total customers connected by approximately 3 per cent to more than 1.16 million customers
- installed new feeders and reinforced existing feeders to increase capacity, reduce feeder peak loading and reduce the risk of long duration outages.

350. We invested the remaining 65 per cent or $1,732.8 million on distribution non-growth activities including:

- replaced 60,723 and reinforced 82,769 distribution poles based on our asset risk prioritisation framework
- replaced 1,627 km of conductor based on condition to maintain the current level of unassisted conductor failure risk
- installed 89,147 meters for new connections and replaced 326,636 existing meters as part of network maintenance and customer requested services
- installed 197 SPS across the Western Power Network, including 52 SPS up to 2020/21, with a further 145 planned for 2021/22
- completed 21 SUPP projects in partnership with the State Government and local governments in a number of metro and rural locations
- replaced obsolete of SCADA and Telecommunication assets, enabling a range of services critical to the operation of the Western Power Network
- invested $199.0 million in compliance activities, including installing approximately 2,030 low voltage (**LV**) spreaders and remediated 640 high voltage (**HV**) clashing bays as part of the bushfire management activities to mitigate the risk of overhead conductors coming into contact with each other and causing sparks.

### *Corporate expenditure investments*

351. In the AA4 period we invested $535.4 million on corporate support activities, including the following IT investments to improve the effectiveness of key operational processes and work practices:

- cyber security strategy, which implemented Western Power's response to cyber security risks in alignment to the AESCSF developed by AEMO and applicable to Wester Power as an electricity utility classified as critical infrastructure
- upgraded a number of systems, including the EMS, enterprise resource planning (**ERP**) system due to ageing hardware platforms and the end of support of those systems
- implemented a CMS to enhance our customers' experience, including by providing more accurate 24/7 information via their preferred communication channels
- designed and implemented new systems, including the Enterprise Grid Transformation Engine which is a new network planning tool to manage transformation of the grid. This tool provides an enhanced planning capability to allow scenario modelling of the network, against possible future scenarios. This, in turn, helps with identifying the prudent level and nature of investments required to meet our customers' energy needs at the most competitive cost.

352. Key facilities were rationalised or upgraded in order to comply with safety, legislative or financial requirements and to better meet the operational needs of the business. This included progressing the delivery of the Depot Optimisation and Consolidation Program, to ensure that we have fit for purpose facilities to enable crews to respond and support our customer base. This has generated cost reductions and disposals benefits as a result of reducing the number of Western Power depots in the Perth Metropolitan and Southwest region of WA. The main depots delivered or nearing completion during the AA4 period were Vasse, South Metro, Pinjarra and Albany. We also progressed design works for Geraldton and further depots will be rebuilt or rationalised in the AA5 period.

353. Further discussion on capex during the AA4 period, including reasons for variance from forecast, is provided in the AA4 Capital Expenditure Report (see Attachment 5.1). Further information is available in the AA4 Capital Expenditure Variance Analysis Report provided at Confidential Attachment 5.2.

## 5.3 Service standard performance

354. During the AA4 period Western Power operated under a modified revenue cap form of regulation. A revenue cap is often accompanied by a service standard incentive scheme to ensure that services are not compromised in the pursuit of incentives to reduce costs. Western Power's incentive mechanisms have been designed to penalise a decline in performance, but also provides an incentive to improve service where it is valued by customers.

355. Western Power's access arrangement accounts for service standard performance in two key elements:

- **service standard benchmarks (SSB**): compliance targets set at minimum service levels that must be achieved. These are typically set with reference to performance in the previous access arrangement period
- **the service standard adjustment mechanism (SSAM):** the financial incentive scheme to provide Western Power with rewards and/or penalties for service improvement or degradation measured against service standard targets (**SST**) set at the beginning of the access arrangement period. The framework is set to allow Western Power to accrue rewards or penalties against each measure each year, culminating in a net reward or penalty to be added or subtracted from target revenue in the following access arrangement period.

356. The service performance measures in the AA4 incentive scheme cover:

- **reliability of electricity supply in the distribution and transmission networks:** which measures the frequency and duration of network interruptions experienced by customers
- **security of electricity supply:** which measures the percentage of time transmission circuits are available
- **customer service:** which measures how well the business engages with customers in relation to non-technical services including such things as call centre performance, notification of planned outages, timely streetlight repairs and response time to re-energise or de-energise a connection point.

357. Measures in the incentive framework must directly relate to one or more of the reference services provided to customers. Measures should provide information that is meaningful to customers and should be an accurate reflection of actual performance.

358. Western Power's reliability performance objectives are to:

- maintain current reliability performance levels – these are aligned to the SSBs in AA4, calculated from five years of historical performance

- maintain current levels of compliance with the minimum service standard performance levels set in WA jurisdictional requirements by the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*
- improve SSTs only where it is valued by customers and economically prudent to do so, as defined in the AA4.

359. Western Power applies the 'maintain current reliability performance levels' approach where the current levels of performance are satisfactory (on average maintain levels of reliability performance at the SSB) and achieve at least the minimum service levels (that is, meet regulatory compliance). Western Power seeks to maintain levels of reliability performance, on average, at the SST[66], where it is valued by customers and efficient and prudent to do so. We may seek to make further improvements to performance only where there is non-compliance (or a trend towards non-compliance) and a pathway to compliance will be established. This is consistent with the findings of our CEP, where customers told us they are generally satisfied with current levels of performance, and do not necessarily want Western Power to invest to improve service.

360. During the AA3 period, the majority of reliability performance SSB measures improved with the exception of rural long feeder performance. As a result, the SSBs compliance targets and SSTs for the AA4 period were set at increased (and harder to achieve) levels to reflect the improvement in performance and to provide the incentive to maintain performance into the AA4 period.

361. During the AA4 period[67], Western Power achieved:

- 13 out of 15 SSBs in 2017/18
- all 15 SSBs in 2018/19
- 14 out of 16 SSBs in 2019/20, and
- 15 out of 16 SSBs in 2020/21.

362. Trends show that performance is plateauing to levels that are consistent with industry practice. Western Power considers that it has reached an investment approach that is valued by customers to address reliability. The feedback from customers is that they are happy with their level of reliability and do not value additional investment to improve reliability.

363. Figure 5.4 provides a summary of performance against SSBs over the AA4 period.

66 The AA4 SSTs represent the average levels of performance experienced on the distribution network during the previous five years in the AA3 period, 2012/13 to 2016/17.

67 In the 2017/18 period, the SSBs that applied were as published in the previous approved access arrangement (AA3).

**Figure 5.4: Western Power's performance against AA4 SSBs[68]**

| | AA4 SSBs | 17/18 | 18/19 | 19/20 | 20/21 |
|---|---|---|---|---|---|
| Transmission network | Circuit availability | ✓ | ✓ | ✓ | ✓ |
| | LOSEF >0.1 and ≤1 system mins | ✓ | ✓ | ✓ | ✓ |
| | LOSEF >1 system mins | ✗ | ✓ | ✓ | ✓ |
| | Average outage duration | ✓ | ✓ | ✓ | ✓ |
| Distribution network | SAIDI CBD | ✓ | ✓ | ✓ | ✓ |
| | SAIDI urban | ✓ | ✓ | ✗ | ✓ |
| | SAIDI rural short | ✓ | ✓ | ✗ | ✓ |
| | SAIDI rural long | ✓ | ✓ | ✓ | ✓ |
| | SAIFI CBD | ✓ | ✓ | ✓ | ✗ |
| | SAIFI urban | ✓ | ✓ | ✓ | ✓ |
| | SAIFI rural short | ✓ | ✓ | ✓ | ✓ |
| | SAIFI rural long | ✓ | ✓ | ✓ | ✓ |
| Call centre | % calls responded to in <30s | ✓ | ✓ | ✓ | ✓ |
| Street lighting repair time | Metropolitan | ✓ | ✓ | ✓ | ✓ |
| | Regional | ✓ | ✓ | ✓ | ✓ |
| Ancillary Services | Supply abolishment | | | ✓ | ✓ |

✓ = SSB met

✗ = SSB not met

Notes:

(1) **LoSEF**= loss of supply event frequency, **SAIDI** = system average interruption duration index, **SAIFI** = system average interruption frequency index

(2) For the streetlight LED replacement reference service, Western Power was not requested to perform this service during the AA4 period.

(3) Remote de-energisation and remote re-energisation SSBs were not reported on in the AA4 period to date. Western Power is currently unable to provide these services and is working on having an IT solution implemented. The services are expected to be available in the third quarter of the 2021/22 period.

[68] Note, the diagram does not include performance against SSBs in 2021/22 as this period is still underway. This will be updated to include the 2021/22 service standard performance at the end of the AA4 period.

364. Service performance was generally maintained over the AA4 period. The SSAM, which presents a more detailed picture of service performance, shows that Western Power exceeded five out of 13 SSTs during the AA4 period.

365. The SSAM was not applied between 1 July 2017 and 30 June 2019.

366. Figure 5.5 shows Western Power's performance against the 13 measures[69] included in the SSAM.

**Figure 5.5: Western Power's performance against AA4 SSTs[70]**

| AA4 Performance against SSTs | | 19/20 | 20/21 | Net reward/penalty |
|---|---|---|---|---|
| Transmission network | Circuit availability | + | = | + |
| | LOSEF >0.1 and ≤1 system mins | + | + | + |
| | LOSEF >1 system mins | = | + | + |
| | Average outage duration | + | − | − |
| Distribution network | SAIDI CBD | − | + | − |
| | SAIDI urban | − | − | − |
| | SAIDI rural short | − | − | − |
| | SAIDI rural long | − | − | − |
| | SAIFI CBD | − | − | − |
| | SAIFI urban | − | − | − |
| | SAIFI rural short | − | + | − |
| | SAIFI rural long | + | + | + |
| Call centre | % calls responded to in <30s | + | − | + |
| Net reward/penalty | | − | − | − |

\+ = Performance better than SST (reward)
− = Performance worse than SST (penalty)
= = Performance equal to SST (neutral)

69 The two street light measures and four ancillary services that feature in the SSB framework are not included in the SSAM.

70 Note, the diagram does not include performance against SSTs in 2021/22 as this period is still underway. This will be updated to include the 2021/22 service standard performance at the end of the AA4 period.

367. The AA4 SSAM was designed so that, on average, performance would exceed the SST 50 per cent of the time and fall below the SST 50 per cent of the time, with the net outcome being that overall service levels are maintained.

368. As per the SSAM design, Western Power incurred a combination of rewards and penalties against each SST over the course of the AA4 period. Performance exceeded the SST more than 50 per cent of the time for five of the 13 measures. The total SSAM penalty decreased in 2020/21 compared to 2019/20 due to targeted reliability improvement activities and a reduction in number of interruptions across the network relative to 2019/20.

369. A small reduction in performance against service incentives resulted in a net financial penalty under the SSAM of ~$32 million (in present value terms) [71], to be deducted from the target revenue of the AA5 period. Details of the SSAM calculation, including penalties/rewards incurred each year, is provided in Chapter 11.

370. The following sections provide a summary of how Western Power has performed during the AA4 period in the following areas of customer service:

- reliability of electricity supply
- security of electricity supply
- call centre performance
- street light repair
- public safety.

371. Public safety does not feature in the service incentive framework but is a key indicator of Western Power's business performance. In addition, Western Power also reports and publishes network safety statistics quarterly under regulation 32 of the *Electricity (Network Safety) Regulations 2015*, which require Western Power to publish outcomes for the network safety performance incident types specified under regulation 31 of the *Electricity (Network Safety) Regulations 2015*.

### 5.3.1 Reliability of electricity supply in the distribution network

372. Western Power generally maintained reliability of electricity supply in the distribution network over the course of the AA4 period. However, performance is under pressure due to increasing environmental and energy industry changes.

373. This is in contrast to our performance during the AA3 period, where the majority of reliability performance SSB measures improved with the exception of rural long feeder performance. The SSBs compliance targets and SSTs for the AA4 period were set at harder to achieve levels to reflect the improvement in performance in the AA3 period and to provide the incentive to maintain performance into the AA4 period.

374. Trends show that performance is plateauing, which is consistent with industry practice. Low-cost investments to address reliability have been implemented and we are getting to a stage where customers are happy with their level of reliability and do not value additional investment to improve reliability.

375. Reliability is usually described in terms of the duration and frequency of a supply outage. This is measured by the System Average Interruption Duration Index (**SAIDI**) and the System Average Interruption Frequency Index (**SAIFI**).

[71] Note, this is a preliminary estimate that excludes performance in 2021/22. This will be updated to include the 2021/22 SSAM performance at the end of the AA4 period.

### *Impact of external weather events and climate change*

376. SSB performance is designed to measure performance valued by customers and which can be controlled and managed. To do so, events or circumstances that are outside of Western Power's control are excluded, including events such as force majeure.

377. 2019/20 and 2020/21 were impacted by an unprecedented increase in bushfire and severe weather events, some of which have been classified as force majeure events:

- 2019/20 reached a high of four events classified as force majeure events, the highest number since access arrangement reliability reporting started in 2006/07:
  - The Yanchep and Two Rocks bushfire event impacted the distribution network from 12 to 17 December 2019 and occurred during an unusual four-day December heatwave. External site access restrictions by the Department of Fire and Emergency Services (**DFES**) impacted Western Power's ability to respond, prohibiting Western Power from access to its network assets. Repairs could not occur until it was deemed safe to do so under the direction of the DFES.
  - The Katanning bushfire event impacted the distribution network from 7 to 9 February 2020 and occurred during a heatwave, with strong winds that fanned the fire. Workforce restrictions put in place by DFES resulted in Western Power not being able to resolve the faults on the network. Repairs could not occur until it was deemed safe to do so under the direction of the local Fire Incident Control Captain.
  - North country abnormal storm events which impacted on the transmission and distribution network from 26 to 28 February 2020, and consisted of localised strong winds, rain, hail and lightning; and
  - Ex-Tropical Cyclone Mangga impacted the network from 24 to 26 May 2020 with rain and strong winds that caused widespread damage over a large area of the Western Power network. Four substations were significantly affected, three of which were completely blacked out for a period of time. The Bureau of Meteorology described Cyclone Mangga as "*a once in a decade strong and complex weather system*"[72].
- 2020/21 the trend in bushfires and severe weather events continued, with two events being classified as force majeure:
  - 2 January – 13 March 2021 bushfires. The combined effect of eight concurrent and widespread bushfire events (including Perth Hills and Wooroloo fires) caused extensive damage to the distribution network and put a significant strain on all Emergency Services, including Western Power.
  - Tropical Cyclone Seroja occurred on 11 and 12 April 2021. Damaging winds (wind gusts of up to 170 km/h were recorded near Kalbarri) and significant rain over a large geographic area approximately 700 km long and 150 km wide causing extensive network damage across the Mid-West region. The event resulted in the largest ever response and recovery effort by Western Power. Western Power and contractor crews worked for over 10 weeks to address over 1,250 hazards, replace more than 1,600 poles and repair or replace over 200 km of conductor. The breadth and severity of Tropical Cyclone Seroja impacted supply to around 31,500 customers.

378. In 2019/20 and 2020/21, there was a reduction in Western Power's performance across some of the SAIDI and SAIFI measures compared to previous years, which we believe can be partly attributed to climate

72 Bureau of Meteorology, 2020, *Greater Perth in May 2020: a wet and cool finish*, http://www.bom.gov.au/climate/current/month/wa/archive/202005.perth.shtml

change, for example the significantly higher number of total fire ban days declared by DFES in 2019/20 and 2020/21 compared to previous years. [73]

379. In 2020/21 reliability performance improved on the distribution network in comparison to 2019/20. However, environmental impacts on our network continue to contribute to the overall performance remaining below the SSTs. Not all external weather events can be excluded from performance, which has resulted in a negative impact on performance levels due to the increasing influence of climate change. We continue to monitor and assess the impact of these climate change impacts on performance and whether it will have ongoing impact on average SAIDI and SAIFI performance.

380. Reliability performance was also impacted during total fire ban days declared by the DFES, which continue to be at an elevated level since 2019/20.[74] Total fire ban days are declared by DFES on days when fires are most likely to threaten lives and property. This means Western Power needed to take appropriate additional work practice and network operation precautions to eliminate or manage potential risks to the public and our people. This can result in wider and longer power outages. Since total fire ban days and other third-party directives (such as local government vehicle movement bans) are events outside Western Power's control, they have been added as a new exclusion for the AA5 period. The SSB and SSAM to apply in the AA5 period are outlined in Chapter 6.

*Emerging challenge*

381. Alongside these environmental challenges, the energy landscape is undergoing an unprecedented transformation from historical one-way power flows to two-way power flows creating operational challenges to the delivery of the safe and reliable electricity service that our customers and the community expect.

382. A growing challenge for Western Power from this transformation is low load and system stability primarily due to the changing generation mix towards renewable generation and increased penetration of DER (such as rooftop PV systems) on our network. System low load events on the Western Power Network are increasing in frequency and magnitude which create a risk of widespread outages. Further information about the energy transformation and its impact on the Western Power Network are outlined in Chapter 2.

383. Western Power continues to collaboratively work with industry stakeholders to manage and seek innovative ways to mitigate the risk of widespread outages that could occur due to low load and environmental challenges. This includes:

- working with AEMO and Energy Policy WA on immediate and longer-term actions to manage low load conditions. We have also begun investing in technology like community batteries to manage low-load conditions in the short-term
- seeking appropriate changes to the service standards in the AA5 period so they remain relevant to represent the value of the service we provide to our consumers.

384. Western Power continues to monitor and assess the sustained impacts of climate change and low load conditions on our average performance as an input into how we can transform our network and meet the needs of our customers to provide a service that is affordable, safe and reliable.

[73] Total Fire Ban Days declared by DFES have increased from 772 in 2015/16 to 1,555 in 2019/20 and 14,35 in 2020/21. DFES Website - https://dfes.wa.gov.au/totalfirebans/Documents/TFB-Declarations-2015-2021.pdf

[74] Total Fire Ban Days declared by DFES have increased from 772 in 2015/16 to 1,555 in 2019/20 and 14,35 in 2020/21. DFES Website - https://dfes.wa.gov.au/totalfirebans/Documents/TFB-Declarations-2015-2021.pdf

### *Key strategies and activities*

385. Western Power continued to implement several key strategies and routine activities during the AA4 period to maintain reliability of supply in the distribution network**.** This included:

- maintenance – routine and targeted asset inspection, maintenance programs, and monitoring of assets. This is done in conjunction with vegetation management programs, as well as the replacement of deteriorating assets and defective assets, such as poles, conductors and plant equipment
- grid augmentation – targeted augmentation in areas of the distribution network based on long-term reliability performance and underlying reliability risk factors. The nature of augmentation will depend on systemic factors that negatively affect reliability and the suitability of options at that location on the network
- adoption of new technology solutions – investigating and utilising new technology that is expected to improve the customer experience, such as microgrids, automation, SPS, portable generation connecting transformers (injection units), battery energy storage systems, fast communication links and protection devices
- targeted reliability activities – bringing forward targeted equipment repairs, network reconfiguration, and updating outages processes enabling Western Power to improve fault response and restoration times in commercial CBD buildings.

386. Western Power has scheduled a significant number of network reconfiguration and optimisation projects for rural short feeders for implementation during the 2021/22 period that are expected to realise network performance benefits from 2022/23 onwards.

### *Reliability performance – distribution*

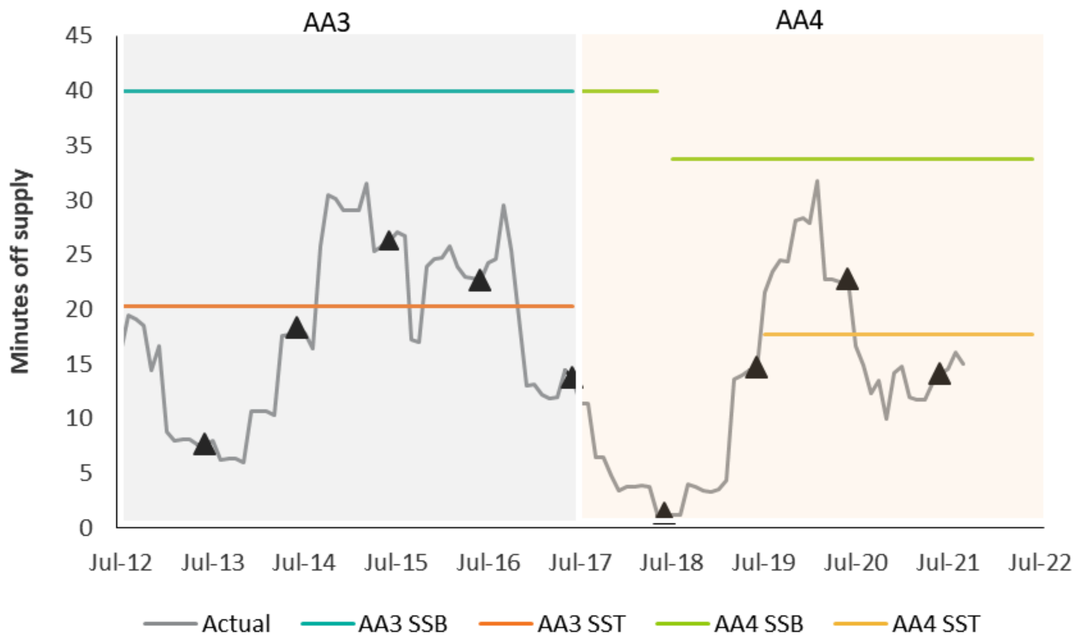
#### *Distribution network reliability, SAIDI - CBD*

387. Figure 5.6 to Figure 5.13 shows performance in relation to the duration (SAIDI) and frequency (SAIFI) of outages on each of the four distribution feeder types (CBD, urban, rural short, rural long)[75]. The black triangle in the figures represents the 12-month rolling average performance for each financial year. A lower number represents an improvement in service for these measures.

388. In the 2017/18 period, the SSBs that applied were as published in the previous approved access arrangement (AA3).

[75] An additional Major Event Day (MED) has been identified on 1 August 2018 post the submission to the 2020/21 service standard performance report to the ERA. As a result, non-CBD distribution reliability performance figures for the 2018/19 financial year are adjusted.

**Figure 5.6: Distribution network reliability, SAIDI - CBD**




389. CBD average performance is highly volatile over short periods of time due to the combined effects of lower number of outages, fewer connections (~5,000 customers over a >1million customer base), and the relatively long repair time for faults in an underground CBD network.

390. During the AA3 period, SAIDI and SAIFI within the CBD tracked within the SSB, reflecting the high levels of reliability in this part of the network. As a result, the SSBs compliance targets and SSTs for the AA4 period were set at harder to achieve levels to reflect the improvement in performance.

391. Similar to our performance during the AA3 period, the SSB relating to CBD SAIDI has been achieved each year of the AA4 period. Performance against the CBD SAIDI SST has been higher than the target in one out of two years of the AA4 period.[76]

392. CBD SAIDI performance in the first two years of the AA4 period was better than SST benchmark due to the reductions in equipment failure, specifically underground cable failure.

393. CBD SAIDI Performance in 2019/20 exceeded the SST benchmark but declined compared to the previous year. The primary contributors to the reduction in performance were unplanned interruptions where the cause could not be determined (a possible reason why the causes could not be determined is transient faults which are difficult to pinpoint on what is largely an underground cable network), and an interruption due to vegetation impacting an overhead network that was connected to the CBD network.

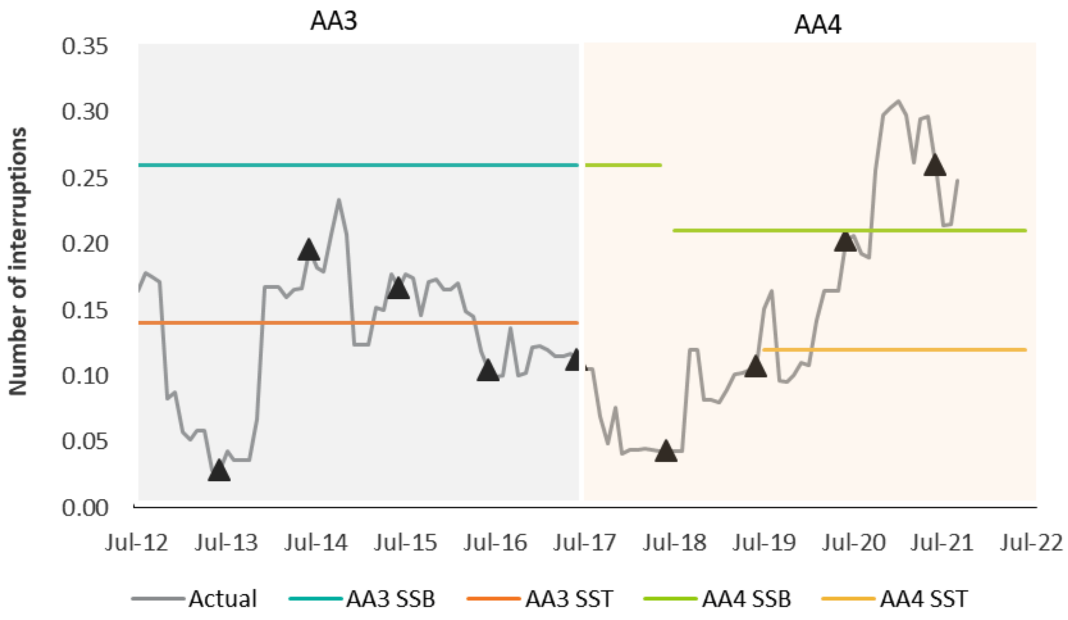
394. To limit volatility and to ensure the expected high performance of the CBD network, customers have been engaged to improve Western Power access to equipment in private buildings. Targeted equipment repair has been executed in 2019/20 and further automation of equipment is underway to enhance automated restoration of customers (to be continued throughout the AA5 period). The CBD SAIDI performance has improved in 2020/21 due to fewer interruptions attributed to unknown causes and equipment failure.

[76] Note, the SST was not applied between 1 July 2017 and 30 June 2019

*Distribution network reliability, SAIFI - CBD*

395. The SSB relating to CBD SAIFI have been achieved each year of the AA4 period except 2020/21. Performance against the CBD SAIFI SST has been lower than the target.

**Figure 5.7: Distribution network reliability, SAIFI - CBD**




396. Reliability performance of the CBD SAIFI has declined in the AA4 period compared to the AA3 period due to a rise in the number of interruptions from feeder circuit breaker trips, resulting in the number of customers interrupted per fault increasing.

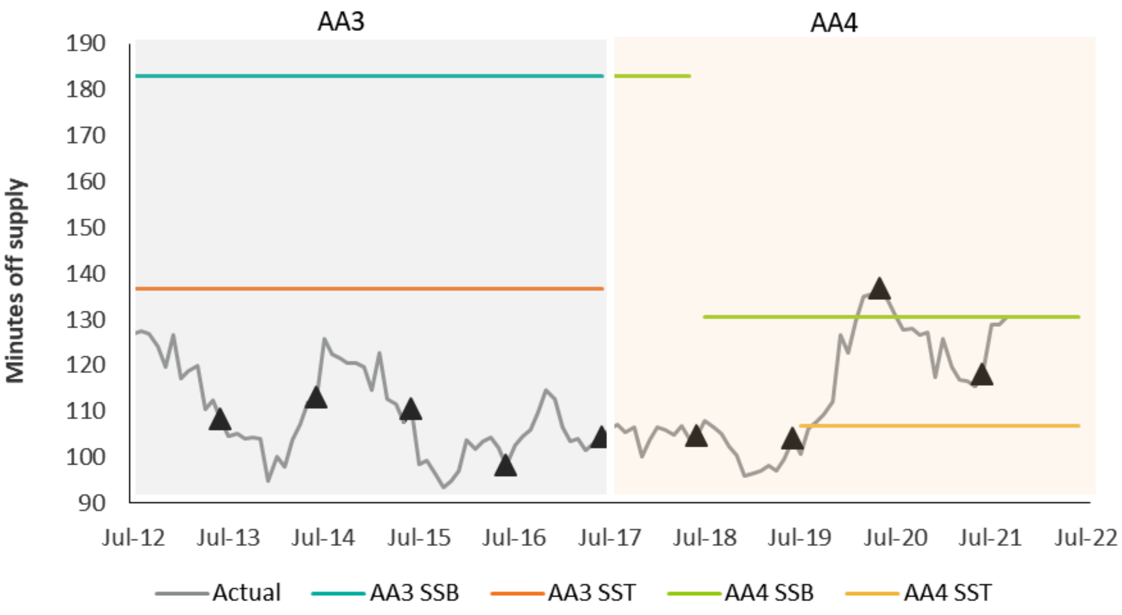
397. The rise in the actual feeder trips is attributed to underground cable failures (directly and indirectly), human error and impacts from tools and machinery (e.g. third parties digging into cables).

398. The rise in the number of interrupted customers per fault is attributed to the ageing CBD network. The CBD is known for its distribution network redundancy, however planned outages to refurbish the CBD zone substations exhaust this redundancy (which diminished the network switching flexibility), causing CBD unplanned outages to affect more customers than they would have otherwise.

*Distribution network reliability, SAIDI - Urban*

399. Western Power improved reliability over the course of the AA3 period for Urban SAIDI and SAIFI performance and this resulted in performance significantly better than the SST level. This trend of improving performance resulted in SSB target levels in the AA4 period that were lower (reflecting improved performance) than both the compliance target (SSB) and the financial target (SST) levels in the AA3 period for both Urban SAIDI and SAIFI.

**Figure 5.8: Distribution network reliability, SAIDI - Urban**




400. Urban feeder performance has been maintained in the first two years of the AA4 period compared to performance at the end of the AA3 period. Urban feeder performance declined in 2019/20 compared to the previous year. The primary contributors to the reduction in performance were faults in underground cables, overhead switchgear, overhead conductor faults, and emergency outages to remove hazards.[77]

401. In anticipation of the reduction in urban feeder performance, immediate network reconfigurations were implemented in the latter part of 2019/20 to minimise the impact of outages on customers. Further network reconfiguration and augmentation is scheduled for 2020/21 and their benefits will be realised in 2022/23.

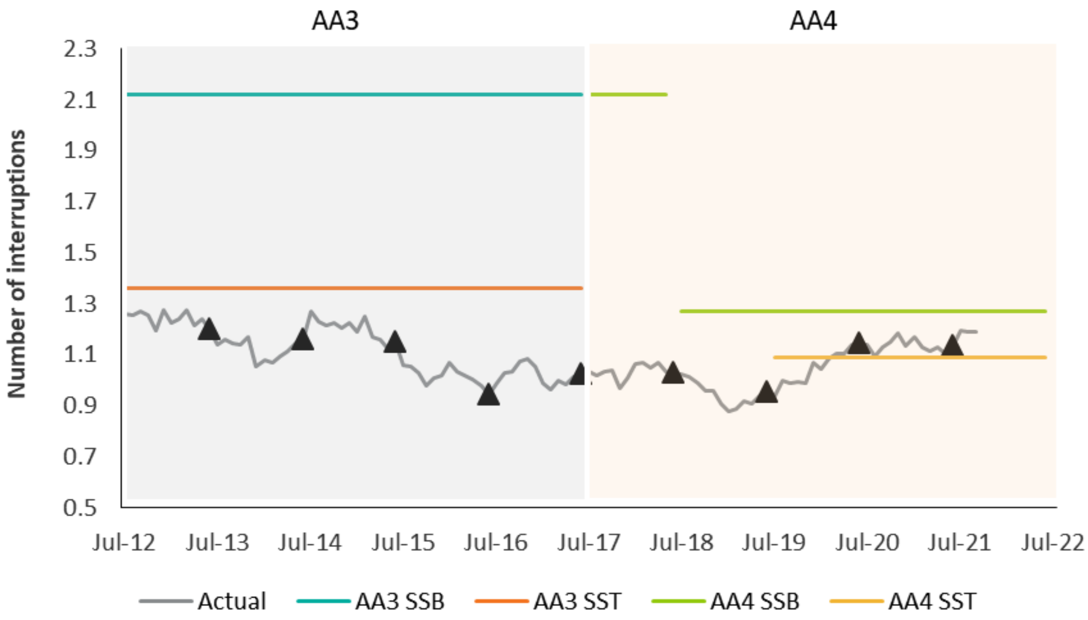
402. The performance improvements that were seen in 2020/21 (where performance improved compared to 2019/20 and the AA4 SSB) were primarily a result of a change in our equipment repair process to increase the speed and operability of automated fault restoration systems.

*Distribution network reliability, SAIFI - Urban*

403. Reliability on urban feeders has been better than the SSB throughout the AA4 period, continuing the trend in improved performance from the AA3 period. The primary contributor to sustained SAIFI performance has been an overall reduction in interruptions attributed to equipment failure.

[77] The root causes of emergency outages to remove hazards includes (but is not limited to) vegetation, equipment failure and third-party impact on the network.

**Figure 5.9: Distribution network reliability, SAIFI - Urban**




### *Distribution network reliability, SAIDI & SAIFI – rural short*

404. Western Power improved reliability over the course of the AA3 period for rural short SAIDI and SAIFI performance and this resulted in performance significantly better than the SST level. This trend of improving performance resulted in SSB target levels in the AA4 period that were substantially lower (reflecting improved performance) than the SSB target levels in the AA3 period for both rural short SAIDI and SAIFI.

**Figure 5.10: Distribution network reliability, SAIDI – rural short**

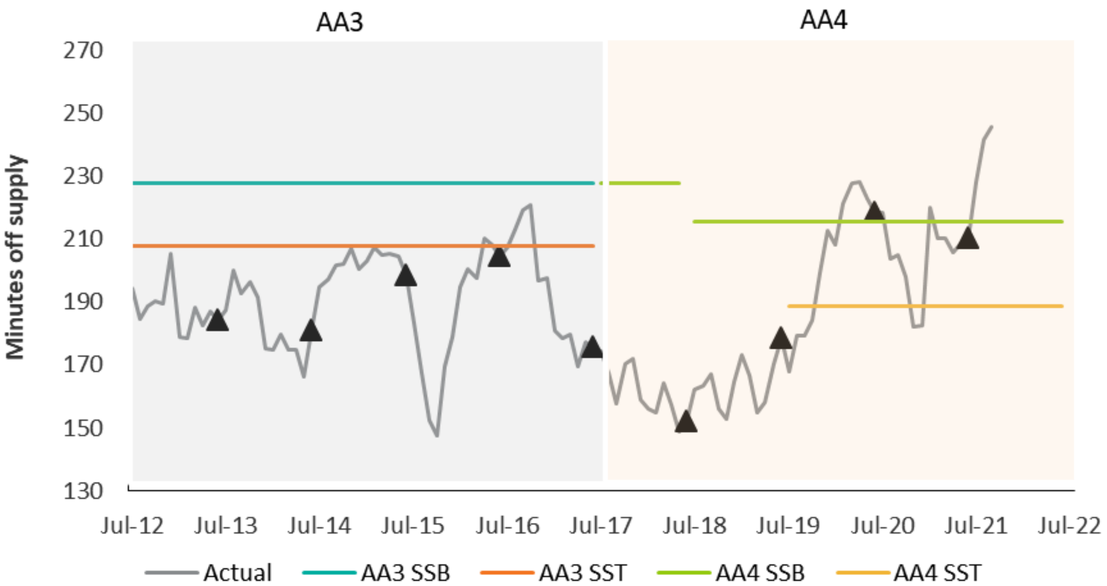
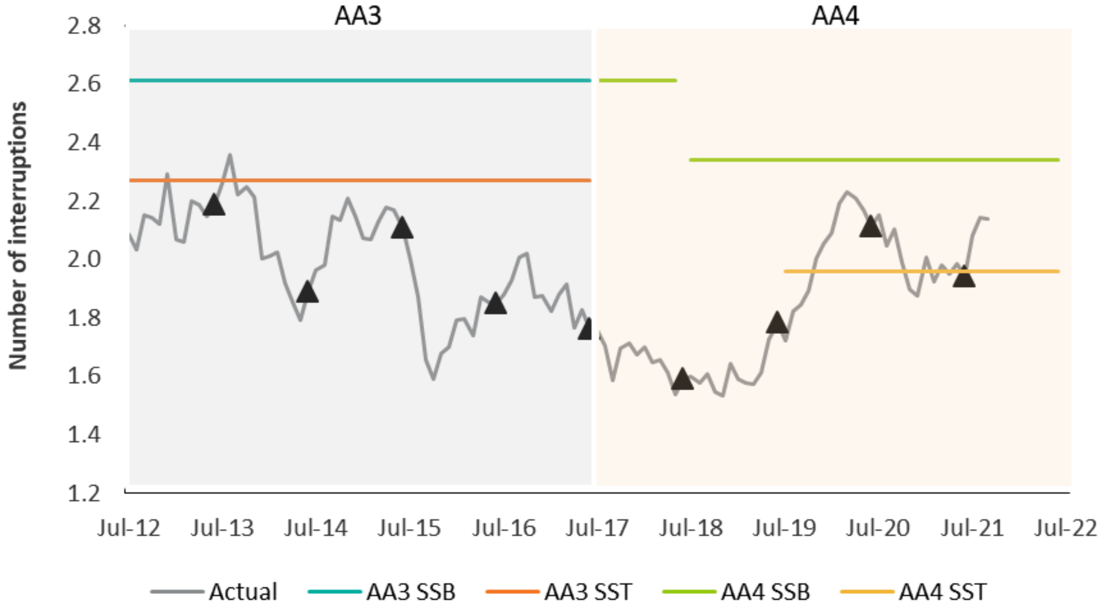


**Figure 5.11: Distribution network reliability, SAIFI – rural short**




405. Reliability on rural short feeders has outperformed the SSB throughout the AA4 period except 2019/20.

406. Rural short feeder performance improved in the first two years of the AA4 period compared to the AA3 period due to reduction of impacts of fauna, vegetation and equipment failure. Rural short feeder performance declined in 2019/20. The primary contributor to the reduction in performance was emergency outages to remove hazards.

407. Western Power responded in anticipation of the SAIDI performance reductions in rural short areas through immediate implementation of network reconfigurations in 2019/20 to minimise the impact of outages on customers and further network reconfiguration and augmentation scheduled for 2020/21, for which benefits will be realised in 2021/22. This was the same approach adopted for urban short areas. The change in our equipment repair process that contributed to SAIDI performance improvements for urban short areas also contributed to visible performance improvements at the end of 2019/20 for rural short areas.

*Distribution network reliability, SAIDI & SAIFI – rural long*

408. Reliability on rural long feeders has been consistently better than the SSB throughout the AA4 period. SAIDI and SAIFI SSB relating to rural long feeders have been achieved each year of AA4.

**Figure 5.12: Distribution network reliability, SAIDI – rural long**

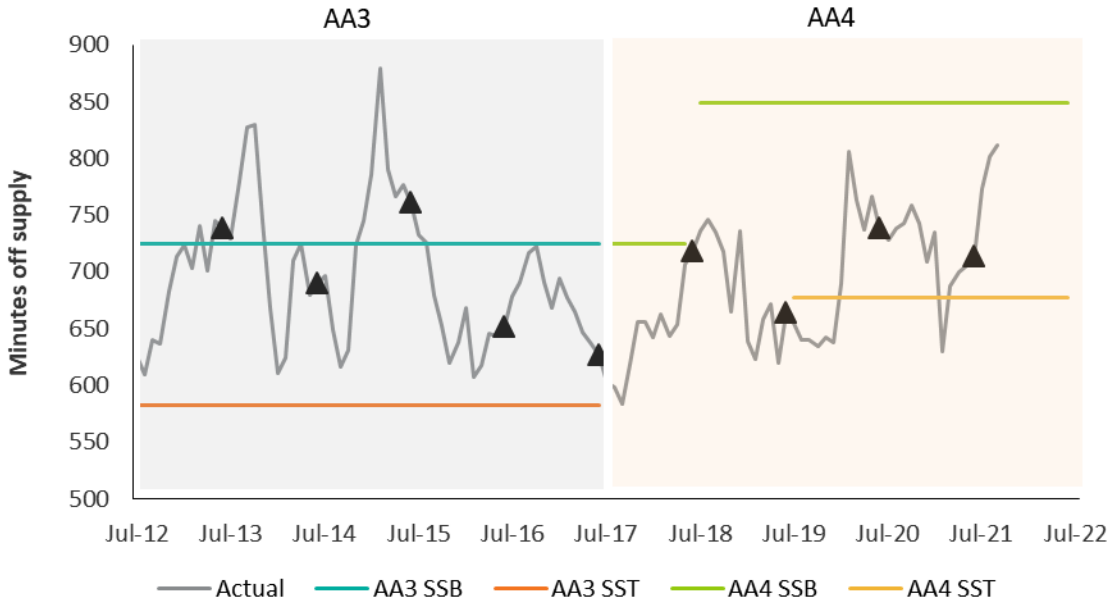
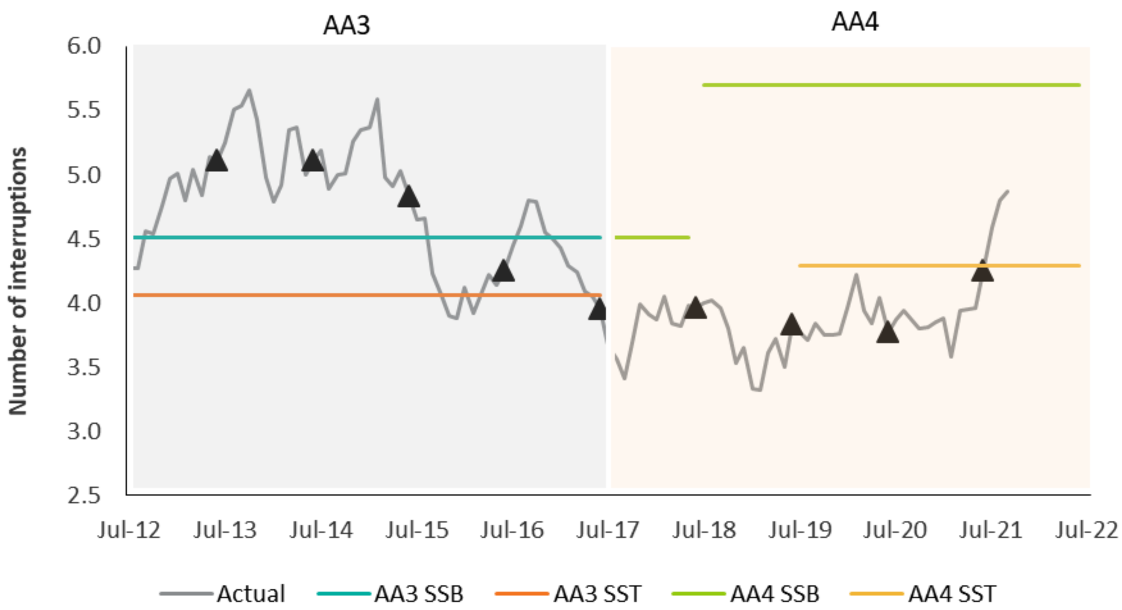



**Figure 5.13: Distribution network reliability, SAIFI – rural long**




409. SAIDI performance has declined against the AA4 SST target and compared to the AA3 period. This is due to increases in inclement weather, emergency outages to remove hazards, overhead equipment failure and ageing network assets. Moreover, feeders in rural areas tend to be more exposed to lightning and incidents of birds and other animals contacting overhead assets than feeders located in urban areas. Rural long feeders also tend to have extensive geographical spread that impacts the time to respond and low levels of redundancy, providing less opportunity to re-route power while repairs are being carried out.

410. Rural long SAIFI performance has improved against the AA4 SST target and compared to the AA3 period due to reductions in unplanned outages and reductions in equipment failure. The performance slightly

declined in 2020/21 compared to 2019/20 due to increases in the interruptions attributed to lightning activity and equipment failure.

411. This improved performance in the AA4 period is due to installation of network microgrids, enhancing the utilisation of automatic restoration on rural long feeders and improving utilisation of high voltage injection units and emergency response generators to reduce outages. We are continuing to implement our long-term strategy to deal with reliability issues on rural long and rural short feeders, including rolling out additional SPS. For example, in the AA4 period, we undertook the following projects to address reliability issues in particular network areas:

- Northampton feeder – investments such as replacement of pole top switches, replacement of fuses, refurbishment of the protection scheme and replacement and removal of sectionalisers to improve the remote operation of the feeder and provide reliability improvements to customers in the area.
- Irwin feeder – works, such as the installation of new or relocation of existing reclosers, replacement of fuses, refurbishment of the protection scheme and removal of redundant overhead line improved the reliability of the Irwin feeder.
- Kalbarri Microgrid – the Kalbarri feeder has been one of the worst performing feeders on the Western Power Network. This project involved the installation of a microgrid to improve supply reliability to Kalbarri town.

412. Detailed commentary on SAIDI and SAIFI performance during the AA4 period, including causes of outages, and remedial activities, is provided in Western Power's 2017/18 to 2019/20 annual Service Standard Performance Reports, available on the ERA's website.

### 5.3.2 Reliability of electricity supply in the transmission network

413. The reliability of the transmission network is monitored in terms of duration and frequency of a supply outage, however, the measures are different to those used on the distribution network. The reliability of the transmission network is monitored in terms of duration and frequency of a supply outage. The duration of outages is measured as average outage duration (**AOD**). The frequency of outages is covered by either:

- the loss of supply event frequency (**LoSEF**) of duration longer than 0.1 system minute but less than or equal to 1 minute, and
- the loss of supply events longer than 1 system minute.

414. Security of supply refers to the availability of the transmission network and is measured by circuit availability.

415. Over the course of the AA3 period, transmission network reliability was maintained, and circuit availability improved, as the capital works program was considerably lower than forecast, primarily due to the flattening of demand growth and with this, a reduced need for capacity expansion. Western Power also commenced its whole of business efficiency review and subsequent Business Transformation Project, which meant a number of proposed work programs were either re-scoped or deferred, therefore overall circuit availability was high.

416. We have maintained the reliability of electricity supply in the transmission network over the course of the AA4 period. Western Power achieved all transmission SSBs in every year.

417. Performance against SSTs was mixed, with net performance over the AA4 period in three out of four transmission measures higher than the target. However, as outlined in section 5.3.1 the changing energy landscape presents increasing risks and challenges to the Western Power Network, including how to manage system low load events and two-way power flows.

*Key strategies and activities*

418. Western Power implemented various routine and targeted activities during the AA4 period to maintain or deliver improvements in the performance of the transmission network. This included:

- routine and targeted maintenance – asset inspection, maintenance programs, and monitoring of assets in conjunction with vegetation management programs, and the replacement of deteriorating and defective assets
- operational response – expedited the restoration of faulted regulated circuits by employing proactive measures such as on-call network switching resources and/or additional resources. In addition, the restoration of supply to customers via the distribution network where possible helps maintain transmission performance within the SSBs.

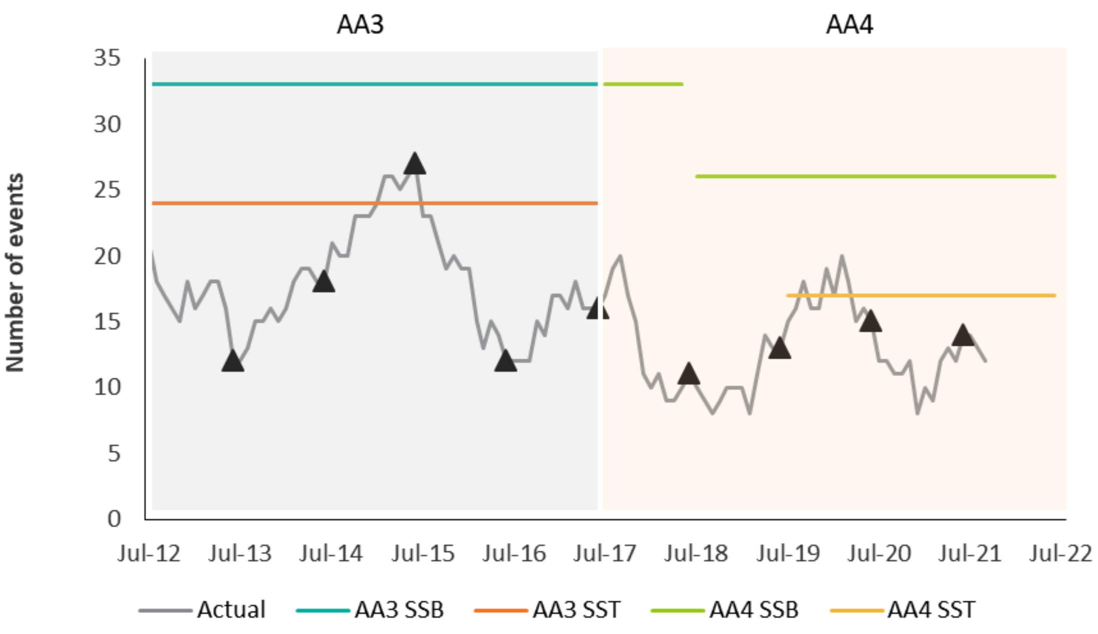
*Reliability performance – transmission*

419. Figure 5.14 to Figure 5.16 shows our performance in relation to the three transmission reliability measures[78]. The black triangle in the figures represents the 12-month rolling average performance for each financial year. A lower number represents an improvement in service for these measures.

*Transmission network reliability, loss of supply event frequency*

420. Western Power improved transmission network reliability over the course of the AA3 period and this resulted in performance significantly better than the SST level. This trend of improving performance resulted in SSB target levels loss of supply event frequency >0.1 and ≤1.0 in the AA4 period that were significantly lower (reflecting improved performance) than the SSB target levels in the AA3 period for loss of supply event frequency >0.1 and ≤1.0.

**Figure 5.14: Transmission network reliability, loss of supply event frequency >0.1 and ≤1.0**




78 2020/21 figures for the LoSEF (>0.1 & <1.0 SMI) and AOD are adjusted due to a data correction identified post the submission to the 2020/21 service standard performance report to the ERA.

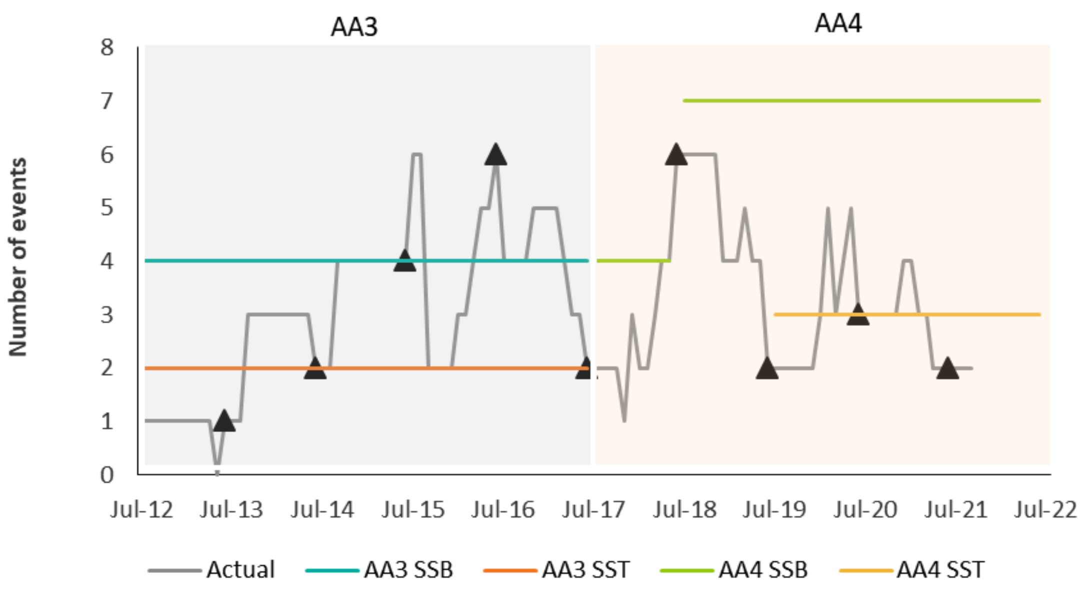
421. The SSB relating to loss of supply event frequency >0.1 and ≤1.0 have been achieved each year of AA4. Performance against the SSTs has also been good.

422. Loss of event supply frequency >0.1 and ≤1.0 performance improved compared to AA3. This was achieved through restoration of customers via the distribution system.

*Transmission network reliability, loss of supply event frequency >1*

423. During the AA3 period, Western Power's performance against the SSB for loss of supply event frequency >1 was generally good. However, the business did not achieve the SSB in 2015/16 due to a transformer tripping at Manjimup (which was caused by water ingress) while the other transformer was out of service due to a planned outage. The overall performance in the AA3 period resulted in SSB and SST target levels in the AA4 period that were higher (reflecting reduced performance) than the SSB target levels in the AA3 period for loss of supply event frequency >1.

**Figure 5.15: Transmission network reliability, loss of supply event frequency >1**




424. The SSB relating to loss of supply event frequency >1 has been achieved each year of the AA4 period. Performance against the SST has been exceeded in the AA4 period.

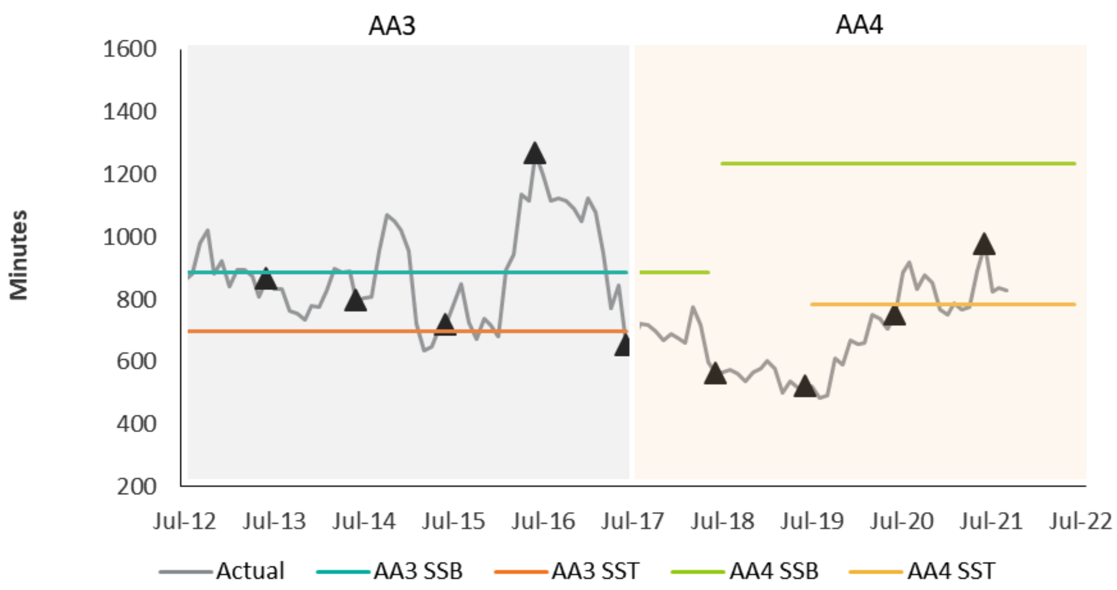
425. Loss of supply event frequency >1 performance in 2017/18 exceeded the AA4 benchmark but declined compared to 2016/17 due to the six events attributed to environmental factors (five events during lightning/thunderstorms) and an asset failure (one event due to distribution equipment defect) in the transmission network. Two of these events were classified as Low Probability – High Impact events whilst one event was a consequence of the protection scheme operating in order to maintain the power system security in a network with large load connected. In addition, there are geographical challenges posed by a long radial network which impact on the time to repair faults.

426. Loss of supply events frequency >1 performance in last three years of the AA4 period improved compared to the AA3 period through restoration of customers via the distribution system.

*Transmission network reliability, average outage duration*

427. Overall, Western Power's transmission reliability, measured by average outage duration, during the AA3 period was good. However, the business did not achieve the SSB in 2015/16 due to transformer failures, as well as a cable failure. The overall performance in the AA3 period resulted in SSB and SST target levels in the AA4 period that were higher (reflecting reduced performance) than the SSB target levels in the AA3 period for average outage duration.

**Figure 5.16: Transmission network reliability, average outage duration**




428. The SSB relating to average outage duration has been achieved each year of the AA4 period. Performance against the average outage duration SST has been higher than the target in three out of four years of the AA4 period. Overall, average outage duration during the AA4 period was lower than the AA3 period, reflecting improved performance.

429. Average outage duration was lower than SSBs and SSTs in the first three years of the AA4 period. This was achieved through priority being placed on the maintenance, inspection and fault management on the regulated circuits. In addition, proactive measures such as on-call network switching resources and/or additional resources were employed to expedite restoration of faulted regulated circuits.

430. Average outage duration performance in 2020/21 exceeded the AA4 SST benchmark but declined compared to the previous year. A number of reasons contributed to the decline in performance, including:

- unavailability of spares and specialized resources due to the impact of COVID-19 supply chain interruptions and national/State border restrictions
- storm activity affecting a number of transmission lines
- environmental clean-up of a transformer oil leak at Southern Terminal
- additional work identified to safely operate the network due to equipment condition.

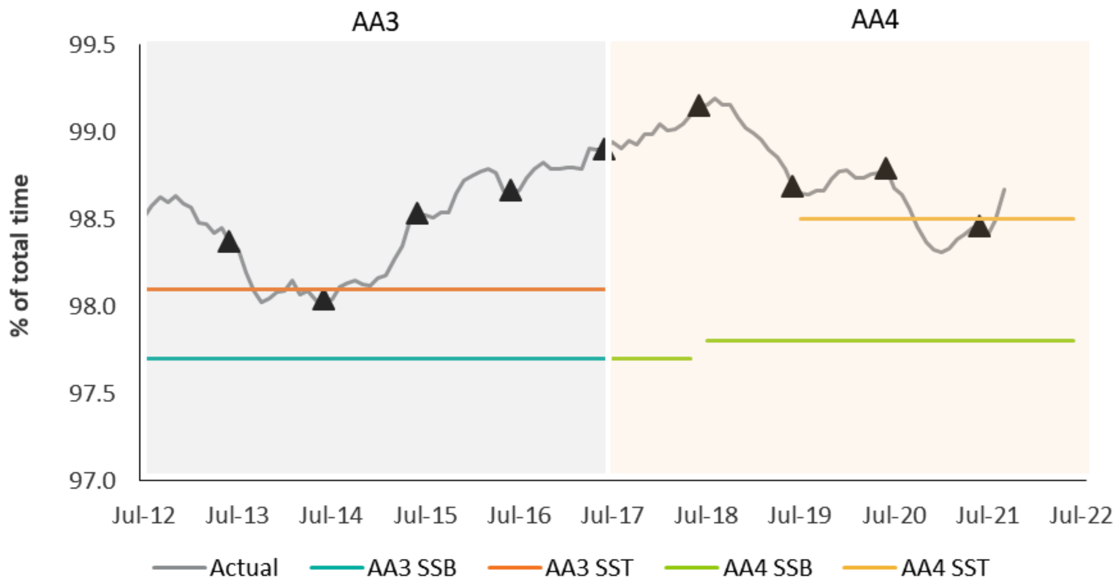
431. Overall, transmission reliability during the AA4 period has been good.

### 5.3.3 Security of electricity supply

432. Security of electricity supply is measured by the percentage of time that transmission circuits are available. The likelihood of an interruption on the transmission network increases when circuits are not available.

433. Figure 5.17 shows Western Power's performance in relation to circuit availability. A higher number represents an improvement in service for this measure.

**Figure 5.17: Transmission network security, circuit availability**




434. Western Power improved circuit availability over the course of the AA3 period and this resulted in performance significantly better than the SST level. This trend of improving performance resulted in SSB and SST target levels in the AA4 period that were higher (reflecting improved performance) than the SSB and SST target levels in the AA3 period.

435. During the AA4 period, circuit availability exceeded the AA4 SSB. Circuit availability exceeded the AA4 SST every year except 2020/21. Overall, compared to the AA3 period, circuit availability was higher during the AA4 period.

436. Circuit availability is directly related to the capital works program as more planned outages of transmission circuits are required to deliver the work, which results in lower circuit availability. Circuit availability was higher than SSBs and SSTs in the first three years of the AA4 period due to improved maintenance planning and coordination across planned outages that results in planned outages which address multiple needs and minimise the outage duration.

437. The slight decline in circuit availability in 2020/21 below the SST (though still higher than the SSB) was a result of extended planned outages due to inclement weather events and a major forced outage involving a terminal transformer that was unavailable for 319 days.

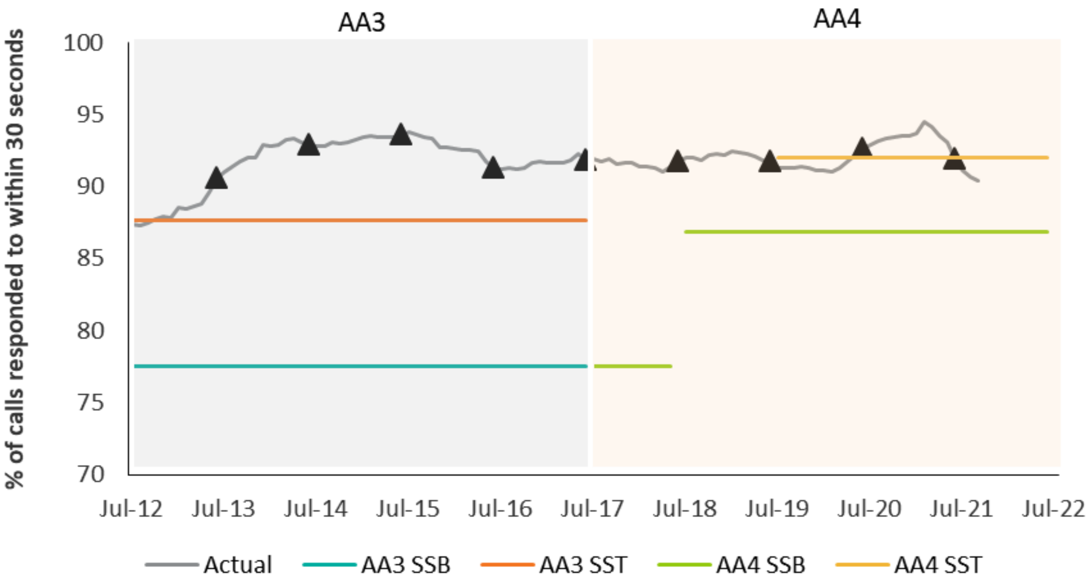
### 5.3.4 Customer service

*Call centre*

438. Western Power's call centre performance has improved and is above the SSB in the AA4 period. We receive approximately two million calls from our customers each year and we respond to at least 90 per cent of these calls within 30 seconds. Western Power customers are demanding a greater use of digital communication channels, such as virtual assistants, social media and via the website.

439. Figure 5.18 shows our call centre performance over the AA4 period. A higher number represents an improvement in service for this measure.

**Figure 5.18: Call centre, percentage of calls responded in <30 seconds**




440. Western Power improved call centre performance over the course of the AA3 period and this resulted in performance significantly better than the SST level. This trend of improving performance resulted in SSB and SST target levels in the AA4 period that were significantly higher (reflecting improved performance) than the SSB and SST target levels in the AA3 period.

441. Western Power's call centre performance has improved in the AA4 period compared to the AA3 period due to a new Customer Management System, and greater use by our customers of communication channels such as social media and Western Power's website for self-service information about outages.

442. Our ability to respond to customer calls was supported by increasing the number of reserve call centre staff that were available for extreme climate events and better use of our automated systems and alerts. Whilst customers are now interacting more through online channels, we have not seen an equivalent drop off in telephone calls.

443. Our aim is to meet the customer's demand for better access to online channels and self-service customer interaction and reducing the reliance on the traditional telephone calls interaction.

444. A slight decline in our call centre performance in 2020/21 compared to previous years (though still better than the AA4 SSB) was due to an isolated technical issue related to an IT upgrade of the automated systems used to keep customers informed during power outages. This issue was quickly resolved.

### *Street light repair times*

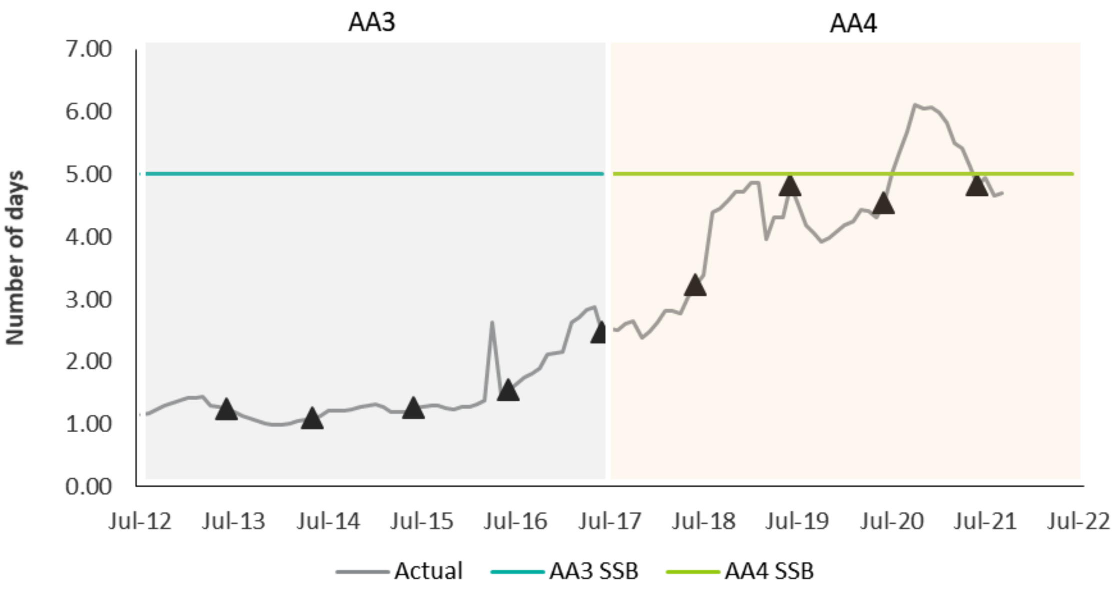
445. Western Power is required to repair any faulty street light within the following regulated periods of the fault being reported or detected:

- five business days (on average) in the metropolitan area
- nine days (on average) in remote and regional areas.

446. Street light repair times have met the SSB for the majority of the AA4 period.[79] This is a result of our proactive street light globe replacement program, which commenced during the AA2 period and continued until 2014/15. As part of Western Power's business review, in 2015/16 the street light repair approach was re-evaluated and changed to a predominantly reactive replacement approach managed by Western Power internal crews. Dedicated streetlight crews manage streetlights within the metropolitan area, supported by maintenance crews. Regional streetlights are managed by maintenance teams (given the lower volume of streetlights in these areas), who balance meeting the streetlight SSB with other maintenance and emergency repair work. This change has helped reduce street light repair costs, while still meeting the regulatory repair targets.

447. Figure 5.19 and Figure 5.20 show our streetlight repair time performance over the AA3 and AA4 period[80]. A lower number represents an improvement in service for this measure.

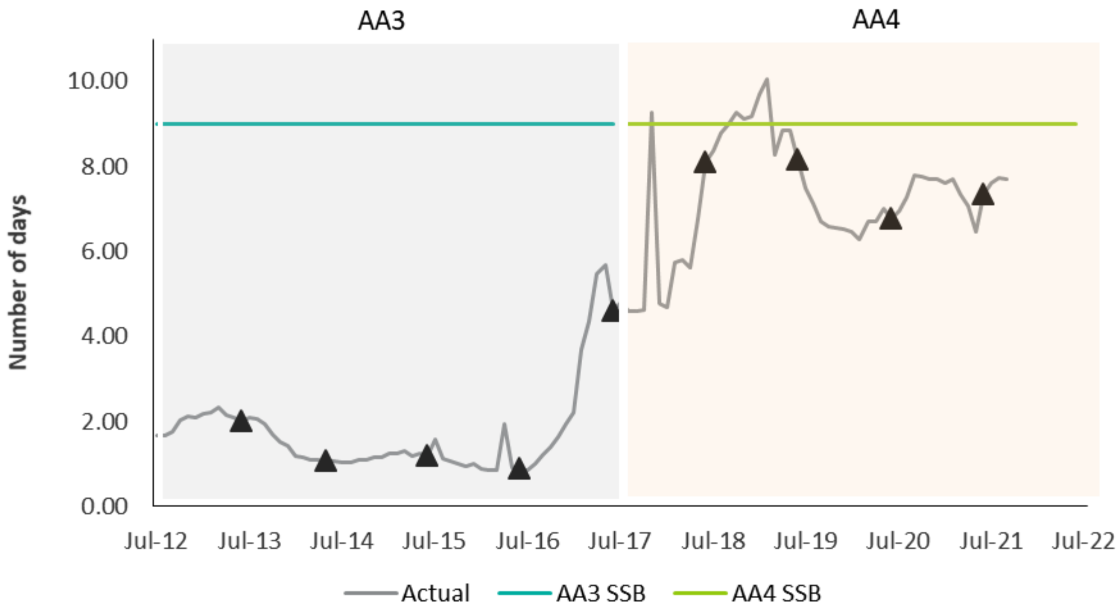
**Figure 5.19: Street lights, metropolitan repair times**




79 Note street light repair times do not feature in the SSAM and therefore have no financial rewards and penalties attributed to performance.

80 2017/18 figures for Streetlights in Metropolitan area and regional area are adjusted post the submission to the 2020/21 service standard performance report to the ERA due to changes to the reporting system in 2019 which resulted in minor data corrections.

**Figure 5.20: Street lights, regional repair times**

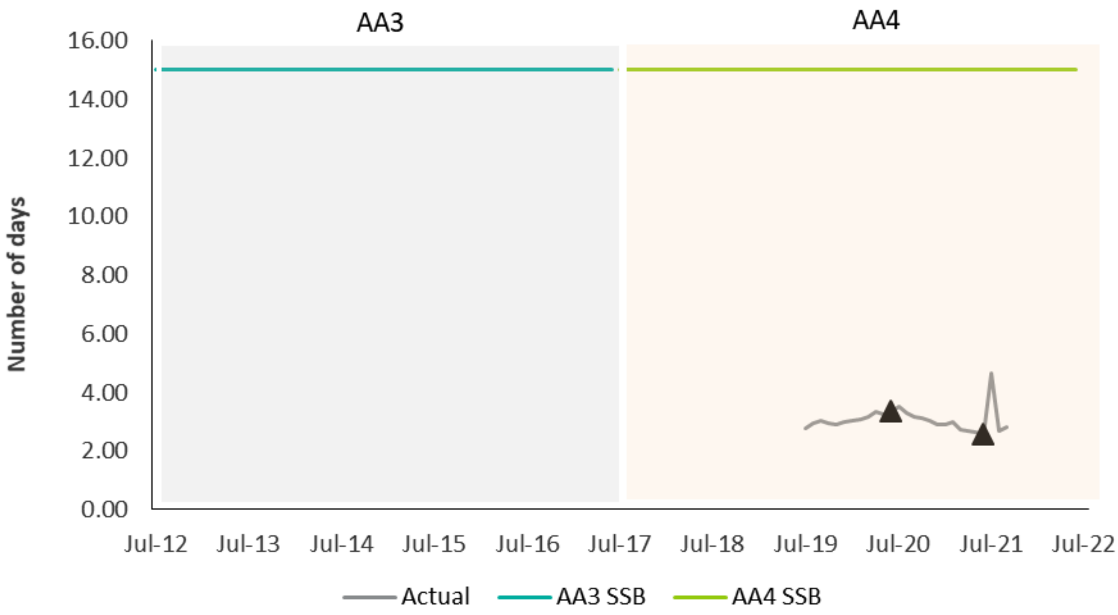



448. Street light repair times was within the AA4 benchmark of 5 business days for metropolitan and 9 business day for regional but declined compared to the AA3 period due to periods of time where streetlighting resources were reallocated to attend to business-wide emergency event response, such as safety and emergency repair work from weather events and bushfire events.

### *Ancillary services*

449. The supply abolishment reference service and service standard benchmark was introduced for the AA4 period. The supply abolishment benchmark was reported by Western Power for the first time in 2019/20. The average performance exceeded the AA4 benchmark of 15 business days. The average performance was 2.5 business days in 2020/21 compared to 3.4 business days in 2019/20 period (see Figure 5.21). Previously, the service was provided under our metering model service level agreement. Review of operational arrangements during the AA4 period contributed to performance that exceeded the SSB during the period.

**Figure 5.21: Supply abolishment, repair times**




450. For reference service D10, the SSB for a streetlight LED replacement requested by the user is to be completed as soon as reasonably practicable in accordance with good electricity industry practice. During the AA4 period, Western Power was not requested to perform this service.

451. Metering remote de-energise and remote re-energise SSBs were not reported on in 2020/21. These services are currently unavailable, however are expected to be available in the third quarter of the 2021/22 period.

### 5.3.5 Safety performance

452. Safety performance has been maintained throughout the AA4 period. Safety performance is predominantly measured in two key dimensions of electric shock and fire incidents due to the Western Power Network:

- electric shocks have decreased from an annual average of 206 in the AA3 period to 158 in the AA4 period. This is mainly due to the rollout of the Service Connection Condition Monitoring program and ongoing maintenance programs. Public awareness campaigns have contributed to an upwards trend in the number of electric shocks reported in the second half of the AA4 period, however, no increase in injuries was observed (see Figure 5.23).
- ground fires have increased from an annual average 117 in the AA3 period to 162 in the AA4 period. This is mainly due to increases in pole top fire events. Ground fires can lead to injury from burning and smoke inhalation as well as environmental impacts on native flora and fauna. Most of these fires are minor, in low or moderate fire risk zones and do not cause significant damage or injury. Fires caused by Western Power assets represent less than 2.5 per cent of the total number of fires recorded in WA each year.[81] Strategies to mitigate pole top fires have been revised to respond to the upwards trend (see Figure 5.22)

81 On average there are approximately 4,000 vegetation fires within the area covered by the Western Power network. DFES, Vegetation Fires 2000-2016 report

**Figure 5.22: Ground fire incidents**

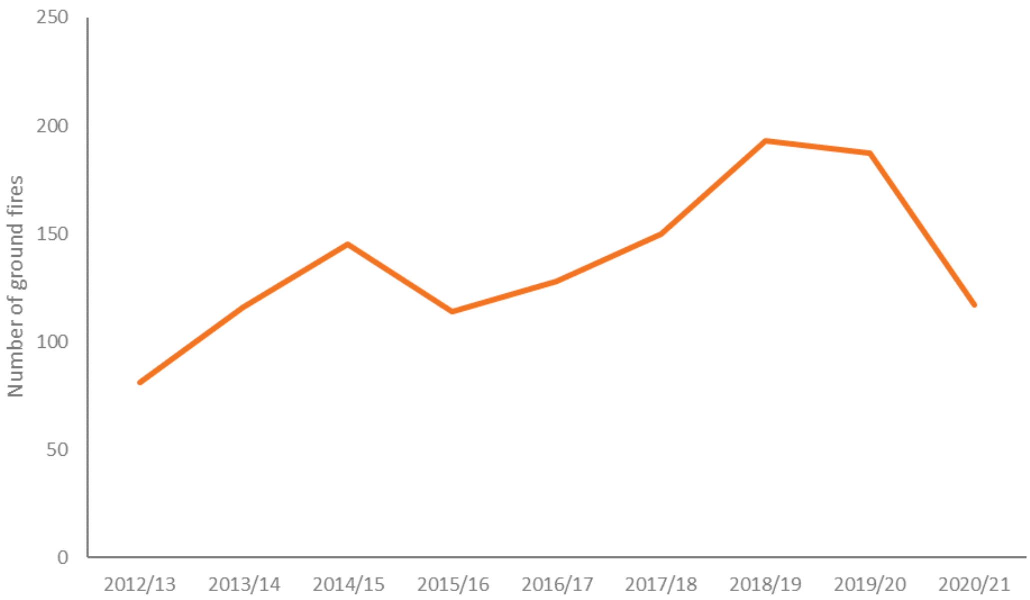
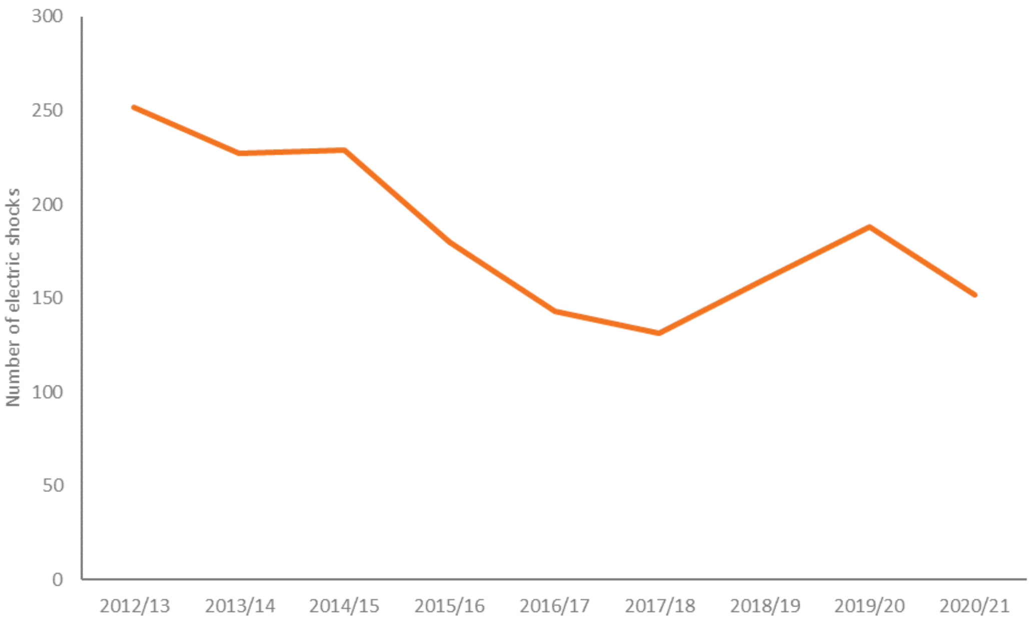



**Figure 5.23: Electric shock incidents**




453. Western Power also measures as indicators of safety performance both public impact incidents and workforce total recordable injury frequency:

- public impact incidents reduced from an average of 0.3 per month in 2016/17 to 0.0 in 2020/21 (see Figure 5.24)
- we have maintained a consistent level of performance measured by our total recordable injury frequency rate (**TRIFR**) (see Figure 5.25).

**Figure 5.24: Public impacts incidents**

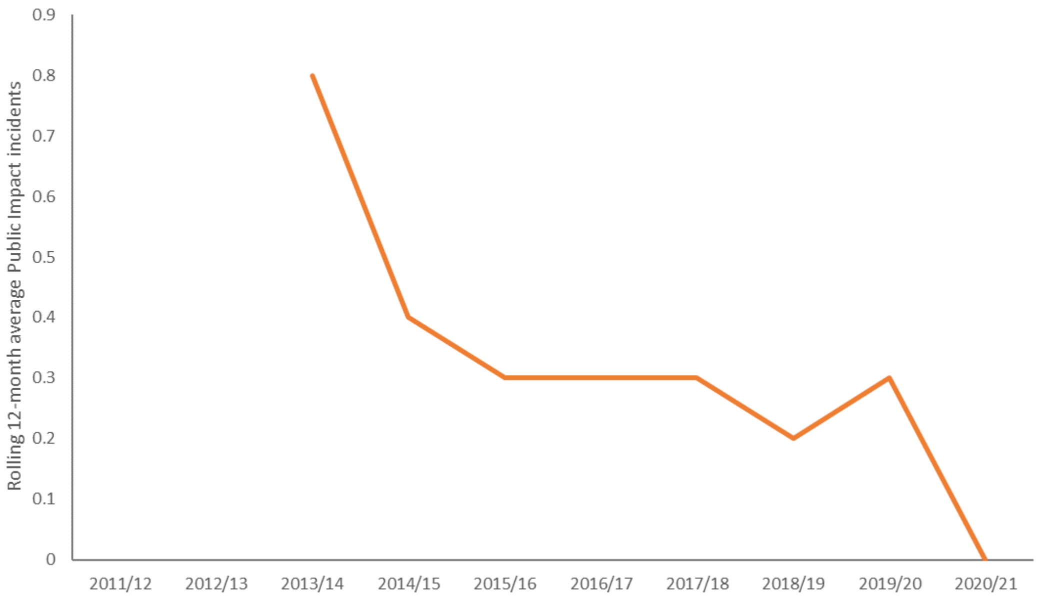
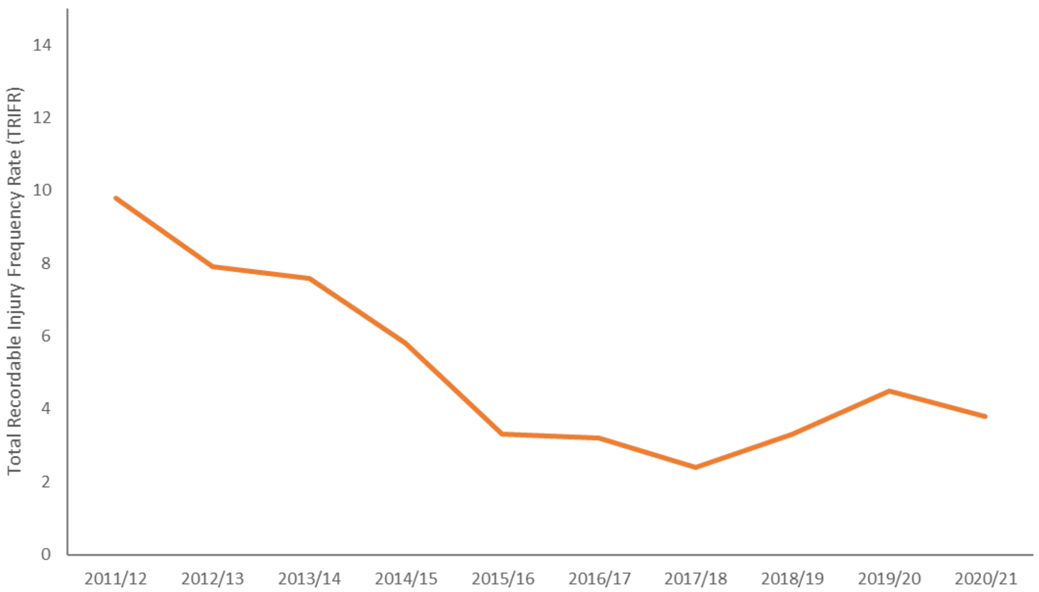



**Figure 5.25: Total recordable injury frequency rate**




454. Owing to inherent risks, Western Power has an obligation to keep the community safe around electricity. We manage our broader public impact through various education and communications campaigns:

- **360 Aware – GamePlan Campaign:** Our 360 Aware is a public safety awareness campaign aimed at third parties that work around the network, educating them on the potential danger of working in proximity to electricity. The campaign emphasises how important it is for people to be aware of their surroundings before undertaking work close to electricity, and how to develop a game plan for safety and what to do if accidental contact with electricity occurs.

  Our successful GamePlan campaign encourages an 'elite athlete mindset' in workplaces and this year promoted our 360 Aware online training tool to educate and support businesses. Available for free, the tool features interactive videos and activities to educate users about what is required to work safely near the network. Users can generate a certificate upon completion.

This year we further developed our GamePlan digital campaign with the addition of a series of 'Rituals' advertisements – online videos featuring the individual daily rituals a tradie might undertake before work. It encourages everyone to consider adding electricity to their daily rituals to avoid injury risks, asset damage or unnecessary outages.

- **Make the Safe Call Campaign:** The Make the Safe Call campaign specifically aims to educate the broader West Australian community about the dangers of electricity and what actions to take to keep safe. The campaign is targeted to all those who live and work in the Western Power Network area.

  This year our new look Make the Safe Call campaign told the stories of characters Jan and Jim and their powerline mishaps. It was designed to provide both a clear course of action and sense of calm and control for people who find themselves in potential danger from an electrical emergency.

  In all campaign scenarios, messaging reinforces that Western Power will provide help and should be contacted. This simple message is further explored through online campaign content that explains how the community can avoid these situations by tying down loose items before a storm, hiring a professional to cut down trees and planting away from powerlines to ensure the safety of individuals and the community.

- **Shocks and Tingles:** Throughout 2020 Western Power partnered with Horizon Power and the Department of Mines, Industry Regulation and Safety's Building and Energy division to deliver a State-wide safety campaign to educate the public on how to respond if they experience an electrical shock or tingle at home.

  The campaign highlighted that Western Power was the priority point of call for all electrical incidents and emergencies within the home. It provided education on the most likely causes of shocks and tingles, and how to take the necessary steps to keep safe.

  The campaign resulted in an incredible 278 per cent increase in reports of shocks and tingles during the campaign period. While 44 per cent of these reported incidents were not assessed to have been caused by hazardous voltage, it was encouraging to see that this important message resonated with our customers, and they knew to call Western Power when an incident occurred.

455. In accordance with our strategic plan, our Safety Maturity Strategy has shifted its focus from 'Engage and Empower' to 'Critical Risks and Fatality Prevention'. In 2021 we kicked off our Work Health and Safety Critical Risk Management workshops where, through consultation with our employees, we are working to establish a very clear and consistent understanding of the top 16 critical risks they face, and the controls required to protect them. As we move through the process, we will be updating and refining our Golden Safety Rules to include these and provide clarity around the performance requirements of the associated critical controls.

456. In the AA4 period we commenced delivery of three key modules from our Safety Leadership Program with the objective to upskill our leaders in safety leadership essentials and fundamental work health and safety risk assessment requirements, including both physical and psychological risk. These courses will continue to be delivered until all busines leaders, from our operational Team Coordinators to our Heads of Function have been trained.

457. Creating a healthy workplace is something we consider a vital investment for our people. The safety changes and leadership training will also support Western Power's response to the new WA Government safety harmonisation laws that will come into effect in the new future. In May 2021 we were recognised for our efforts by Healthier Workplace WA who has awarded us with Gold Recognition. Gold Recognition is for workplaces leading the way and demonstrating strong and ongoing health and wellbeing policies, infrastructure that encourages healthy behaviour, and education and awareness.

458. For us that encompasses:

- our Health and Wellbeing program with dedicated resources within Safety, Environment, Quality & Training (**SEQT**) delivering the program
- our facilities (e.g. end of trip facilities) through Property & Fleet to support mental and physical health and wellbeing
- executive endorsement and an executive sponsor.

459. The Program has created and will continue to maintain a workplace where recognising and strengthening the preventative side of mental and physical health outcomes is as important as being prepared to support those who are suffering from ill-health and injury.

# 6. Services and service standards

460. This chapter lists the reference services to be delivered by Western Power in the AA5 period. This chapter also provides an overview of Western Power's service standards proposed for the AA5 period including an explanation for any changes proposed by Western Power or arising from the Access Code changes and the ERA's framework and approach.

**Key Messages**

- For the AA5 period, we have introduced new reference services to improve the efficient use of the network, limit increases in future costs, and support integration of new technologies and services
- We are retaining our service standard benchmarks measures consistent with the AA4 period, except transmission circuit availability as it is not a measure of service experienced by our customers. We have also altered the method for measuring reliability of supply, (i.e. the duration and frequency of outages), to better reflect the specific service received by our transmission-connected customers and distribution-connected customers.
- Our service standard adjustment mechanism targets have been revised using the same methodology as the AA4 period to reflect the most recent actual performance and the most recent estimate of the value customers place on reliability. However, we will no longer include a call centre performance target because there is no support from customers to pay more to deliver a higher level of performance than the minimum standard. The target for receiving a financial benefit would increase in the AA5 period compared to the AA4 period.
- Consistent with the ERA's framework and approach, financial incentives (and penalties) under the scheme will be lower in the AA5 period due to lower values of customer reliability and limits on revenue at risk. The effect is a lower powered incentive regime which is consistent with customer views that improvements to services are not a priority.

## 6.1 Overview of services and service standards proposal

461. The Energy Transformation Strategy included changes to the regulatory framework to improve the access arrangement process. The Access Code was amended in September 2020 to require that, prior to Western Power submitting the AA5 proposal, the ERA must produce a framework and approach document, which sets out the ERA's decision on various matters, including classification of services, SSAM and method for setting SSBs.[82] The intent of the framework and approach process is to facilitate early public consultation and stakeholder agreement on these matters.

462. The ERA's Final Decision on the framework and approach[83] sets out its decision to:

- retain the current reference services with some amendments
- retain the current method for calculating the loss of supply event frequency, average outage duration, SAIDI, SAIFI and call centre performance service standard benchmark levels, with adjustments to these levels if appropriate
- make changes to specific measures for service standard benchmarks
- retain the current service standard adjustment mechanism with amendments to how the rewards and penalties are calculated.

82 Subchapter 4.A, Electricity Networks Access Code 2004.

83 ERA, Framework and approach for Western power's fifth access arrangement review, Final Decision, 9 August 2021.

463. Western Power's AA5 proposal is consistent with the decisions set out in the ERA's framework and approach, apart from the approach to setting call centre service standard benchmarks and removing the related service standard target. The proposed changes to the services and service standards for the AA5 period are listed in Figure 6.1.

**Figure 6.1: Summary of the proposed changes to the services and service standards for the AA5 period**

**Services**

Introduced 18 new reference services designed to:

- deliver price signals to customers about the most efficient times to use the network, give customers greater control over their electricity bills, and help Western Power mitigate the need for costly capital investment to address significant peaks or lows
- support new technologies, including services for transmission connected batteries, distribution connected batteries, and electric vehicle charging stations.

**Service standard benchmarks**

- Removed circuit availability measure as a service standard benchmark
- Included transmission unplanned outages affecting distribution connected customers in SAIDI and SAIFI
- Included transmission service standards to measure impact on transmission reference service customers
- Removed force majeure exclusion from the SAIDI and SAIFI service standards
- Maintained the AA4 call centre service standard benchmark target in the AA5 period
- Added a new clause to the SAIDI and SAIFI service standards to exclude load interruptions caused or extended by a total fire ban or direction from a local or state government body or state or federal emergency services, provided that a fault in, or the operation of the network did not cause, in whole or in part, the event giving rise to the direction
- Commenced preparation for a new service standard based on the market impact component of the AER's service standard performance incentive scheme.

**Service standard adjustment mechanism**

- Set service standards targets at the average annual performance (financial year) achieved in the AA4 period, adjusted where individual penalty caps applied during the AA4 period
- Removed call centre SST, and retained the SSB to align with customer sentiments to keep levels of performance at industry levels and focus improvements on digital service offerings
- Included the relevant changes to the method for calculating service standard benchmarks in the service standard adjustment mechanism
- Based rewards and penalties for SAIDI and SAIFI on the latest Value of Customer Reliability report prepared by the AER
- Based rewards and penalties for transmission service standards on the revenue attributable to customers connected to the transmission network and receiving reference services
- Removed the individual caps on penalties
- Set the overall caps for rewards and penalties at one per cent of target revenue.

464. Western Power's service standard performance in the AA4 period is discussed in Chapter 5, and the associated adjustments to target revenue are discussed in Chapter 11.

### 6.1.1 Services

465. Western Power offered 61 reference services in the AA4 period across distribution services, transmission services and street light services. These included:

- 17 exit services
- 3 entry services
- 15 bi-directional services
- 10 ancillary services
- 16 metering services.

466. Western Power will retain most of the same reference services as provided during the AA4 period, with some changes. We are consolidating six current services into two new services and are providing 16 new reference services, consistent with the ERA's Final Decision on the framework and approach.

467. As the energy landscape is transforming and uptake of DER is increasing, new reference services are needed for transmission connected batteries, distribution connected batteries, and EV charging stations.

468. These new services are also designed to deliver price signals to customers about the most efficient times to use the network, give customers greater control over their electricity bills and help Western Power to mitigate the need for capital investment to address significant peaks or lows in customers' electricity use.

469. We will provide 16 transitional time of use services. Western Power's intention, which is consistent with our approach in previous access arrangements, is to continue providing existing users with these transitional services where they request them if:

- the services were provided at the relevant connection points at the date the AA5 period takes effect, and
- those services continue from the AA5 period effective date.

However, from the AA5 period effective date, the current (transitional) time of use services will be closed for new nominations.

470. The transitional, consolidated, and new services are listed below.

471. Western Power will provide two new reference services at exit points:

- Super off-peak energy (residential) exit service
- Super off-peak energy (business) exit service.

472. Western Power will provide seven new reference services at bi-directional points:

- Super off-peak energy (residential) bi-directional service
- Super off-peak energy (business) bi-directional service
- Low Voltage distribution storage service
- High Voltage distribution storage service
- Transmission storage service
- Low Voltage Electric Vehicle (EV) charging service
- High Voltage Electric Vehicle (EV) charging service.

473. Western Power will provide three new and two consolidated reference services at connection points (ancillary):

- Capacity allocation service (consolidating four capacity allocation services provided during the AA4 period to simplify administrative arrangements)
  - The capacity allocation services removed are:
    - Capacity allocation swap (nominator) (business) service
    - Capacity allocation swap (nominee) (business) service
    - Capacity allocation same connection point (nominator) (business) service
    - Capacity allocation same connection point (nominee) (business) service
- Remote load/inverter control service (consolidating two load control/limitation services provided during the AA4 period)
  - The load control/limitation services removed are:
    - Remote direct load control service
    - Remote load limitation service
- Site visit to support remote re-energise service[84]
- Manual de-energise service
- Manual re-energise service.

474. Western Power will provide four new standard metering services as reference services:

- Unidirectional, interval, weekly, manual
- Unidirectional, interval, weekly, remote
- Bidirectional, interval, weekly, manual
- Bidirectional, interval, weekly, remote.

475. The tariffs associated with these new services are discussed in Chapter 12.

### 6.1.2 Service standards

476. The service standard framework establishes a minimum average level of service that customers should expect from a network business providing reference services. The framework also includes an incentive regime designed to promote cost efficiencies, without compromising the level of service, through financial rewards and penalties.

477. The measure of a network business's service levels is typically determined in relation to:

- **reliability of supply:** the frequency and duration of network interruptions and provision of services experienced by customers
- **security of supply:** the ability of the network to withstand events without interrupting supply to customers
- **quality of supply:** the characteristics of the supply including such things as voltage changes and harmonic distortions

84 This service is proposed to complement the remote re-energise service, for circumstances where the controller/end-use customer requires on-site support to commence the flow of electricity behind a connection point.

- **customer service:** how well the business engages with customers in relation to the non-technical services including, for example, call centre performance, and timely streetlight repairs.

478. The ERA's Final Decision on the framework and approach determined the method for setting SSBs, which retained the current method for calculating the benchmarks. It also made some changes to the service standard framework for the AA5 period, including:

- changes to the definitions of distribution and transmission SSBs including the removal of the force majeure event exclusion and the inclusion of transmission unplanned outages affecting distribution connected customers in the outage duration and frequency measures (SAIDI and SAIFI).
- amendments to the current SSAM, including:
  - the removal of individual caps on the penalties
  - for the distribution network measures, setting the combined cap for rewards and penalties at one per cent (symmetrical) of the total revenue applicable to reference service customers connected to the distribution network
  - for the transmission network measures, maintaining the combined cap for rewards and penalties at one per cent of the total revenue applicable to reference service customers connected to the transmission network

479. Western Power's AA5 proposal is consistent with the ERA's Final Decision on the framework and approach on the service standards framework, with the exception of proposed departures for call centre performance to align with our customer preferences for call centre performance and affordability. Western Power validated this customer preference through our CEP after the ERA's Final Decision on the framework and approach was released. The changing customer preference for the method of communication with Western Power and level of call centre performance is a material change in circumstance that supports the departure from the framework and approach, and is allowed for under the Access Code clause 4.A11[85].

480. We propose to maintain the AA4 call centre SSB and remove the SST in the AA5 period, with the aim of meeting customer preferences for more digital communication without incurring additional cost to them. This is in response to customers' evolving preferences in how they communicate with us and what we heard in our CEP after the ERA's Final Decision on the framework and approach, described in Chapter 4. The proposed approach allows us to explore new ways of communicating with our customers, with the intent of gathering data during the AA5 period to set relevant customer service performance standards in the future. It also ensures we are keeping our investment levels in line with what customers value in terms of customer service delivery.

481. In summary, the service incentive framework proposed for the AA5 period is designed to provide an incentive for Western Power to maintain overall performance at the current levels that our customers have experienced during the AA4 period[86]. This will reflect the reliability performance customers have received over the past five years of the AA4 period. Western Power's proposed investment during the AA5 period is to maintain performance to the service standard benchmarks and targets proposed for the AA5 period, and we will not specifically invest to raise overall service standard performance as our customers have told us

[85] *Electricity Networks Access Code*, clause *4.A11 "Any proposed access arrangement or proposed revisions submitted by a service provider to the Authority must be consistent with the framework and approach that applies to it. The service provider may propose departures from the framework and approach if there has been a material change in circumstances in which case it must provide reasons for the departure."*

[86] With the exception of call centre performance, which Western Power propose to maintain performance at the AA4 target levels based on what customers value and have provided in customer feedback

they do not consider it necessary.[87] As such, there have been no proposed adjustments to the AA5 service standard benchmarks or targets, with the exception of call centre performance, as the proposed AA5 investment is to maintain performance.

482. Finally, we have retained the AA4 methodology for setting the financial incentive rates for the SSAM, with updates to reflect a more contemporary estimate of the value to customers of a reliable supply of electricity, consistent with the ERA's Final Decision on the framework and approach. [88] We have used the most recent available estimates of the value of customers reliability (**VCR**) from the Value of Customer Reliability Report[89] prepared by the AER in December 2019 to estimate suitable values for our customers. Overall, this has resulted in lower financial incentive rates than those applied in the AA4 period. This will result in lower rewards and penalties for the same change in performance relative to the AA4 period.

## 6.2 Regulatory framework

### 6.2.1 Minimum service standards – regulatory requirements

483. The Access Code requires Western Power to include in its access arrangement SSBs as follows:

> *5.1 An access arrangement must:*
>
> *…*
>
> *(c) include service standard benchmarks under section 5.6 for each reference service*
>
> *5.6 A service standard benchmark 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.*

484. Western Power must provide services to its customers that at least meet the SSBs in accordance with section 11.1 of the Access Code and report its performance against the SSBs to the ERA annually.

> *11.1 A service provider must provide reference services at a service standard at least equivalent to the service standard benchmarks set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract.*
>
> *11.2 The Authority must monitor and, at least once each year, publish a service provider's actual service standard performance against the service standard benchmarks.*

### 6.2.2 Service standard adjustment mechanism – regulatory requirements

485. Section 6.30 of the Access Code requires Western Power's access arrangement to contain a SSAM. Sections 6.29 to 6.31 of the Access Code provides the following in relation to the SSAM:

> *6.29 A "service standards adjustment mechanism" is a mechanism in an access arrangement detailing how the service provider's performance during the access arrangement period*

87 Customers have told us they are generally satisfied with current levels of reliability performance, and do not necessarily want Western Power to make further investment to improve service. Customers in regional areas value improvement in reliability performance but this needs to be balanced with keeping prices low. There are areas of the network that perform more poorly than others, and Western Power will target improvement in these areas, recognising that there is little appetite among our customers for Western Power to invest more to raise overall service levels.

88 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final decision*, 9 August 2021, pg. 49

89 AER, *Values of Customer Reliability, Final report on VCR values*, December 2019

*against the service standard benchmarks is to be treated by the Authority at the next access arrangement review.*

*6.30 An access arrangement must contain a service standards adjustment mechanism.*

*6.31 A service standards adjustment mechanism must be:*

*(a) sufficiently detailed and complete to enable the Authority to apply the service standards adjustment mechanism at the next access arrangement review; and*

*(b) consistent with the Code objective.*

## 6.3 AA5 Services

### 6.3.1 Reference services

486. Western Power's approach to considering reference services for the AA5 period is to ensure the available service offerings meet the changing energy needs of Western Australians. Western Power proposes to retain 39 of the current 61 reference services provided in the AA4 period as we believe these are the only services that are likely to be sought in the AA5 period by a substantial proportion of our customers, consistent with the requirements of section 5.2 of the Access Code. Western Power has also introduced 16 new reference services, consolidated six of the current AA4 reference services into two reference services and maintained 16 of the current AA4 reference services as transitional reference services which may apply during AA5.

487. Services are categorised as either:

- **Distribution services:** most of our customers are connected to the distribution network and receive a distribution reference service. Their reference service is influenced by the performance of and forecast expenditure in both the distribution and transmission network. The revenue is therefore recovered from both transmission and distribution customers
- **Transmission services:** a small number of large customers and generators are connected directly to the transmission network and receive a transmission reference service. Their reference service is influenced by the performance of, and expenditure in the transmission network only and the revenue is therefore only recovered from transmission customers
- **Streetlight services:** we operate, maintain, and provide streetlight services in the Western Power Network. The revenue is recovered from distribution and transmission customers.

488. We have summarised the new and consolidated reference services below consistent with the ERA's Final Decision on the framework and approach.

#### *New reference services at exit points, and bi-directional points*

489. The time of use periods have been changed to reflect forecast demand patterns for the AA5 period. Time of use tariffs enable a customer-led, demand-side solution to address the changing drivers of our network costs. A super off-peak period, applying from 9am to 3pm every day, with a very low variable energy price, will encourage customers to shift load to times when supply significantly exceeds demand on our network, such as during low load events. Consistent with feedback from users of our services, on-peak, off-peak and shoulder periods will also apply in the same way every day of the week to deliver intended price signals to users. Time of use periods consistently applied across the week will provide a simpler tariff structure for customers to understand and manage their energy use and may result in more consistent usage of the network. This, in turn would reduce the need for network augmentation to address significant peaks or lows, which would result in lower network costs for the benefit of customers in the long-term. We have

proposed four new super off-peak energy services, which are multi part time of use energy services with a super off-peak period and charging periods consistently applied for every day of the week to reflect feedback from customers:

- Super off-peak energy (residential) exit service
- Super off-peak energy (business) exit service
- Super off-peak energy (residential) bi-directional service
- Super off-peak energy (business) bi-directional service.

490. We have introduced new services in response to technological advancements and our customers' increased uptake of different technologies (including PV, storage and EVs). We propose to introduce five new reference services to support customers maximising their benefits of investing in these new technologies:

- Low Voltage distribution storage service[90]
- High Voltage distribution storage service[91]
- Transmission storage service[92]
- Low Voltage Electric Vehicle (EV) charging service
- High Voltage Electric Vehicle (EV) charging service.

### *New and consolidated capacity allocation services*

491. The introduction of constrained access in the WEM requires amendments to the capacity allocation swap reference services provided by Western Power in the AA4 period. The Access Code has been amended with the inclusion of section 2.4C, which requires entry services to allow interruption or curtailment in either of the following circumstances:

- where constraints are created by other users of the Western Power Network
- in connection with the operation of security constrained economic dispatch.

492. In addition to amending the capacity allocation swap reference services, we have also consolidated the existing four capacity allocation services into a single service to meet the needs of our customers and provide the benefits of simpler administrative arrangement and a single electricity transfer application to customers.

493. We also consolidated the remote direct load control and remote load limitation services into a single capacity allocation service and expanded the consolidated service to include control of an inverter via the meter.

### *Ancillary services*

494. We are proposing three new de-energise and re-energise services for the AA5 period:

- Site visit to support remote re-energise service
- Manual de-energise service

[90] As Western Power develops the parameters that will apply to this service, consideration will be given to whether multiple variants are required.

[91] As Western Power develops the parameters that will apply to this service, consideration will be given to whether multiple variants are required.

[92] As Western Power develops the parameters that will apply to this service, consideration will be given to whether multiple variants are required.

- Manual re-energise service.

495. The new site visit to support remote re-energise service will complement the remote re-energise service for circumstances where a controller or end-use customer needs on-site support to start the flow of electricity behind a connection point.

496. The proposed manual de-energise and manual re-energise reference services are consistent with the remote de-energise and remote re-energise services. We have introduced these services for customers where remote de-energisation and re-energisation is not possible. These services are already included under the model service level agreement.

### *Metering services*

497. We will provide four new standard metering services to support the recently introduced five-minute settlement arrangements for the WEM:

- Unidirectional, interval, weekly, manual service
- Unidirectional, interval, weekly, remote service
- Bidirectional, interval, weekly, manual service
- Bidirectional, interval, weekly, remote service.

498. Table 6.1 provides a full list of reference services that we propose to offer customers in the AA5 period. The tariffs associated with these new services are discussed in Chapter 12. A marked-up version of the Reference Services is also provided as Appendix E to the proposed access arrangement with changes to the reference services described in a change summary report provided in Attachment 6.1.

**Table 6.1: AA5 reference services**

| Service | Reference service | Category | Revenue cap recovery<br>Tx = transmission<br>Dx = distribution |
|---|---|---|---|
| **Reference services at exit points** | | | |
| A1 | Anytime Energy (Residential) Exit Service | Distribution | Tx and Dx |
| A2 | Anytime Energy (Business) Exit Service | Distribution | Tx and Dx |
| A5 | High Voltage Metered Demand Exit Service | Distribution | Tx and Dx |
| A6 | Low Voltage Metered Demand Exit Service | Distribution | Tx and Dx |
| A7 | High Voltage Contract Maximum Demand Exit Service | Distribution | Tx and Dx |
| A8 | Low Voltage Contract Maximum Demand Exit Service | Distribution | Tx and Dx |
| A9 | Streetlighting Exit Service (including streetlight maintenance) | Streetlights | Tx and Dx (including streetlight operating and maintenance costs) |
| A10 | Unmetered Supplies Exit Service | Distribution | Tx and Dx |
| A11 | Transmission Exit Service | Transmission | Tx |
| A18 | Super Off-peak Energy (Residential) Exit Service | Distribution | Tx and Dx |

| Service | Reference service | Category | Revenue cap recovery<br>Tx = transmission<br>Dx = distribution |
|---|---|---|---|
| A19 | Super Off-peak Energy (Business) Exit Service | Distribution | Tx and Dx |
| **Reference services at entry points** | | | |
| B1 | Distribution Entry Service | Distribution | Tx and Dx |
| B2 | Transmission Entry Service | Transmission | Tx |
| B3 | Entry Service Facilitating a Distributed Generation or Other Non-Network Solution | Distribution | Dx |
| **Reference services at bi-directional points** | | | |
| C1 | Anytime Energy (Residential) Bi-directional Service | Distribution | Tx and Dx |
| C2 | Anytime Energy (Business) Bi-directional Service | Distribution | Tx and Dx |
| C5 | High Voltage Metered Demand Bi-directional Service | Distribution | Tx and Dx |
| C6 | Low Voltage Metered Demand Bi-directional Service | Distribution | Tx and Dx |
| C7 | High Voltage Contract Maximum Demand Bi-directional Service | Distribution | Tx and Dx |
| C8 | Low Voltage Contract Maximum Demand Bi-directional Service | Distribution | Tx and Dx |
| C15 | Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution | Distribution | Tx and Dx |
| C16 | Super Off-peak Energy (Residential) Bi-directional Service | Distribution | Tx and Dx |
| C17 | Super Off-peak Energy (Business) Bi-directional Service | Distribution | Tx and Dx |
| C18 | Low Voltage Distribution Storage Service [93] | Distribution | Tx and Dx |
| C19 | High Voltage Distribution Storage Service [94] | Distribution | Tx and Dx |
| C20 | Transmission Storage Service[95] | Transmission | Tx |
| C21 | Low Voltage Electric Vehicle Charging Service | Distribution | Dx |
| C22 | High Voltage Electric Vehicle Charging Service | Distribution | Dx |
| **Reference services at connection points (ancillary)** | | | |
| D1 | Supply Abolishment Service | Distribution | Tx and Dx |
| | Capacity Allocation Service | Distribution | Tx and Dx |
| D6 | Remote Load/Inverter Control Service | Distribution | Tx and Dx |
| D8 | Remote De-energise Service | Distribution | Tx and Dx |
| D9 | Remote Re-energise Service | Distribution | Tx and Dx |

93 As Western Power develops the parameters that will apply to this service, consideration will be given to whether multiple variants are required.

94 As Western Power develops the parameters that will apply to this service, consideration will be given to whether multiple variants are required.

95 As Western Power develops the parameters that will apply to this service, consideration will be given to whether multiple variants are required.

| Service | Reference service | Category | Revenue cap recovery<br>Tx = transmission<br>Dx = distribution |
|---|---|---|---|
| D10 | Streetlight LED Replacement Service | Streetlight | Streetlights (including streetlight operating and maintenance costs) |
| D11 | Site visit to support remote re-energise service[96] | Distribution | Tx and Dx |
| D12 | Manual De-energise | Distribution | Tx and Dx |
| D13 | Manual Re-energise | Distribution | Tx and Dx |
| **Standard metering services** | | | |
| M1 | Unidirectional, accumulation, bi-monthly, manual | Distribution | Tx and Dx |
| M2 | Unidirectional, accumulation (TOU), bi-monthly, manual | Distribution | Tx and Dx |
| M3 | Unidirectional, interval, bi-monthly, manual | Distribution | Tx and Dx |
| M4 | Unidirectional, interval, monthly, manual | Distribution | Tx and Dx |
| M5 | Unidirectional, interval, bi-monthly, remote | Distribution | Tx and Dx |
| M6 | Unidirectional, interval, monthly, remote | Distribution | Tx and Dx |
| M7 | Unidirectional, interval, daily, remote | Distribution | Tx and Dx |
| M8 | Bidirectional, accumulation, bi-monthly, manual | Distribution | Tx and Dx |
| M9 | Bidirectional, accumulation (TOU), bi-monthly, manual | Distribution | Tx and Dx |
| M10 | Bidirectional, interval, bi-monthly, manual | Distribution | Tx and Dx |
| M11 | Bidirectional, interval, monthly, manual | Distribution | Tx and Dx |
| M12 | Bidirectional interval, bi-monthly, remote | Distribution | Tx and Dx |
| M13 | Bidirectional, interval, monthly, remote | Distribution | Tx and Dx |
| M14 | Bidirectional, interval, daily, remote | Distribution | Tx and Dx |
| M15 | Unmetered supply, accumulation, bi-monthly, manual | Distribution | Tx and Dx |
| M16 | One off manual interval read | Distribution | Tx and Dx |
| M17 | Unidirectional, interval, weekly, manual | Distribution | Tx and Dx |
| M18 | Unidirectional, interval, weekly, remote | Distribution | Tx and Dx |
| M19 | Bidirectional, interval, weekly, manual | Distribution | Tx and Dx |
| M20 | Bidirectional, interval, weekly, remote | Distribution | Tx and Dx |

499. We are providing 16 transitional time of use services. Western Power's intention, which is consistent with our approach in previous access arrangements, is to continue providing users with our existing time of use reference services if:

96 This service is proposed to complement the remote re-energise service, for circumstances where the controller/end-use customer requires on-site support to commence the flow of electricity behind a connection point.

- the services were provided at the relevant connection points at the date the AA5 period takes effect, and
- those services continue from the AA5 period effective date.

However, from the AA5 period effective date, the current (transitional) time of use services will be closed for new nominations. Existing connection points under those services will transition to the new time of use service over time as the users transition connection points to alternative services. This is consistent with our approach from previous access arrangements.

500. Table 6.2 provides a full list of the transitional reference services in the AA5 period.

**Table 6.2: Transitional reference services for the AA5 period**

| Service | Reference service | Category | Revenue cap recovery<br>Tx = transmission<br>Dx = distribution |
|---|---|---|---|
| A3 | Time of Use Energy (Residential) Exit Service | Distribution | Tx and Dx |
| A4 | Time of Use Energy (Business) Exit Service | Distribution | Tx and Dx |
| A12 | 3 Part Time of Use Energy (Residential) Exit Service | Distribution | Tx and Dx |
| A13 | 3 Part Time of Use Energy (Business) Exit Service | Distribution | Tx and Dx |
| A14 | 3 Part Time of Use Demand (Residential) Exit Service | Distribution | Tx and Dx |
| A15 | 3 Part Time of Use Demand (Business) Exit Service | Distribution | Tx and Dx |
| A16 | Multi Part Time of Use Energy (Residential) Exit Service | Distribution | Tx and Dx |
| A17 | Multi Part Time of Use Energy (Business) Exit Service | Distribution | Tx and Dx |
| C3 | Time of Use Energy (Residential) Bi-directional Service | Distribution | Tx and Dx |
| C4 | Time of Use Energy (Business) Bi-directional Service | Distribution | Tx and Dx |
| C9 | 3 Part Time of Use Energy (Residential) Bi-directional Service | Distribution | Tx and Dx |
| C10 | 3 Part Time of Use Energy (Business) Bi-directional Service | Distribution | Tx and Dx |
| C11 | 3 Part Time of Use Demand (Residential) Bi-directional Service | Distribution | Tx and Dx |
| C12 | 3 Part Time of Use Demand (Business) Bi-directional Service | Distribution | Tx and Dx |
| C13 | Multi Part Time of Use Energy (Residential) Bi-directional Service | Distribution | Tx and Dx |
| C14 | Multi Part Time of Use Energy (Business) Bi-directional Service | Distribution | Tx and Dx |

### 6.3.2 Non-reference services

501. Where a customer requests Western Power to provide an access service that is not covered by the stipulated reference services, we will work with the customer to develop a customised product as a non-reference service. Examples of non-reference services currently provided by Western Power include:

- processing and administration fees associated with an application for network access as detailed in the AQP
- network access services with conditions that vary from reference services, including:

- transmission connected customers that have agreed to accept an interruptible service to avoid paying prohibitive deep connection costs that would otherwise be required to provide a standard service
- customers with additional network redundancy or back-up supply available have paid for increased security and reliability for their connection
- connections for which the customer's equipment does not meet the Technical Rules, but for which Western Power has sought an exemption from the ERA.

502. The specifics of the non-reference services and corresponding tariffs provided by Western Power is negotiated with the customer following a request for a non-reference service. The non-reference services we provide are not listed or priced, other than in the associated network access contract. Further, as these services are negotiated with customers, they do not have pre-determined minimum service standards (any standards are negotiated with the customer).

## 6.4 Reporting on the level of service provided to our customers

503. Western Power monitors and reports on a comprehensive range of performance measures. Almost 200 of these performance measures relate to service standards. The reporting framework is prescribed by a range of legal instruments, including the access arrangement.

504. Legislative obligations relating to service performance include those contained in the *Code of Conduct for the Supply of Electricity for Small Use Customers 2008*, *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (**NQRS Code**) and Standing Committee on National Regulatory Reporting Requirements.

505. Through the AA5 period we will continue to report publicly on our service performance via the following channels:

- **quarterly reports:** providing an overview of our performance during the quarter against the key performance indicators that are in our Statement of Corporate Intent[97] which includes safety, reliability and financial measures
- **annual service standard performance reports:** providing an overview of our performance against the SSBs and targets in our access arrangement
- **annual reliability and power quality reports:** providing information required as part of Schedule 1 of the NQRS Code.

506. The ERA also independently reviews and reports on our service performance in its *Annual Performance Report - Energy Distributors*, in accordance with its administration of the electricity licence scheme under Part 2 of the *Electricity Licence Act 2004*. The *2017 Electricity Distribution Licence Performance Reporting Handbook* details the performance indicators that Western Power is required to report annually.

## 6.5 Determining appropriate service performance measures

507. The access arrangement details each of the specific minimum service standards Western Power must meet during that access arrangement period, as per section 11.1 of the Access Code[98]. Under section 5.1 of the

[97] The Statement of Corporate Intent is a one-year plan for the business agreed with State Government, which incorporates the business objectives and performance targets for the year. It is tabled in Parliament and made public.

[98] The Electricity Networks Access Code 2004 clause 11.1 requires Western Power to comply with the service standard benchmarks: *"A service provider must provide reference services at a service standard at least equivalent to the service standard benchmarks set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract."*

Access Code, Western Power is required to have SSBs for each of its reference services[99]. These SSBs are our minimum service standards.

508. For each reference service, we have proposed measures that are practical and will ensure our customers receive at least a minimum level of service in relation to reliability, quality of supply and customer service. Quality of supply is measured under the NQRS Code and reported in Western Power's annual Reliability and Power Quality Report.

509. We have implemented the ERA's Final Decision on the framework and approach to apply 30 measures for which there are SSBs for reliability of supply across the transmission and distribution network, timely repair of streetlights, call centre performance, and ancillary reference services for the AA5 period. The proposed SSBs are summarised in Figure 6.2.

99 Western Power has several different measures that apply to each of its transmission and distribution reference services. The measures do not have a direct relationship with a single service and vice versa. The access arrangement specifies which measures apply to each reference service.

## Figure 6.2: AA5 proposed service standard benchmarks

| | Transmission | Distribution | Customer communication | Street lights | Ancillary services |
|---|---|---|---|---|---|
| **Frequency** | **Loss of supply event frequency (LoSEF)** – the frequency of unplanned customer interruption event impacting transmission connected reference service customers only where the loss of supply is either:<br>• >0.1 and ≤1.0 system minutes interrupted<br>• >1 system minutes interrupted | **System Average Interruption Frequency Index (SAIFI)** – the average number of times a customer's electricity is interrupted each year for longer than one minute, attributable to the distribution and transmission network. It is measured separately for:<br>• **CBD**<br>• **Urban**<br>• **Rural Long**<br>• **Rural Short** | | | |
| **Duration** | **Average Outage Duration (AOD)** – the average duration of all unplanned outages on the transmission network impacting transmission connected reference service customers only | **System Average Interruption Duration Index (SAIDI)** – the total number of minutes on average the customer is without electricity each year for longer than one minute, attributable to the distribution and transmission network. It is measured separately for:<br>• **CBD**<br>• **Urban**<br>• **Rural Long**<br>• **Rural Short** | | | |
| **Response time** | | | **Call centre performance** - the percentage of fault calls responded to in ≤30 seconds | **Street light repair time** – repair response time to repair a faulty street light. It is measure separately for:<br>• **Metropolitan area**<br>• **Regional area** | Response time for:<br>• **Streetlight LED Replacement**<br>• **Supply abolishment**<br>• **Remotely de-energise a meter**<br>• **Remotely re-energise a meter**<br>• **Site visit to support remote re-energise service**<br>• **Manually de-energise a meter**<br>• **Manually re-energise a meter** |

510. The ERA's Final Decision on the framework and approach retained most of the measures from the AA4 period (with minor updates) for which there are SSBs. We consider these measures represent the key services we provide, and which are valued by our customers. Consistent with the ERA's Final Decision on the framework and approach, we have updated some definitions of the distribution and transmission SSBs, included three new ancillary services SSBs and removed the circuit availability transmission measure as an SSB.

511. Key changes to the proposed benchmarks for the AA5 period are discussed in the following sections.

### 6.5.1 Implementing the Framework and Approach final decision

***Transmission outages affecting customers on the distribution network will be included in the distribution SAIDI and SAIFI measures***

512. The transmission network is a source of electricity supply for customers on the distribution network. Reliability for distribution-connected customers is captured by the outage duration and frequency benchmarks (SAIDI and SAIFI). However, these measures currently exclude transmission outages. This means that if an interruption to a distribution-connected customer was caused by an outage on the transmission network, it is excluded under AA4 from the distribution SAIDI and SAIFI benchmarks.

513. Western Power supports the proposition in the Final Decision that distribution services to customers are essentially provided by both the transmission and distribution network. Therefore, any interruptions to distribution customers caused by Western Power unplanned outages on the transmission network will be included in SAIDI and SAIFI SSBs. This will provide a better measure of the value represented by each reference service at the reference tariff and the effectiveness of Western Power's management of the network.

***Transmission service standards will include only outages affecting transmission-connected customers***

514. Since transmission unplanned outages affecting distribution-connected customers will now be included in SAIDI and SAIFI benchmarks (which are distribution SSBs), the transmission service standards (loss of supply frequency and average outage duration measures) will include only unplanned outages affecting transmission-connected customers. Similarly, this will provide a better measure of the service provided to transmission-connected customers only.

***The force majeure exclusion will be removed, and new exclusions will be added to distribution SAIDI and SAIFI measures***

515. In the ERA's Final Decision on the framework and approach, the ERA considered the current exclusion of force majeure events in the distribution SAIDI and SAIFI measure is not required because it is adequately addressed through the calculation of major event days. However, the ERA accepted that total fire bans and directives from emergency services can prevent Western Power from entering an area to restore supply. Therefore, the ERA has added the following exclusion to the distribution SAIDI and SAIFI measures:

> *"exclude load interruptions caused or extended by a total fire ban or direction from a local or state government body or state or federal emergency services, provided that a fault in, or the operation of the network did not cause, in whole or part, the event giving rise to the direction".*

516. Accordingly, Western Power has removed the force majeure exclusion and included the new exclusion for total fire bans and directives from emergency services to the distribution SAIDI and SAIFI measures for the AA5 period.

517. The removal of the force majeure exclusion only applies to SAIDI and SAIFI measures and does not impact any other provisions under the Access Arrangement. Specifically, the force majeure exclusion remains in place for all other service standard measures, with the exception of call centre performance. This approach is aligned with the approach under AA4.

***Circuit availability measures have been removed as an SSB***

518. The ERA's Final Decision on the framework and approach removed circuit availability transmission measure as an SSB for the AA5 period as it does not measure the actual service provided to customers. Accordingly, Western Power has removed circuit availability transmission measure as an SSB for the AA5 period.

### 6.5.2 Western Power proposed step change in customer service performance levels

***Material change in circumstances for call centre performance***

519. The ERA's Final Decision on the framework and approach proposes to continue to use the same methodology for setting AA5 SSBs and SSTs as applied in the AA4 period, updated with the most historical performance. For the call centre performance measure, if the ERA's Final Decision on the framework and approach is followed, the SSB and SST levels will rise, driving Western Power to invest to achieve improved call centre performance in the AA5 period. In doing this, the assumption is that customers value (and are willing to pay for) continued improvements in the speed of answering fault related phone calls.

520. Under section 4.A12 of the Access Code:

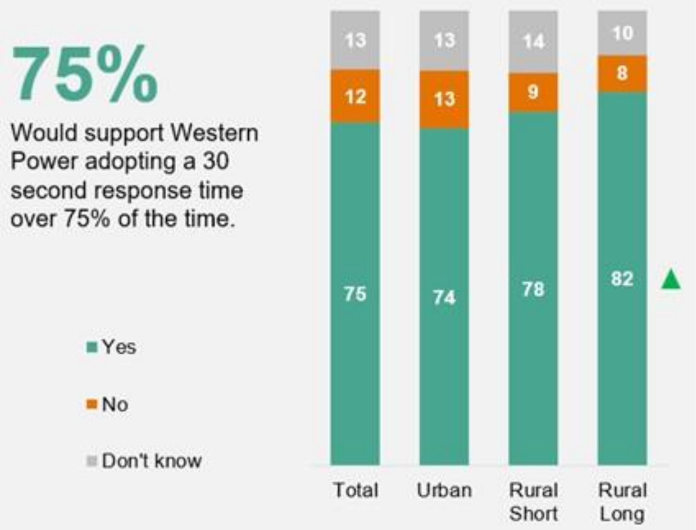
> *The Authority must not approve a proposed access arrangement or proposed revisions that departs from the framework and approach unless there has been a material change in circumstances, in which case it must provide reasons for the departure.*

521. Western Power proposes to retain the AA4 SSB and to remove the SST applied to call centre performance in the AA5 period. This is a result of new facts arising since the ERA's Final Decision on the framework and approach, which represent a material change in circumstances since that decision. These new facts are the evolving customer preferences in the method of communication with Western Power, in particular the preference for more digital communication, without incurring additional cost. These changing customer preferences were findings of our CEP, which was still underway at the time the framework and approach process was undertaken.

522. In any event, the preference for more digital communication and willingness to accept lower levels of call centre performance without increasing cost to customers, is the material change which requires a variation from the method for setting service standard benchmarks for call centre performance at the 97.5$^{th}$ percentile of recent historical performance.

523. The proposed changes to the call centre SSB and SST were developed as a result of findings from our CEP and demonstrates that we are listening to our customers and delivering service they value and are willing to pay for. The findings of our CEP identified that customers are not willing to pay more for better call centre response times compared to the response times currently experienced. Instead, most customers (75 per cent) prefer to experience slightly longer call centre response times in exchange for an improvement in other service channels available to them such as digital (e.g. Western Power website, Facebook), provided that there is no overall increase in their bills to achieve this improvement (see Figure 6.3).

**Figure 6.3: Customer responses on willingness to accept a decrease in the percentage of phone response within 30 seconds**[100]




Notes:

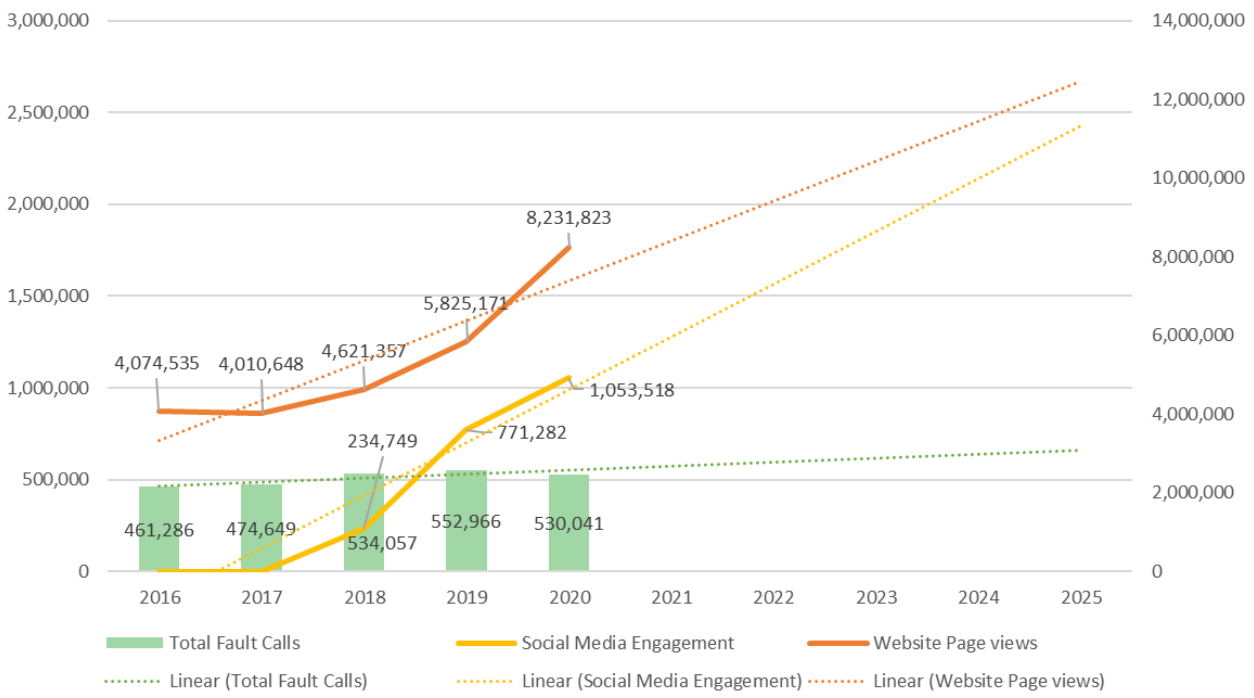
(4) Responses to the question: "The range of ways in which Western Power communicates with its customers has increased significantly over recent years. However, the increased number of communication channels to be serviced by Western Power call centre staff whilst maintaining existing service levels can add costs to customers' bills. One solution to overcome this challenge is to slightly increase the response times in some channels in order to service customer enquiries or issues via other channels (e.g. online chat) with the intent of not putting upward pressure on customer bills. Western Power is required to respond within 30 seconds 87 per cent of the time. Would you support Western Power adopting a 30 second response time over 75 per cent of the time?

### *Increasing customer use of digital channels and digital preferences*

524. In addition to the CEP findings regarding digital preferences, Western Power's data on our customer engagements demonstrates the significant increase in digital engagement. In the past two years, our website traffic has increased 76 per cent, from 4.6 million page views in 2018 to 8.2 million in 2020 and our social media channel engagement (likes, shares, comments, inbound enquiries, link clicks) has increased 349 per cent from 235,000 in 2018 to more than 1.05 million in 2020. This trend of increasing digital engagement is occurring whilst phone call volumes have remained relatively steady and have even increased slightly in recent years (see Figure 6.4).

100 Kantar Public and Synergies Economic Consulting, *Community and Customer Engagement Program Report*, Western Power, July 2021. A 30 second response time over 75% is a decrease from the current AA4 minimum service standard SSB level of 87%.

**Figure 6.4: Social media channel engagement, website page views and fault call volumes, 2016-2025**[101]




525. This increase in digital engagement by customers is something we need to ensure we can resource, in addition to phone calls, without putting upward pressure on electricity bills. In our CEP, we found that customers were generally sensitive to price increases, particularly the residential segment, and communication/customer service was a relatively unimportant issue in comparison to other priorities such as supporting renewables.[102]

526. Recognising the need to evaluate customer service measures beyond phone call response times, the AER recently introduced a customer service incentive scheme (**CSIS**). It was recognised amongst stakeholders that "the call answering parameter in the existing service target performance incentive scheme provided a narrow incentive for maintaining and improving customer service performance." [103] The CSIS is viewed as providing flexibility that will allow distributors to "respond to the evolution (in) customer engagement and the introduction of new technologies", and "encourage electricity distributors to provide customer service in accordance with the preferences of their customers".[104] Our proposed approach to customer service measures in AA5 aligns to this evolving view of service delivery, as we seek to consider measures beyond phone call response.

527. It is our view that in the AA5 period, we need to propose a step change to the existing SSB and remove the SST for call centre performance to ensure investment is driven where it is valued by customers as demonstrated by our CEP findings and our digital data trends. This is consistent with the logic that drove the development of the CSIS in broadening the measure of customer service beyond spend of phone call response times. Speed of phone call response remains an important metric, however, we also need to consider how we balance this with how we serve customers via our digital communication channels.

528. As we test the transition towards greater digital engagement, we will need to measure call centre performance as well as seek to measure our performance in digital channels. As we continue to develop our digital capabilities, we may determine additional metrics that are appropriate to measure and track in

---

101 Dotted line represents linear extrapolation, this assumes linear growth for the duration of the AA5 period based on historic data
102 Kantar Public and Synergies Economic Consulting, *Community and Customer Engagement Program Report*, Western Power, July 2021
103 AER, Explanatory Statement Customer Service Incentive Scheme, July 2020
104 AER, Explanatory Statement Customer Service Incentive Scheme, July 2020

the AA5 period and propose to include as SSB measures with SSB and SST targets in future access arrangement periods.

529. Collecting the performance data from both our phone and digital service channels over the AA5 period will enable us to propose relevant customer service performance measures in the AA6 period. It will also mean the subsequent benchmarks and targets can be informed by historical performance data, which currently does not exist.

530. As part of our normal access arrangement process, we will seek to test any new customer service performance measures and related benchmarks and targets for the AA6 period in our next customer engagement program.

***Test the proposed approach with our Customer Reference Group***

531. We engaged our Customer Reference Group to test the proposed approach to call centre service standards in the AA5 period. Feedback from the Customer Reference Group indicated that:

- customers felt that a phone response decrease from 92 per cent to 85 per cent would not impact their service experience on the condition it would not mean significantly delays from current phone response levels
- most customers favoured the redirection of investment from the call centre to social media and online website content, especially if it increases user autonomy, displays updated or real time accurate data and is easy to navigate
- customers valued omnichannel engagement opportunities, noting that different channels are useful for different purposes:
  - call centre is typically used for live emergencies in the area
  - social media is good for push notifications for faults or impacts to local area and mass communications for safety concerns affecting a large population. Customer expectation is that this is live with current or up to date fault information
  - website and email are largely used for non-urgent enquiries.[105]

## 6.6 Setting the minimum service standards for the AA5 period

### 6.6.1 Service standard benchmarks

532. Section 5.6 of the Access Code requires our SSBs to be reasonable and sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff. Section 11.1 of the Access Code requires Western Power to provide services to its customers at a service standard that is at least equivalent to the SSBs. This means that the SSBs are to be set at a minimum service level.

533. Consistent with the ERA's Final Decision on the framework and approach, Western Power is implementing the same approach that applied in the AA4 period to calculating its SSBs for the AA5 period but updated with the latest historical performance data for the 5-year period in the AA4 period[106]. The exception to this

105 Kantar Public, Tariff Structure Statement Research Customer and Community Reference Group #2 - Summary, September 2021, p. 7.

106 For this proposal, the SSBs have been set based on the 97.5$^{th}$ percentile of the distribution of best fit using historical performance data from June 2017 to September 2021. This analysis will be updated to use the full 5 years of AA4 actual historical performance data, July 2017 to June 2022, to set the final SSB targets for the AA5 period to apply from 2023/24 to 2026/27.

is the call centre measure, where we propose to maintain the AA4 SSB in the AA5 period. The methodologies are summarised below:

- Set our Reliability SSBs (SAIDI and SAIFI, LoSEF and AOD) by:
  - Establishing the data series on which our AA5 reliability SSBs are based by using the actual monthly 12-month rolling average performance for each SSB in the AA4 period,

    Note: For SAIDI and SAIFI SSBs by feeder category (CBD, Urban, Rural Short and Rural Long), the major event days for this data series are determined using the same methodology that was applied and reported on during the AA4 period:
    - Major event days are determined for the overall SWIN and these major event days are excluded from all SAIDI and SAIFI SSBs by feeder category,
    - SWIN unplanned daily SAIDI is used to calculate the major event day threshold, and
    - the Box-Cox transformation is used to determine the probability of a major event day.
  - Set our SSBs using the 97.5$^{th}$ percentile of the distributions of best fit[107]
- Set our call centre SSB by maintaining the SSB set in the AA4 period:
  - In the AA4 period, the call centre SSB was set by applying the same methodology outlined for reliability SSBs using the 2.5$^{th}$ percentile of the distributions of best fit using the actual monthly 12-month rolling average performance for call centre performance in the AA3 period
  - Further explanation of the proposal to maintain the AA4 SSB in the AA5 period, rather than calculating a new SSB using the same methodology is explained in Section 6.6.2
- Set our SSBs for streetlights to align with the *2019 Electricity Distribution Licence Performance Reporting Handbook*[108]*.* These requirements have not changed from the AA4 period.
- Set our Ancillary Service SSBs as follows:
  - retain the SSBs for supply abolishment, remote de-energise service and remote re-energise service at AA4 level
  - SSB for manual de-energise & manual re-energise service have been moved from the metering model service level agreement
  - SSB for site visit to support remote re-energise service aligned to the manual re-energise service

Further detail on the method for developing the service standard benchmarks and targets is provided in Attachment 6.2 - Fitting Distributions for AA5 Service Standard Benchmarks.

534. Also consistent with the ERA's Final Decision on the framework and approach, the AA5 period is targeted to commence on 1 July 2023. Therefore, the revised targets and SSAM mechanism will apply from 1 July 2023. As a result, for 2022/23 and until the AA5 period commences we will continue to operate and invest in the business to meet the current AA4 suite of SSBs, with the exception of circuit availability, as per the ERA's Final Decision on the framework and approach. The ERA's Final Decision on the framework and approach determined that the circuit availability measure should be removed as it does not measure the actual service provided to customers.[109]

535. While other aspects of the revised access arrangement, such as target revenue and resulting prices, will be adjusted and back dated to 1 July 2022, any revised service level benchmarks and targets can only take effect from the time the revised access arrangement is finalised. This is because Western Power would not

107 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final decision*, 9 August 2021, pg. 27

108 ERA, *April 2019 Electricity Distribution Licence Performance Reporting Handbook*, pg. 15

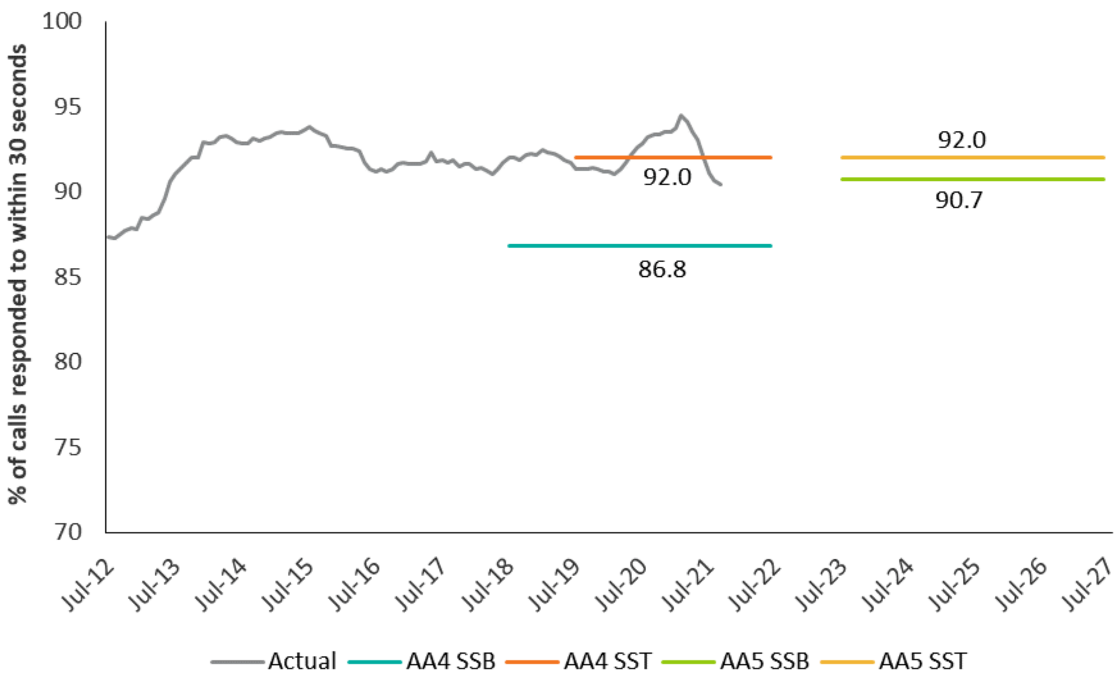
109 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final decision*, 9 August 2021, pg. 28 and 33

have the opportunity to manage the network prior to and during 2022/23 to comply with unknown SSBs in 2022/23. Applying the current suite of AA4 SSBs, excluding circuit availability, during 2022/23 provides certainty for Western Power and our customers of the minimum service standards that apply during 2022/23. It also ensures that our AA5 period forecast capex and opex, discussed in Chapter 7 and Chapter 8, are sufficient to allow Western Power to meet those SSBs.

### *Proposed change to applying the call centre SSB*

536. As noted in section 6.5.2, Western Power proposes to retain the AA4 SSB for call centre performance in the AA5 period. Adopting the AA4 methodology to calculate the call centre SSB and SST for the AA5 period, as outlined in the ERA's Final Decision on the framework and approach, would result in a SSB of 90.7 per cent and SST of 92.0 per cent. As shown in Figure 6.5, the potential SSB is a marked increase from the AA4 SSB of 86.8 per cent. The increase in the SSB is a result of more stabilised call centre performance in recent years. We estimate to meet this increase in the SSB, an extra 3-5 call centre staff at a potential cost of over $500,000 per year would be required to ensure we could meet a minimum service standard at 90.7 per cent (represented by the SSB). As such, we would need to increase investment in call centre performance, which is inconsistent with feedback in the CEP that our customers do not value an increase in call centre performance nor a price increase to do so.

**Figure 6.5: Call centre SSB & SST – AA4 and forecast AA5, using the existing approach to calculating targets**



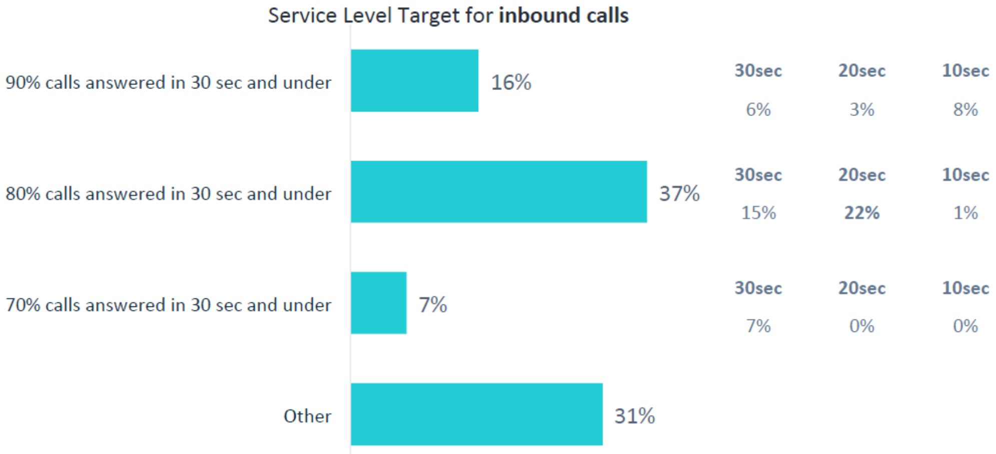

537. A potential SSB of 90.7 per cent is also significantly higher than contact centre industry standards for speed of phone call response. A recent contact centre industry report[110] identified that the most common service level agreement (**SLA**) for inbound calls was 80 per cent of calls answered within 30 seconds (see Figure 6.6). Just 16 per cent had an SLA higher than that, at 90 per cent, and specifically in utilities, 24 per cent of the top organisations had SLAs between 70 per cent and 90 per cent. These services also averaged 78 per

[110] Fifth Quadrant, Australian Contact Centre Industry Benchmark Report, 2018

cent of calls being answered within their nominated SLA, well under the 90.7 per cent level of the potential AA5 SSB.

538. Our proposal to maintain the AA4 SSB of 86.8 per cent in the AA5 period is above the 75 per cent which a majority of customers said they would be willing to accept in our CEP, and still above industry average. It ensures we avoid the situation where we need to increase investment to increase our speed of response to phone calls, which our customers are not willing to pay for.

**Figure 6.6: Service Level Agreements for inbound calls[111]**




### *AA5 Service Standard Benchmarks*

539. Table 6.3 shows the proposed SSBs for the AA5 period.

**Table 6.3: AA5 period proposed service standard benchmarks**

| Performance measure | Unit | AA4 | 2022/23 | From 2023/24 onwards |
|---|---|---|---|---|
| **Distribution** | | | | |
| **System average interruption duration index (SAIDI)** | | | | |
| CBD | Minutes | 33.7 | 33.7 | 35.2 |
| Urban | Minutes | 130.6 | 130.6 | 138.9 |
| Rural short | Minutes | 215.4 | 215.4 | 236.9 |
| Rural long | Minutes | 848.3 | 848.3 | 812.5 |
| **System average interruption frequency index (SAIFI)** | | | | |
| CBD | Number of events | 0.21 | 0.21 | 0.44 |
| Urban | Number of events | 1.27 | 1.27 | 1.33 |
| Rural short | Number of events | 2.34 | 2.34 | 2.28 |
| Rural long | Number of events | 5.70 | 5.70 | 4.71 |
| **Calls responded to in 30 seconds** | Per cent | 86.8 | 86.8 | 86.8 |

111 Fifth Quadrant, Australian Contact Centre Industry Benchmark Report, 2018

| Performance measure | Unit | AA4 | 2022/23 | From 2023/24 onwards |
|---|---|---|---|---|
| **Transmission** | | | | |
| **Loss of supply event frequency** | | | | |
| >0.1 and ≤1 system minutes | Number of events | 26 | 26 | 4 |
| >1 system minutes | Number of events | 7 | 7 | 2 |
| **Average outage duration** | Minutes | 1,234 | 1,234 | 1,746 |
| **Street lighting** | | | | |
| Repair times for Perth Metropolitan area | Days | 5 | 5 | 5 |
| Repair times for major regional towns | Days | 9 | 9 | 9 |
| **Ancillary services** | | | | |
| **Streetlight LED Replacement Service** | Note[112] | | | |
| **Supply abolishment service** | Days | 15 | 15 | 15 |
| **Remote de-energise service** | Days | 1 | 1 | 1 |
| **Remote re-energise service** | Days | 1 | 1 | 1 |
| **Site visit to support remote re-energise service** | | | | |
| **Standard response time** | | | | |
| Metropolitan area | Days | N/A | N/A | 1 |
| Regional area | Days | N/A | N/A | 5 |
| **Urgent response time** | | | | |
| Perth Metropolitan area | Hours | N/A | N/A | 3 |
| Metropolitan area | Days | N/A | N/A | 1 |
| Regional area | Days | N/A | N/A | 1 |
| **Manual de-energise** | | | | |
| Metropolitan area | Days | MSLA[113] | MSLA | 1 |
| Regional area | Days | MSLA | MSLA | 5 |
| **Manual re-energise** | | | | |
| **Standard response time** | | | | |
| Metropolitan area | Days | MSLA | MSLA | 1 |
| Regional area | Days | MSLA | MSLA | 5 |
| **Urgent response time** | | | | |

112 For the reference service D10 the Service Standard Benchmark is the LED replacement, requested by the user, will be completed as soon as reasonably practicable in accordance with good electricity industry practice. During the 2020/21 period, Western Power was not requested to perform this service.

113 Model Service Level Agreement. Service standards are defined in Metering Code Model Service Level Agreement

| Performance measure | Unit | AA4 | 2022/23 | From 2023/24 onwards |
|---|---|---|---|---|
| Perth Metropolitan area | Hours | MSLA | MSLA | 3 |
| Metropolitan area | Days | MSLA | MSLA | 1 |
| Regional area | Days | MSLA | MSLA | 1 |

## 6.7 Service standard adjustment mechanism

540. Under section 6.30 of the Access Code, Western Power's access arrangement must contain a SSAM. Western Power's SSAM provides financial rewards and penalties for service that is better or worse than the expected level of performance (which we expect to achieve 50 per cent of the time). The rewards or penalties are awarded in the following access arrangement period via a revenue building block adjustment.

541. The performance targets are typically based on the level of performance achieved by Western Power over the previous access arrangement period. Western Power will receive a financial reward only if we improve performance compared to the targets. Western Power will be able to retain the reward only if we maintain the performance improvement. Once an improvement is made, the performance targets will be tightened for future access arrangements to reflect the improved level of performance. If the higher level of performance is not maintained in each year of the access arrangement, or if performance decreases for any other reason, a penalty is payable. A financial reward for improved customer performance is paid by customers while penalties to Western Power for a reduction in performance mean customers get a price reduction.

542. The following sections discuss the parameters for the SSAM – the measures, SSTs, the incentive rates and the revenue at risk.

### 6.7.1 Measures

543. Western Power proposes that 11 of the 30 proposed AA5 period SSBs are used as SSTs to calculate the SSAM.

544. Aligned with our approach in the AA4 period, streetlight and ancillary services measures will be excluded from the SSAM in the AA5 period.

***Proposed change to removing the call centre SST***

545. As noted in section 6.5.2, Western Power proposes that the call centre performance measure is also excluded from the SSAM in the AA5 period, to create capacity for resourcing the increase in digital engagement by our customers, whilst maintaining an expected minimum level of phone call response times and maintaining the same levels of investment. This also allows for capturing data over the AA5 period to inform customer service measures for the AA6 period that reflect our customers' changing preferences in how they communicate with us.

546. This brings the call centre performance measure in line with streetlight and ancillary service measures which ensures customers receive the minimum level of service that they expect and value without incurring additional costs. It also demonstrates we are putting customer feedback into action based on the outcomes of our customer engagement program. The proposed approach for call centre performance in the AA5 period is further explained in section 6.7.2.

### 6.7.2 Service standard targets

547. The ERA's Final Decision on the framework and approach determined that, "*the service standards targets must be set at the average annual level of performance achieved in the AA4 period, adjusted for anticipated changes in service reliability and where individual penalty caps applied during the AA4 period. Western Power must include details of any planned disruptions, new investment or changes to maintenance activities that would affect service standard performance, in its access arrangement proposal so that the service standard targets can be adjusted if appropriate. For example, any forecast improvements in SAIDI and SAIFI due to the installation of stand-alone power systems*"[114].

548. Consistent with the ERA's Final Decision on the framework and approach, Western Power has set its SSTs at the average annual level of performance achieved in the AA4 period, with adjustments where appropriate to the relevant measure and where individual penalty caps applied during the AA4 period. The exception to this is the call centre measure where we propose to remove the service standard target in the AA5 period.

549. For the reasons set out in section 6.6.1, we propose to continue to operate and invest in the business to meet the current suite of SSBs, excluding circuit availability, until the ERA makes a final decision on the AA5.

550. Consistent with the ERA's Final Decision on the framework and approach, the SSAM will apply from 1 July 2023 and no SSTs are set for the 2022/23 year.[115] In practice, this will mean that we will not receive any SSAM rewards or pay any penalties for the first year of the AA5 period. We will continue to apply AA4 SSBs in 2022/23, with the exception of circuit availability as per the ERA's Framework and Approach. This will ensure that the minimum standards are maintained, and our customers will not be worse-off.

551. We submit that this is consistent with the design of the SSAM as an incentive regime, whereby its associated financial rewards and penalties should be the subject of well-measured and reasoned analysis and not be:

- a transitional measure, as would be the case with the application of the proposed AA5 period SSAM and the associated SSTs
- retrospectively applied after the point that we would be able to affect the outcome, as would be the case with the back-dated application of the AA5 period SSAM and the associated SSTs
- applied in a context different to the one in which it was intended, as would be the case with the continued use of the AA4 period SSAM and the associated SSTs.

***Proposed changes to the call centre Service standard targets***

552. As outlined in Section 6.5.2, the CEP and our own data on digital engagement suggests a need to re-evaluate how customer service is delivered and measured in the AA5 period. Western Power proposes to enable this transition to take place by removing the SST applied to call centre performance in the AA5 period.

553. Removing the SST yet retaining the minimum level of service by applying the AA4 SSB allows us to allocate existing resources to responding to increased digital communication with our customers, without requiring further investment to do so. This is important as customers told us through the CEP they were generally unwilling to pay for improvements to the call centre response time service they currently experienced, and were instead willing to forgo some speed of phone call response if it meant improved digital service without the cost implications. It is also important with the increasing digital interactions evident, which are expected to continue.

114 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final decision*, 9 August 2021, pg. 50

115 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final decision*, 9 August 2021, pg. 48

554. If the proposed SST is applied to speed of phone response in the AA5 period, all resources will need to remain dedicated to phone call response. This prevents us being able to respond to the increasing digital communication we are seeing, unless we were to increase investment above existing levels for additional resources. The CEP tells us this is not what customers want – they want to see us improving our digital communication without increasing investment to do so.

#### *AA5 Service Standard Targets*

555. Table 6.4 shows the proposed SSTs for the AA5 period.

**Table 6.4: AA5 period proposed service standard targets**

| Performance measure | Unit | 2022/23 | From 2023/24[116] |
|---|---|---|---|
| **Distribution** | | | |
| **System average interruption duration index** | | | |
| CBD | Minutes | - | 13.7 |
| Urban | Minutes | - | 118.5 |
| Rural short | Minutes | - | 197.9 |
| Rural long | Minutes | - | 704.3 |
| **System average interruption frequency index** | | | |
| CBD | Number of events | - | 0.17 |
| Urban | Number of events | - | 1.23 |
| Rural short | Number of events | - | 2.02 |
| Rural long | Number of events | - | 4.33 |
| **Transmission** | | | |
| **Loss of supply event frequency** | | | |
| >0.1 and ≤1 system minutes | Number of events | - | 1 |
| >1 system minutes | Number of events | - | 1 |
| **Average outage duration** | Minutes | - | 852 |

### 6.7.3 Valuing reliability for our customers

556. Consistent with the ERA's Final Decision on the framework and approach, Western Power must use the most recent available estimates of the VCR from the Value of Customer Reliability Report prepared by the AER to estimate suitable values for our customers[117]. To obtain suitable values for our customers, Western Power will need to account for some differences in the method and format of data compared with the previous values that were determined using the values of customer reliability published by AEMO in 2014[118].

116 This assumes the revised access arrangement commences on or before 1 July 2023.
117 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final decision*, 9 August 2021, pg. 49
118 AEMO, Value of Customer Reliability Statement of Approach, and Methodology Paper, 11 November 2013

557. Western Power has retained the AA4 methodology for setting the financial incentive rates for the SSAM, with updates to reflect a more contemporary estimate of the value to customers of a reliable supply of electricity, using:

- VCR estimates from the most recent available AER Values of Customer Reliability Report, adjusted to apply in Western Australian, to set incentive rates for distribution measures
- revised weightings for the revenue at risk associated with each transmission measure because of the proposed exclusion of the Circuit Availability measures from the SSAM
- AA5 revenue attributable to customers connected to the transmission network and receiving reference services, to set incentive rates for transmission measures

558. This approach is consistent with the ERA's Final Decision on the framework and approach and has resulted in lower financial incentive rates than those applied in the AA4 period. This will result in lower rewards and penalties for the same change in performance relative to the AA4 period.

### *Distribution network reliability incentive rates*

559. Consistent with the ERA's Final Decision on the framework and approach, Western Power adopted the VCR estimates from the AER's 2019 Value of Customer Reliability Report[119], adjusted to apply in Western Australia, to set the financial incentive rates for our distribution reliability SSTs for the AA5 period. These estimates provide updated values from the AEMO 2014 approach, which was used by Western Power for setting the AA4 period incentive rates.

560. The VCR is used to represent, in dollar terms, our customers' willingness to pay for the reliable supply of electricity. The VCR serves as an important input into regulatory and network investment contexts; informing the reliability incentive rates used in service standard incentive schemes, as well as informing decision making with respect to the trade-off between the benefit of reliability improvements and the cost of investment needed to achieve such improvements. The VCR acts as a proxy for the value customers place on an investment to improve reliability or maintain average reliability of service levels.

561. The VCR is applied under the SSAM to calculate the financial incentives that will apply to Western Power for each distribution reliability measure to ensure the framework drives economically efficient investment in the reliability of the network.

562. We propose to use the VCR estimates in Table 6.5 to apply to our distribution reliability measures under the SSAM. These estimates are lower than those applied in the AA4 period and will therefore lead to lower rewards and penalties for the same change in performance relative to the AA4 period with the exception of rural short feeder category.

**Table 6.5: Value of customer reliability estimates, real $ at 30 June 2022, per kWh[120]**

| | AA4 | AA5 |
|---|---|---|
| CBD | 55.7 | 43.3 |
| Urban | 47.2 | 42.3 |
| Rural short | 45.8 | 40.9 |
| Rural long | 47.1 | 40.4 |

119 Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/final-decision

120 VCR estimates used during AA4 were adapted from the 2014 AEMO review, which used a different methodology to the 2019 AER review from which Western Power have adapted VCR estimates for AA5. Therefore, it is not appropriate to draw a direct comparison between the AA4 and AA5 VCR estimates.

563. The VCR was most recently reviewed in the national electricity market (**NEM**) by the AER in 2018[121]. The AER updated the methodology for calculating the VCR to take account of climate zones and remoteness as key drivers of reliability preferences for residential customers.[122] The AER released the final outcomes of its VCR review in December 2019, setting out VCR values for both distribution and transmission connected customers for the NEM and Northern Territory. Since WA is not a participating jurisdiction in the NEM, there are no VCR estimates for WA included in the AER's study. Western Power has therefore engaged an independent economic consulting firm – KPMG – to develop VCR estimates for Western Australia leveraging the AER's study to the extent possible.

564. To adapt the AER's VCR estimates to Western Power's context, KPMG have used a three-step methodology:

- Segment Western Power's customers to align with the AER's VCR method as closely as the available data allows
- Calculate VCR values for each Western Power customer segment based on the 2019 AER values (adjusted for inflation to June quarter 2021) and Western Power's own outage data
- Weight these VCR values together using energy consumption (kWh) weights to calculate estimates for each network segment.

565. KPMG's approach to determining probability-weighted VCR values for residential customers was to:

- map the relevant climate zone and remoteness classification to each of Western Power's outages on the basis of postcode
- apply the AER's VCR estimates for the proxy NEM jurisdiction by:
  - using Western Power's historical interruption data to calculate interruption probabilities for each customer class based on the time of day, weekday and season
  - multiplying the probability of each interruption by the corresponding VCR estimate from the AER.

566. Further information on the approach to determining VCR estimates for Western Power's context is provided in Attachment 6.3 - Estimation of value of customer reliability for Western Power's network.

567. We have incorporated these updated VCR estimates into the SSAM based on the AER's current 2009 service target performance incentive scheme (**STPIS**) Guideline[123], consistent with the approach adopted for the AA4 period. The penalty and reward rates have been calculated using 12 months of consumption data to 30 June 2021.

568. Table 6.6 shows the resulting SSAM incentive rates for the distribution measures.

**Table 6.6: SSAM financial incentive rates for AA5 period distribution measures, $ real at 30 June 2022**

| Performance measure | Unit | AA4 | | AA5 proposed | |
|---|---|---|---|---|---|
| | | Reward | Penalty | Reward | Penalty |
| **System average interruption duration index** | | | | | |
| CBD | Minutes | $33,022 | $33,022 | $21,195 | $21,195 |
| Urban | Minutes | $488,162 | $488,162 | $393,457 | $393,457 |

121 AER, December 2019, Values of Customer Reliability, Final report on VCR values, p. 56

122 AER, December 2019, Values of Customer Reliability, Final report on VCR values

123 AER, *Electricity distribution network service providers: Service target performance incentive scheme*, May 2009.

| Performance measure | Unit | AA4 | | AA5 proposed | |
|---|---|---|---|---|---|
| | | Reward | Penalty | Reward | Penalty |
| Rural short | Minutes | $156,416 | $156,416 | $159,066 | $159,066 |
| Rural long | Minutes | $57,381 | $57,381 | $48,918 | $48,918 |
| **System average interruption frequency index** | | | | | |
| CBD | Number of events | $31,939 | $31,939 | $11,175 | $11,175 |
| Urban | Number of events | $317,708 | $317,708 | $253,131 | $253,131 |
| Rural short | Number of events | $100,351 | $100,351 | $103,786 | $103,786 |
| Rural long | Number of events | $60,483 | $60,483 | $53,056 | $53,056 |

### *Transmission network reliability values*

569. Consistent with the ERA's Final Decision on the framework and approach, rewards and penalties for transmission service standards must be based on the revenue attributable to customers connected to the transmission network and receiving reference services[124]. This is a significant change from AA4 where rewards and penalties for transmission service standards were based on the total transmission revenue at risk instead of revenue attributable to customers connected to the transmission network and receiving reference services only. Therefore, the transmission revenue at risk for AA5 is significantly less compared to AA4.

570. For the AA4 period, Western Power applied a percentage of its revenue at risk to each transmission measure. There were four transmission SSTs used in the SSAM calculation. The ERA's Final Decision on the framework and approach removed the circuit availability measure as an SSB for the AA5 period, and therefore, also as an SST.

571. Western Power proposes to reallocate the revenue at risk previously allocated to the circuit availability measure among the remaining three transmission measures as shown in Table 6.7.

**Table 6.7: Transmission measure allocation of revenue at risk, per cent**

| Measure | AA4 | AA5 proposed | Difference |
|---|---|---|---|
| Circuit availability | 50 | - | -50 |
| Loss of supply event frequency >0.1 and ≤1 system minutes | 15 | 30 | 15 |
| Loss of supply event frequency >1 | 15 | 30 | 15 |
| Average outage duration | 20 | 40 | 20 |
| **Total** | **100** | **100** | **-** |

572. This reallocation maintains the allocation of the total transmission revenue at risk (one per cent of transmission revenue) to 30 per cent each to the two loss of supply event frequency measures and 40 per cent for the average outage duration measure.

573. We have applied these weightings to the AA5 period transmission revenue at risk.

124 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final decision*, 9 August 2021, pg. 49.

574. Table 6.8 shows the resulting SSAM incentive rates for the transmission measures.

**Table 6.8: SSAM financial incentive rates for AA5 period transmission measures, $ real at 30 June 2022**

| Performance measure | Unit | AA5 | |
|---|---|---|---|
| | | Reward | Penalty |
| **Loss of supply event frequency** | | | |
| >0.1 and ≤1 system minutes | Number of events | $254,899 | $84,966 |
| >1 | Number of events | $254,899 | $254,899 |
| **Average outage duration** | Minutes | $507 | $380 |

### 6.7.4 Capping rewards and penalties under the SSAM

575. In the AA4 period:

- the sum of the rewards and penalties for the transmission network is capped at one per cent of total transmission revenue
- the sum of the rewards for the distribution network each year is capped at one per cent of total distribution revenue, and
- the sum of the penalties for the distribution network each year is capped at 2.5 per cent of total distribution revenue.

576. Consistent with the ERA's Final Decision on the framework and approach, in the AA5 period, individual caps on the penalties are removed and the overall caps for rewards and penalties[125] are:

- for the distribution SSBs, based on one percent (symmetrical) of the distribution reference service customer target revenue
- for the transmission SSBs, based on one percent of the transmission reference service customer target revenue.

577. Table 6.9 shows the total average AA5 target revenue at risk applicable to transmission reference service customers and distribution reference service customers respectively.

**Table 6.9: AA5 period revenue at risk applied to each financial year, $ real at 30 June 2022**

| | AA5 proposed |
|---|---|
| **Transmission reference service customer** | $849,663 |
| **Distribution reference service customer** | $12,928,763 |

## 6.8 Actual performance and proposed service standards

578. Figure 6.7 to Figure 6.20 shows the SSBs and SSTs proposed for the AA5 period in the context of actual performance during the AA4 period.

125 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final decision*, 9 August 2021, pg. 50.

579. The actual data is presented based on the changes proposed for the AA5 period unless otherwise stated.

### 6.8.1 Proposed Distribution measures

**Figure 6.7: CBD SAIDI**

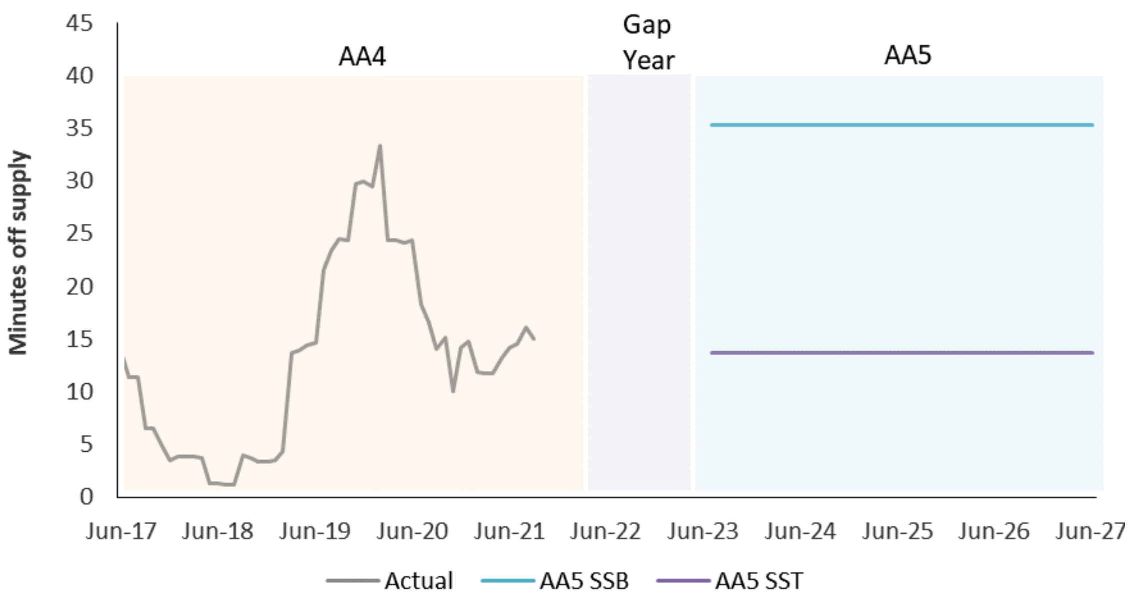



**Figure 6.8: Urban SAIDI**

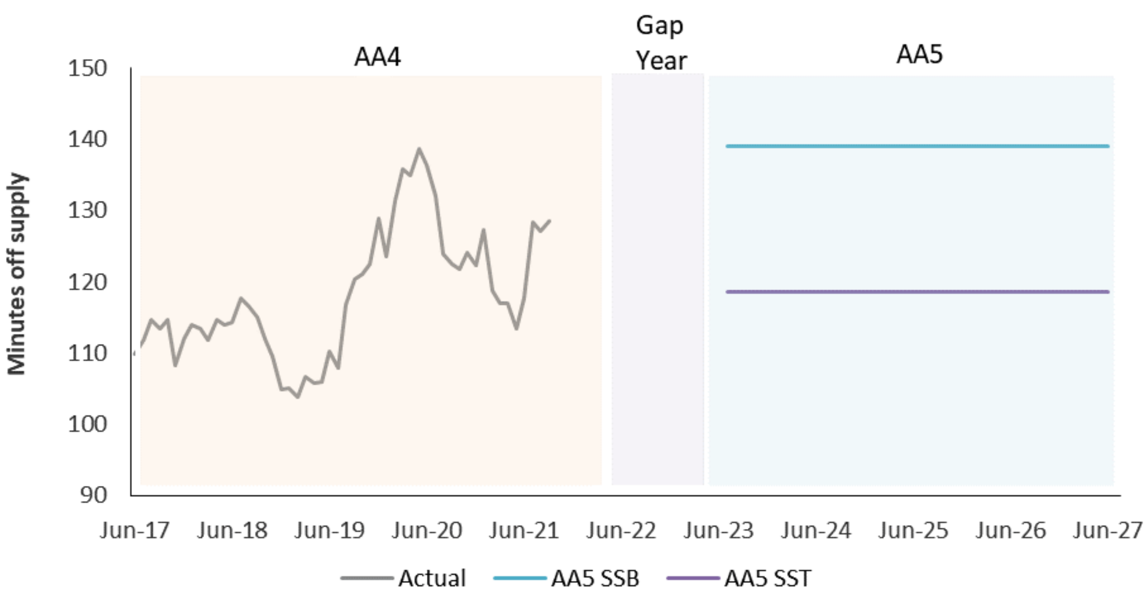


**Figure 6.9: Rural short SAIDI**

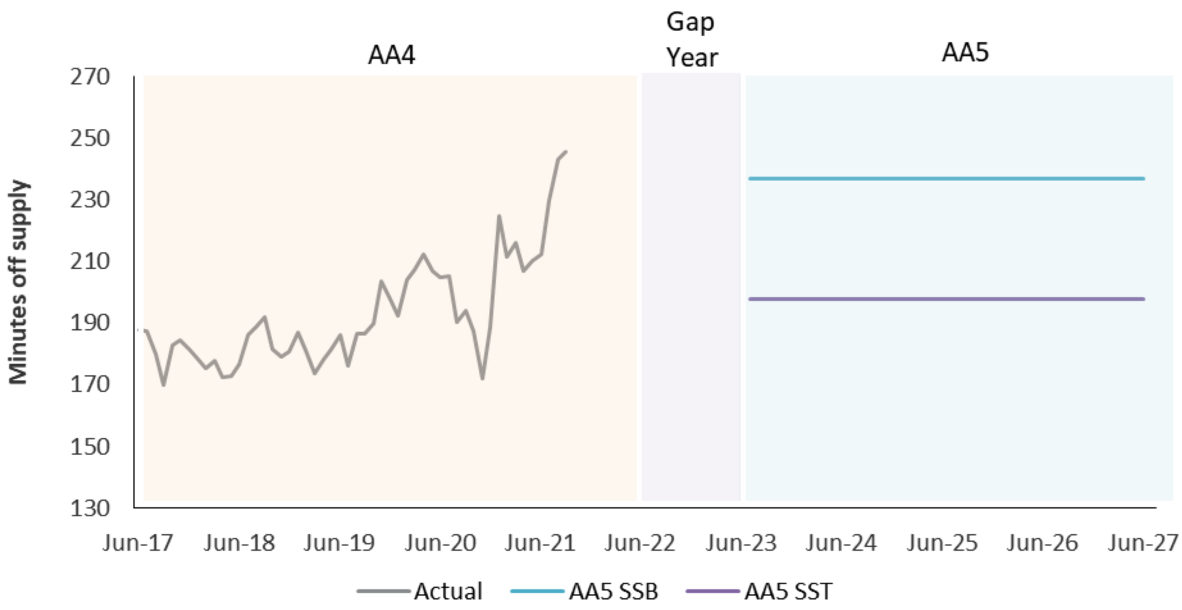



**Figure 6.10: Rural long SAIDI**

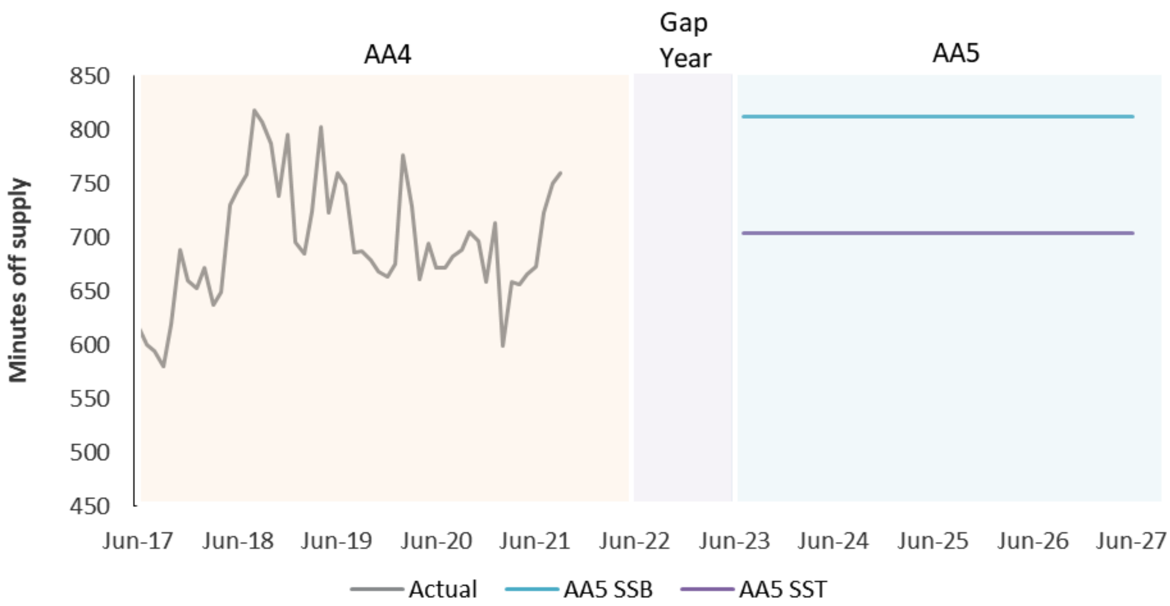


**Figure 6.11: CBD SAIFI**

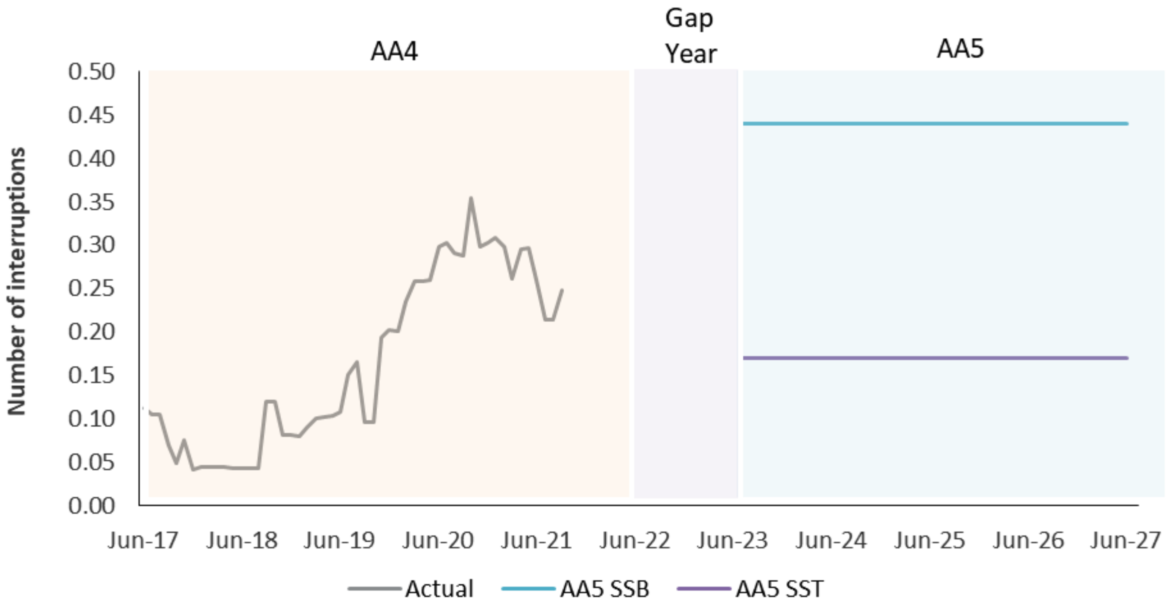



**Figure 6.12: Urban SAIFI**

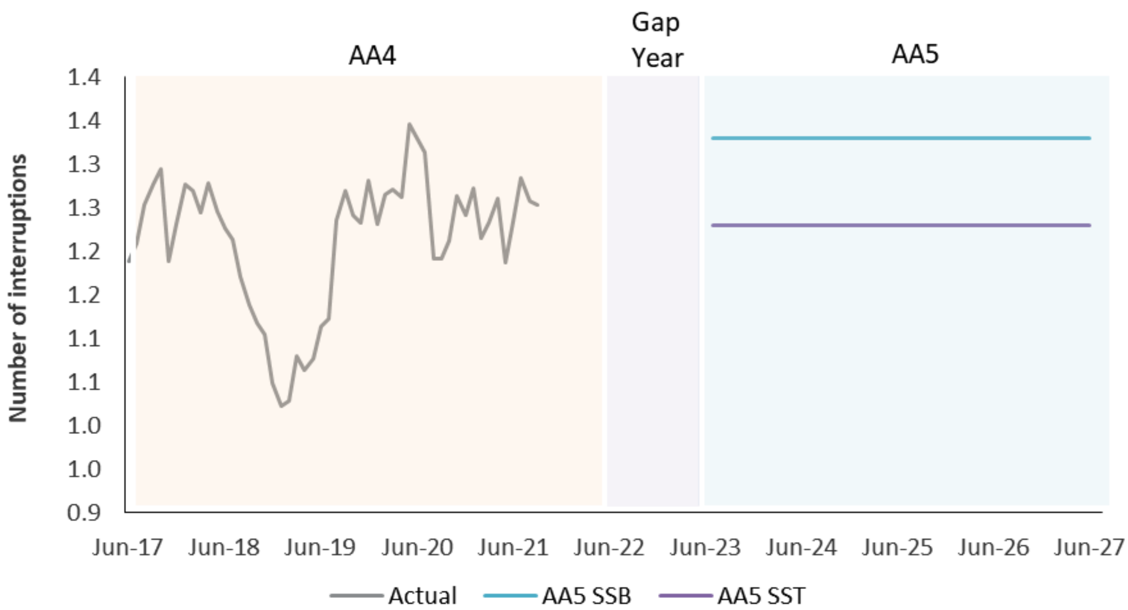


**Figure 6.13: Rural short SAIFI**

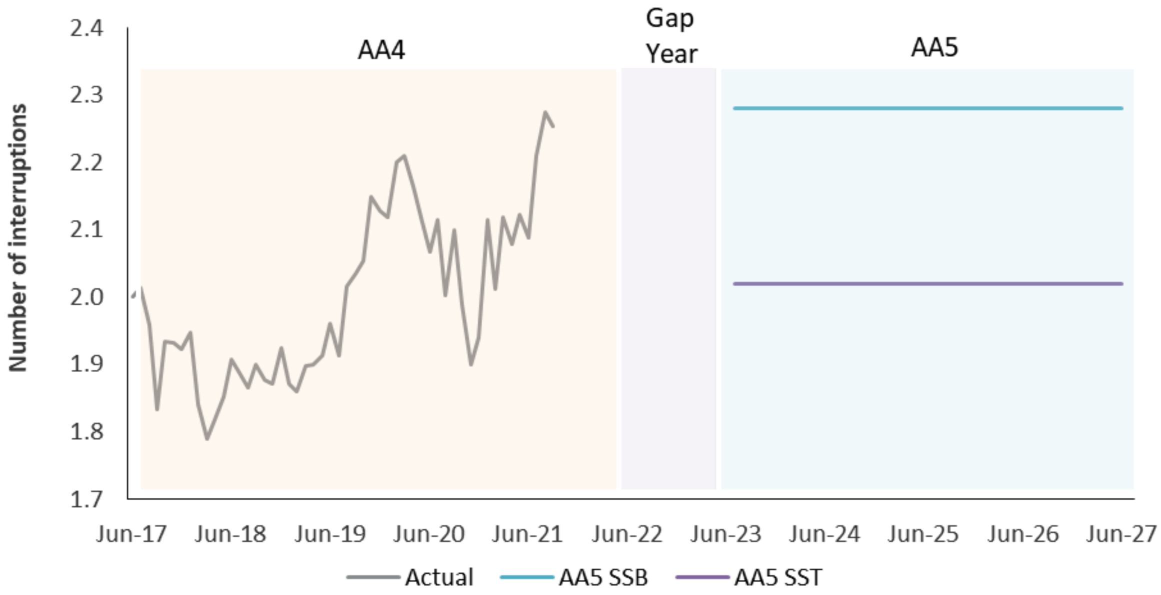



**Figure 6.14: Rural long SAIFI**

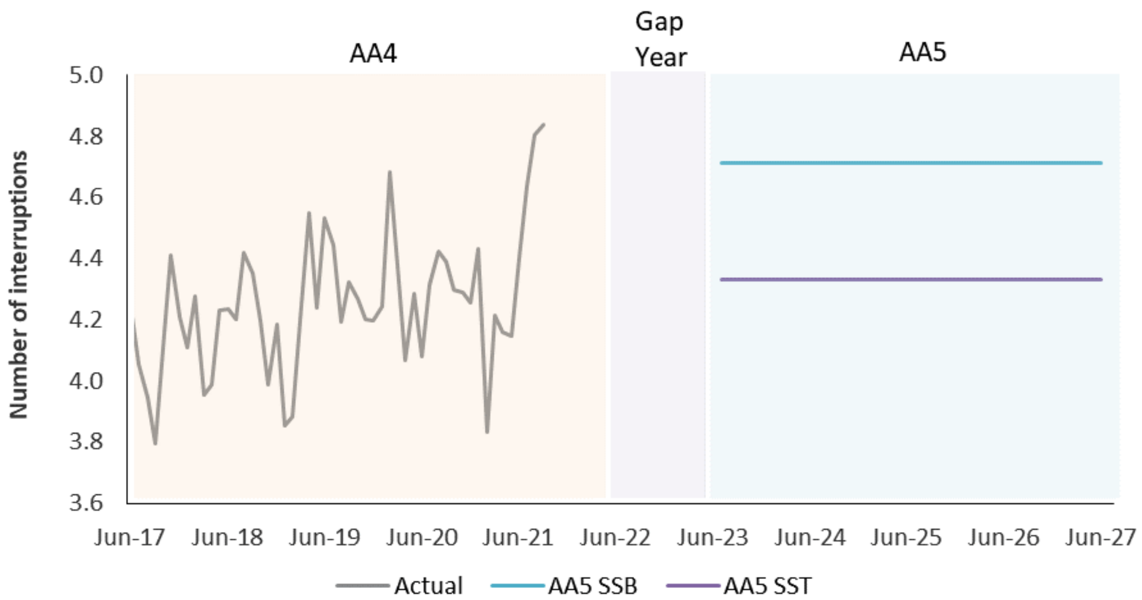
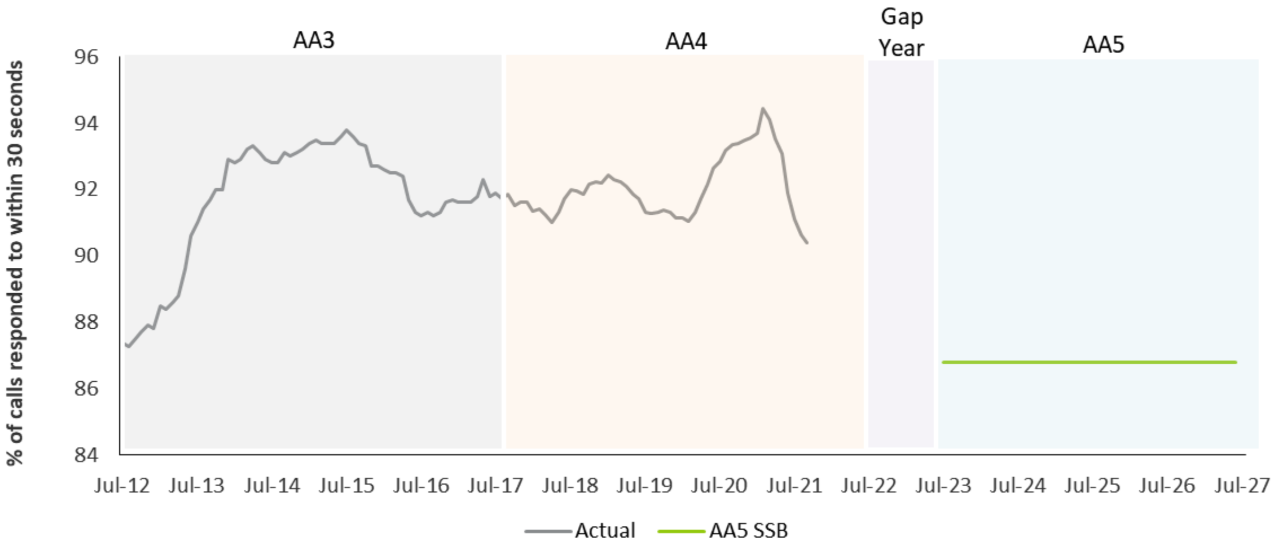
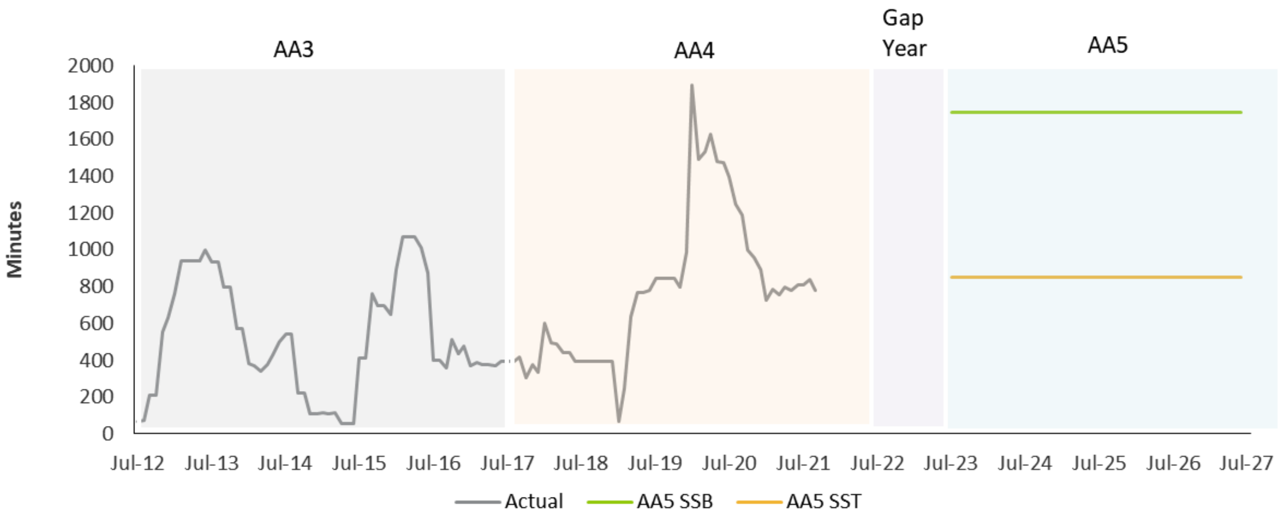


**Figure 6.15: Call centre**[126]




### 6.8.2 Transmission measures

**Figure 6.16: Average outage duration**




126 Prior to 2011, the actual performance for call centre has not been adjusted to reflect the proposed change to major event days, as only the reported data was able to be accessed at the time of developing this submission. However, as the AA4 period SSBs and SSTs are calculated on the basis of the previous five years, this has not affected the proposed benchmarks and targets and is only provided for illustrative purposes.

**Figure 6.17: Loss of supply event frequency >0.1 and ≤ 1**

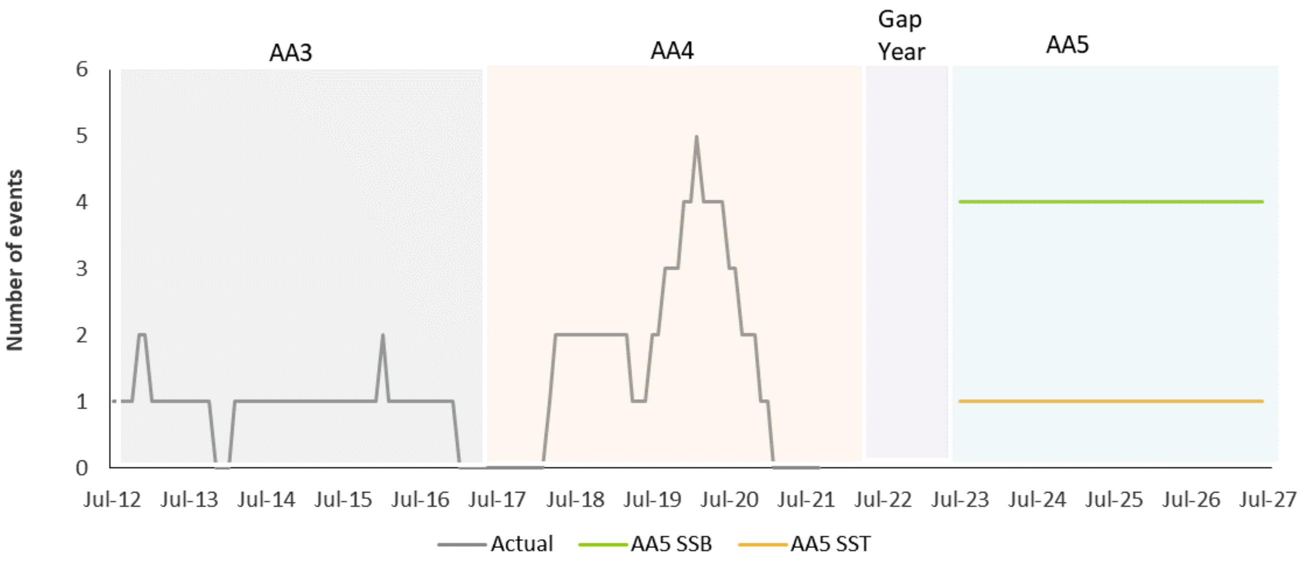
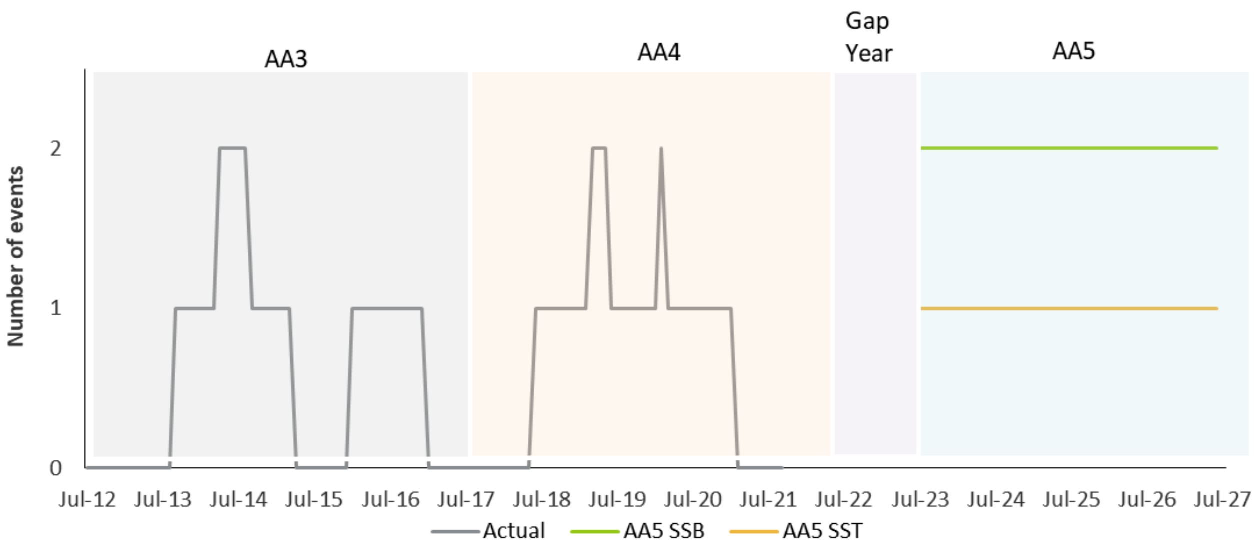



**Figure 6.18: Loss of supply event frequency >1**



### 6.8.3 Streetlight network measures

**Figure 6.19: Streetlights metropolitan area repair time**

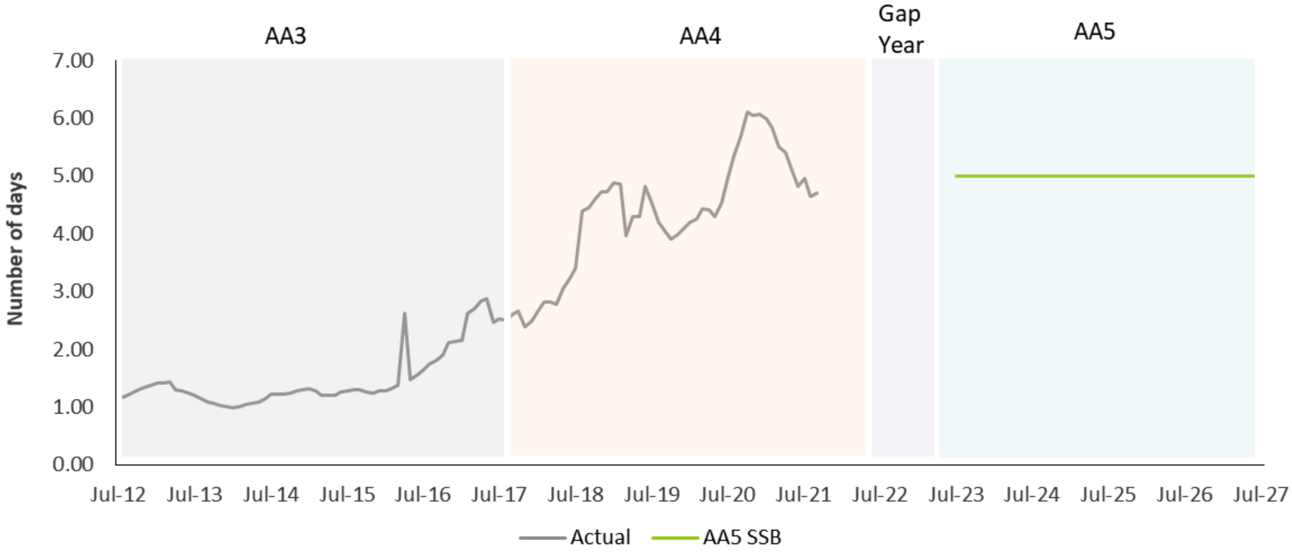
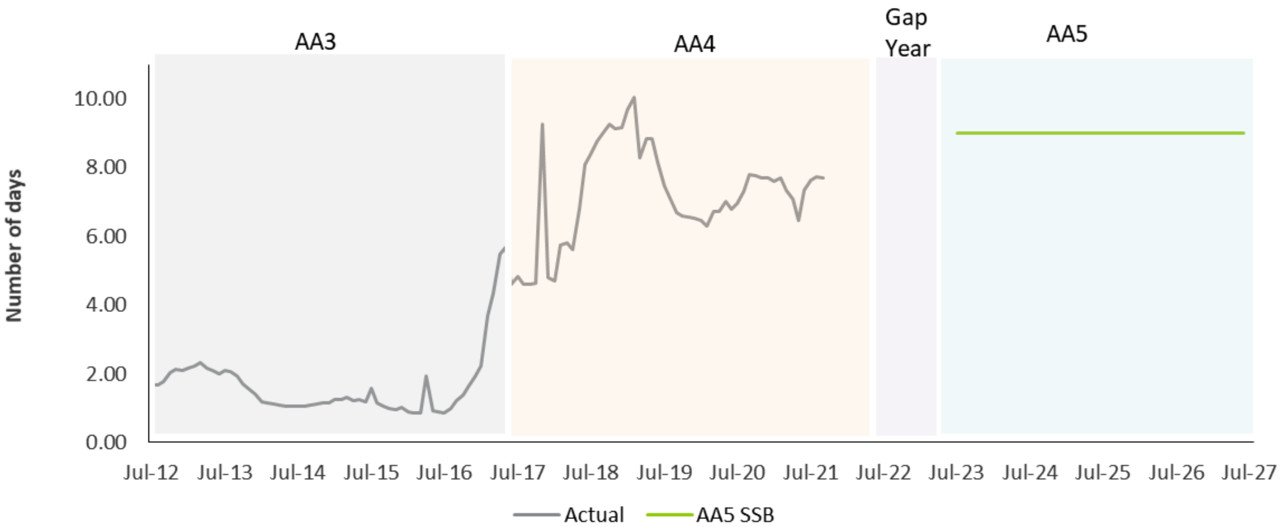



**Figure 6.20: Streetlights regional area repair time**



# 7. Forecast operating expenditure

580. This chapter provides the methodology used to determine the forecast opex required by Western Power over the AA5 period. It also provides an overview of the opex forecasts, including the rationale for any changes from the AA4 period.

**Key Messages**

- Efficiencies achieved during AA4 are embedded in to our AA5 forecast operating expenditure as well as additional expected productivity improvements
- Our operating expenditure forecast is marginally lower than last period despite absorbing additional costs associated with growth in the network, labour costs and increased obligations and functions
- We have adopted the base-step-trend approach that complies with the Access Code and is the current practice of the ERA and AER. This is the same method we used to forecast our costs in the AA4 period.
- Our operating expenditure forecast is $2,169.8 million, which is marginally lower than the costs incurred in the AA4 period of $2,175.6 million. This forecast includes $104.9 million in additional costs associated with new obligations and functions, $52.9 million due to growth in our network and $42.7 million to reflect rising labour costs

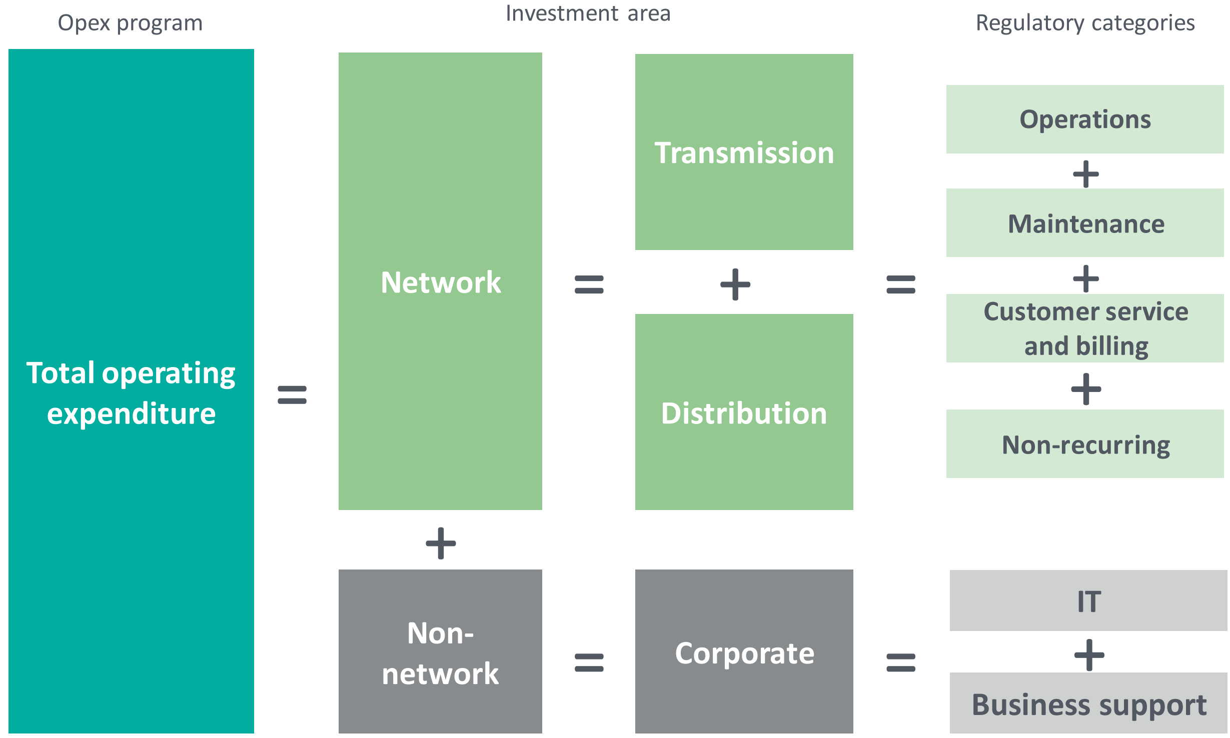
## 7.1 Overview of the operating expenditure proposal

581. Western Power forecasts it will require $2,182.7 million in opex to safely and effectively operate and maintain the Western Power Network over the AA5 period. In general, opex reflects activities and costs that are ongoing and recurring. It includes the costs of:

- operating and maintaining our physical and digital assets, such as our poles, wires, substations, monitoring and control systems and maintaining and improving levels of safety on the Western Power Network
- responding to faults and emergencies, such as reactive repair and maintenance activities to rectify unsafe conditions arising from extreme climate events
- performing customer-related functions, such as customer service, billing, and call centre services
- corporate support services, including business support functions such as human resources, finance, governance, legal and compliance.

582. Western Power's opex is split into the categories shown in the figure below.

**Figure 7.1: Regulatory opex categories**




Notes:

(5) Areas not to scale of the investment

583. The opex forecast over the AA5 period is consistent with section 6.40 of the Access Code in that it contains only non-capital costs that would be incurred by a service provider efficiently minimising costs. Our opex forecast reflects improvements we have made to our work practices and processes during the AA3 and AA4 periods while continuing to maintain a safe and reliable network and deliver services in line with customer expectations.

584. We have used the 'base-step-trend' method to forecast recurrent opex. In summary, the method takes the most recent efficient year of opex and adjusts the level of expenditure for:

- any expenditure not reflective of the recurrent cost base
- categories of opex impacted by discrete step changes
- changes in output and cost input trends over the forecast period.

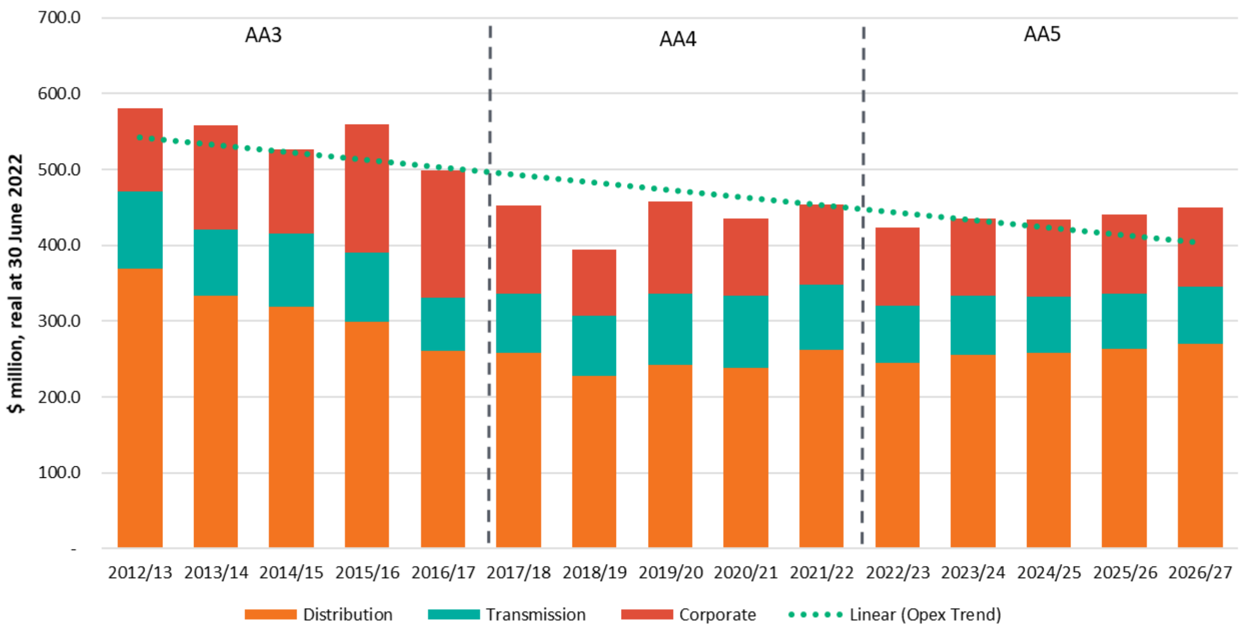
585. We have developed our AA5 opex forecast using the base-step-trend method, which has the following benefits:

- it is simple and transparent
- it has been applied in recent regulatory decisions in Australia, including Western Power's AA4 decision
- it embeds efficiency gains made by Western Power during the AA4 period.

586. Figure 7.2 shows how historical opex compares to the AA5 forecast opex, split by the three investment areas.

587. Note that Figure 7.2 and Table 7.1 include real cost escalation and expensed indirect costs. Unless otherwise stated, all other expenditure numbers in this chapter do not include real cost escalation and indirect costs.

**Figure 7.2: AA3 and AA4 historical and AA5 forecast opex, including indirect costs and escalations, $ million real at 30 June 2022**




588. Western Power's forecast opex for the AA5 period is $2,182.7 million. This is in line with the $2,193.2 million opex incurred during the AA4 period and 20 per cent lower than actual opex in the AA3 period.

589. Our proposed base year incorporates the business improvements we made over the AA4 period to make costs more effective and sustains these savings over the AA5 period.

590. Table 7.1 summarises the total AA5 opex forecast, including real cost escalation and indirect costs, split between corporate support opex and the opex required to operate and maintain the transmission and distribution networks.

**Table 7.1: AA5 forecast opex including indirect costs and escalations, $ million real at 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Distribution | 245.7 | 255.8 | 258.8 | 262.9 | 270.7 | 1293.9 |
| Transmission | 74.8 | 77.7 | 72.9 | 73.6 | 74.4 | 373.5 |
| Corporate | 103.4 | 101.3 | 102.6 | 103.6 | 104.5 | 515.4 |
| **Total opex** | **423.9** | **434.9** | **434.3** | **440.1** | **449.5** | **2182.7** |

591. The remainder of this chapter explains:

- how Western Power has developed the opex forecasts, including how the AA5 proposal meets the regulatory requirements
- how our proposal addresses the matters raised by customers and stakeholders.

### 7.1.1 Opex forecast informed by customer insights

592. We have taken into account the key findings of our CEP to develop our proposed opex forecasts. We have balanced our opex proposal to ensure it provides sufficient revenue to maintain a safe and reliable network

and accommodate the changing landscape and customer requirements, while efficiently optimising expenditure so that the flow-through impact on customers' electricity prices is minimised.

593. Our proposed step changes are in line with our customers' investment priorities:

- decommissioning of portions of the distribution network as they are replaced by SPS solutions in our asset replacement program to transform the network to more effectively meet customers' reliability and safety needs
- investments in SCADA to support an increase in AMI and SPS on the Western Power Network, to manage equipment obsolescence and to combat the increasing cyber security threats, which will support the transformation of the network to meet future needs and maintain the safety and reliability of the network.
- changing the approach to our silicone treatment program to maintain the safety and reliability of the Western Power Network
- investments in condition monitoring capabilities to maintain the reliability of supply, which is critical to customers
- investments in DSO capability that will support and improve the integration of DER in the Western Power Network.

## 7.2 Regulatory framework

594. Western Power's opex forecast is required to meet the Access Code objective, which is:

> *to promote efficient investment in and efficient operation and use of, services of networks in Western Australia for the long-term interests of consumers in relation to:*
>
> *a) price, quality, safety, reliability and security of supply of electricity;*
>
> *b) the safety, reliability and security of covered networks; and*
>
> *c) the environmental consequences of energy supply and consumption, including reducing greenhouse gas emissions, considering land use and biodiversity impacts and encouraging energy efficiency and demand management.*

595. Section 6.40 of the Access Code requires our opex forecasts to include only those non-capital costs which would be incurred by a service provider efficiently minimising costs, which is defined in the Access Code as follows:

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

596. Sections 6.41 and 6.42 of the Access Code provide for Western Power to recover opex where it is incurred as an alternative to providing covered (regulated) services through investing in a major augmentation of the network:

> *6.41 Where, in order to maximise the net benefit after considering alternative options, a service provider pursues an alternative option in order to provide covered services, the non-capital*

*costs component of approved total costs for a covered network may include non-capital costs incurred in relation to the alternative option ("alternative option non-capital costs") if:*

*a) the alternative option non-capital costs do not exceed the amount of alternative option non-capital costs that would be incurred by a service provider efficiently minimising costs; and*

*b) at least one of the following conditions is satisfied:*

*i. the additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs; or*

*ii. the alternative option provides a net benefit in the covered network over a reasonable period of time that justifies higher reference tariffs; or*

*iii. the alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.*

*6.42 For the purposes of section 6.41(b)(i) "additional revenue" for an alternative option means:*

*a) the present value (calculated at the rate of return over a reasonable period) of the increased tariff income reasonably anticipated to arise from the increased sale of covered services on the network to one or more users (where "increased sale of covered services" means sale of covered services which would not have occurred had the alternative option not been undertaken)*

*minus*

*b) the present value (calculated at the rate of return over the same period) of the best reasonable forecast of the increase in non-capital costs (other than alternative option non-capital costs) directly attributable to the increased sale of the covered services (being the covered services referred to in the expression "increased sale of covered services" in section 6.42(a))*

*where the "rate of return" is a rate of return determined by the Authority in accordance with the Code objective and in a manner consistent with this Chapter 6, which may be the rate of return most recently approved by the Authority for use in the price control for the covered network under this Chapter 6.*

597. Western Power submits that the proposed AA5 opex forecast, as determined by the base-step-trend method, reflects the expenditure that would be incurred by network service provider efficiently minimising costs, as discussed in section 7.3.

## 7.3 Development of the opex forecasts

598. Western Power applies a robust governance framework to expenditure. The opex program is revised and updated annually in line with the investment planning cycle and documented in our Network Management Plan and business outlook. Significant increases in existing opex programs or new opex requirements are subject to an investment governance process. Further information on the Investment Governance Framework (**IGF**) is provided in Confidential Attachment 7.1.

599. Opex is recurrent in nature and, at an overall level, typically does not materially change from year to year. While there will be fluctuations in costs at a category level from one year to the next, at a total level, opex is relatively stable. As such we applied a top down forecasting approach (the base-step-trend method) that forecasts future costs on the basis of revealed past costs.

600. The base-step-trend method escalates base year opex using growth factors, to account for changes in input prices, higher expenditure to deliver greater output, and productivity improvements. Annual fluctuations in costs at a category level can typically be managed within the existing base and the rate of change forecast.

601. Where costs change due to capex-opex trade-offs or reasons beyond Western Power's control (such as cost increases associated with new regulatory obligations), the base-step-trend method accounts for these cost increases through step changes, where such costs are considered to be efficient.

602. To be internally consistent, and develop an opex forecast that is reflective of costs that would be incurred by a service provider efficiently minimising costs, it is important that the base-step-trend method is applied in its entirety and all elements are applied consistently.

603. Figure 7.3 summarises how the base-step-trend methodology is applied.

**Figure 7.3: Summary of opex forecasting method (base-step-trend) (1)**

**1 Start with the efficient base year**

We have used 2020/21 actual audited recurrent opex as the base year, which is our most recent year of financials. We have adjusted this for non-recurrent costs which are not reflective of ongoing opex required. We consider that this is representative of the efficient costs needed to operate and maintain the network in 2020/21.

**2 Adjust for step changes in recurrent opex**

We have forecast and adjusted the recurrent base year opex for increases or decreases in costs arising from new or amended obligations and/or activities expected over the AA5 period.

**3 Trend to account for network growth**

We have forecast the growth drivers of opex and added incremental changes in costs associated with servicing a growing network and customer base over the AA5 period.

**4 Adjust for productivity improvements**

We have applied a productivity adjustment to our AA5 forecast to reflect expected industry-wide improvements in finding more efficient ways of delivering services.

**5 Adjust for non-recurrent opex**

We have forecast and adjusted the opex for one-off changes in costs arising from new or amended obligations and/or activities expected to occur as discrete activities over the AA5 period.

**6 Trend to account for changes in labour costs**

We have forecast the changes in labour costs over the AA5 period and added incremental changes in costs to reflect these changes in costs over time.

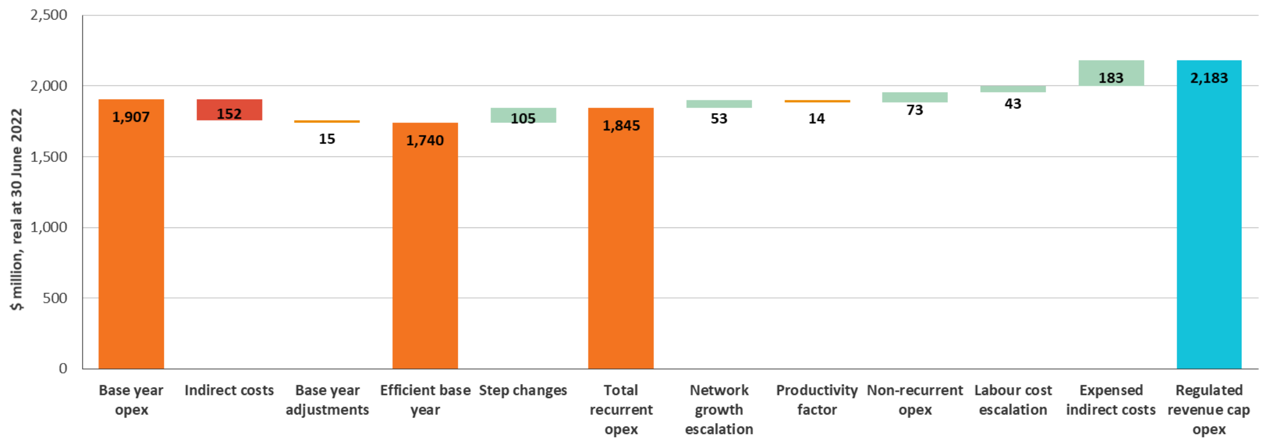
**7 Forecast opex for AA5**

Notes:

(1) The base-step-trend methodology is applied to direct and indirect costs separately. That is, expensed actual indirect costs are removed from the 2020/21 actual audited recurrent opex. Indirect costs (including both expensed and capitalised costs) are forecast for the AA5 period using the same base-step-trend approach. Indirect costs are then allocated between opex and capex in accordance with Western Power's Cost and Revenue Allocation Methodology.

604. Figure 7.4 shows the build-up of the AA5 forecast opex using the base-step-trend method. The values include expensed indirect cost and labour escalation.

**Figure 7.4: Build-up of AA5 total opex forecasts, $ million real at 30 June 2022**




605. Each year Western Power incurs costs that cannot be directly attributed to specific projects but are required to facilitate the delivery of the overall business requirements. These are referred to as 'indirect costs'. We have removed actual expensed indirect costs from the base year and forecast total indirect costs separately, using the same base-step-trend method, and then allocated them between opex and capex in accordance with Western Power's Cost and Revenue Allocation Methodology (see Attachment 7.2). Indirect costs over the AA4 period are forecast to be $842.6 million, with $183.4 million being expensed and the remaining $659.2 million being capitalised.

606. Table 7.2 shows a summary of the various components of the forecast opex build up.

**Table 7.2: AA5 forecast opex including expensed indirect costs and escalations, $ million real at 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| **Efficient base year** | **348.1** | **348.1** | **348.1** | **348.1** | **348.1** | **1,740.5** |
| Step changes | 21.9 | 21.1 | 20.9 | 20.7 | 20.3 | 104.9 |
| **Total recurrent opex** | **370.0** | **369.2** | **369.0** | **368.8** | **368.4** | **1,845.4** |
| Network growth escalation | 5.1 | 7.1 | 10.7 | 13.8 | 16.2 | 52.9 |
| Productivity improvement | -0.9 | -1.9 | -2.8 | -3.8 | -4.8 | -14.3 |
| Non-recurrent opex | 10.9 | 18.1 | 13.4 | 13.2 | 16.9 | 72.5 |
| Labour cost escalation | 4.3 | 6.5 | 8.5 | 10.6 | 12.9 | 42.7 |
| Expensed indirect costs | 34.7 | 35.8 | 35.5 | 37.5 | 39.9 | 183.4 |
| **Regulated revenue cap opex** | **423.9** | **434.9** | **434.3** | **440.1** | **449.5** | **2,182.7** |

## 7.4 Establishing the efficient base year

607. The purpose of the base year in the base-step-trend method is to provide a reasonable starting point for our forecast opex. The base year shows what we currently incur for recurrent activities and reflects our on-going requirements to maintain the quality, safety and reliability of the Western Power Network during the

AA5 period in line with our customers' expectations and help the network transition to a zero carbon future in line with Government commitments.

608. Western Power has determined our proposed base year opex according to our actual recurring opex for 2020/21, which is $348.1 million. This includes:

- $194.1 million of recurring opex on the distribution network
- $60.6 million of recurring opex on the transmission network
- $93.4 million of recurring corporate opex.

609. The efficient base year has been determined by adjusting the 2020/21 regulated financial statements actual opex for the following items:

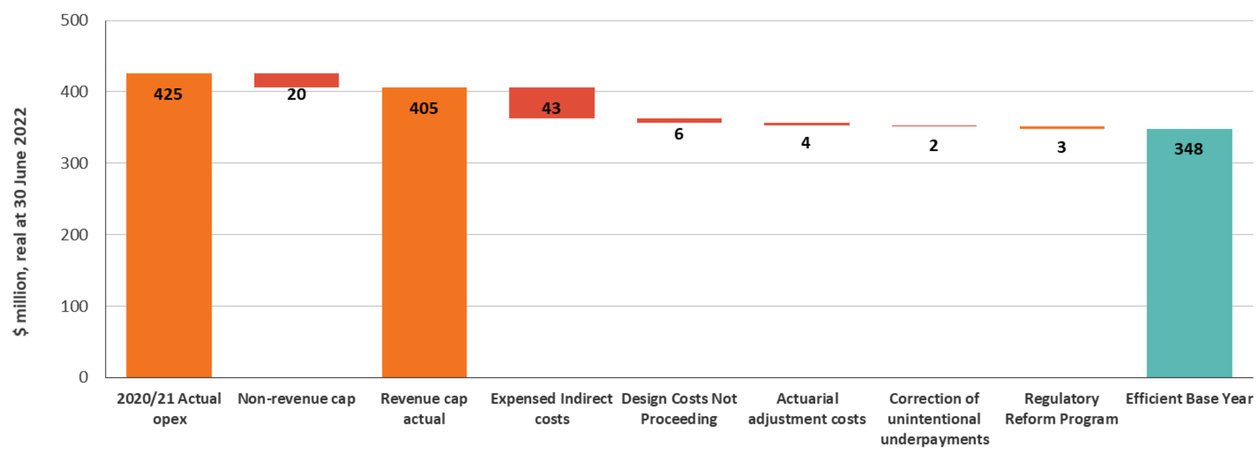
- **Removal of non-revenue cap services:** Western Power's non-revenue cap services, such as high load escorts and transmission line relocations, are forecast independently and are not required to be approved by the ERA. The 2020/21 actual opex amount included $20 million[127] of non-revenue cap services expenditure. This has been removed from the recurrent base year.
- **Removal of non-recurrent expenditure:** We have removed the $14.6 million of non-recurrent expenditure from the 2020/21 actual opex. The following costs are non-recurrent in nature and not reflective of ongoing opex required to maintain the quality, safety and reliability of the Western Power Network:
  - *Design costs:* The 2020/21 actual opex includes $5.6 million of design costs for a specific project that did not proceed. The design costs incurred for this project were subject to a customer contribution and therefore have been removed from the base year.
  - *Actuarial adjustment costs:* The 2020/21 actual opex includes $4.2 million of actuarial adjustment costs. The actuarial adjustment occurs annually and will fluctuate based on a number of factors such as actual leave taken, hourly rate increases, length of tenure/turnover rates and change in retirement age assumptions. The adjustment for 2021/22 actual costs was substantially higher than the observed five-year average and therefore, we have removed the additional cost above the five-year average from the recurrent base year.
  - *Removal of correction of unintentional underpayments:* The 2020/21 actual opex includes $1.8 million of incremental one-off costs associated with a correction of unintentional underpayments identified in Western Power's underpayment review. As these costs are not recurrent in nature, they have been removed from the base year.
  - *Removal of Regulatory Reform costs:* The 2020/21 actual opex includes $3.1 million of operating costs associated with regulatory reform initiatives. As noted in Chapter 3, the WA Government launched the Energy Transformation Strategy in March 2019 in response to the changing energy landscape and changing customer behaviour. Accordingly, Western Power established a Regulatory Reform Program to work closely with Energy Policy WA, AEMO and the Taskforce in the development and implementation of the Energy Transformation Strategy. Western Power considers that the incremental costs of the Regulatory Reform Program will not be recurring on an annual basis and have therefore removed the incremental costs incurred in 2020/21. A corresponding non-recurring adjustment has also been included in 2022/23 to reflect the expected costs to be incurred by Western Power in addressing and implementing Stage 2 of the Energy Transformation Strategy.

127 Including the indirect cost allocation to non-revenue cap services.

- **Removal of indirect costs:** The 2020/21 actual opex amount includes $42.8 million of expensed indirect costs. We have removed these from the recurrent base year. This is because we forecast indirect costs separately and then allocate them between capex and opex activities (to leave indirect in the base year would result in a double count). The forecasting approach for indirect costs is discussed in section 7.9.

610. Figure 7.5 shows the adjustments from the 2020/21 regulated financial statements to determine the efficient base year.

**Figure 7.5: Determination of efficient base year, $ million real at 30 June 2022**




### 7.4.1 Inclusions in the efficient base year

611. The majority of recurring opex during 2020/21 (60 per cent) was for the recurrent operating and maintenance activities that Western Power undertakes to meet safety service standard and compliance obligations. The remaining share was driven by corporate support services such as human resources, finance, governance, legal and compliance.

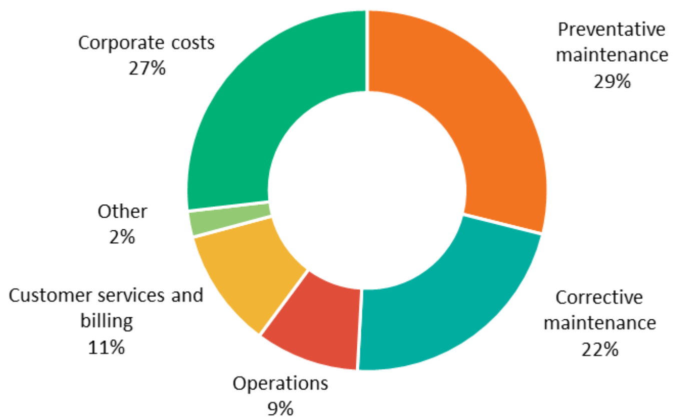
612. Table 7.3 below sets out the opex categories included in the efficient base year and Figure 7.6 summarises the allocation of our forecast opex to each of the categories in our base year.

**Table 7.3: Recurrent opex categories**

| Opex category | Description | Base year total ($ million, real at 30 June 2022) |
|---|---|---|
| ***Recurrent opex*** | | |
| Preventative maintenance | Proactive inspection, identification and treatment of poor performing assets that are likely to fail, to:<br>– maintain our assets across their expected lives<br>– maintain network performance. | 100.6 |
| Corrective maintenance | Maintenance activities to rectify unsafe conditions arising from extreme climate events, deteriorating performance of ageing assets, failed assets and other reactive events. | 76.5 |

| Opex category | Description | Base year total ($ million, real at 30 June 2022) |
|---|---|---|
| Operations | Communication within the Western Power Network to:<br>– allow access to the network for maintenance and capital works<br>– maintain reliability through network monitoring and other network switching operations. | 32.4 |
| Customer services and billing | Activities to maintain service to customers through our call centre, billing services, and repair and maintenance of meters. | 37.1 |
| Other | Works required at the initiation stage to identify network issues and determine high level solutions. This includes developing annual load forecasts, exploring emerging technologies, non-network solutions development and creating new standards and policies. | 8.2 |
| ***Corporate costs*** | | |
| Corporate costs | Recurrent administrative activities and corporate support services to run the business (including business support functions such as human resources, finance, governance, legal and compliance). | 93.4 |
| **Total** | | **348.1** |

**Figure 7.6: Forecast base year opex by category**

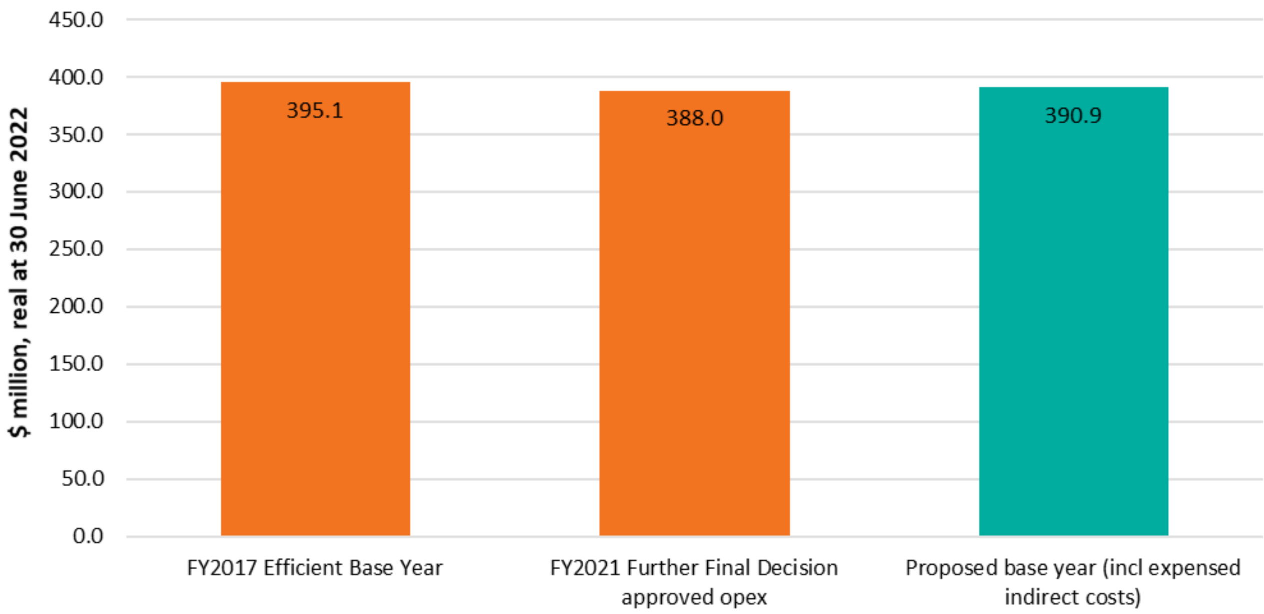



### 7.4.2 Why the base year is efficient

613. We consider our proposed base year opex is efficient for the following reasons:

- our proposed base year is in line with the ERA’s approved opex for 2020/21 and the ERA's approved base year opex for 2016/17 in the AA4 Further Final Decision (see Figure 7.7)
- the 2020/21 base year amount embeds opex savings resulting from improvements to Western Power’s work practices and processes, asset strategies, procurement processes and organisational structure implemented during the AA3 and AA4 periods. These improvements have ensured that our proposed base year remained efficient, and we will sustain these efficiencies into the AA5 period
- we were subject to the gain sharing mechanism during the AA4 period and responded to the incentives to improve productivity.

**Figure 7.7: Efficient base year compared to AA4 opex, including expensed indirect costs, $ million real at 30 June 2022**




### 7.4.3 Rolling forward the base year

614. As our proposed base year is the penultimate year of the AA4 period, we need to roll forward the base year to account for inflation in the final year of the AA4 period. To do this, we engaged Synergies to determine the inflation rate for 2021/22 as well as the inflation rates to apply for the AA5 period. Synergies determined the inflation rate for 2021/22 to be 1.75 per cent based on the most recent WA Treasury forecast and this is used to roll forward the efficient base year opex to 2021/22 (the final year of the AA4 period). Further information on Synergies inflation forecasts is in Attachment 7.3 – Forecast Cost Escalators for the AA5 Period.

## 7.5 Adjusting for step changes

615. Step changes are increases or decreases in our opex associated with meeting new or changed regulatory obligations or new activities. As such, the costs of step changes are not captured in the base year expenditure or trend escalation and will be added separately to recover our efficient costs.

616. Our forecast opex includes 11 step changes. Table 7.4 provides a summary of our proposed step changes. Each step change is discussed below.

**Table 7.4: Step changes, $ million real at 30 June 2022**

| Step Change | Description | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total |
|---|---|---|---|---|---|---|---|
| Repair streetlight faults | Additional volume of streetlights to repair, and additional cost due to increase in labour and LED material costs | 4.5 | 4.5 | 4.5 | 4.5 | 4.5 | 22.7 |

| Step Change | Description | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total |
|---|---|---|---|---|---|---|---|
| DSO capability | Develop the necessary internal capability within Western Power to Operate its DSO function as stipulated in the DER roadmap, including processes to ensure compliance of new DER devices connecting to the network meet technical standards | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 21.8 |
| Meter reading | Less manual meter reading as a result of the acceleration of the AMI deployment | -0.8 | -2.1 | -2.8 | -3.6 | -4.5 | -13.9 |
| Silicone treatment program | Changing the approach to our silicone treatment program to maintain the safety and reliability of the Western Power Network and our workforce | 5.3 | 5.3 | 5.3 | 5.3 | 5.3 | 26.4 |
| Digital substation | Support for installation of devices and additional resources to analyse and prosses the data associated with new digital substation program | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 5.0 |
| SCADA and Tele-communications | Cyber security, SPS and AMI implementation | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 19.5 |
| SPS maintenance | Inspections and emergency response aligned with increase in SPS volumes | 0.2 | 0.7 | 1.3 | 1.8 | 2.4 | 6.4 |
| Governance and safety assurance | Increased Safety, Environment, Quality & Training (**SEQT**) training program & increased focus on compliance & governance | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 3.8 |
| Light Detection and Ranging (**LIDAR**) program | New strategy to survey one-quarter of the network each year rather than the full network each 3-4 years. Shifted from non-recurrent to recurrent expenditure | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 6.1 |
| Distribution power quality monitoring | New system to be developed to improve data accessibility for the low voltage network's power quality meters | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 2.2 |
| HV injection unit and emergency response generator | New strategy to deploy additional emergency response generators as part of fault response | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 5.0 |
| **Total value of step changes** | | **21.9** | **21.1** | **20.9** | **20.7** | **20.3** | **104.9** |

### 7.5.1 Repair streetlight faults

617. The repair streetlight faults activity is the non-routine repair of streetlight faults and predominantly responds to customer reports of faulty streetlights. This activity is a direct requirement of the defined restoration timeframes defined in Western Power's Access Arrangement for streetlighting reference

services, for restoration of streetlight faults within the defined restoration timeframes. This is to restore the public safety benefit of a suitable and reliable visual environment.

618. Western Power's Public Lighting Strategy defines the current strategy of identifying and responding to streetlight faults. Specifically, that streetlights that have failed in service are identified by the public or workforce and are progressed for remediation. As part of this, we have developed a transition strategy to efficiently manage a transition to LED globes and luminaires in line with the cessation of the use of mercury vapour as per the Minamata Convention on Mercury and supports the Code objective in section 2.1(c) of the Access Code. The strategy aims for 100 per cent LED streetlights by 2029 (as compared to 3 per cent on 30 June 2020), which will lower carbon emissions and streetlighting energy costs. The shift to replacing mercury vapour globes with LED is overall a slightly higher material cost, with the added benefits of reducing maintenance expenditure due to a longer life of globes, reduced energy consumption and better environmental outcomes.

619. The opex step change will be an ongoing $4.5 million per annum cost. This is due to:

- **increased unit rates**: $3.0 million of the step change is attributable to an increased unit rate, predominately driven by:
  - increased material cost: As an alternative to replacing the full luminaire to facilitate replacement of mercury vapour globes with LED, Western Power has designed a LED globe that can be fitted to existing luminaires. This requires a comparatively marginal increase in cost of approximately $25 additional material expense but enables Western Power to preserve existing luminaires without having to replace the full luminaire at substantially higher cost. Further, an update to the maintenance guidelines included the requirement to replace the globe, fuse and PE cell on identification of a fault on either component. This decision was made with the intention to decrease repeat visits to the same asset, which is expected to result in a gradual reduction in volumes of the repair streetlight fault activity over the AA6 and AA7 periods.
  - increased delivery cost: The cost of labour delivering streetlight fault response has increased due to the decision to replace the globe, fuse and PE cell on identification of a fault on either component. This change is expected to result in a gradual reduction in volumes of the repair streetlight fault activity over the AA6 and AA7 periods. Further, this transition enables improved operational flexibility to respond to emergency events.
- **increased volumes**: $1.5 million of the step change is attributable to a 12 per cent increase in the forecast volumes of streetlight faults. The number of faults reported have been increasing in recent years as a result of enhanced public awareness and with technological advancements in the ability to report streetlight faults. Western Power expects a gradual reduction in the number of streetlight faults over the AA6 and AA7 periods as the transition to the use of LEDs progresses.

620. We assessed various options to address the identified need in developing our step change forecast, summarised in the table below. Our assessment of these options demonstrated that reactive replacement of streetlights with LED globes is the most cost-effective option.

Table 7.5: Summary of repair streetlight faults options assessment

| Option | Summary of assessment |
|---|---|
| Replace reactively with LED globes | Market changes to respond to Australia's obligation under the Minamata Convention has improved LED technology as well as driven down the costs to a comparable level as like for like options. Further, reactive replacement with LED globes will deliver added benefits of reducing maintenance expenditure due to a longer life of globes, reduced energy consumption and better environmental outcomes. Reactive replacement using LED globes is the recommended option. |
| Replace like for like | This option does not meet the requirements of the Minamata Convention to phase out mercury vapour globes and does not deliver lower carbon emissions and reduced streetlighting energy costs. Further, market changes to respond to Australia's obligation under the Minamata Convention has resulted in unavailability of traditional mercury globes and has driven down the costs of LED globes to a comparable level as like for like options. In addition to the inability to procure, replacing like for like does not represent much of a cost saving and also does not deliver the customer benefits provided by replacing with LED. |

### 7.5.2 DSO capability

621. Consumers and the broader community have told us they expect Western Power to integrate more renewables into the grid and to prepare the grid for the future. This requires a sustainable approach to DER management, to manage critical minimum demand risks while maximising the opportunity for the community to invest in DER.

622. DER, such as solar panels, batteries and EVs, are revolutionising the electricity industry, by giving customers more choice in generating, storing and using energy. The co-ordinated integration of DER has the potential to offer our customers better value through better use of resources.

623. Western Power's drive to support changing energy sources and leverage emerging technologies to provide greater customer choice is reflected in our role in the WA Government's DER Roadmap, which outlines Western Power's evolving role as the DSO in the SWIS.

624. DSO business and operating models around the world are nascent and will continue to evolve based on developments and learnings both here in Australia and internationally. We have been evolving our DSO strategy since 2017 and have been working with industry to deliver a functioning DSO by 2023 and increasing our capability beyond this.

625. To do this, Western Power has been collaborating with Energy Policy WA, AEMO and industry to create the conditions for maximising the value of DER in the interest of reducing energy costs and facilitating the transition to renewable energy. We seek to do this by:

- Facilitating the connection of DER to our grid in line with Western Power Corporate Strategy which aims to support greater than 50% of all energy needs being met by renewable sources by 2031. This will provide environmental benefits to the community by de-carbonising our grid while maintaining existing safety and reliability objectives
- Reducing network augmentation costs by leveraging customer DER, in the form of Network Support Services (NSS) and NCESS and increasing utilisation of our existing asset base, and
- Minimising the amount we pay for NSS by maximising potential for customer DER to access other value streams (via participation in wholesale energy market) within technical limits of the grid at any given time (via Dynamic Operating Envelopes)

626. We are evolving our technical connection agreements to ensure that they are in-line with customer expectations by supporting customer DER participation in future energy markets. This capability will be achieved by dynamically managing network capacity through Dynamic Operating Envelopes (DOE) that represent the physical capacity of the local distribution network that is available for all customers to export energy at any given point in time.

627. Western Power is looking to work collaboratively with Aggregators such that they are able to establish VPPs that can export their customer DER capacity to provide:

a) Services to the wholesale market within the technical limits of the distribution network (i.e. within a calculated DOE)

b) NSS or NCESS to us to address technical network issues.

628. The enhancement of our DSO role needs to integrate with Western Power's essential function in operating and maintaining the network, particularly with respect to outage management. Active visibility and management of DER to ensure that the network remains within its technical limits is essential.

629. Our AA5 proposal includes investment to enable sustainable DER management and to meet our actions under the Energy Transformation's DER Roadmap. A key component of this is enhancing our DSO capability.

630. As noted in Chapter 2, the rapid uptake of DER is causing technical challenges in managing the Western Power Network (such as voltage management), that, unmanaged, will continue to escalate and require intervention and planning.

631. In its most recent distribution decision for SA Power Network, the AER accepted a step change increase in opex for DER management, noting that SA Power Networks appears to be facing significant demands to manage its network and address its customers' needs, including potential voltage non-compliance. The AER considered that the output growth factors may not fully compensate for the higher cost to address DER management.[128]

632. Western Power considers this reasoning is equally applicable to the costs Western Power is facing with increased DER penetration on the Western Power Network, and the transition to the DSO role. If anything, the technical challenge for Western Power in DER management is greater given the Western Power Network is a stand-alone network with no interconnectors that can assist with demand management and other stability issues.

633. Further, establishing this capability is necessary for Western Power to be able to leverage third-party DER via NSS / NCESS in future. These services are expected to reduce in cost over the coming years, with the goal of being lower cost in many instances than capex investment in keeping with our obligations under 6.41 and 6.42 of the Access Code. Further information about the regulatory change introducing the DSO role is provided in Chapter 3.

634. There will be an ongoing $4.4 million per annum cost to develop capability and processes to enable Western Power to develop DSO capabilities.

635. A foundation of our AA5 proposal is to continue to build capability in and develop alternative solutions and leverage technology that have the potential to reduce long-term costs for customers. Leveraging existing opportunities, building the capability of our business and alternative options now, enables Western Power to select the most prudent and cost-efficient option to address the issues expected to face the network during the AA5 period and beyond. As such, our forecast operating expenditure and capital expenditure reflects a set of least-regrets initiatives in response to changes we know will continue to occur in our energy

[128] AER, *SA Power Networks Distribution Determination 2020 to 2025 – Final Decision*, Attachment 6 – Operating expenditure, June 2020

market over the coming access arrangement, particularly as the customer take-up of DER continues to accelerate. Given the relative uncertainty about the future, and as the role of the DSO continues to evolve, we intend to build ‘no-regret’ initial DSO capabilities:

- DER Roadmap: We are actively delivering and supporting a number of the actions under the Roadmap.
- Project Symphony: A collaboration with AEMO, Synergy and Energy Policy WA to demonstrate how a version of the Hybrid model could demonstrate how DER can be aggregated into a VPP facility to participate in the WEM and provide services to the network. This project will provide a foundational evidence base for understanding what works and what does not, with the project outcomes informing the blueprint for the future.
- Network Opportunities Map (NOM): We have recently published the first NOM, giving aggregators an early indication of where we may have future network constraints that could be alleviated via non-network solutions. These opportunities will be updated annually via the NOM on the Western Power website.
- LV Visibility: We already can measure, control and validate performance of the distribution network, though this is predominantly at Medium Voltage level only. It is essential that this capability is extended to the LV network to include residential customers to facilitate provision of future services via DER. We're committed to installing AMI on our network to pave the way for new technologies that will boost renewable energy and add value to grid connections. Advanced meters allow us to:
  - increase penetration of distributed energy resources
  - increase customer choice and safety benefits
  - enable government policy and initiatives that will help create the electricity grid of the future
  - reduce the number of estimated reads resulting in more accurate billing from the retailer
  - reduce our carbon footprint as more services can be provided remotely.
- Emergency Solar Management: The State Government has introduced a new emergency solar management measure (Distributed Photovoltaic Management) as a last resort to assist AEMO maintain power system security during extreme low load events. This measure will help facilitate greater levels of low-cost, low-emissions renewable generation overall, while managing the effects of the power system. From February 2022, all new or upgraded solar panel systems (with an inverter capacity of 5 kW or less) installed in Western Australian homes and businesses will be required to have the capability to be remotely turned down or off on mild sunny days when network-supplied demand for electricity reaches a critically low level. The capability to remotely switch off household solar panels will only be used as a last resort to manage the risks of low demand and its impact on secure electricity supply.
- Flexibility Services Pilot: A pilot to learn how to contract energy flexibility through customer assets. This project is providing valuable insight into the practicalities associated with market response validation within the technical limitations of the network.

636. The DSO capability step change has been estimated on the basis of resource requirements assumptions for both a DSO transition team and the required functional uplifts across the Western Power business to support the development and operation of this enhanced capability.

### 7.5.3 Meter reading

637. Western Power commenced AMI deployment in 2019, with the deployment due for completion in 2027. It is expected that approximately 92 per cent of customers will have advanced meters installed once the

deployment is completed.[129] Nearly half a million advanced meters will be rolled out by June 2022, with a further 795,130 scheduled to be rolled out during the AA5 period. Further information about the AMI deployment during the AA5 period is outlined in Chapter 8.

638. As the AMI deployment accelerates, the number of manual meter reads required decreases and will result in ongoing opex savings. We estimate the opex savings over AA5 will be $13.9 million. These savings have been forecast on the basis of our current unit costs and forecast roll-out of AMI during the AMI period.

#### 7.5.4 Silicone treatment program

639. The primary driver of this step change is the safety of Western Power and contractor personnel undertaking the silicone treatment program.

640. To reduce the likelihood of pole top fires, Western Power applies silicone grease on insulators periodically on its distribution overhead network. Western Power's siliconing program contributes to maintaining the safety and reliability of the network. Pole top fires are one of the key contributors to overall ground fires in the Western Power Network historically and have had a high incidence rate between 2017/18 and 2019/20. Pole top fires can also have reliability impacts when they cause damage to electrical infrastructure and that results in an outage.

641. The silicone treatment program involves washing and then coating insulators on poles with silicone to counteract the effects of dust and pollution build up. This maintenance treatment prevents the increase in leakage current that can cause pole top fires.

642. Historically, the silicone application process was applied while the line was energised (i.e. live-line), which was considered the most cost-effective application technique available at the time. A review of work practices was undertaken in 2020/21 and this determined that the application of silicone treatments would be undertaken on deenergised lines.

643. While this review was being undertaken, silicone treatments were carried out in the latter half of 2020/21 on de-energised lines. This change had the impact of reducing the volume of assets treated in this year as well as increasing the unit rate threefold. This unit rate increase can be primarily attributed to the additional time and resources required to plan and execute outages on lines to be treated.

644. As a result of the change in live-line washing and siliconing approach, Western Power has determined that silicone treatments in the AA5 period will be applied on de-energised lines, at the higher unit rates. These increased unit rates are driving the step change in the opex forecast expenditure for this program, combined with the base year of 2020/21 having a lower than normal expenditure.

645. In the AA5 period, the pole top fire mitigation strategy will focus on using the forecast expenditure to treat assets that pose the highest fire risks. Additionally, the strategy will be reviewed during the AA5 period to ensure that the treatments applied provide optimal value, and risks are adequately managed.

646. This investment will contribute towards maintain the safety (fire) and reliability performance of the network which is consistent with the findings of our CEP, where customers indicated that maintaining safety and reliability performance was critical.

647. There will be an ongoing $5.3 million per annum cost for the silicone treatment program. These costs have been forecast using a bottom up approach based on forecast volumes and forecast unit rates. The increase in cost is because of both the increase in the unit rate, due to the change in approach, and the higher volumes than during the base year. As the siliconing program was paused during the base year during the

129 AMI penetration is not expected to reach 100% as some premises are not suitable for AMI due to locational and physical factors that prevent mobile signals reaching the meter location.

review of work practices, lower than normal scheduled volumes were completed in the base year. The forecast volumes for the AA5 period are lower than the average volumes during the AA4 period due to challenges associated with the requirement to get planned outages for silicone treatment on de-energised lines.

648. We assessed various options to address the identified need in developing our step change forecast, summarised in the table below. Our assessment of these options demonstrated that silicone treatment on de-energised line is the only feasible option; hence this option forms the basis of our step change forecast.

**Table 7.6: Summary of silicone treatment program options assessment**

| Option | Summary of assessment |
|---|---|
| Live line silicone treatment | This option is to silicone insulators live-line, prioritising on insulators prone to pole top fires in extreme & high fire risk zones and on feeders known as prone to pole top fires (repeat offenders).<br>Although this option is lower cost, and provides better reliability performance outcomes, this option has been assessed as posing an unacceptable risk to the workforce. In addition, the outcome from this option will result in:<br>• Non-compliance to Work Health and Safety Act 2020<br>• Not meeting Western Power's risk appetite.<br>• Non-compliance to Western Power's Safety, Environment and Health Policy and Asset Management Policy.<br>As such, this option is not considered to be feasible. |
| Replace insulators | This option is to replace the at-risk insulators with new insulators that demonstrate superior leakage current performance in high polluting environment.<br>This option was not selected as this is not a financially prudent option. Standalone replacement of insulators requires significant capital expenditure compared to de-energised silicone treatment. |
| Silicone treatment on de-energised line | This option is to apply silicone treatment on de-energised line to treat assets in extreme and high fire risk zone as they pose the highest pole top fire risks. This option was chosen due to following benefits.<br>• Feasibility of the treatment given the workforce safety risk.<br>• Targeting insulators that pose high safety (fire) risk and so it is expected to return high benefit for moderate additional cost.<br>• Complaint to Electricity (Network Safety) Regulation 2015 and associated Electricity Network Management Safety System requirements.<br>• Complaint to Western Power's Asset Management Policy<br>• In line with Western Power's risk appetite.<br>• In line with customer and community expectation with respect to safety.<br>As outline above, even with this option, the forecast for pole top fires shows an increase of pole top fires in medium and low fire risk zones during the AA5 period resulting in localised reliability impact on the feeders with repeat pole top fires. The strategy will be reviewed during the AA5 period to ensure that the treatments applied provide optimal value, and risks are adequately managed. |

### 7.5.5 Digital substation

649. The digital substations initiative (online condition monitoring) is intended to improve condition information of critical transmission assets and deliver the following benefits:

- Capture condition data in 'real time' increasing accuracy, accessibility and timeliness of data.
- Enable more valuable insights into asset performance and defect management.
- Improve the depth and insight of asset performance to trend data over a period of time reducing the risk of regrettable spend on ageing assets, thereby reducing costs.
- Reduce system outages by analysing timely data to optimise the operational use of existing assets.
- Enable network level strategies (e.g., Rationalization Strategy) by providing Western Power with an important tool to help manage the risk associated with extending the life of the assets.
- Deferral of capital expenditure by enabling cheaper life extension options such as refurbishment.

650. The AA5 and AA6 periods will be crucial for the transitioning from the conventional coal generated, one way supply to the decentralized renewable generation model that community expects. Managing end-of-life of aged network assets is key initiative to facilitate a prudent transformation.

651. The digital substations initiative allows Western Power to refurbish expensive assets at a fraction of the cost of replacing and monitor their behaviour in real-time.

652. The plan for power transformers refurbishments in the AA5 and AA6 periods relies on the availability of online condition monitoring (devices and comms) that will be implemented by the digital substation's initiative.

653. There are 11 power transformers either refurbished in the AA4 period or planned to be refurbished in the AA5 and AA6 period that would have to be replaced if Western Power did not implement digital substations. Therefore, digital substations will support an identified cost avoidance of approx. $38 million in the AA5 period and so far, approx. $7 million in the AA6 period. This avoided cost estimate corresponds to the difference in cost between replacement and refurbishments. As other assets targeted in the digital substations initiative age and deteriorate, it is expected that similar cost avoidance opportunities will be explored.

654. The digital substation initiative will install sensors in primary plant assets (including switchboards and power transformers), establish communication links, and interface for analysis of the data. There will be an ongoing $1.0 million per annum opex cost to support the initiative and provide ongoing data analysis. These costs cover:

- support for the installation of the devices (such as scoping, planning, design, commissioning and project management) [130]
- establish and maintain (pay fees) of cloud-based service for storing collected data
- additional resources to analyse the data and change maintenance strategies
- device maintenance (minor works during planned shutdowns).

655. In the current operating context of the transmission network, this project is becoming increasingly critical to manage the network, particularly the Power Transformer fleet from the AA5 period onwards and the Switchboard fleet from the AA6 period onwards.

656. Costs for the digital substation were forecast as a total cost (combined capex and opex) to account for potential synergies. The opex component was estimated based on the costs incurred in the trial (based on a daily rate) and the estimated pace of the roll-out. Synergies and efficiencies expected from moving from a

130 This portion of opex may be susceptible to capitalisation when installed devices are capitalised. Due to an optimised approach to design with a fixed and a variable component, Western Power will journal costs to capex as appropriate and as the project progresses.

trial to a program were accounted for by defining the expected execution of the roll-out and expected utilisation of internal resources.

### 7.5.6 SCADA and Telecommunications

657. Western Power has proposed a step change for an increase in SCADA and Telecommunications expenditure to:

- improve security (cyber and physical security) to manage risks against our business and the Western Power network
- manage an increase in the operations and maintenance of SCADA and Telecommunications asset base, increased data and additional software and licencing to support increased AMI and SPS on the Western Power Network over the AA5 period.

#### *Security*

658. As critical community infrastructure, the potential impact of increasingly sophisticated cyber-attacks on the operation of the Western Power Network has come into sharp focus. In response to the increasing threat landscape, Western Power has been implementing enhanced cyber security controls and capability uplift programs in recent years.

659. To manage the resilience of critical digital assets such as SCADA and Telecommunications systems, and minimise the likelihood of cyber-attacks, all assets are purchased, operated, maintained, monitored and disposed of in line with Western Power's Cyber Security Strategy and standards. The Cyber Security Strategy includes a cyber security capability uplift program to develop and assist with the implementation of enhanced cyber security controls which will assist in managing Western Power's cyber security risk within our enterprise risk appetite and meet all applicable compliance requirements that are currently anticipated for the electricity sector, through proposed reforms to the *Security of Critical Infrastructure Act 2018*.

660. Western Power commenced delivery of Phase 1 of the Cyber Security Program in 2018, however the implementation of the cyber security controls and practices will continue during the AA5 period.

661. To assist in managing Western Power's cyber security risk within our enterprise risk appetite and meet all applicable cyber security compliance requirements, additional change in practices and implementation of new controls and capabilities is required, which have not been included in the proposed base year opex. This includes:

- reviewing and changing maintenance processes and practices to ensure compliance with proposed provisions for enhanced cyber security obligations
- enabling and/or modifying remote access to field assets for the purpose of maintenance and updates
- implementing specialised training to maintenance teams to ensure that critical field assets are maintained in accordance with the proposed revisions for enhanced cyber security obligations.

662. Additional opex is required to ensure delivery of this required capability uplift and change of existing practices to meet the new regulatory requirements.

#### *Increase in the SCADA and Telecommunications AMI and SPS asset base, increased data and additional software and licencing*

663. The activities in the work program that are driving the step change increase are aligned to the deployment of AMI and SPS over the AA5 period.

664. The continued deployment of AMI is resulting in an increase in the data being provided to Western Power. AMI data will travel from the meter via on-premise systems to be stored in the cloud. The on-premise system will require sufficient licencing to communicate to the total number of meters. Additional software licencing is required to support this increase in volumes of AMI in the Western Power Network.

665. The increase in SPS units being rolled out into the Western Power Network is also requiring a step change in costs for SCADA databases, and with the operations and maintenance of the AMI and SPS asset base. These costs are not included in our efficient base year, as opex associated with SPS will be incurred only from the AA5 period, in line with the changes to the regulatory frameworks to enable the inclusion of SPS as a technology option in the SWIS. Further information about the energy market reforms is provided in Chapter 3. The increase in SPS is consistent with the State Government's priorities, as outlined in the Energy Transformation Strategy. [131]

666. We have forecast an ongoing increase in opex of $3.9 million per annum for SCADA and Telecommunications. These costs have been forecast on the basis of the annual programs of work to manage the assets based on historical data, condition of the assets and volumes of assets. Activities in the annual work program are developed from an enterprise maintenance management system, Ellipse, and created based on risk and prioritisation. Routine, corrective and operations and support work orders are then scheduled accordingly. Resource requirements and contractor unit costs are applied to the program to develop an expenditure profile across each year.

### 7.5.7 SPS maintenance

667. Western Power plans to deploy an additional 1,861 SPS units during the AA5 period. The principal driver for this activity is the need to provide a more innovative, cost-effective, reliable and greener energy solution in sections of Western Power's rural network that are approaching the end of their useful life and need to be replaced. Further information about the SPS investment during the AA5 period are outlined in Chapter 8.

668. The increase in the number of SPS in the Western Power Network results in a step change increase in the opex required for the operation and maintenance of these units. All SPS have controller and telecommunication devices that transfer data to the monitoring and management platform for SPS management. These are new assets for which Western Power needs to provide maintenance support, including purchasing of adequate spares and tools.

669. The increase in SPS on the Western Power Network is not captured as part of the network growth escalation, as it is not currently included as one of the growth factors. However, the reduction in overall network length as a result of SPS installations is captured as part of the network growth factors. As such, a step change is required for the operation and maintenance of SPS units.

670. We have forecast an increase in opex of $6.4 million during the AA5 period for SPS maintenance. This is based on the historical mix of events per year for SPS units deployed to date:

- The forecast rate for maintenance is based on the observed mix of events (in terms of K1, K2, K4) per year per SPS unit on the units deployed to date
- Maintenance costs are assumed to begin one year after the installation of the SPS and are ongoing
- Increase in SCADA opex relating to the remote monitoring of installed units, which progressively increases as more SPS volumes are installed.

[131] Energy Policy WA, *Leading Western Australia's brighter energy future*, Energy Transformation Strategy, Stage 2: 2021-2025, July 2021, pg. 14.

671. This increase in opex is offset by a reduction in opex from the maintenance of overhead lines that are decommissioned following the installation of the SPS units. This reduction is accounted for in the forecasts of the distribution circuit length network growth factor.

### 7.5.8 Governance and safety assurance

672. The primary driver of this step change is the safety of our workforce. Our safety program includes assurance audits, periodic medicals (e.g., to assess fitness for work), drug and alcohol program and contemporary training delivery such as virtual reality, augmented reality, audio and e-learning improvements. During 2020/21 there were several constraints on our delivery of the safety program due to the COVID-19 pandemic. As such, expenditure on our safety program in 2020/21 is below the five-year average expenditure.

673. In addition, Western Power will review and update our contract management framework to include an end-to-end procurement cycle and ensure compliance with the Electricity Network Safety Regulations and the new Work Health and Safety legislation, which will come into effect in the early part of 2021 and replace the current Occupational Safety and Health Act. This will include the development of appropriate systems and tools to measure contractor performance, reduce risk (safety, health, financial), reduce the likelihood of disputes and unnecessary additional costs, and maintain compliance/assurance records.

674. Failure to make the changes required would result in Western Power being non-compliant with the new Work Health and Safety legislation and hence exposed to significant reputational and regulatory risk, and potentially subject to considerable corporate and individual person fines including up to 10 years imprisonment for Western Power's Officers.

675. An appropriate program delivery model and resourcing is considered a critical success factor in achieving the overall objective of uplifting the current contract management framework to a fit for purpose, flexible, enterprise-wide framework that is compliant with the new Work Health and Safety legislation.

676. Our Enterprise Data Strategy is key to delivering the strategic benefits to Western Power as it ensures that the data is relevant, reliable and accessible in a consistent manner to enable the streamlining of processes, automation and efficiencies across the business.

677. The delivery of the Work Health and Safety contract management framework solution has been planned in accordance with Western Power's Enterprise Data Strategy and Enterprise Information Architecture which takes into consideration the governance of the data being created, stored and used. The impact of Work Health and Safety contract management framework to Western Power's data, processes, people and information will be assessed and documented in the Data Strategy Assessment during the 'Develop' phase, with the resulting findings forming part of scope of this program.

678. We have forecast an ongoing increase in opex of $0.8 million per annum to bring our safety program in line with the five-year average expenditure.

### 7.5.9 LiDAR

679. Western Power has been using LiDAR[132] in the AA4 period to collect the geometric data of the network and its surrounding environment. The collected data helps understand:

- existing asset condition (e.g., pole lean)

[132] LiDAR (Light Detection And Ranging) technology uses aircraft-mounted laser imaging to record a three dimensional view of the surveyed network, including showing the distance between powerlines and vegetation, the ground and structures.

- risks posed by the network due to compromised clearances (e.g., vegetation, ground, structural encroachments)
- loading of poles used in the Serviceability Index calculations

680. Prior to using LiDAR, this data was predominantly collected as part of the Holistic Inspections program, where geometric data was obtained using manual measurement methods. The LiDAR methodology is a proven technology and is deployed regularly by many other Australian utilities for surveying their networks. The geometric data obtained through LiDAR is more accurate, consistent and reproducible, compared to the previously used manual methods.

681. Western Power carried out its first network-wide LiDAR survey in 2018/19 and is currently executing its second network-wide survey in 2021/22. Two complete network surveys were required in the AA4 period, with the scope of the first survey to establish a new digital dataset capturing the geometric configuration of the network and the second survey to establish a new digital dataset that captures the rate of changes in this configuration (asset and environment). The costs of these two full-network LIDAR surveys carried out in the AA4 period are fully capitalised as they establish new capability and new data sets. The financial treatment of these costs has been assessed under the requirements of AASB 138 Intangible Assets.

682. The expected benefits of the LiDAR surveys to date have been to reduce the need for collecting geometric data of the Western Power Network across a number of different programs and activities including:

- distribution holistic Inspection program (opex)
- distribution and transmission vegetation management (opex)
- distribution conductor replacement (capex)
- distribution clashing conductor (capex)
- distribution substandard clearance (capex)
- transmission NBT line reactor project (capex)
- transmission design project survey costs (capex)
- data corrections (opex).

683. In the AA5 period, the LiDAR data acquisition costs will be expensed (treated as opex), as data obtained from the surveys is considered as updating an existing dataset and is more aligned to other regular asset inspection and maintenance activities. There is no LiDAR-related capital expenditure forecast for the AA5 period. As a result, the forecast LiDAR opex expenditure in the AA5 period is considered as a recurrent step change, as no LiDAR-related opex was incurred in the base year (FY20/21).

684. The LiDAR related costs in the AA5 period are forecast to be lower than the expenditure incurred in the AA4 period as no ICT enablement expenditure will be required, and the frequency of surveys will change as explained in the summary of the options assessment below.

685. The LiDAR surveys are expected to provide risk avoidance / mitigation benefits through improved knowledge of localised environmental and asset conditions. This will benefit incident root cause investigations and fine tune asset strategies, especially in clearance management (e.g., vegetation, structural encroachments and conductor ground clearances) as well as pole management.

686. Improved network data, with the associated improved risk management, can have a significant positive impact on Western Power's insurance costs. Property and liability underwriters take great interest in how Western Power prevents incidents that can lead to loss and injury. Implementing LiDAR as a regular means to survey and model for various incident or risk scenarios will position Western Power with the other Australian and global network utilities who regularly undertake LiDAR surveys of their networks.

687. We have forecast an ongoing increase in opex of $1.2 million per annum for the regular LiDAR surveys. The expenditure profile is based upon surveying up to a quarter of the network each year, so the whole of the network will be covered over 4 years recurring.[133] These costs have been estimated based on historical costs to undertake the full-network LiDAR surveys.

688. We assessed various options to address the identified need in developing our step change forecast, summarised in the table below. Our assessment of these options demonstrated that the proposed surveying option is the most cost-effective option.

**Table 7.7: Summary of LiDAR options assessment**

| Option | Summary of assessment |
|---|---|
| Discontinue LiDAR survey and revert to manual inspections | This option would involve increasing the scope of the current Holistic Inspections to include the manual measurement and capture of geometric data as part of regular inspections. This will lead to an increase in the cost of Holistic Inspections, estimated at approximately $1 million per annum, due to increased time required to manually capture the configuration data. Discontinuing the full-network LIDAR surveying would also forego all the qualitative benefits achieved through LiDAR, including data quality (accuracy and consistency), ability to reproduce geometrical configuration of the network and the surrounding environment at points in time, and the ability to model change detection. As a result, this option is not recommended. |
| Whole of network LiDAR survey in one year | This option would involve the surveying of the entire Western Power network in one year within the AA5 period. Whilst this option may be cost-effective in terms of bulk capturing and processing of the LiDAR data, it limits Western Power's ability to customise its' data capture requirements. Areas of the network that require more or less frequent surveying, based upon the rate of change and/or the risk presented by the assets, will all have a similar survey frequency based upon this regime. Additionally, surveying the whole network in a single year increases the deliverability risk of the survey and potentially treatments required depending on the quantity of conditions found. As a result, this option is not preferred. |
| Surveying one quarter of the network each year | This option involves surveying up to a quarter of the network each year, with the ability to customise the frequency of surveys in areas based upon the rate of change and/or the risk presented by the assets. Due to the volume of surveys required under this option, the cost of this option is not expected to be significantly greater than the option of surveying the entire network in one year. This option does provide the benefits of added flexibility in terms of being able to customise the survey regime for assets/parts of the network that require more or frequent surveying, whilst keeping the relevance of the data based upon the expected rates of change. This options also has a lower deliverability risk as compared to the option of capturing the whole network in a single year. As a result, this option is recommended. |

### 7.5.10 Distribution power quality monitoring

689. The key driver for this step change is maintaining power quality on the Western Power Network

690. Western Power has a range of compliance obligations relating to power quality and will invest significant capex during the AA5 period to address power quality issues. Power quality obligations are included in the NQRS code and specific limit are also included in the Western Power Technical Rules where limits for quality of supply parameters are included.

[133] Pending the analysis of the change detection from the second LiDAR survey in the AA4 period, the expenditure may be reprofiled for the AA5 period to reflect areas of the network that have higher rates of change and/or risk, requiring more frequent surveys.

691. Exceedance of limits for quality of supply paraments results in a non-compliance typically, such as lights flickering or appliance power supply over heating that can stem from issues such as overvoltage, undervoltage, voltage fluctuations, overloading, voltage imbalance and harmonics on the LV network. These issues are caused by natural load growth, increase of generation, aging assets, change of load patterns that exceeds the original designed portion of the network.

692. An increase in the uptake of rooftop PV during the AA4 period (from 932MW in 2018 to over 1,357 MW in 2021) has resulted in a significant shift in the patterns of high and low load demand on the network. This trend has led to an increase in low load system events and network instability. Long term solutions are being developed to better integrate DER into the network. In the meantime, we are assessing solutions to maintain power quality and reduce/avoid overloading on distribution transformers, and robust power quality data and insight is necessary to manage this transition.

693. Our current level of performance in Power quality is measured on an annual basis utilising power quality metering device which are indicating for some parameters in parts of the network the performance limits are being exceeded.

694. In order to respond to those obligations and performance issues, our Grid Strategy and our power quality strategy includes a collection of actions that address performance of networks (i.e., reliability, voltage, utilisation, protection and power quality) across the lifecycle. These actions rely on the performance data collected from monitoring equipment. Although the data provided from the existing monitoring equipment are adequate quality, they don't necessarily provide enough data for an accurate network-wide evaluation of compliance.

695. Western Power has existing power quality meters (separate to customer meters such as AMI) installed on its network to monitor distribution power quality. Additional power quality meters will be purchased to replace and add to our existing power quality meter fleet to assist improving network visibility. These new meters are likely to be different meters to our current meter fleet and will require the data systems to be enhanced to accommodate the different method of data extraction and format/structure of the data retrieved. Our AA5 Plan forecasts capex of $3.5M for expansion of LV power quality monitoring availability & functionality, which is classified as Power Quality Compliance. These additional and replacement meters will enable us to replace the existing fleet that will be obsolete and will be strategically position at a greater number of sites to capture data for quality of supply paraments such as voltage, voltage fluctuations, flicker, harmonics and power parameters. The systems for accessing and using data will also be improved such that it will be accessible and usable for more than the current annual use for power quality audit purposes.

696. The data collected by these meters is used for annual audits on our power quality performance and has proven limited usefulness in investigation of system wide fault impact as well as understanding changing load patterns that affect planning criteria. The current meters and software platforms are reaching 10 years and are obsolete. There is potential for further uses of these meters to be realised with outcome of this planned work. The current data collection process from our existing PQ meter fleet is cumbersome, and has limited documented processes, it is based on local knowledge that is undesirable from a business continuity perspective.

697. Addressing those issues will not immediately result in cost savings, however, the improved processes, improved accessibility and data quality will enable a better and more efficient monitoring process redirecting the time saved to more value-add activities that will flow into better asset management and investment decision making. The improved data will also ensure we meet the 3-yearly NQRS performance audit and the annual license performance audit obligations.

698. As part of the detailed design of the solution and the implementation of more streamlined processes, cost savings will be proactively sought during the AA5 period. Furthermore, as we will be able to proactively mitigate issue, this could result in reduced resources required to deal with customer complaints and ministerial queries.

699. To support the development and to operate the system and the processes to support the monitoring and responses to the insight that will then become available, we proposed a step change to opex to employ better techniques to manage and address power quality issues, improve data accessibility for the low voltage network's power quality meters for analysis to:

- better address voltage issues and assess PV hosting capability
- better inform necessary changes to all associated strategy
- assess if changes to strategies have led to LV network performance improvement.

700. The information collected from these power quality meters will:

- enhance data application from power quality meters to better identify and address voltage issues, including development and improvement to the operation of the network
- enable better identification and mitigation of constraints to allow more PV to be connected, supporting the implementation of the DER roadmap
- be integral in informing compliance to the technical rules which apply to power quality in the distribution network.
- be used for annual power quality compliance audits and make the annual power quality meter data gathering exercise more efficient.

701. We have forecast an ongoing increase in opex of $0.4 million per annum to develop and operate the new system to improve data accessibility for power quality meters. These costs have been estimated on the basis of proposed scope of the tools and implementation effort to integrate the current and new power quality meters into the tools.

702. Due to immaturity of the solution's scope, we have included this cost as opex in the initial submission, this may be refined as part of the AA5 response. It may later evolve into a capex project to establish the tool, but would still see there being an ongoing opex costs to add future power quality meter and enhance the tools performance such that data can be retrieved easily in the right format and possibly displayed in real time for Network Operations.

703. The $2.2 million is a broad estimate at this stage and is based only on very high-level assumptions covering the costs of a high-level scope development and ongoing operating costs.

### 7.5.11 HV injection unit & emergency response generator deploy and operate

704. This expenditure relates to the mitigation of the risk of long supply interruptions in the worst performing hot spots across the Western Power Network.[134] During the AA4 period, there has been a significant increase in the number of complaints from the customers and regional communities due to extended outages in this region. In addition to reputational concerns, this reliability issue also has risk implications with respect to non-compliance with the Network Quality and Reliability of Supply code.

705. Feeders classified as Rural Long under the SSB scheme are currently experiencing poor reliability issues as a result of power interruptions, caused by various environmental factors such as severity of weather,

[134] Hot spots are areas of the distribution network that experience poor reliability performance measured by frequency and/or duration of interruptions.

lightning, pollution and wildlife impacts on the overhead lines. As a result, Western Power is currently failing its reliability (SAIDI) SSBs and as such is needing to reduce the duration of extended outages impacting our customers, through deployment of emergency response generators and high voltage injection units.

706. In addition, the operational risk level associated with non-compliance to technical rules due to extended outages (greater than 12 hours) is currently rated 'high' and the proposed solution would reduce it down to 'medium'.

707. A post event analysis of catastrophic fires and extreme climate events (such as the Wooroloo bushfire and Tropical Cyclone Seroja) during the AA4 period identified the importance of emergency response generators and HV injection units. This equipment enables the timely and efficient restoration of supply to large areas where the network has been severely damaged and network repair and restoration will take an extended period (in Wooroloo the restoration effort took several weeks and after Tropical Cyclone Seroja it took months).

708. In line with the reliability strategy, Western Power is currently developing a new strategy for timely and efficient rollout of portable HV injection units with accompanying emergency response generators to resupply customers after a network outage and reduce the impact on customers where the duration of outage is likely to be extended, thus improving SAIDI compliance. Sometimes a HV injection unit is also deployed if the emergency response generator is required to connect to the HV network. The HV injection unit is typically a transformer (0.415/22 kV) on a trailer, which helps reduce the impact on customers where the duration of outage is likely to be extended.

709. This strategy is in line with our customers' investment priorities. The CEP has identified that addressing the duration of outages is important for our customers, and also that rural customers, who are generally most impacted by long duration outages, value improvement in performance. Further information about the findings of the CEP is provided in Chapter 4.

710. During the AA4 period, we hired 14 emergency response generator units, deployed 7 for mitigating reliability hotspots seasonally, leaving 7 to be available for planned and fault work at any time. During the AA4 period, we have also purchased 4 HV injection units, with two to be delivered in 2021-22.

711. We have determined that, for the AA5 period, the following would be the most cost-effective solution:

- hiring an additional 8 emergency response generator units (total of 22 emergency response generator units made available for mitigating seasonal reliability issues and planned & fault work)
- purchasing 20 emergency response generator trailers ($900,000 included in our capex plan), total of 20 emergency response generator trailers made available
- replace one damaged HV injection unit trailer ($55,000 included in our capex plan)

712. As a result, we have forecast an ongoing increase in opex of $1.0 million per annum to deploy additional emergency response generators to improve our restoration of supply to the community. This cost includes:

- $0.4 million to hire 8 additional emergency response generator units
- $0.4 million for deployment of emergency response generators (estimated deployment cost, including transport and labour)
- $0.1 million for operating costs (cost of diesel to operate the units)
- $0.1 million for maintenance of 20 trailers.

713. These costs have been estimated on the basis of the historical average number of extended outage events per year, being 14 events per year.

## 7.6 Trending the base year

714. In accordance with the base-step-trend method, we 'trend' our efficient base year forward to take account of how opex changes over time reflecting:

- network growth – to account for changes to the physical size of the transmission and distribution networks and the number of customers to whom we provide services
- productivity growth – to reflect expected industry-wide improvements in finding more efficient ways of delivering services.

### 7.6.1 Network growth

715. Western Power engaged KPMG to assist with the development of the network growth escalation factors to apply to trend the base year forward over the AA5 period. Key considerations included:

- whether the changing energy landscape was impacting on the relevance of network growth factors
- a range of options for network growth escalation factors for the AA5 period.

716. KPMG's findings are set out in the Attachment 7.4 - Network Growth Factors Review for Western Power Report.

717. KPMG noted that changes in the energy landscape are impacting on the relevance of network growth factors, specifically that:

- energy throughput no longer accurately predicts proportionate changes in peak demand or network operators' costs due to the growing penetration of DER on the Western Power Network
- increased use of SPS will require changes to network growth factors in the long term. Opex required to serve a SPS customer is materially different to that required to serve a grid-connected customer. As the use of SPS increases, base opex will not reflect the impact of SPS. Further, the installation of SPS will impact network growth metrics under existing network growth factor definitions.

718. In its most recent distribution decisions, the AER adapted its approach to calculating network growth to reflect changes in the energy landscape in response to feedback from distribution networks. The output weights previously used by the AER were materially shifting over time and providing results that were not conceptually sensible given the drivers of network costs and changes in the operating environment, such as increased penetration of DER. Output growth factors are expected to continue to be reviewed to reflect the evolving external environment, including as mentioned in Section 7.5, the consideration of higher costs associated with DER management.

719. The AER has revised its approach to determining distribution network growth factor weightings, and has:

- adjusted its calculation of output weights to better reflect drivers of opex by excluding opex multilateral total factor productivity inputs
- removed energy throughput as a network growth factor
- calculated Translog elasticities at the full sample mean only for the Australian data set.[135]

[135] See for example, AER Final Decision, Powercor Distribution Determination 2021 to 2026, Attachment 6 Operating expenditure, pages 6-26 to 6-29. The AER has also commented that as more data becomes available they will consider the possible extension of output coverage to include DER variables.

720. Western Power has adopted the prevailing best practice methodology employed by the AER and other Australian distribution and transmission electricity network service providers to forecast network growth, consistent with KPMG's findings.[136] While the general principle is the same as that used for Western Power's AA4 proposal, the methodology has matured since our AA4 proposal to:

- apply different network growth factors than the AA4 methodology to account for changes in the energy landscape that have impacted on the relevance of network growth factors
- adjust the calculation of the network growth factor weighting in line with the AER's revised approach to better reflect drivers of opex
- apply network growth factors and weighting to total opex, including corporate and indirect opex. This is consistent with the AER's recent decisions to apply network growth to total opex. This approach recognises that there is likely to be a positive correlation between network growth and corporate and indirect costs, as a larger network will require more opex to maintain.

### *Transmission network growth*

721. The transmission network growth factors, weightings and the resulting weighted average growth rate are provided in Table 7.8. These are applied to all transmission opex categories.

**Table 7.8: Transmission network growth factors, per cent per annum**

| Growth factor | Weighting | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Compound annual growth rate (CAGR) |
|---|---|---|---|---|---|---|---|
| Customer numbers | 24.10% | 1.50% | 1.52% | 1.50% | 1.49% | 1.49% | 1.50% |
| Circuit length | 49.30% | 0.60% | -1.33% | 1.02% | -0.22% | -0.22% | -0.03% |
| Ratcheted maximum demand | 26.60% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **Transmission network growth** | **100.00%** | **0.66%** | **-0.29%** | **0.87%** | **0.25%** | **0.25%** | **0.30%** |

722. The transmission network growth factors are defined in the table below. The approach to forecasting transmission circuit length and ratcheted maximum demand is consistent with the approach used for the AA4 period. For customers numbers, we have updated the approach for the AA5 period to recognise that the transmission network provides a service to both distribution and transmission customers. As such, the AA5 approach proposes that customers numbers are forecast using the total end-use customers that the transmission network provides a service for. This is different to the AA4 approach which used the number of connections on the transmission network only. The proposed approach for the AA5 period is consistent with industry practice and the AER's approach to count the number of end-use customers[137]. Customer numbers and maximum demand are based on the Western Power's 2020 peak demand, energy consumption and customer number forecasts[138] which were independently reviewed by the National Institute of Economic and Industry Research (NIEIR) in June 2021[139]. These forecasts are updated annually.

[136] The network growth methodology and current weighting factors are consistent with recent AER decisions. See for example, AER Final Decision, Powercor Distribution Determination 2021 to 2026, Attachment 6 Operating expenditure, pages 6-26 to 6-29.

[137] Attachment 7.4 – KPMG, Network Growth Factors Review for Western Power Report, page 14

[138] Attachment 7.5 – Western Power's Energy and Customer Numbers Forecast Report 2020

[139] Attachment 7.7 – NIEIR, Report on Western Power's Forecasting Methodology for Western Power's 2022-27 Regulatory Period, June 2021

Western Power will update the network growth factor forecasts and actuals accordingly in response to the draft decision.

723. Note: For the purposes of measuring AA4 performance under the gain sharing mechanism in section 11.8.2, we report AA4 actual network growth factor outcomes on the same basis that the network growth factors were forecast for the AA4 period.

**Table 7.9: Transmission network growth factors**

| Growth factor | Description |
|---|---|
| Customer numbers | This is the annual average growth in the number of end-use customers that the transmission network provides a service for as forecast in Western Power's Energy and Customer Numbers Forecast Report (2020) (see Attachment 7.5). This is measured as the number of active connections on the distribution and transmission network, excluding streetlight and unmetered connections. |
| Transmission circuit length | This is the length (measured in kilometres) of lines in service (the total length of lines including interconnectors, backbones, and spurs). A double circuit line counts as twice the length. Length does not take into account vertical components such as sag.<br>The length of customer driven transmission lines to be installed is difficult to forecast accurately and, therefore, Western Power uses an estimate of the proportion of customer lines installed during the AA4 period to forecast this component of transmission forecast line length growth.<br>An estimate of transmission lines expected to be removed during the AA5 period is then deducted from the forecast, and an estimate of transmission lines to be installed due to capacity expansion is added to the forecast. |
| Ratcheted transmission maximum demand | This is the annual average growth in the highest maximum demand on the transmission network. Growth is calculated as the difference between the highest maximum demand that has ever occurred and the highest maximum demand that is forecast. Where the future maximum demand is lower than historical maximum demand, the growth factor would be zero.<br>The previous highest maximum demand that has occurred on the transmission network was 3,989 MW in 2015/16. However, during the recent heatwave conditions in late December 2021, maximum demand increased above this level. Western Power will update the maximum demand accordingly in response to the draft decision |

### *Distribution network growth*

724. The distribution network growth factors, weightings and the resulting weighted average growth rate is provided in Table 7.10. These weightings are applied to all distribution opex categories.

**Table 7.10: Distribution network growth factors, per cent per annum**

| Growth factor | Weighting | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | CAGR |
|---|---|---|---|---|---|---|---|
| Customer numbers | 55.70% | 1.50% | 1.52% | 1.50% | 1.49% | 1.49% | 1.50% |
| Circuit length | 15.50% | -0.27% | -0.20% | 1.07% | 0.94% | -0.34% | 0.24% |
| Ratcheted maximum demand | 28.80% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

| Growth factor | Weighting | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | CAGR |
|---|---|---|---|---|---|---|---|
| **Distribution network growth** | **100%** | **0.80%** | **0.82%** | **1.00%** | **0.97%** | **0.78%** | **1.05%** |

725. The distribution network growth factors are defined in the table below. The approach to forecasting distribution circuit length and ratcheted maximum demand is consistent with the approach used for the AA4 period. For customers numbers, we have updated the approach to align with industry practice to count the number of distribution connections excluding streetlight connections and unmetered connections. This is consistent with the AER's approach to count the number of distribution connections based on the national metering identifiers of which streetlights and unmetered connections are not included as they are not assigned a national metering identifier[140]. Customer numbers and maximum demand are based on the Western Power's 2020 peak demand, energy consumption and customer number forecasts[141] which were independently reviewed by the NIEIR in June 2021[142]. These forecasts are updated annually. Western Power will update the network growth factor forecasts and actuals accordingly in response to the draft decision.

726. Note: For the purposes of measuring AA4 performance under the gain sharing mechanism in section 11.8.2, we report AA4 actual network growth factor outcomes on the same basis that the network growth factors were forecast for the AA4 period.

**Table 7.11: Distribution network growth factors**

| Growth factor | Description |
|---|---|
| Distribution customer numbers | This is the annual average growth in distribution-connected customer numbers over the AA5 period as forecast in Western Power's Energy and Customer Numbers Forecast Report (2020) (see Attachment 7.5). This is measured as the number of active connections on the distribution network, excluding streetlight and unmetered connections. |
| Distribution circuit length | This is the annual average growth in the length of distribution lines (where each single wire earth return line, single-phase line and 3 phase line counts as one line).<br>The length of customer driven distribution lines to be installed is difficult to forecast accurately and, therefore, Western Power uses an estimate of the proportion of customer lines installed during the AA4 period as the first step to forecast the AA5 line length growth.<br>The final step is to forecast length of distribution lines to be decommissioned in AA5 following the installation of forecast SPS units, as mentioned in Section 7.5.7. As such, the base-step-trend approach ensures the step change in recurrent opex for SPS maintenance is offset by the reduction in maintenance for decommissioned line lengths. |

[140] p. 14 of KPMG's Attachment 7.4 - Network Growth Factors Review for Western Power Report
[141] Attachment 7.5 – Western Power's Energy and Customer Numbers Forecast Report 2020
[142] Attachment 7.7 – NIEIR, Report on Western Power's Forecasting Methodology for Western Power's 2022-27 Regulatory Period, June 2021

| Growth factor | Description |
|---|---|
| Ratcheted maximum demand | This is the annual average growth in the highest maximum demand on the distribution network. Growth is calculated as the difference between the highest maximum demand that has ever occurred and the highest maximum demand that is forecast. Where the future maximum demand is lower than historical maximum demand, the growth factor would be zero.<br>The previous highest maximum demand that has occurred on the distribution network was 3,504 MW in 2015/16. However, during the recent heatwave conditions in late December 2021, maximum demand increased above this level. Western Power will update the maximum demand accordingly in response to the draft decision. |

#### *Corporate and indirect opex network growth*

727. As noted above, we have adopted the same methodology to forecast network growth that the AER applied in its recent decisions. The AER applies network growth factors and weightings that are calculated using total opex, including corporate and indirect opex. To be internally consistent, this means that network growth escalation must be applied to all opex, including corporate and indirect costs.[143]

728. This approach recognises that there is likely to be a positive correlation between network growth and corporate and indirect costs, as a larger network will require more opex to maintain.

729. The transmission network growth weighting, as per Table 7.8, is applied to transmission corporate and indirect costs and the distribution network growth weighting, as per Table 7.10, is applied to distribution corporate and indirect costs.

#### *Total network growth*

730. This methodology has resulted in the total opex network growth escalation forecast of $52.9 million, as shown in Table 7.12.

**Table 7.12: AA5 total opex network growth escalation ($ million, real at 30 June 2022)**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | AA5 total |
|---|---|---|---|---|---|---|
| Opex network growth escalation | 5.1 | 7.1 | 10.7 | 13.8 | 16.2 | 52.9 |

### 7.6.2 Productivity improvements

731. In accordance with the base-step-trend method, we have incorporated expected productivity improvements in our forecast opex. This reflects expected industry-wide improvements in finding more efficient ways of delivering services.

732. Accordingly, we have adopted the prevailing best practice methodology employed by the AER[144] and other Australian distribution and transmission electricity network service providers to estimate expected productivity improvements.

733. We engaged Synergies to forecast opex productivity estimates for our AA5 proposal. Synergies used a Multilateral Total Factor Productivity model[145] to generate productivity estimates using data from the AER's

143 The AER only excludes limited costs from network growth escalation where there is no clear relationship between network outputs and those costs. In recent decisions, these have been limited to costs such as levies, fees and debt raising costs.

144 AER, Final Decision Paper, Forecasting productivity growth for electricity distributors, March 2019

145 This approach is consistent with the AER's method for forecasting productivity growth. https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors

2019-20 Benchmarking Regulatory Information Notices. Synergies selected five networks most comparable to the Western Power Network for this analysis: SA Power Networks, Powercor, AusNet Services, Essential Energy and Ergon Energy.

734. Based on an assessment of five and 10 years of data, Synergies forecast productivity growth of between 0 and 0.5 per cent per annum. Further information on Synergies productivity growth forecasts is in Attachment 7.3 – Forecast Cost Escalators for Western Power's 2022-27 regulatory period.

735. We have applied the average of the forecast productivity growth calculated by Synergies, which results in a 0.25 per cent per annum productivity adjustment over the AA5 period. This has reduced our opex forecasts by $14.3 million, and partly offsets the forecast network growth escalation. Table 7.13 shows the productivity improvements applied to our opex forecast.

**Table 7.13: Opex productivity applied in AA5**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | AA5 total |
|---|---|---|---|---|---|---|
| Opex productivity improvements (% p.a. / CAGR) | -0.25% | -0.25% | -0.25% | -0.25% | -0.25% | -0.25% |
| **Opex productivity improvements ($ m, real at 30 June 2022)** | **-0.9** | **-1.9** | **-2.8** | **-3.8** | **-4.8** | **-14.3** |

## 7.7 Adjusting for non-recurrent opex

736. Western Power forecasts it will spend $72.5 million of non-recurrent opex during the AA5 period. This includes:

- $7.4 million associated with the costs incurred for 66 kV line removal
- $4.1 million associated with the Regulatory Reform Program
- $61.0 million associated with decommissioning of distribution overhead lines.

737. These costs are provided by year in Table 7.14 and discussed further below.

**Table 7.14: Summary of AA5 non-recurrent costs by activity, $ million real at 30 June 2022**

| Category | Activity | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | AA5 total |
|---|---|---|---|---|---|---|---|
| Transmission | 66 kV line removal | 2.3 | 4.9 | 0.1 | 0.0 | 0.0 | 7.4 |
| Corporate | Regulatory Reform Program | 3.7 | 0.4 | 0.0 | 0.0 | 0.0 | 4.1 |
| Distribution | Decommissioning of distribution overhead line | 4.9 | 12.7 | 13.3 | 13.2 | 16.9 | 61.0 |
| **Total non-recurrent** | | **10.9** | **18.1** | **13.4** | **13.2** | **16.9** | **72.5** |

### 7.7.1 66 kV line removal program

738. This non-recurrent step change is for the decommissioning of the East Perth 66 kV substation to facilitate redevelopment of the East Perth Power Station site. This is in line with our CBD 66 kV strategy however the timing of the project has been brought forward to comply with the needs of the East Perth Power Station

redevelopment. The redevelopment is part of the State Government's Economic Stimulus Program sponsored by Development WA.

739. The decommissioning work is to be delivered through two investments:

- Cook Street – install a third transformer in 2022/23
- Wellington Street & East Perth 66 kV asset decommissioning in 2023/24.

740. The non-recurrent opex component of the decommissioning of the East Perth Power station is $7.5 million. The estimate includes costs associated with demolition and soil remediation within the East Perth 66 kV substation. This is required to facilitate the transfer of the land to Development WA as part of the East Perth Power Station redevelopment.

741. Development WA is expected to fully reimburse Western Power for expenditure incurred to prepare the land for transfer. Development WA will also contribute the cost associated with 'bringing forward' the two investments listed above, which have a total value of $34.4M ($25.9M capex and $8.5M opex). The residual opex cost of $7.4 million during the AA5 period is the basis for the non-recurrent step change.

### 7.7.2 Regulatory Reform Program

742. As noted in section 7.4, Western Power established a Regulatory Reform Program during the AA4 period to work closely with Energy Policy WA, AEMO and the Taskforce in the development and implementation of the Energy Transformation Strategy. The incremental costs incurred by the Regulatory Reform Program in 2020/21 have been removed from the efficient base year as Western Power does not consider these to be recurring annual costs. Instead, Western Power has included non-recurring costs only in 2022/23 and 2023/24 to reflect the current estimate of incremental costs to Western Power to continue the implementation of changes from Stage 1 of the Energy Transformation Strategy during the AA5 period. Further information about the Energy Transformation Strategy is provided in Chapter 3.

743. As noted in Chapter 3, Stage 2 of the Energy Transformation Strategy was announced on 16 July 2021[146]. Western Power has not included any specific costs in the AA5 proposal to assist with the development and implementation of Stage 2 initiatives. As the initiatives are further developed with Energy Policy WA, AEMO and the Taskforce, Western Power will consider whether any incremental operating or capital expenditure is required to enable implementation of the initiatives. Once the Stage 2 initiatives are further developed, we will review the impact on our opex and capex and may propose investments related to this in our response to draft decision.

### 7.7.3 Decommissioning of distribution overhead lines

744. Western Power forecasts it will spend an additional $70.7 million during the AA5 period for decommissioning and removal of the overhead network replaced by SPS. Decommissioning is assumed to take place within two years after the SPS unit is installed. Reduction in maintenance costs associated with decommissioning of lines during the AA5 period has been accounted for in the network growth escalation in Section 7.6.1.

745. Within the AA5 period we have forecast approximately 19,000 poles and associated conductors will be removed from the network as a result of our SPS program. Our cost forecasts have been developed on a volumetric basis using the line removal unit rate model and includes both the removal and disposal of the removed material.

---

146 https://www.wa.gov.au/government/announcements/western-australias-energy-transformation-strategy-moves-its-next-stage

746. These are non-recurring costs associated with our proposed deployment of SPS during AA5. Further information about the SPS investment during the AA5 period are outlined in Chapter 8.

## 7.8 Real price growth

747. Our base year opex reflects the costs of providing covered services in 2020/21. However, costs change over time, sometimes by more or less than inflation. We have rolled our base year cost forward to reflect forecast changes in wages over the AA5 period. To do this, we engaged Synergies to determine the real price growth to apply for the AA5 period. We have not forecast any real changes in material costs over the AA5 period.

748. The labour cost component[147] of the opex forecast is escalated by the forecast annual rate of growth in the wage price index for Western Australia electricity, gas, water, and waste water services. This is consistent with our approach in the AA4 period, and the method of escalation adopted by all other Australian regulated energy businesses.

749. Western Power applied the AER benchmark methodology to determine the proportion of labour costs of a benchmark efficient business. Under this approach, the real labour escalator benchmark weighting used for distribution total opex costs is 59.2 per cent[148] and the real labour escalator benchmark weighting for transmission total opex costs is 70.4 per cent[149]. The higher percentage for transmission reflects the higher labour component for transmission opex.

750. The real labour cost escalation and weightings are applied to total opex, including corporate and indirect opex, based on their distribution and transmission components. This is consistent with the AER's recent decisions to apply labour cost escalation to total opex and consistent with the approach used for network growth. This approach recognises that there is likely to be a positive correlation between labour costs and corporate and indirect costs.

751. Real labour cost escalation is forecast to grow by 0.77 per cent per annum[150] and contributes $42.7 million to opex forecasts over the AA5 period.

752. Table 7.15 shows the labour cost escalation rates applied to labour opex costs and the labour cost escalation forecast for the AA5 period.

**Table 7.15: AA5 total labour cost escalation**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | AA5 total |
|---|---|---|---|---|---|---|
| Distribution labour cost opex | 2.4 | 3.6 | 4.8 | 6.1 | 7.5 | 24.4 |
| Transmission labour cost opex | 0.9 | 1.3 | 1.6 | 2.0 | 2.4 | 8.2 |
| Corporate labour cost opex | 1.1 | 1.5 | 2.0 | 2.5 | 3.0 | 10.1 |
| **Total Labour cost opex excluding indirects ($ million real at 30 June 2021)** | **4.3** | **6.5** | **8.5** | **10.6** | **12.9** | **42.7** |

147 This includes internal labour and embedded contractors.

148 AER, 2021, Final Decision, Powercor Distribution Determination 2021 to 2025, Attachment 6: Operating expenditure, April 2021, p. 25. The AER's final decisions for the Victorian DNSPs are its most recent distribution determinations.

149 AER, 2021, Draft Decision, Powercor Queensland, Transmission Determination, 2022-27, Attachment 6: Operating expenditure, September 2021, p. 17. The approved real labour escalator weighting in this draft decision is the same as that in the AER's draft decision for AusNet's transmission network released in June 2021.

150 Attachment 7.3, Synergies Economic Consulting, Forecast cost escalators for Western Power's 2022-27 regulatory period, 4 October 2021, Table 9, p.32

753. Our wage price growth forecasts are lower than historical Australian wages growth as shown in Figure 7.8.

**Figure 7.8: Australian wages growth, electricity gas and waste water services and all industries**


754. Further detail on labour cost escalation factors is provided in the Synergies report Forecast Cost Escalators for Western Power's 2022-27 Regulatory Period provided at Attachment 7.3.

## 7.9 Indirect costs

755. Costs that cannot be directly attributed to activities driving expenditure, but are required to enable, manage and support those activities are categorised as indirect costs. Indirect costs include management and support costs associated with field staff, network and non-network asset management and planning, contract management and procurement teams. It also includes IT services and facilities management services.

756. Western Power forecasts it will spend $842.6 million on indirect costs over the AA5 period. This includes $183.4 million being expensed and the remaining $659.2 million being capitalised.

757. The forecast of indirect costs for the AA5 period is lower than the comparative forecast for the AA4 period of approximately $910 million.

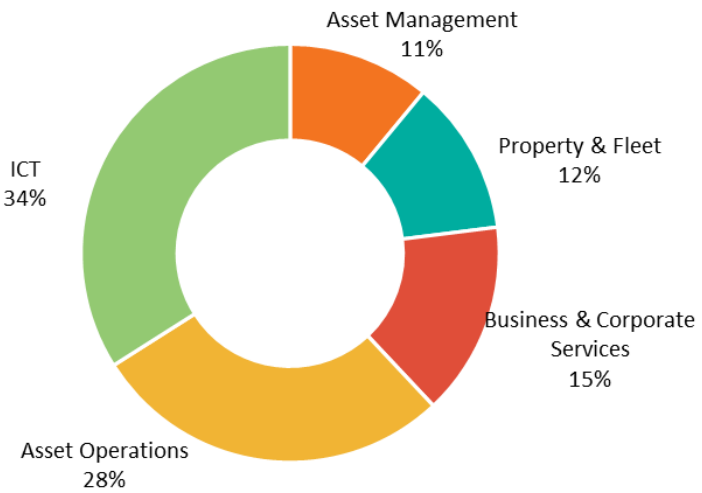
758. Table 7.16 and Figure 7.9 below set out the breakdown of total indirect costs.

**Table 7.16: Indirect cost categories**

| Indirect cost category | Description |
|---|---|
| Asset operations | Costs associated with field staff that are not directly booked to projects |
| IT | Costs associated with the provision of computers and third party support services for our staff, software, licensing and communications |
| Asset management | Costs associated with engineering and design, safety, environment, planning and asset management that are not booked to projects |
| Property and fleet | Costs associated with the purchase and leasing of our vehicles and the ownership and maintenance of our sites, including offices, depots and other land |

| Indirect cost category | Description |
|---|---|
| Business and corporate services | Costs associated with customer services, contract management and procurement teams |
| **Total** | |

**Figure 7.9: Breakdown of indirect costs**




759. Western Power has forecast indirect costs separately from direct opex. To do so, we applied the same base-step-trend method as described in the previous sections. Whilst some components of indirect costs do not fluctuate significantly in relation to the works program, other cost categories will (for example, network planners, supervisors, IT licences for increased headcount).

760. Figure 7.10 shows the build-up of the AA5 forecast indirect costs and Table 7.17 provides a summary of the various components of the build-up of the indirect cost forecast.

**Figure 7.10: Breakdown of indirect costs, $ million real at 30 June 2022**

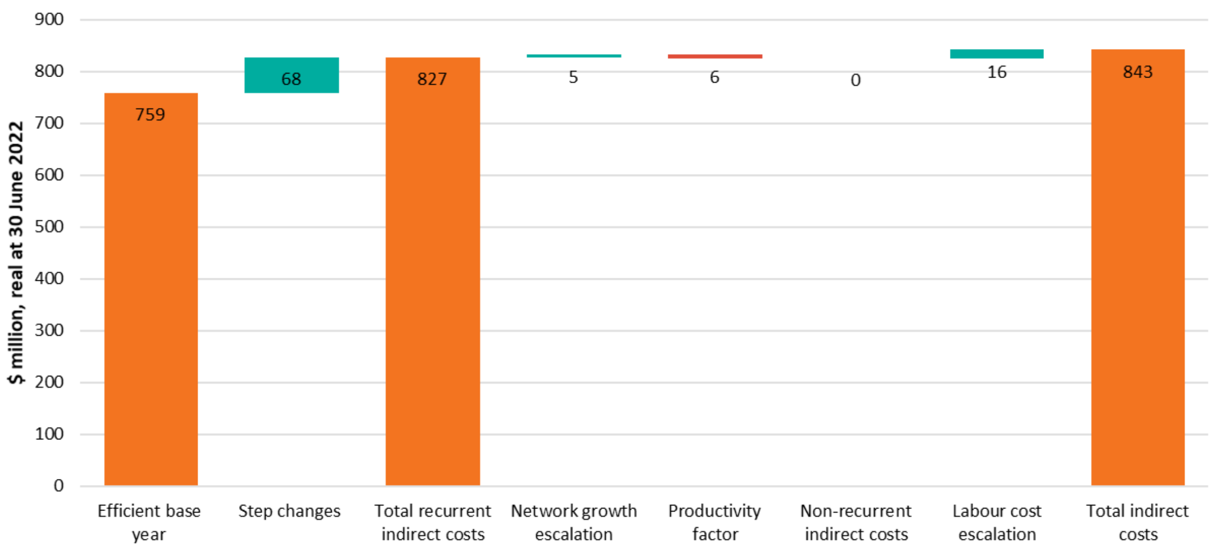


Table 7.17: Build-up of AA5 total indirect cost forecasts, $ million real at 30 June 2022

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Efficient base year | **151.8** | **151.8** | **151.8** | **151.8** | **151.8** | **758.9** |
| Step changes | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 68.2 |
| **Total recurrent indirect costs** | **165.4** | **165.4** | **165.4** | **165.4** | **165.4** | **827.1** |
| Network growth escalation | 0.5 | 0.7 | 1.0 | 1.4 | 1.7 | 5.2 |
| Productivity factor | -0.4 | -0.8 | -1.2 | -1.7 | -2.1 | -6.2 |
| Non-recurrent opex | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Labour cost escalation | 1.7 | 2.5 | 3.3 | 4.1 | 4.9 | 16.5 |
| **Total regulated revenue cap indirect costs** | **167.2** | **167.8** | **168.5** | **169.2** | **169.9** | **842.6** |

761. These costs are then allocated to all activities that attract indirect costs, as per Western Power's Cost and Revenue Allocation Methodology (see Attachment 7.2). This results in a portion of the costs being capitalised and the remainder being expensed.

762. Table 7.18 shows the indirect costs applied to our expenditure program.

Table 7.18: AA5 indirect costs, $ million real at 30 June 2022

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | AA5 total |
|---|---|---|---|---|---|---|
| Capitalised indirect costs | 132.5 | 131.9 | 133.0 | 131.7 | 130.1 | 659.2 |
| Indirect costs expensed to revenue-cap services | 34.7 | 35.8 | 35.5 | 37.5 | 39.9 | 183.4 |
| **Total indirect costs** | **167.2** | **167.8** | **168.5** | **169.2** | **169.9** | **842.6** |

### 7.9.1 Establishing the efficient base year

763. Consistent with our approach to direct opex, we have used 2020/21 as the base year to calculate our indirect costs.

### 7.9.1 Adjusting for indirect cost step changes

764. Our forecast indirect cost includes three step changes. Table 7.19 provides a summary of our proposed step changes. Each step change is discussed in more detail below.

Table 7.19: Indirect cost step changes, $ million real at 30 June 2022

| Step Change | Description | Annual cost |
|---|---|---|
| Increased support services | Increased support services to deliver the increased capital works program, for example, contract management, procurement, planning and supervisors | $6.3 |
| Cyber security | A new cyber function has been established with additional headcount and provisional fee for service in line with the new cyber security strategy and new cyber security obligations | $3.5 |

| Step Change | Description | Annual cost |
|---|---|---|
| IT | Increase in managed contracts aligned to business driven activities and software support linked to volume and price increases in our IT investment program | $3.8 |
| **Total value of recurrent step changes** | | **$13.6** |

### *Increased support services*

765. The capital works program is forecast to increase over the AA5 period, driven by the following factors:

- the need to continue to address our ageing asset base and provide for adequate life extension treatments to maintain the safety and reliability of the Western Power Network
- asset obsolescence, meeting compliance requirements (including cyber security obligations) and strategic investments to facilitate the transformation of the network and meet customer expectations in the changing energy landscape
- investment in SPS and undergrounding as part of the implementation of our Grid Strategy.

766. We have included a step change for increased support services to deliver the increased work program. The additional support services include:

- additional commercial headcount required for contract management and procurement due to the increase in procurement associated with the growing program of work
- additional resources for certain programs of work due to the scale of the work program or new skillset required
- additional headcount in customer connection services, engineering and design and operational maintenance areas to support the growing work program.

767. The proposed step change is in line with the proposed capex program. Chapter 8 provides further information about our proposed capex program.

### *Cyber security*

768. As noted in section 7.5.6, the potential impact of increasingly sophisticated cyber-attacks on the operation of the Western Power Network has come into sharp focus. The implementation of the next stage of the Cyber Security Strategy, particularly investments required to meet the new cyber security obligations proposed in the *Security of Critical Infrastructure Act 2018* under the *Security Legislation Amendment (Critical Infrastructure) Bill 2020,* have resulted in an uplift in our proposed capex.

769. We have proposed a step change in indirect costs for cyber security which is for additional headcount and provisional fee for service to implement the new Cyber Security Strategy and new cyber security controls to meet prevailing obligations. This is in line with the proposed capex program for cyber security. Chapter 8 provides further information about our proposed capex for cyber security investments.

### *IT*

770. Western Power must prepare for a changing energy market where changing consumer demand patterns and growth in the penetration of DER, including solar PV and battery storage systems, will present both challenges and opportunities to the business. As the use of digital technology expands IT will play a key role ensuring that Western Power maximises value from technology investments by increasing agility and reducing time to benefits, targeting operational efficiencies and effectively managing cyber security risk.

We must ensure that our systems, applications and hardware remain current, reliable and vendor supported to meet a changing market and new customer demands.

771. We have proposed a recurrent step change to manage contracts aligned to business-driven activities and software support linked to volume and price increases in our IT capex program. This is in line with the proposed IT capex program.

### 7.9.2 Trending the base year

772. We escalated base year indirect costs to account for forecast network growth and real price growth, using the same growth factors as those used to escalate the direct opex forecasts:

- network growth – as discussed earlier in section 7.6.1, the network growth weightings are applied to indirect costs are as per Table 7.10 for distribution indirect costs and as per Table 7.8 for transmission indirect costs
- productivity improvement – the network growth escalation is wholly offset by our proposed efficiency adjustment of 0.25 per cent per annum, which we are also applying to our indirect cost base.

773. This methodology has resulted in:

- total indirect cost network growth escalation forecast of $5.2 million
- an indirect cost efficiency adjustment of -$6.2 million (see Table 7.20).

**Table 7.20: AA5 total indirect cost network growth and productivity improvement, $m, real at 30 June 2022**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | AA5 total |
|---|---|---|---|---|---|---|
| Indirect cost network growth escalation | 0.5 | 0.7 | 1.0 | 1.4 | 1.7 | 5.2 |
| Indirect cost productivity improvement | -0.4 | -0.8 | -1.2 | -1.7 | -2.1 | -6.2 |

### 7.9.3 Adjusting for non-recurrent indirect costs

774. Western Power has not identified any non-recurrent indirect cost step changes over the AA5 period.

### 7.9.4 Escalating for labour costs

775. The labour cost component of the indirect cost forecast is escalated using the same approach to that used in our direct opex forecasts. As discussed earlier in section 7.8, the real labour escalator benchmark weighting used for distribution total opex costs is 59.2 per cent and the real labour escalator benchmark weighting for transmission total opex costs is 70.4 per cent. This methodology results in the total indirect labour cost escalation forecast of $16.5 million, as shown in Table 7.21.

**Table 7.21: AA5 total indirect cost labour cost escalation, $ million real at 30 June 2022**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | AA5 total |
|---|---|---|---|---|---|---|
| Indirect labour cost opex | 1.7 | 2.5 | 3.3 | 4.1 | 4.9 | 16.5 |

### 7.9.5 Total expensed indirect costs

776. Western Power has forecast $183.4 million of expensed indirect costs over the AA5 period, allocated between transmission and distribution expenditure categories, as shown in Table 7.22.

**Table 7.22: AA5 total expensed indirect costs, $ million real at 30 June 2022**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | AA5 total |
|---|---|---|---|---|---|---|
| Transmission | 8.9 | 9.1 | 8.5 | 8.9 | 9.2 | 44.5 |
| Distribution | 25.8 | 26.8 | 27.0 | 28.7 | 30.7 | 138.9 |
| Corporate | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total indirect costs expensed to revenue cap services** | **34.7** | **35.8** | **35.5** | **37.5** | **39.9** | **183.4** |

## 7.10 Total opex forecast

777. Table 7.23 provides a summary of Western Power's forecast opex by category.

**Table 7.23: Summary of AA5 forecast opex including indirect costs and escalations, $ million real at 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Operations | 15.2 | 15.2 | 15.4 | 15.5 | 15.7 | 76.9 |
| Maintenance | 54.7 | 54.6 | 55.3 | 55.9 | 56.5 | 277.0 |
| Other | 4.9 | 7.9 | 2.3 | 2.2 | 2.2 | 19.6 |
| **Total transmission opex** | **74.8** | **77.7** | **72.9** | **73.6** | **74.4** | **373.5** |
| **Distribution** | | | | | | |
| Operations | 24.8 | 25.1 | 25.4 | 25.8 | 26.1 | 127.1 |
| Maintenance | 168.6 | 170.7 | 173.4 | 177.2 | 180.6 | 870.5 |
| Customer service and billing | 38.2 | 37.3 | 37.0 | 36.7 | 36.1 | 185.3 |
| Other | 14.0 | 22.7 | 23.0 | 23.3 | 27.9 | 111.0 |
| **Total distribution opex** | **245.7** | **255.8** | **258.8** | **262.9** | **270.7** | **1,293.9** |
| **Corporate** | | | | | | |
| Business support | 103.4 | 101.3 | 102.6 | 103.6 | 104.5 | 515.4 |
| **Total corporate opex** | **103.4** | **101.3** | **102.6** | **103.6** | **104.5** | **515.4** |
| **Total regulated revenue-cap opex** | **423.9** | **434.9** | **434.3** | **440.1** | **449.5** | **2,182.7** |

# 8. Forecast capital expenditure

778. This chapter provides an overview of Western Power's forecast capex investment plan over the AA5 period, including the forecasting approach and key investment drivers. This chapter should be read in conjunction with the AA5 Forecast Capital Expenditure Report provided in Attachment 8.1, which provides further details on the proposed capex program and forecasting approach.

**Key Messages**

- Our capital expenditure is designed to maintain safety and service performance whilst facilitating ever increasing demand for renewable generation connections, improving resilience to extreme climate events, meeting shifting localised demand and supporting changing customer behaviour and requirements.
- Our capital expenditure requirements are greater in the AA5 period than in the AA4 period, 11.4 per cent for transmission network, 33.6 per cent for distribution network, and 29.3 per cent overall. Our investment in SCADA and telecommunications will double driven by asset obsolescence, management of cyber security risk and implementing outcomes of the Energy Transformation Strategy
- The higher capital expenditure required for the AA5 period reflects the emerging and ongoing challenges associated with the changing energy environment. These challenges include:
  - Significant new renewable connections
  - Transformation from one-way power flows to two-way power flows, and the management thereof, including that of distributed energy resources
  - Increasing proportion of aging assets with deteriorating performance
  - Increasing extreme climate events
  - Supporting significant energy reforms.
- Once delivered, these investments will reinforce our network's role as an efficient delivery network for all energy technologies, provide a platform for new and different services and provide the improved communication that will enable more efficient operations and support emerging market mechanisms to manage demand and supply
- Our capital expenditure program of $5,375.6 million will be funded in part, $1,034.5 million, by new connecting customers so the net expenditure to be paid for by customers is $4,341.1 million

## 8.1 Overview of the investment proposal

779. During the AA5 period, Western Power proposes to invest $5,375.6 million of capital to deliver covered services. Of this, approximately $1,034.5 million will be recovered directly from customers in the form of either capital contributions or gifted assets. We forecast $4,341.1 million will be added to the RAB and recovered through reference and non-reference tariffs.

780. Our proposed investment will help us deliver on our Corporate Strategy, which will ensure the Western Power Network is future focused to enable the most flexible connection and operation of DER and large-scale renewables possible, for the benefit of all Western Australians.

781. More specifically, our proposed capex plan during the AA5 period is designed to:

- maintain overall safety of the network in line with jurisdictional obligations, with actual performance not deteriorating below current levels
- maintain current service standard levels, as measured by the SSBs, whilst ensuring ongoing sustainability of the network and optimising the transition to the modular grid
- deliver services at the agreed levels and at the lowest practical cost
- satisfy applicable regulatory obligations and maintain current network compliance risk ratings
- enable increased levels of renewable generation connection to our network
- implement Energy Transformation Strategy Stage 1 outcomes, as applicable (e.g. five-minute settlement, DER Roadmap)
- meet Government policies and requirements, including SPS roll out and climate change policy, and support the Economic Stimulus Package (**ESP**).

782. Our proposed capex investment plan for the AA5 period is designed to move as safely and as affordably as possible to the modular version of the grid during a period of energy transformation. Western Power is developing the modular grid as it affords the least cost technology, whilst maximising benefits, to meet the requirements of the differing customer groups served by Western Power. At the same time, the proposed investment will allow us to continue to manage the existing network and maintain safety and reliability, while we transform into the future.

783. Our Grid Strategy is based on long-term scenario planning for evolving customer preferences and needs, which identifies the right technology to use at the right place and time. This approach provides a roadmap to the grid vision which minimises whole of life cycle costs and regrettable investment.

784. To support our Corporate Strategy to introduce new cost-effective technology, achieving both performance and affordability objectives, whilst facilitating the changing needs of our customers via the realisation of our modular network vision during the AA5 period, Western Power plans to underground 876 km of distribution conductors and install 1,861 SPS or equivalent units[151] to replace or support overhead network infrastructure where it addresses a network need and is financially prudent to do so.

785. Through the planned investment in the AA5 period and into the AA6 period, Western Power will enable increasing connection and use of renewable energy by the community by improving DER integration and coordination (our DSO functions). This will be achieved by leveraging our AMI, advanced connection standards for DER and greater amounts of grid-connected storage to help maintain stability during periods of low demand and intermittent supply and lay the foundation for the increasing use of network support services in place of network augmentation to maximise existing investment and deliver greater value for customers.

786. For the distribution network, the proposed capex plan includes investment in SPS, undergrounding, the continuing deployment of AMI, a roadmap for microgrids and developing a functioning DSO capability. These investments are critical to facilitate the transformation of the network and support future customers' needs, such as EVs. We will manage critical system low risks while maximising the opportunity for the community to invest in DER.

787. For the transmission network, asset life extension techniques such as refurbishment, digital asset management techniques and delivery optimisation have underpinned our proposed capex investment plan to ensure current levels of network performance are maintained. We are also investing to ensure

---

[151] This includes 1,630 units or equivalent under the SPS program and 231 units or equivalent to support the microgrid program.

customers can continue to connect more renewable generation and load and address emerging grid stability issues resulting from high penetration of DER in the distribution network.

788. Western Power will modernise its largely obsolete SCADA and Telecommunications network during the AA5 and AA6 periods to support the digital network and enable the integration of DER. This investment will enable a secure transformation to a modular grid by improving our foundational cyber security controls and adopting a 'secure by design' approach to the introduction of new and emerging technologies so that they are foundationally secure.

789. The proposed investment plan will also assist Western Power to respond to physical and transitional risks from climate change and environmental impact, which will see a need for greater emphasis required on disaster preparedness and network resilience, and supply to remote communities.

790. Western Power understands that it plays a pivotal role in the decarbonisation of our communities, ensuring an orderly and just transition away from the fossil fuels that have powered the Western Australian way of life to date. This includes supporting broader decarbonisation by enhancing our technical solutions, products and infrastructure to ensure grid security and reliability while facilitating the further uptake and equitable access to renewable energy resources. Our proposed investment plan for the AA5 period supports the decarbonisation of the community through facilitating connection of renewable generation to the grid, replacement of traditional mercury vapour or compact fluorescent streetlights with more efficient LEDs and the modernisation of our depots which will reduce their carbon footprints. The installation of SPS and microgrids also contributes to decarbonisation as the main source of energy is renewable.

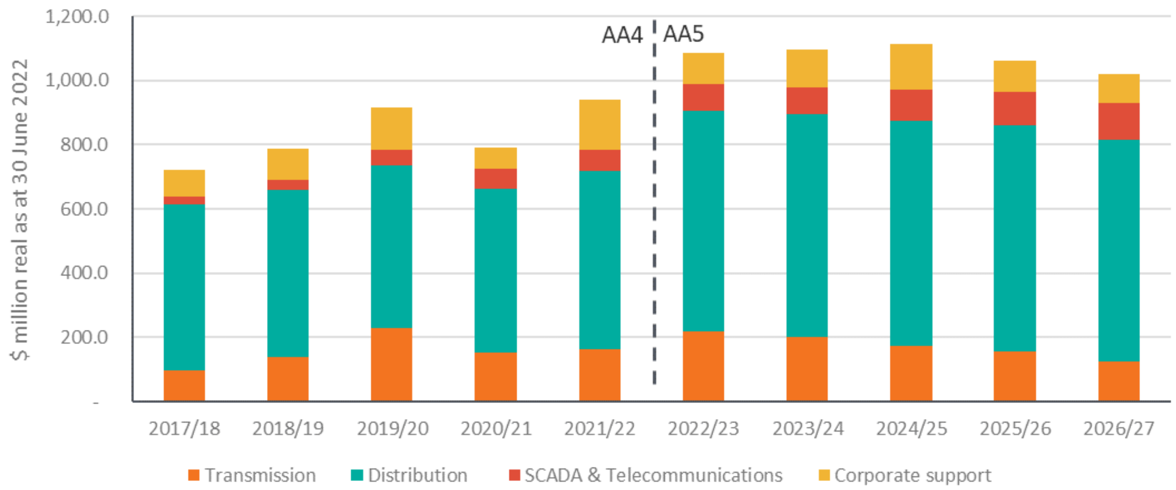
791. Table 8.1 summarises the total AA5 capex forecast split between investment in the transmission network the distribution network, the SCADA and Telecommunications network, and corporate support. All expenditure values in this chapter are presented in real dollars, including real cost escalation and indirect costs, at 30 June 2022. Note that totals provided in the tables may not sum due to rounding.

**Table 8.1: AA5 forecast capex summary, including real cost escalation and indirect costs, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 | % of gross capex |
|---|---|---|---|---|---|---|---|
| Transmission network | 217.6 | 199.9 | 172.5 | 156.7 | 124.9 | 871.7 | 16% |
| Distribution network | 688.6 | 695.1 | 702.4 | 702.7 | 691.1 | 3,479.9 | 65% |
| SCADA and Telecommunications network | 83.2 | 84.0 | 98.1 | 106.0 | 112.0 | 483.4 | 9% |
| Corporate support | 96.7 | 117.2 | 139.1 | 96.9 | 90.9 | 540.7 | 10% |
| **Gross capex** | **1,086.1** | **1,096.2** | **1,112.1** | **1,062.3** | **1,018.9** | **5,375.6** | |
| Less contributions | 216.4 | 196.0 | 208.4 | 220.7 | 193.1 | 1,034.5 | |
| **AA5 capex to be recovered via tariffs** | **869.7** | **900.2** | **903.8** | **841.6** | **825.8** | **4,341.1** | |

792. Figure 8.1 shows how the AA5 forecast capex compares with that incurred during the AA4 period.

**Figure 8.1: Comparison of AA5 forecast and AA4 actual gross capex[152]**




793. Gross capex for the AA5 period is forecast to increase by 29.3 per cent relative to actual capex for the AA4 period. We are forecasting increases in capex for each network, while corporate capex is forecast to remain steady relative to the actual expenditure incurred in the AA4 period. The increases in forecast capex reflect the following factors:

- **Transmission network:** forecast capex is expected to increase by 11.4 per cent (compared to transmission capex in the AA4 period) to continue to address the ageing asset base, facilitate additional capacity for customer connection (including connection of renewable generation and load to meet their carbon reduction requirements) and rationalise voltages, whilst improving network utilisation
- **Distribution network:** the increase in forecast capex of 33.6 per cent (compared to distribution capex in the AA4 period) is driven primarily by the installation of SPS, undergrounding programs (such as the Network Renewal Undergrounding Program (**NRUP**)), acceleration of the AMI deployment and maintaining safety performance of our network (including addressing ring main unit (**RMU**) safe operating risk issues)
- **SCADA and Telecommunications:** there is a significant increase in forecast capex of 109.9 per cent (compared to capex in the AA4 period) for SCADA and Telecommunications driven primarily by asset obsolescence, management of cyber security risk, meeting compliance requirements and meeting investments required to implement the outcomes of the Energy Transformation Strategy (e.g. five-minute settlement and DER integration).

794. Western Power will need to manage the complex and often competing objectives and strategies we have set ourselves during the network transformation. This includes maintaining safety while undergrounding the metropolitan areas and accelerating the roll out of SPS and AMI deployment.

795. Western Power will never compromise on safety. Safety expenditure during the period continues to focus on distribution wood poles, with 34,974 planned replacements and a further 27,500 reinforcements. Approximately 27,000 wood poles will be removed from the distribution network during the AA5 period as part of the forecast SPS and undergrounding investment. In the transmission network, Western Power also plans to replace 2,030 wood poles and reinforce a further 2,250 wood poles. Our bushfire management programs will also continue, focusing on mitigating safety risks in line with our Asset Management Framework.

152 Capex in the final year of the AA4 period is based on budgeted data for 2021/22.

796. The following section provides an overview of Western Power's approach to developing capex forecasts.

797. The remainder of this chapter then presents forecast capex broken down by regulatory category, adjusted to show the SCADA and Telecommunications[153] network separately, in line with how this is treated for planning and operational purposes by Western Power.

798. A breakdown of capex by regulatory expenditure category, excluding real cost escalation and indirect costs is provided in AA5 Forecast Capital Expenditure Report provided in Attachment 8.1.

## 8.2 Approach to developing the capex forecasts

799. The AA5 capex program has been developed using Western Power's business as usual processes, which uses a combination of bottom up build and top down assessment, tailored for each investment type / asset class. Insights from our customer engagement program have helped shape our plans for the next five years and beyond.

800. Our top down assessment involves the following key activities:

- optimisation across portfolios to validate the timing of expenditure, deferring expenditure where it makes sense, and ensuring the best investment solution is selected across programs. An example of how this works in practice is to ensure we don't plan to replace any more assets than necessary, for example pole replacement in identified SPS treatment areas, or transformers in our regional transmission strategies
- reprofiling expenditure to meet any perceived delivery constraints related to resourcing or supply chain
- expenditure challenge, focussing on any expenditure activities which increased spend above the AA4 average. This challenge involves ensuring the cost is efficient, and assessing the impact on performance measures of any potential reductions to expenditure.

801. The following sections provide further information on the Asset Management Framework, customer insights and regulatory requirements that have informed the forecast capex investment plan for the AA5 period. Further information on the development of the capex investment plan is provided in AA5 Forecast Capital Expenditure Report provided in Attachment 8.1.

### 8.2.1 Asset Management Framework

802. Western Power's Asset Management Framework is set within the context of the Australian and International Standard on Asset Management (ISO55001), ERA Audit Guidelines, *Electricity (Network Safety) Regulations 2015* and Electricity Network Safety Management Systems standard (AS 5577).

803. This framework underpins Western Power's Asset Management Policy and defines the structure of Western Power's AMS. Western Power's AMS has been built on this framework and is a collection of strategies, standards, specifications, procedures, processes, tools and systems used for asset management.

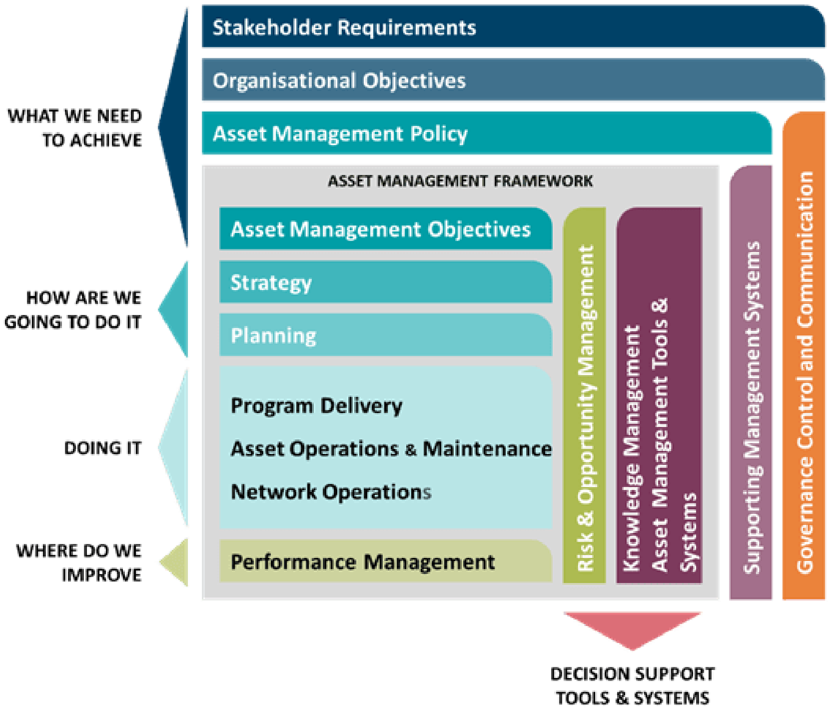
804. The AMS supports risk-based decision making and sustainable management of network assets, as per the requirements of Western Power's transmission and distribution licences and other compliance requirements. This encapsulates all asset management documentation, responsibilities and supporting systems. The AMS is also a structured tool that supports due diligence requirements and achieving continuous improvement in asset management performance.

---

153 SCADA and Telecommunications is included as subcategories within the transmission and distribution networks for the purposes of the ERA's *Guidelines for Access Arrangement Information* (December 2010).

805. The structure of Western Power's Asset Management Framework is shown Figure 8.2. The AMS is built upon this structure.

**Figure 8.2: Western Power's Asset Management Framework**




806. Western Power's AMS and Electricity Network Safety Management System (**ENSMS**) are applied to the development of the Network Management Plan and the Grid Strategy that the network investment components of the AA5 proposal are based on. These have undergone a range of independent assessments for maturity, adequacy and application. Western Power's Network Management Plan and Grid Strategy are provided as Confidential Attachments 8.2 and 8.3.

807. Recent significant audits of these systems have included:

- The AMS review (completed in September 2020), which found that "*Western Power has developed a sophisticated, well-structured and disciplined Asset Management System*"[154]
- Certification of Western Power's AMS to the International Standard for Asset Management ISO 55001 in August 2019. The ISO55001 assessment (completed in July 2019) found that "*Western Power has a number of industry leading practices, particularly in the areas of asset risk management and the "line of sight" linkages to organisational objectives, as well as the optimisation and prioritisation of programs and projects"*[155]
- The ENSMS audit (concluded in April 2017), which found that the Western Power's ENSMS is compliant with the requirements of AS5577 (the applicable Australian Standard for the Electricity Network Safety Management System), is appropriate and is effectively implemented.[156]

### *Grid Strategy*

808. The objective of the Grid Strategy is to manage systems across their lifecycle to deliver an optimal balance of cost, performance and safety while satisfying short and long-term expenditure constraints and

[154] AMCL, *Western Power 2020 Asset Management System Review*, Review Report, 30 November 2020, p.23.
[155] Lloyd's Register, *Stage 2 Assessment Report for: Electricity Networks Corporation trading as Western Power*, July 2019
[156] CutlerMerz, *Electricity Network Safety Management System (ENSMS) Independent Audit Report*, May 2017

minimising constraints on customer choice. It supports the realisation of Western Power's vision for a modular grid.

809. The purpose of the Grid Strategy is to:

- provide an overview of current performance, issues and drivers for investment on the network
- provide an overview of currently available and emerging solution options to address these drivers (i.e. design, maintenance and operational options)
- outline the current strategies that are applied across the network
- outline high level considerations for investment planning.

810. The Grid Strategy includes a collection of strategies grouped into:

- **Performance Strategies:** that address performance of networks (i.e. reliability, voltage, loading, protection and power quality) across the lifecycle. Grid performance strategies drive project-based network planning studies and investigations. They are typically focussed on short to medium term responses to existing and emerging issues and provide an input to long term strategy development and planning
- **Transformation Strategies:** that target changes to networks when they reach end of life. These include SPS, microgrids, undergrounding, 66 kV rationalisation and transmission de-meshing. They typically focus on longer term responses to emerging and future issues although they still drive planning actions in the short term.

811. The Grid Strategy also sets out the grid vision for the transmission and distribution networks:

- The transmission future grid vision is for an efficient and sustainable long-term vision for the future state of the transmission network that delivers optimised outcomes for the whole of the energy sector, effectively manages risk, leverages technology and promotes opportunities and minimises costs to customers
- The distribution grid vision is defined in terms of the target future state – the modular grid – comprising a tightly meshed urban network in metropolitan areas, an autonomous network for remote customers and a hybrid network in between those.

812. A copy of the Grid Strategy is provided at Confidential Attachment 8.3.

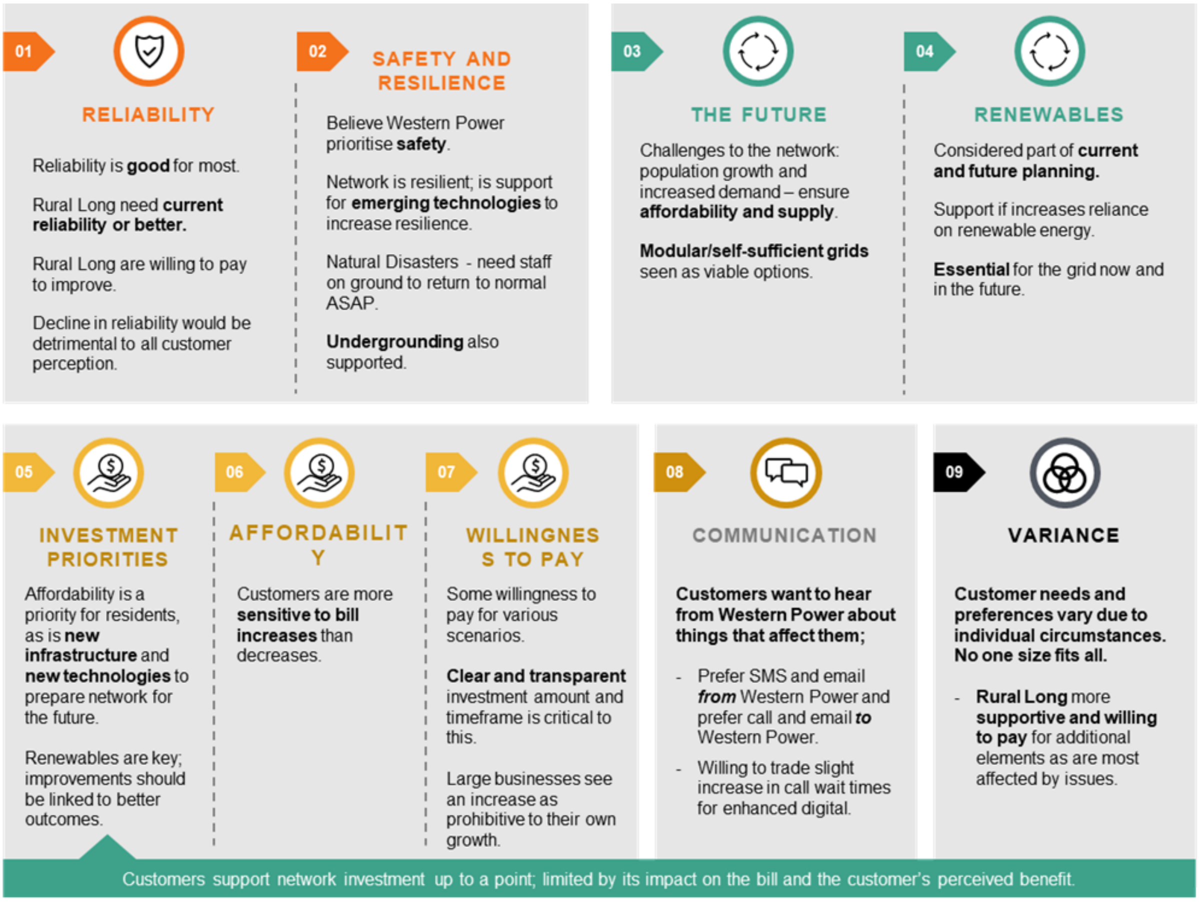
### 8.2.2 Customer insights

813. Western Power undertook an extensive customer engagement program in 2021. The core focus of our customer engagement was to understand our community's attitudes towards electricity, network performance and safety, network tariff preferences, affordability of services, future opportunities, new technologies, climate change and access to renewables.[157]

814. A summary of our customer insights is provided in Figure 8.3

[157] The customer engagement program is discussed in detail in Chapter 4.

**Figure 8.3: Summary of customer insights**




Source: Kantar Public, 2021, *AA5 Customer and Community Engagement Program*

815. It is clear that our customers' main priorities are:

- affordability – residential customers are sensitive to price increases
- support of renewables – management of solar connections to the network, with some willingness to accept small bill increases to increase future investment in new technologies and renewables, and to increase network reliability
- future focus – building new infrastructure to cope with future demand and investing in new technologies for the evolving network
- maintenance of reliability standards – maintaining or improving reliability of the power system against outages.

816. Safety is considered critical by customers. Should the level of service surrounding safety decline, it would be detrimental to customer perceptions of Western Power. Customers believe there is already significant importance given to safety and do not prioritise additional investment in this area however, there is no willingness to trade-off safety for cheaper bills.

817. Western Power is perceived to be performing well in areas of safety, customer service and to a large degree reliability, but the community expects these areas to be maintained at current levels as a minimum. There is no willingness to trade-off safety for cheaper bills, greater reliability or increased sustainability.

818. The customer engagement program found that customers are sensitive to price increases but support prudent investment particularly in integrating renewables, new technologies and (for rural customers)

improved reliability. Likewise, the community understands the impact of climate change and there is strong community support for further investment to support an increased reliance on renewable energy.

819. Customers are open to increased investment, particularly in new technologies (such as community batteries, SPS and microgrids), but remain cautious as to how much additional cost they are willing to absorb. Modelling clearly shows that customers are willing to pay more to enable these investments, however, they need to understand the impact on their bill.

820. These insights allowed Western Power to understand community requirements and preferences and has helped inform our investment plan. The insights have shaped our thinking on the services we will provide and the technology solutions we will invest in over the AA5 period. In particular:

- forecast capex is designed to maintain the current level of safety performance associated with our network assets, consistent with our customers' views that they do not prioritise additional investment in this area given the significant importance we already give to safety
- proposed investment during the AA5 period is designed to maintain current overall reliability levels rather than incur additional costs to improve reliability across the network
- investment is targeted at pockets of the network that have the poorest reliability, have high failure risks (e.g. ageing assets) and have high network security risks
- we are integrating and piloting new solutions to test their suitability as part of the evolving network, such as SPS, community batteries, DER integration and management technologies, microgrids and digital substations
- all expenditure forecasts have been subject to top down review and assessment to ensure they represent a network business efficiently minimising costs and take price impacts into account.

### 8.2.3 Regulatory requirements

821. Western Power's capex forecast is required to meet the Access Code objective, which is:

> *to promote efficient investment in, and efficient operation and use of, services of networks in Western Australia for the long-term interests of consumers in relation to:*
>
> *(a) price, quality, safety, reliability and security of supply of electricity;*
>
> *(b) the safety, reliability and security of covered networks; and*
>
> *(c) the environmental consequences of energy supply and consumption, including reducing greenhouse gas emissions, considering land use and biodiversity impacts, and encouraging energy efficiency and demand management.*[158]

822. Section 6.51 of the Access Code states that forecast capex may be included in the forward looking and efficient costs of providing covered services to the extent that it relates to investment that is reasonably expected to satisfy the new facilities investment test (**NFIT**).[159]

823. The NFIT in section 6.52 of the Access Code was amended in September 2020 to include an assessment of alternative options for all capital investments. The Access Code was also amended to require the ERA to publish guidelines for valuing the net benefits of expenditure by a service provider (see section 6A.6) and

158 See section 2.1 of the *Electricity Networks Access Code 2004*

159 See sections 6.51 and 6.51A, *Electricity Networks Access Code 2004*

also on what factors it will take into consideration in making an NFIT determination (see section 6.56).[160] The ERA published these guidelines on 20 December 2021.

824. The Access Code was also amended to include a requirement for Western Power to publish a Network Opportunities Map by 1 October each year. The Network Opportunities Map is to provide a range of information to service providers to facilitate procurement of alternative solutions, such as 5-year forecast for loads on zone substations, connections, energy consumption, output of embedded generation, emerging network constraints and risks, planned investment and priority projects. Our proposed investment in DSO capabilities will facilitate our obligations under the Access Code to facilitate alternative solutions.

825. Western Power published its inaugural Network Opportunities Map in October 2021. The report provides:

- a snapshot of the SWIS' condition and our challenges and objectives for the next ten years
- insight into how Western Power plans, develops and maintains the network and the forecasting methods used to inform this.

826. Western Power assesses all capex against the NFIT[161] as part of its IGF. In all cases, we consider which limb of the NFIT is satisfied before undertaking any investment. To ensure the investment program efficiently minimises costs, we also consider deliverability, economies of scale or scope, and forecast movements in market prices of labour and materials. Further information on the development of our capex forecast is provided in AA5 Forecast Capital Expenditure Report provided in Attachment 8.1.

## 8.3 Transmission network capex

827. The transmission network comprises assets used in the transmission of electrical power at voltages of 66 kV and above. It allows bulk transfer of power between generators and substations and serves both the energy needs of the distribution network as well as customers directly connected at transmission voltage levels such as power generating stations and large industrial consumers of electricity (e.g. refineries).

828. The transmission network as it exists today is based on second generation design that commenced in the 1950s, when various voltages were introduced to manage the load growth and to cover the vast land area in the SWIN. The reliable operation of the transmission network – which functions as the backbone of the system – is fundamental to ensuring grid stability of the SWIN.

829. A key challenge for the transmission network is the retirement of coal generation, which is shifting the mix of generation from large scale synchronous in the South-East to non-synchronous (i.e. wind and solar) renewable generation in the Central, North and East Country. Augmentations to the transmission system are required to encourage future renewable generation.

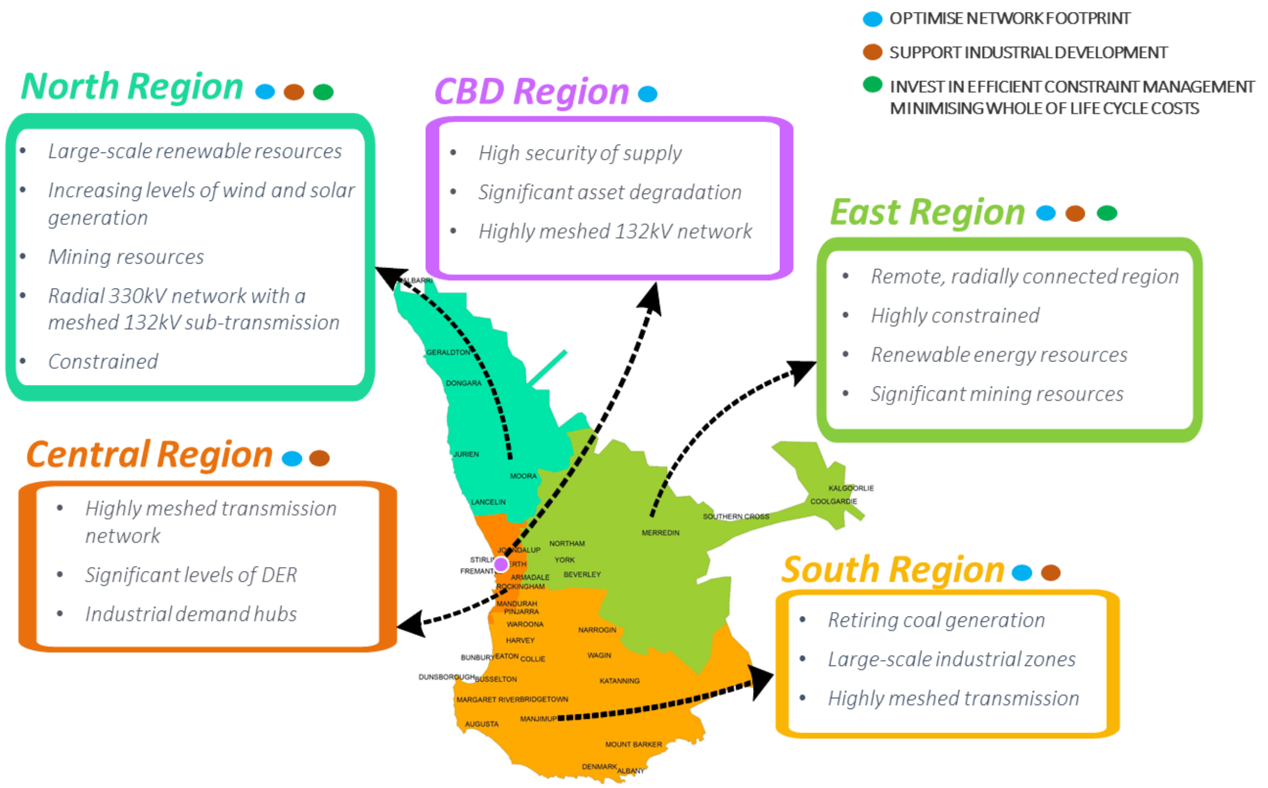
830. Western Power has developed a suite of regional strategies that cover the North, South, Central, East and CBD regions of the Western Power Network. These strategies have been developed to ensure any investment made in these regions is aligned with the future grid vision for these regions as set out in the Grid Strategy. These regional strategies incorporate asset, customer, stability, and network growth drivers (i.e. load) together with changes in the regional distribution network. The aim is to ensure the most optimal investment outcomes whilst minimising the risk of stranded assets.

160 Western Australian Government, *Electricity Networks Access Code Amendments (No.2) 2020*, WA Government Gazette, No.157, 18 September 2020.

161 See section 6.4.2 of the Access Code.

831. Figure 8.4 summarises the distinct characteristics and strategic goals for each of the transmission planning regions.

**Figure 8.4: Transmission planning regions**




832. Internal and external benchmarks indicate that, despite the performance of the transmission network being within committed targets, it has been deteriorating over the past few years. Internal metrics indicate plant functional failures, pole top fires and incidents that cause system disturbances and load loss have been increasing (e.g. 49 per cent more pole top fires and 69 per cent increase in load loss due to power transformer functional failure).

833. The most recent International Transmission Operations and Maintenance Study (**ITOMS**)[162] performed in 2019, shows that the transmission network has experienced three times as many outages as the average Australian utility. The number of outages reported in this study has increased by 170 per cent in the last four years whilst maintenance costs have increased 20 per cent in the same period.

834. The transmission network topology, as well as current operational practices, have helped in mitigating the effects of performance issues on individual assets without experiencing any catastrophic system-level event. However, the deteriorating performance of certain asset classes in conjunction with constraints in accessing the network to perform planned maintenance continue to put pressure on network performance as measured by the SSBs. See Chapter 5 for further details on our network performance during the AA4 period.

835. Our key challenge is to balance customer affordability against the scale and age profile of the transmission network. Life extension techniques such as refurbishments, digital asset management techniques and

162 ITOMS is a consortium of Australian and international transmission companies, which was established in 1994 to identify and share industry best practice. A benchmarking survey of members is completed every two years by UMS Group (https://www.umsgroup.com/Americas/What-we-do/Learning-Consortia/ITOMS.html, Accessed 22 August 2021).

delivery optimisation have underpinned our proposed capex investment plan to ensure current levels of network performance are maintained.

836. The network investment profile reflects the early works required to deliver complex transmission investments with long lead times and realise required in-service dates to mitigate network risk.

837. The proposed investment for the AA5 period requires an uplift on historic spend to adequately address asset condition and risk associated with the following asset classes:

- **Power transformers:** the investment decisions in this category utilise a risk-based framework that accounts for condition and criticality of each asset. The majority of the proposed investment is centred around the application of refurbishment techniques and life extensions in order to manage the condition of as many transformers as possible for the optimum amount of investment
- **Primary plant:** this category accounts for primary plant[163] assets other than power transformers and switchboards within transmission substations. The proposed delivery plan addresses asset condition in the most opportune and cost effective manner by utilising optimised delivery and, where practical, digital technologies and refurbishment
- **Protection:** assets in this category perform the critical function of monitoring abnormal conditions by applying the necessary actions to isolate a failure and prevent it from affecting larger segments of the transmission network. Protection assets are also the last line of defence in mitigating potential safety risks. A large portion of this asset base is obsolete and no longer supported by the manufacturer
- **Other:** additional investments are required to enable customers to keep connecting more generation[164] to the transmission network (e.g. improvements to planning capability), as well as to address emerging grid stability issues caused by the high penetration of renewable resources in the distribution network.

838. Western Power will invest $871.7 million in total capex for the transmission network during the AA5 period. This investment is designed to address existing network security and power quality issues, meet forecast growth and compliance obligations. It is also necessary to maintain current reliability levels. It includes an estimated $190.1 million in capital contributions from customers.

839. Table 8.2 provides a summary of the proposed investment in transmission network capex in the AA5 period, broken down by the regulatory categories.[165]

**Table 8.2: AA5 forecast transmission capex, including real cost escalation and indirect costs, excluding SCADA and Telecommunications, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Asset Replacement | 73.6 | 72.4 | 65.2 | 64.9 | 66.9 | 343.1 |
| Growth | 102.3 | 84.7 | 60.9 | 60.1 | 32.4 | 340.4 |
| Improvement in Service[166] | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Compliance | 41.8 | 42.7 | 46.3 | 31.7 | 25.6 | 188.2 |

163 Transmission substation contain primary plant assets (used in the primary function of transmitting power), secondary system assets (used to support and protect the primary functions) and lines assets (underground and overhead lines network interface)

164 There is minimal additional investment required as Western Power is currently operating under Generator Interim Access (**GIA**) arrangements, which provides for Western Power to issue curtailment instructions to generators. These arrangements will be in place until constrained access commences in 2023.

165 Excluding investment in SCADA and Telecommunications network.

166 Excluding investment in SCADA and Telecommunications network.

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| **Transmission network** | **217.6** | **199.9** | **172.5** | **156.7** | **124.9** | **871.7** |
| Less Contributions | 66.6 | 36.3 | 36.5 | 36.8 | 13.9 | 190.1 |
| **Net AA5 Capex added to RAB** | **151.0** | **163.6** | **136.0** | **119.9** | **111.0** | **681.6** |

840. Figure 8.5 shows forecast transmission capex for the AA5 period compared with historical levels.

**Figure 8.5: Comparison of AA4 actual and AA5 forecast transmission capex by regulatory category**


841. The sections below summarise the key investments in the transmission network in the AA5 period. Further information on the AA5 transmission capex program is provided in the AA5 Forecast Capital Expenditure Report provided at Attachment 8.1 and in the Network Management Plan provided in Confidential Attachment 8.2.

### 8.3.1 Asset replacement and renewal

842. The asset replacement and renewal capex forecast covers expenditure on poor condition or obsolete transmission network assets. This expenditure is necessary to ensure the ongoing safety and security of the transmission network.

843. Western Power plans to invest $343.1 million in transmission asset replacement and renewal during the AA5 period, with the majority of this investment being for primary plant, protection systems and power transformers (see Table 8.3).

**Table 8.3: AA5 forecast transmission asset replacement and renewal capex, including real cost escalation and indirect costs, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Primary Plant | 30.4 | 26.7 | 25.5 | 25.9 | 26.1 | 134.6 |
| Protection Systems | 17.4 | 17.4 | 17.4 | 17.6 | 17.8 | 87.6 |
| Power Transformers | 16.3 | 17.4 | 14.0 | 13.6 | 14.2 | 75.5 |
| Switchboards | 6.6 | 10.9 | 3.9 | 2.8 | 1.9 | 26.2 |

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Other | 2.9 | 0.0 | 4.4 | 5.0 | 6.9 | 19.2 |
| **Gross Capex** | **73.6** | **72.4** | **65.2** | **64.9** | **66.9** | **343.1** |
| Less Contributions | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Net AA5 Capex added to RAB** | **73.6** | **72.4** | **65.2** | **64.9** | **66.9** | **343.1** |

844. Failure of transmission assets and their potential failure consequences contribute to unplanned network outages and place pressure on network performance and system security. Over a 10-year period with no treatment of the above assets, more failures will occur which will pose a threat for Western Power's ability to manage the network and fulfill its licence obligations. It is expected that without treatment, the resulting increase in failures would result in negative reliability impacts (i.e. an increase in frequency and duration of outages) and instability of the transmission network (presenting system security challenges). This would result in an increase in the likelihood of 'system black' type events due to the tendency of transmission asset failures to have flow-on effects on the network.

845. The main asset replacement programs are summarised below. Details of forecast asset replacement and renewal capex is provided in the AA5 Forecast Capital Expenditure Report provided in Attachment 8.1 and the Network Management Plan in Confidential Attachment 8.2.

### *Primary Plant*

846. Primary plant includes outdoor circuit breakers, instrument transformers, surge arrestors, disconnectors and earth switches. There are four separate asset classes[167], each with their own profile, condition and strategy information.

847. Western Power proposes to invest $134.6 million on primary plant replacement and renewal during the AA5 period. This is 86.7 per cent higher than the capex incurred in the AA4 period for this expenditure category. Proposed investment is driven by:

- the increase in the number of conditions identified (backlog of almost 3,200 conditions)
- the increase in the number of interruptions and load loss caused by primary plant failure
- a risk of partial or full system black incident if the risk index is not managed below the target[168]
- replacement on failure only would result in unacceptable safety and reliability risks
- the potential risk to public and workforce safety from surges affecting primary plant.

848. The proposed investment focuses on replacement of the following assets:

- **Outdoor circuit breakers:** which are switching devices that can make, carry and break currents under design service conditions (including design short circuit conditions) to connect or disconnect circuits. There are 1,591 outdoor circuit breakers in Western Power's fleet. Approximately 13 per cent of the outdoor circuit breakers are operating beyond their Mean Replacement Life (**MRL**). As of 30 June 2020, there were 615 defects awaiting action
- **Instrument transformers:** which convert current and voltage from its primary levels to secondary levels, of a defined magnitude, frequency and phase to allow the measurement of current and voltage

167 Disconnectors and earth switches are in the same asset class, with the same strategy.

168 The target is the maximum value the index can be to maintain performance. By managing the risk below target, Western Power is maintaining performance at historic levels.

present on the primary circuit. There are 6,733 instrument transformers on Western Power's fleet. Approximately 12 per cent of instrument transformers are operating beyond their MRL and consequently are more exposed to the potential effects of electrical and mechanical stresses. As of 30 June 2020, there were 312 defects awaiting action

- **Surge arrestors:** which are protective devices that limit surge voltages by diverting surge currents to earth and thereby prevent exposure of the protected primary plan or line from severe over-voltages. There are 2,392 surge arrestors on the transmission network, of which approximately 10 per cent are operating beyond their MRL
- **Disconnectors and earth switches:** which are mechanical switches that provide isolation and earthing to un-loaded and un-faulted equipment, circuits, plants and busbars. There are 10,423 disconnectors and earth switches on the transmission network, of which approximately nine per cent are operating beyond their MRL.

849. The proposed investment also includes installation of online monitoring devices on critical transmission assets such as power transformers and switchboards. Western Power plans to install condition monitoring devices in approximately 40 substations to improve understanding of asset condition. The use of digital substations is expected to improve accuracy, accessibility and timeliness of condition and operational data for substation assets to increase reliability, safety, network flexibility and resilience. Condition monitoring allows Western Power to treat selected assets by refurbishing them instead of replacing those assets, which could be up to six to ten times lower cost than replacement, supporting approximately $38M in cost avoidance in AA5. This will allow the transmission network to better adapt to a changing energy landscape.

850. The asset renewal strategies for primary plant are risk-based and involve inspections and repairs at regular intervals.

### *Protection*

851. The protection systems investment relates to the replacement of protection systems, including feeder, transformer, line, busbar and circuit breaker protection. Assets in this category perform the critical function of monitoring abnormal conditions and applying the necessary actions to isolate a failure and prevent it from affecting larger segments of the transmission network.

852. Western Power proposes to invest $87.6 million in protection asset replacement and renewal during the AA5 period. The main drivers for the proposed protections systems investment are:

- approximately one-third of the fleet is obsolete without manufacturer support and with limited industry skills to perform repairs
- around 43 per cent of the fleet is beyond the MRL
- obsolete relays not having all the functionalities required to operate a contemporary network
- high safety risk due to potentially catastrophic consequences of a failure of the main and back up protection
- inability to limit the impact of faults on the network
- compliance with the Access Code and Technical Rules.

853. Failures associated with this asset class typically cause extended outages and lead to unsecure network states. Minimal investment was allocated to this category early in the AA4 period which resulted in a decrease in performance and required an increase in expenditure towards the end of AA4 to avoid further deterioration. Solutions developed during AA4 have informed the required solutions and volumes to maintain performance at historical AA4 levels. The proposed investment is necessary to meet safety and

reliability objectives. Without treatment, there will be an increase to the risk of failures and the associated consequences.

### *Power transformers*

854. The power transformers investment focuses on the refurbishment and replacement of power transformers that have been identified in bad or poor condition with failure modes that could lead to major consequences, have reached the end of their life cycle and / or have failed in service.

855. As of 30 June 2020, approximately 27 per cent of the power transformer population were categorised as ‘poor’ or ‘bad’, requiring major intervention (replace or refurbish). This issue is compounded by:

- an ageing asset population, particularly on the 66 kV network where 21 per cent of power transformers are operating beyond their MRL
- limited manufacturer support, with eight per cent of assets without support available
- environmental risks from insufficient bunding required to prevent oil leaks
- pitch-filled cable boxes that are at risk of explosive failure
- increasingly constrained access to the network, making it more difficult to access the transformers for maintenance and refurbishment
- increasing operational demand on the transformer fleet with the decentralisation of generation.

856. The investment decisions for power transformers utilise a risk-based framework that accounts for asset condition, criticality and lifecycle strategy. The majority of the investment is centred around the application of refurbishment techniques in order to manage the condition of as many transformers as possible for the optimum amount of investment. For example, if a transformer is approaching its end of life and is scheduled to be decommissioned in the future, the intention is to extend its asset life via refurbishment (rather than replace). Network-driven growth is factored in these decisions to optimise asset replacements.

### 8.3.2 Growth

857. Growth capex is generally focused on increasing the capacity of existing assets or the construction of new assets to meet growth in demand, which is primarily driven by forecasts of energy demand and customer growth and the optimisation of assets (e.g. replacement of an ageing substation in one location with a new substation in a different location). These investments are influenced by the network strategies for the regions and are optimised against asset condition drivers, the retirement of the aged 66 kV network and the de-meshing of the 132 kV networks.

858. Western Power will invest $340.4 million in transmission growth projects during the AA5 period, including $190.1 million in capital contributions. This is $71.3 million (17.3 per cent) less than that incurred in the AA4 period (see Table 8.4).

**Table 8.4: AA5 forecast transmission growth capex, including real cost escalation and indirect costs, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Customer Driven | 70.6 | 39.5 | 39.7 | 40.1 | 17.2 | 207.2 |
| Capacity Expansion | 31.7 | 45.2 | 21.2 | 19.9 | 15.2 | 133.2 |
| **Gross Capex** | **102.3** | **84.7** | **60.9** | **60.1** | **32.4** | **340.4** |
| Less Contributions | 66.6 | 36.3 | 36.5 | 36.8 | 13.9 | 190.1 |

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| **Net AA5 Capex added to RAB** | **35.7** | **48.4** | **24.4** | **23.2** | **18.5** | **150.3** |

859. Our transmission growth capex is summarised below. Further details of forecast growth expenditure is provided in the AA5 Forecast Capital Expenditure Report provided in Attachment 8.1 and the Network Management Plan in Confidential Attachment 8.2.

### *Customer driven*

860. The customer driven expenditure category comprises all the capex required to augment the transmission network to facilitate customer access or customer driven projects. In terms of access, this includes where customers seek to connect new facilities and equipment, increase consumption or generation at an existing connection point, or modify their existing facilities. Facilitating customer driven projects predominantly involves asset relocations.

861. Western Power proposes to invest $207.2 million during the AA5 period on transmission customer driven projects, including contributions of $190.1 million. The proposed investment is primarily for relocations ($151.2 million, 73 per cent), with the balance being for transmission access projects ($56.0 million, 27 per cent).

862. Examples of key customer driven projects for the AA5 period are:

- Undergrounding relating to the East Perth Power Station redevelopment project. The undergrounding will be 100 per cent customer funded and has a required in service date of December 2022
- Relocation of assets to facilitate the Oat Street level Crossing Removal project, which is part of the ESP for Metronet. This project will be 100 per cent customer funded and has a required in service date of November 2022.

863. The proposed investment for customer driven projects in the AA5 period also includes $91.6 million for the relocation of other transmission assets to support the WA Government's ESP.[169]

### *Capacity expansion*

864. Capacity expansion investment for the transmission network is focused on optimising against asset condition and region strategies. Given the age of the transmission network, a significant portion of the 66 kV networks are approaching their mean replacement life. Therefore, a common underlying theme in these regions is the need to decommission aged 66 kV networks and associated zone substations and maximise the utilisation of the higher voltage networks. This is further emphasised by the concept of de-meshing networks which balances the utilisation between 132 kV and 330 kV networks. These drivers will also allow to facilitate new customer connections providing for the 'right-size' network to meet customer needs.

865. Western Power will invest $133.2 million during the AA5 period on transmission capacity expansion projects. The proposed investment is primarily for supply projects ($121.3 million, 91 per cent), with the balance being for distribution driven projects, thermal management and voltage management.

866. The key supply projects for the AA5 period are:

- **installation of transformers**:

[169] Further information on the ESP is available from the WA Government website: COVID-19 coronavirus: Western Australian Government response (www.wa.gov.au)

- installation of a third 132/22 kV transformer at Black Flag substation to address a current capacity short fall and N-1 non-compliance, whilst enabling new customer connections given the significant growth in customer demands. The required in-service date is 2025/26
- installation of a third 132/11 kV transformer at Cook Street substation to facilitate the decommissioning of Wellington Zone substation and East Perth 66 kV switchyard and enable new customer connections at Perth City Link and Edith Cowan University CBD campus. This project is interlinked with the East Perth Power Station redevelopment, which is a priority project for the WA Government. The required in-service date is 2023/24
- installation of a new 330/132 kV transformer at the Kemerton terminal substation to address the asset condition issues of the existing transformer. This transformer has been assessed as having the maximum criticality score for post failure fault response compared to all other transformers on the network. The transformer will facilitate new growth opportunities such as Abermarle and reference services to Bininup. The required in-service date is 2021/22
- installation of a third 132/22 kV transformer at Henley Brook substation to address approximately 8 MW of capacity short fall under N-1 conditions. The required in-service date is 2027/28
- Installation of a third 132/22 kV transformer at Clarkson substation to address approximately6 MW of capacity short fall under N-1 conditions. The required in-service date is 2026/27

• **installation of new transmission lines**:
  - a new 132 kV connection between Kwinana to Leith Rd Substation which will provide reliability to existing customers, facilitating network security and future network de-mesh plans for the Kwinana load area. The required in-service date is 2023/24

• **asset decommissioning / retirement**:
  - decommissioning of Coolup substation and the Picton to Coolup (PIC-CLP 71) 66 kV transmission line (70 km) due to asset condition issues and low peak demand forecasts (~6 MVAr). This demand at Coolup will be resupplied from the adjacent Wagerup substation. The required in-service date is 2024/25
  - decommissioning of Mundaring Weir substation and the transmission lines from Cannington Terminal to Northam substation (total 88 km) due to low demand forecasts. The required in-service date is 2023/24

• **grid stability**:
  - investment in solutions (such as wide area monitoring protection & control) to provide increased visibility on the network and allow for more informed operational and planning investment decisions. Greater visibility will enable Western Power to more effectively identify and implement risk mitigation solutions to address grid stability challenges resulting from having limited to no visibility on issues of system strength.

867. Western Power also plans to invest $17.6 million to increase capacity at Busselton and Capel by installing reactive support at Busselton for voltage management. Assets in poor condition will be addressed whilst these works are being conducted. Initial plans for the 132 kV conversion of the existing 66 kV transmission line between Picton and Busselton substations have been deferred to AA6 (deferment of $40 million) based on the application of prudent risk-based planning techniques.

### 8.3.3 Improvement in service[170]

868. This expenditure category covers reliability-driven capex that is designed to achieve improvements in reliability and power quality service standard targets for the transmission network.

869. In line with customer feedback, Western Power does not plan to increase the reliability and power quality standards during the AA5 period and, hence, no additional investment is required for improvement in service.

870. Western Power notes that forecast investment to meet current reliability and power quality standards is included in the asset replacement and renewal expenditure category. Furthermore, the investment in the modular grid and the technologies therein (i.e. SPS and microgrids) will significantly improve the level of reliability and resilience and this will be delivered with a lower cost technology than traditional poles and wires (due to the long rural feeders required to service customers dispersed over large distances).

### 8.3.4 Regulatory Compliance

871. Western Power has a range of compliance obligations relating to safety, environmental, power quality, and network security obligations for the transmission network. During the AA5 period, Western Power will invest $188.2 million on satisfying these obligations (see Table 8.5).

**Table 8.5: AA5 forecast transmission compliance capex, including real cost escalation and indirect costs, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Tx Poles & Towers | 10.7 | 10.8 | 10.8 | 10.9 | 11.0 | 54.2 |
| Substation security | 8.0 | 7.8 | 7.8 | 7.9 | 5.7 | 37.2 |
| Substation Building Upgrades | 5.5 | 2.7 | 2.7 | 2.7 | 2.9 | 16.4 |
| Tx Cables | 1.8 | 4.6 | 7.6 | 2.4 | 0.0 | 16.3 |
| Cross-arm Replacement | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 10.9 |
| Transformer Compliance | 2.4 | 1.7 | 1.3 | 1.2 | 1.2 | 7.8 |
| Other TX compliance | 11.2 | 13.0 | 14.0 | 4.5 | 2.6 | 45.3 |
| **Gross Capex** | **41.8** | **42.7** | **46.3** | **31.7** | **25.6** | **188.2** |
| Less Contributions | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Net AA5 Capex added to RAB** | **41.8** | **42.7** | **46.3** | **31.7** | **25.6** | **188.2** |

872. The major transmission compliance programs for the AA5 period include:

- **poles and towers** ($54.2 million, 29 per cent): which includes replacement and reinforcement of transmission wood poles and replacement of non-wood structures in the transmission network based on condition of the asset. This program addresses Western Power's obligations under Part 4 of the *Electrical (Supply Standards and System Safety) Regulations 2001* to operate and maintain a safe and

[170] Excluding SCADA and Telecommunications network, which is considered separately in Section8.5.

reliable transmission network by minimising public safety risk from asset failure and maximisation of reliability performance

- **substation security** ($37.2 million, 20 per cent): which covers ongoing investment in security fencing, electronic access, closed circuit television (CCTV) systems and key management systems. Substation buildings and grounds are essential facilities that house primary and secondary substation equipment. Substations must comply with the National Guidelines for Protecting Critical Infrastructure from Terrorism and the proposed reforms to the requirements of the *Security of Critical Infrastructure Act 2018* which are anticipated to come into effect in AA5, as well as non-compliance with the statutory requirements applicable for buildings, workforce safety and building envelop. Compliant security fencing is also an important barrier for preventing access to substations by those who seek to commit vandalism or self-harm
- **substation building upgrades** ($16.4 million, 9 per cent): which covers a range of activities relating to buildings and grounds, including investment in very early smoke detection apparatus (**VESDA**) systems, fire indicator panels, asbestos removal and rectification of structural defects to comply with statutory requirements applicable for buildings, workforce safety and building envelop. Following a substation roof collapse in AA4, several structural defects at substations were identified. In response a network facilities strategy was developed which applies a risk-based approach based on substation criticality, prioritising mitigation of building conditions to protect staff and equipment. The strategy is aligned with industry practice and has informed the timing and level of AA5 expenditure.
- **transmission cables** ($16.3 million, 9 per cent): which covers replacement of transmission underground cables (including fluid filled cables) that are aged, present poor performance (reliability / availability / environment) and can no longer be cost efficiently maintained using opex treatments. It also includes replacement of cable accessories (such as joints and terminations) and the pressuring equipment used to monitor the fluid within the cable at a positive pressure
- **other transmission compliance** ($45.3 million, 24 per cent): which covers a range of activities relating to the grid stability toolkit, under frequency load shedding (**UFLS**) mitigation, integrated grid planning systems, network monitoring and remote black start operation. The predominant driver of this expenditure relates to the growing grid stability issues and system low, which if unaddressed will result in widespread network outages and substantial impacts to customer supply.

873. In addition to meeting compliance requirements, the proposed investments are critical for ensuring the safe and reliable operation of the transmission network and avoiding adverse impacts on the environment.

874. Details of forecast compliance expenditure for the transmission network are provided in the AA5 Forecast Capital Expenditure Report provided in Attachment 8.1 and the Network Management Plan in Confidential Attachment 8.2.

## 8.4 Distribution network capex

875. The distribution network transports electricity from zone substations to individual customers at voltages ranging from 240 V to 33 kV. Increasingly, the distribution network is hosting bi-directional flows from customer PV which also result in reverse flows to the zone substation levels. The distribution network investment is made up of two distinct categories:

- overhead corridor (structures, overhead conductors, pole mounted equipment)
- ground mounted plant, service connections, public lighting and underground cables.

876. Our key challenge is to maintain customer affordability given the scale and age profile of the distribution network. At a rebuild value of approximately $23 billion (including $7 billion of underground assets), it

constitutes two thirds of the value of the Western Power Network. A considerable portion of these assets were constructed as the State population grew in the 1970s and 80s.

877. The distribution network also faces a number of uncertainties and challenges as customers embrace DER technology such as PV systems, smart homes and EVs. Western Power's response to the changing needs of our customers is focussed on the development and implementation of a Grid Strategy with a future grid vision and developing new capability to turn this vision into reality.[171]

878. Our Grid Strategy is based on long-term scenario planning for evolving customer preferences and needs, which identifies the optimum solution for technology to use at the right place and time. This approach provides a vision and roadmap for the grid vision which minimises whole of life cycle costs and regrettable investment.

879. As demonstrated in Chapter 2, Western Power is developing a modular grid that comprises three zones:

- **tightly meshed urban network**: for metropolitan customers, Western Power will focus on undergrounding assets where possible and facilitating ever increasing amounts of renewables and DER, such as rooftop solar and EVs
- **hybrid network**: for those customers between the metropolitan and regional areas, Western Power will maintain a network of mostly overhead assets, with new technologies like SPS and microgrids where they make economic sense for the community
- **autonomous stand-alone network**: for remote customers, the modular grid will mean a new way of delivering power, like SPS and microgrids. However, the regional depots will remain to enable Western Power to maintain and respond to faults and outages on the ageing rural overhead network.

880. The proposed increase in distribution investment for the AA5 period focuses on the following:

- **Distribution overhead**: increased expenditure is required for the increasing deployment of SPS and to achieve a 'maintain performance' objective. The application of the new distribution overhead Network Rebuild Strategy has mitigated against further increases in the medium term as the network continues to age. Provision has also been made for discrete investments in underperforming reliability 'hot spot' areas to meet the SSB performance
- **Underground cables**: an increasing asset failure rate within this category has also contributed negatively to reliability performance compared to the SSB. The investment is to apply a proactive and targeted cable replacement strategy to avoid the risk of poor reliability performance in high customer density parts of the network (e.g. Perth CBD)
- **Ring Main Units:** a particular type of RMU has been identified with a manufacturing defect that poses both a workforce safety risk and reliability risk. This investment is for a like-for-like replacement of these impacted assets with new, non-defective units
- **Metering:** increased expenditure reflects the acceleration of the AMI deployment (with completion of the program aimed for 2027) and replacement or re-configuration five-minute capable metering to support the mandated implementation of five-minute settlements in the WEM
- **Future capability**: provision has been made to fund commitments made in the DER Roadmap and the Energy Transformation Strategy to ensure an efficient grid which is fit for customer needs and emerging technology trends. The investments include two disconnected microgrids[172], provision to support Project Symphony and associated network-level devices to monitor bi-directional flows on the distribution network

171 Further information on the Grid Strategy is provided in the AA5 Forecast Capital Expenditure Report provided at Attachment 8.3.

172 One of these will be a trial, with the subsequent investment being business as usual investment (pending the outcome of the trial).

- **Loading and voltage**: the number of over-utilised feeders is forecast to increase compared to previous years of flat or negative growth. Investment will be required to cater for excess load and avoid rolling blackouts, depending on customer responses to hot weather events. Additionally, we expect to see a continuing uptake of PV on rooftops and a continuing decline in daytime minimum load on the network. This minimum load increases the possibility of localised over-voltages which requires investment to mitigate the risk of non-compliance.

881. This investment is required to meet safety obligations (as per the requirements of Western Power's ENSMS) and Technical Rules obligations. Without this investment, there will be significant pressure on the reliability service standards and a failure to invest for the future, thus increasing whole of life cycle costs.

882. We will invest $3,479.9 million (including capital contributions) in our distribution network during the AA5 period (see Table 8.6). This investment is designed to address existing network security and power quality issues. It is also necessary to maintain current reliability levels and safety.

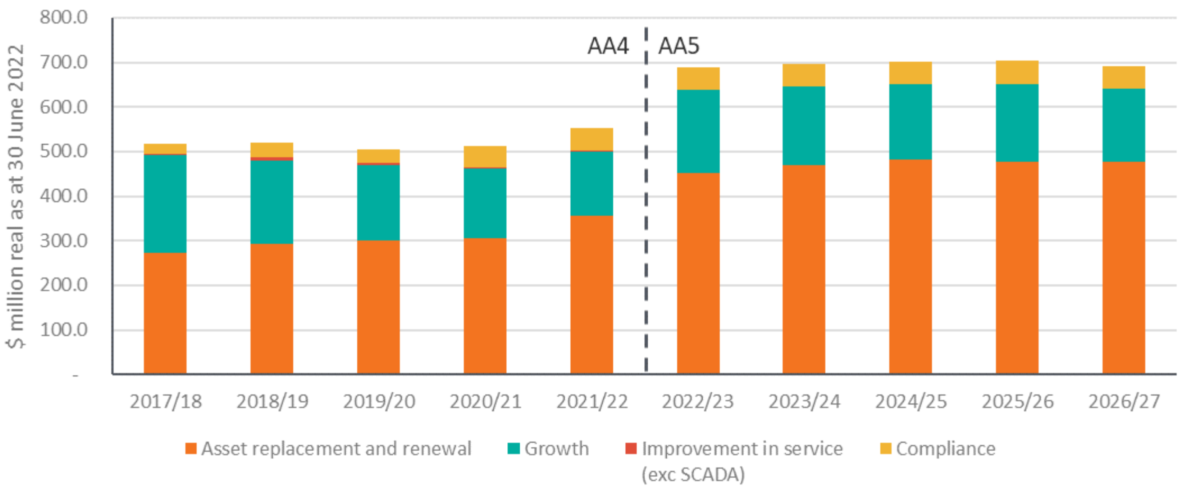
**Table 8.6: AA5 forecast distribution capex, including real cost escalation and indirect costs, excluding SCADA and Telecommunications $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Asset Replacement | 451.5 | 469.6 | 480.9 | 476.5 | 475.8 | 2,354.3 |
| Growth | 187.0 | 176.3 | 170.9 | 175.4 | 164.6 | 874.3 |
| Improvement in Service[173] | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 |
| Regulatory Compliance | 49.8 | 49.2 | 50.6 | 50.7 | 50.7 | 251.1 |
| **Gross Capex** | **688.6** | **695.1** | **702.4** | **702.7** | **691.1** | **3,479.9** |
| Less Contributions | 149.7 | 159.7 | 171.9 | 183.8 | 179.2 | 844.4 |
| **Net AA5 Capex added to RAB** | **538.8** | **535.5** | **530.5** | **518.8** | **511.9** | **2,635.5** |

883. Figure 8.6 shows forecast distribution capex for the AA5 period compared with historical levels.

173 Excluding investment in SCADA and Telecommunications Network.

**Figure 8.6: Comparison of AA4 actual and AA5 forecast distribution capex by regulatory category**




884. The sections below summarise the key investments in the distribution network in the AA5 period. Further information on the AA5 distribution capex program is provided in the AA5 Forecast Capital Expenditure Report provided at Attachment 8.1 and in the Network Management Plan provided in Confidential Attachment 8.2.

### 8.4.1 Asset Replacement and renewal

885. Western Power will invest $2,354.3 million in asset replacement and renewal for the distribution network in the AA5 period. This investment is driven primarily by the need to maintain network safety and reliability performance.

886. Table 8.7 summarises AA5 period forecast distribution asset replacement and renewal capex.

**Table 8.7: AA5 forecast distribution replacement and renewal capex, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Pole Management | 89.8 | 90.2 | 78.0 | 82.3 | 82.8 | 423.1 |
| Asset replacement[174] | 138.3 | 124.7 | 93.3 | 79.4 | 78.3 | 514.1 |
| SPS | 60.0 | 61.6 | 60.9 | 73.1 | 75.2 | 330.8 |
| NRUP | 81.5 | 113.3 | 160.8 | 161.8 | 164.5 | 681.8 |
| Metering | 70.4 | 68.3 | 76.2 | 68.3 | 63.2 | 346.3 |
| Streetlights | 11.5 | 11.6 | 11.6 | 11.7 | 11.8 | 58.2 |
| **Gross capex** | **451.5** | **469.6** | **480.9** | **476.5** | **475.8** | **2,354.3** |
| Less contributions | 31.5 | 41.1 | 52.9 | 63.9 | 66.7 | 256.2 |
| **AA5 capex to be added to the RAB** | **419.9** | **428.5** | **428.0** | **412.6** | **409.0** | **2,098.1** |

174 This category includes distribution assets other than poles, such as conductors, switchgear and cables.

887. The following sections provide further information on the distribution asset replacement and renewal capex subcategories.

*Pole management*

888. Poles are a critical element of the distribution overhead network in providing the function of supporting overhead conductors. Failures of poles can potentially cause physical impact injury and property damage. More importantly, it may also cause conductors to fail or to come into contact with vegetation or the ground and cause fire, electric shock and/or service disruption.

889. Western Power will invest $423.1 million in wood pole replacement and reinforcement in the AA5 period. This is $329.9 million (44 per cent) less than incurred on wood pole management in the AA4 period.

890. The investment in pole management includes both:

- reactive replacement of assets that fail while in service. The reactive forecast is based on expected wood pole failures in service (both assisted and unassisted failures). Forecasts for assisted failures is based on historical performance data using a simple forecasting methodology. The unassisted failure forecast considers the 10-year treatment plan and asset treatment volumes and uses the Equivalent Distribution Calculator
- proactive replacement and reinforcement of assets selected through the application of the Distribution Overhead Network Rebuild Strategy.

891. Western Power plans to replace 34,974 wood poles and reinforce a further 27,500 wood poles during the AA5 period.

892. The proposed investment contributes to the following outcomes:

- maintains overall safety of the network in line with jurisdictional obligations (eliminate / reduce risk as low as is reasonably practicable (**ALARP**))
- maintain current service standard levels, as measured by SSBs, whilst ensuring ongoing sustainability of the network
- optimise the transition to the modular grid.

*Asset replacement*

893. Western Power plans to invest $514.1 million in other asset replacement and renewal during the AA5 period, with the majority of this investment being for:

- **conductor management** ($181.4 million, 35 per cent): covers the replacement of overhead conductors on the distribution network, including both HV and LV mains conductors, but excludes any customer service conductors and underground cables. It also includes the associated conductor scoping and validation activities required to select and design the individual assets that will be treated
- **switchgear management** ($122.9 million, 24 per cent): targeted at HV RMUs and ground-mounted indoor metering unit replacements. A particular type of RMU has been identified with a manufacturing defect that poses both a workforce safety risk as well as a reliability risk. During AA4 we were able to manage emerging RMU failures in the short term via a combination of operational restrictions and limited replacements, which is no longer viable in AA5 due to increasing failures. This investment is for a like-for-like replacement of these impacted assets and additional inspections to maintain performance and risk ratings. Western Power plans to replace approximately 1,000 RMUs with the identified manufacturing defect during the AA5 period, with the replacement prioritised by risk.

Western Power plans to replace a further 180 RMUs based on condition and risk during the AA5 period

- **cable management** ($80.3 million, 16 per cent): covering both the reactive replacement of identified in-service cable failures and related faults and operations (e.g., damaged insulation during inspection or excavation of adjacent assets), and proactive replacement of critical cables that have been identified as having severe defects (detected via the testing program) that require replacement. An increase in AA4 of unassisted cable failures, electric shocks and associated reliability impacts informed the need to increase investment in AA5. The treatment volumes are based on addressing in-service cable failures, and testing and condition assessment of critical cables to inform proactive replacements.
- **transformer management** ($69.0 million, 13 per cent): relates to replacement of transformers that fail in-service (reactive) and / or have been identified with conditions or defects that require a replacement (proactive) in accordance with applicable asset management strategies.

*Standalone power systems*

894. Western Power plans to invest $330.8 million in SPS during the AA5 period.

895. Consistent with the Grid Strategy and Corporate Strategy, SPS will be deployed during the AA5 period where the SPS solution is determined to be the least cost solution over the long term, as an alternative option to replacing the overhead network.

896. The deployment sequence for SPS targets sections of the network that have the optimal balance of asset deterioration and cost efficiency. As this solution is implemented, large geographical areas of overhead network will be decommissioned.

897. The deployment of SPS is also driven by the medium and long term benefits they provide, including an inherent reduction in electric shock and bushfire risk, increased reliability, improved network access, lower whole of life costs and supporting decarbonisation of the economy.

898. SPS has a higher upfront cost in the period it is installed however it is cheaper than traditional network over the lifetime. The upfront cost is concentrated into the SPS unit, whereas the alternative is to replace the existing poles and wires piecemeal over a number of years as they become mature. Not only is this solution lower cost over the long term, but it also provides greater benefits for customers in both safety and reliability performance.

899. Western Power plans to transition 4,000 existing connection points to either SPS or proactive supply abolishment by 2031. Approximately 1,861 units or equivalent are scheduled for deployment in the distribution area over the AA5 period. This includes 1,630 SPS equivalents for the SPS program and 230 SPS equivalents to enable microgrids.

900. Cost efficiency will be facilitated through competitive tendering processes to select vendors for the provision of turnkey SPS solutions.

901. The roll out of the SPS will be undertaken over several rounds, with each round of asset replacement addressing the network risk posed by the distribution overhead assets that are in deteriorated condition and which have been identified for replacement in the relevant asset strategy. Analysis conducted during the scoping and planning phases of each round needs to demonstrate that replacing the overhead assets with SPS is the recommended option, providing the following benefits:

- reduction of bushfire and electric shock risk associated with the targeted assets
- improved customer experience (reliability)

- lower net present cost than a like-for-like replacement.

902. These benefits are aligned with the strategic objective of meeting future demand for safe and reliable power that efficiently meets customer needs.

*Network Renewal Undergrounding Program (**NRUP**)*

903. The NRUP involves the targeted conversion of overhead areas to underground power. These projects are proposed for areas in the meshed urban network where:

- the overhead assets are deteriorated and require replacement, and
- underground replacement presents a comparable cost to a like for like overhead replacement.

904. Where a funding gap in proposed projects is identified, Western Power will seek to underground the network through financial partnerships with local communities (via the relevant local governments).

905. The need for this investment is driven by a significant part of the metropolitan overhead network reaching the end of its service life. NRUP projects are timed to address the largest proportion of overhead assets that require treatment.

906. The benefits of this investment program are providing lower total cost of ownership of Western Power assets (through gifted assets), improved reliability, increased ability to host DER, improved safety and enhanced customer choice. Furthermore, the proposed investment aligns with the strategic objective of meeting future demand for safe and reliable power that efficiently meets customer needs.

907. Western Power plans to invest $681.8 million in the NRUP during the AA5 period, including $241.9 million in capital contributions.

908. Western Power will invest in undergrounding only where it makes economic sense. Customers' willingness to pay any incremental costs (the capital contribution) will be determined on a case-by-case basis for each area, in consultation with the relevant local government. Project selection will take into account the required contribution from local governments to ensure external requirements are satisfied.

909. Customer and community expectations are for an affordable contribution to facilitate the underground transformation. Where the incremental cost is not supported by the local government or the community, the undergrounding project will not proceed and an alternative risk mitigation solution will be implemented.

*Advanced metering infrastructure*

910. AMI refers to digital meters with a communication device installed. Advanced meters can automatically and remotely read electricity flows and provide early detection of connection faults and supply issues. They provide a clearer picture of the power quality data, including the voltage and current levels, and how much renewable energy is being fed back into the network.

911. AMI plays a key role in a range of emerging network requirements which require increased visibility (and potentially control) of the distribution network, including both customer and network, and technology connected to it. AMI is a critical enabler for the effective integration of DER, solutions for mitigating the risk of low load, flexible tariffs and allowing customers to actively participate in the energy market.

912. Western Power commenced deployment of AMI in 2019, with the deployment aimed for completion in 2027. An estimated half a million advanced meters will be installed by June 2022, with a further 795,130 scheduled to be installed during the AA5 period.

913. Investment in AMI is forecast at $317.1 million for the AA5 period. This will allow the continued deployment from the current basic meter standard to the advanced meter standard. Metering capex also includes the associated communications infrastructure and IT system costs to allow Western Power to access interval data and meter alarms remotely.

914. The Access Code was amended in September 2020[175] to enable cost recovery of AA4 AMI expenditure relating to communications and IT. The amendments allow recovery of AMI expenditure through a separate building block, similar to how deferred revenue is recovered. Further information on the cost recovery of AA4 AMI expenditure is provided in Chapter 11.

#### *Meters for five-minute settlement*

915. Western Power will invest $29.2 million in the AA5 period for metering to support the mandated implementation of five-minute settlements in the WEM.[176] This is separate to the AMI deployment investment (see above).

916. Western Power has estimated that around 20,984 existing meters will need to be replaced with five-minute meters and around a further 7,604 will be reconfigured to provide five-minute data required to support five-minute settlement. The replacements and reconfigurations are planned for 2022/23 to 2023/24, with five-minute settlements to commence in October 2025.

917. Drafted amendments to the *Electricity Industry (Metering) Code 2021* are expected to be approved by the Minister in 2021, enabling the recovery of expenditure associated with the implementation of IT system uplifts and meter deployment and reconfiguration.

#### *Streetlight management*

918. Public lighting provides illumination for roads and public areas to enhance public safety and security.

919. Western Power plans to invest $58.2 million on streetlight replacement and reinforcement in the AA5 period, including:

- planned and reactive replacement and reinforcement of metal streetlight poles that have failed or been identified for treatment via inspection
- reactive luminaire replacement at end of life / failure
- streetlight cable replacement (usually reactive).

920. As of 30 June 2020, there were 274,217 streetlights (luminaires) connected to the distribution network. There were 152,421 Dedicated Streetlight Metal Poles (**DSLMP**), 2,463 km of underground cabling for streetlights and 1,785 streetlight control boxes. The number of luminaires mounted on DSLMP is increasing, reflecting the increasing proportion of the distribution network being undergrounded.

921. As of 30 June 2020, 49 per cent of public lighting (luminaires) are mercury vapour. Ratification of the Minamata Convention would result in Western Power being unable to procure new mercury vapour lamps (globes) to maintain the in-service mercury vapour luminaires. Western Power supports the ratification of objectives of the Minamata Convention and has developed a strategy to efficiently manage a transition away from mercury vapour lamps.

[175] https://www.wa.gov.au/government/electricity-networks-access-code-tranche-1-amendments

[176] The implementation of five-minute settlements also requires investment in SCADA and Telecommunications and IT, which are included in the respective expenditure categories.

922. Public lighting assets are treated (e.g. replaced and reinforced) based on their condition. There are currently more than 6,800 conditions awaiting action, including 4,452 DSLMP requiring repair, 1,243 requiring reinforcement and 1,150 requiring replacement.

923. The streetlight expenditure program enables Western Power to:

- comply with jurisdictional safety obligations by maintaining current safety performance
- manage the public lighting network to maintain compliance with the minimum service standards for reliability performance
- address higher risk assets
- support decarbonisation and reduce environmental impacts through transition to LED
- provide a reliable and efficient public lighting service.

### 8.4.2 Growth

924. Western Power will invest $874.3 million in distribution growth projects during the AA5 period. Of this, $588.2 million will be recovered via customer contributions and gifted assets. Net distribution growth capex is $286.1 million and is comparable to that incurred during the AA4 period.

925. Table 8.8 summarises AA5 period forecast distribution growth capex by regulatory category.

**Table 8.8: AA5 forecast distribution growth capex, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Capacity expansion | 39.3 | 28.1 | 22.2 | 25.5 | 21.8 | 136.9 |
| Customer driven | 109.8 | 110.0 | 110.4 | 111.5 | 104.1 | 545.8 |
| Gifted assets | 38.0 | 38.1 | 38.3 | 38.5 | 38.7 | 191.5 |
| **Gross capex** | **187.0** | **176.3** | **170.9** | **175.4** | **164.6** | **874.3** |
| *Less* Contributions | 118.2 | 118.6 | 119.0 | 120.0 | 112.5 | 588.2 |
| **AA5 capex to be recovered via tariffs** | **68.8** | **57.8** | **51.9** | **55.5** | **52.1** | **286.1** |

926. The majority of forecast distribution growth capex is for customer driven projects (including contributions), with the balance being for capacity expansion. Further information on the forecast growth capex subcategories is provided in the following sections.

*Capacity expansion*

927. Western Power will invest $136.9 million during the AA5 period on distribution capacity expansion projects.

928. Capacity expansion projects for the distribution network will continue to address future loading and voltage obligations based on Western Power's forecast customer demand for load over the AA5 period. The number of over-utilised feeders is forecast to increase compared to previous years that had flat or negative growth in areas. Dependent on customer responses to hot weather events, investment will be required to cater for load growth and avoid premature asset ageing. Additionally, we expect to continue to see PV uptake on rooftops, resulting in a continued decline in daytime minimum load. The future minimum load increases the probability of localised over-voltages and requires investment to mitigate the risk of non-compliance.

929. Western Power will invest $83.9 million on HV distribution-driven projects during the AA5 period. HV distribution-driven expenditure is designed to ensure the parts of the network that are experiencing growth have sufficient capacity and that the following requirements in the Technical Rules are met:

- the distribution feeders do not exceed optimal utilisation levels
- the voltage is within the required limits
- the load on the network is balanced across the three phases
- there is the required level of redundancy in the network.

High demand and overloading in AA4 prior to the summer of 2020 was not significant which enabled the deferral of this work to AA5. The need to address over-utilised feeders in AA5 however, is forecast to increase in order to avoid widespread outages as experienced over the Christmas period in 2021.

930. Voltage limits are specified in the Technical Rules to ensure the safe and efficient operation of customer equipment. The voltage across distribution feeders typically reduces over the distance of the feeder from the zone substation (**ZSS**) when the load supplied via the ZSS to the feeder increases. Conversely, as more PV or generation is added to distribution feeders, at times of low load, voltages at the end of the feeder rise and then fall as the feeder nears the zone substation from reverse energy flows. Voltages near the end of the feeder may increase to a level that is outside the allowable compliance range. If no action is taken to reduce the voltage, it may increase to the extent that connected customer equipment will not function correctly or even at all.

931. Western Power's distribution network is predominantly a three-phase configuration (with three conductors per circuit). In certain rural areas we have established extensive single-phase networks that are sufficient to support the electricity needs of the area or locality (and where a more costly higher capacity three-phase network cannot be justified).

932. Single-phase networks can lead to a load imbalance on the three-phase network that supplies them. This will in turn lead to a voltage imbalance on the three-phase network. This affects the quality of the supply to customers (that are supplied by the three-phase network upstream) and can cause electrical interference with any nearby telecommunications circuits affecting their ability to function correctly. If the voltage unbalance is not corrected, it could lead to mal-operation of their equipment or prevent new customers from connecting.

933. During the AA5 period, Western Power will invest $33.7 million on transmission driven projects that will be undertaken in conjunction with the relevant transmission capacity expansion projects. The need for this investment arises from the need to:

- provide distribution capacity to accommodate new zone substation capacity and interconnection
- provide distribution feeder load transfer capability that enables utilisation of existing zone substations capacity
- maintain clearances between distribution and transmission assets as transmission lines are developed or augmented
- reinforce the distribution network to cater for a change in voltage levels from the zone substation
- provide distribution capacity to resupply a decommissioned zone substation.

934. Example projects to be undertaken during the AA5 period include:

- decommissioning of Wundowie zone substation ($5.1 million), with customers to be supplied via a new Sawyer's Valley distribution feeder

- reinforcement of the Black Flag distribution feeder ($8.5 million) to support the third power transformer which was installed to address capacity shortfall at Black Flag
- transferring load off the Wellington Street zone substations ($5.2 million) to facilitate the accelerated decommissioning of the East Perth 66 kV assets
- reinforcing the distribution network to support the decommissioning of the Tate Street zone substation ($2.5 million), which has been identified as the preferred solution for addressing asset conditions issues with Tate Street power transformers 1 & 3
- support for the decommissioning Kellerberrin and Carrabin and resupplying associated customers from Merredin ($9.9 million).

935. Western Power will invest $12.9 million during the AA5 period, to address HV fault rating and protection issues. There are rising fault levels at certain locations on the distribution network as a result of the connection of new generation, network upgrades and changes in network topology. In addition, as the grown in PV displaces synchronous generation, there is a need for more sensitive protection settings.

936. Other capacity expansion investment includes $6.4 million for addressing overloaded distribution transformers to ensure that service levels are maintained in accordance with the Access Code. As distribution transformers become overloaded, there is an increasing likelihood of failure resulting in public safety risk and disruptions to customer supply.

*Project Symphony*

937. The proposed investment in HV distribution driven projects (see above) includes an investment of $6.0 million on Project Symphony.

938. Project Symphony, an active DER demonstration project, will inform the evolution of the DSO role and contribute to understanding and building of required capability within Western Power. It is a key project under the State government's DER Roadmap.

939. Project Symphony is a collaborative project between Energy Policy WA, Western Power, AEMO and Synergy, with funding from ARENA. It aims to build industry capability by developing and testing the end-to-end customer, market and technical capabilities and functions required to safely and securely integrate DER within the SWIS:

- **Technical:** focusing on how DER can be used to manage compliance, security and reliability issues on the SWIS
- **Customer:** focusing on understanding customer preferences and behaviour around DER products and services
- **Market:** focusing on DER participation in the wholesale market to reduce system costs.[177]

940. Project Symphony will create VPPs by aggregating solar panels, batteries and other controllable appliances. It commenced in April 2020 and is due for completion in December 2022.

941. The investment in the AA5 period will cover Western Power's role until the completion of the project as well as implementation post project completion.

[177] Energy Policy WA, *Leading Western Australia's brighter energy future*, Energy Transformation Strategy, Stage 2: 2021-2025, July 2021.

*Customer driven*

942. Western Power will invest $545.8 million during the AA5 period on customer driven projects. This includes capital contributions of $396.7 million. Table 8.9 summarises AA5 period forecast customer driven distribution capex.

**Table 8.9: AA5 forecast distribution customer driven growth capex, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Network extension | 56.2 | 56.3 | 56.5 | 57.1 | 57.6 | 283.6 |
| Major relocations | 16.5 | 16.6 | 16.6 | 16.8 | 8.6 | 75.1 |
| Relocations | 12.7 | 12.7 | 12.8 | 12.9 | 13.0 | 64.1 |
| Subdivision | 8.6 | 8.6 | 8.6 | 8.7 | 8.8 | 43.3 |
| Major access | 8.4 | 8.4 | 8.4 | 8.5 | 8.6 | 42.2 |
| Connection | 7.4 | 7.4 | 7.5 | 7.5 | 7.6 | 37.5 |
| **Gross capex** | **109.8** | **110.0** | **110.4** | **111.5** | **104.1** | **545.8** |
| Less contributions | 80.2 | 80.4 | 80.7 | 81.5 | 73.8 | 396.7 |
| **AA5 capex to be added to the RAB** | **29.6** | **29.6** | **29.7** | **30.0** | **30.3** | **149.2** |

943. Distribution customer driven capex includes all work associated with connecting customer loads or generators, and the relocation of distribution assets at the request of a third party. Projects range from small residential connections (pole to pillar), through to network extensions to cater for large industrial customers. This category of investment generally includes high volumes of low cost works, thus historical expenditure tends to be a good indicator of future investment.

944. New facilities investments in distribution customer access projects are only undertaken only where section 6.52(b)(i) of the Access Code is met or the connecting customer contributes that part of the investment that does not meet section 6.52(b).

945. Section 6.52(b)(i) of the Access Code requires that the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment. The connecting customer contributes that part of the investment that does not meet the incremental revenue test, in accordance with the Contributions Policy developed under sections 5.12 to 5.17 of the Access Code.

### 8.4.3 Improvement in service[178]

946. This expenditure category covers reliability-driven capex that is designed to achieve improvements in reliability and power quality service standard targets for the distribution network. The investment focuses on improving reliability in hot spots (i.e. areas within the distribution network that are performing significantly below service standards).

947. Western Power plans to invest $0.3 million in the AA5 period on addressing hotspots on the network primarily by upgrading and installing automated devices to sectionalise the network. Investment to improve reliability and power quality service standards targets for the distribution network is captured in the Regulatory Compliance category.

[178] Excluding SCADA and Telecommunications network, which is considered separately.

### 8.4.4 Regulatory Compliance

948. Western Power has a range of compliance requirements relating to environmental, power quality, and network security obligations (safety compliance obligations are captured in the 'maintaining safety' capex category). During the AA5 period, Western Power will invest $251.1 million on satisfying these requirements for the distribution network.

949. These investment programs are critical for public safety, providing a reliable supply and protecting the environment.

950. Table 8.10 summarises AA5 period forecast distribution compliance capex.

**Table 8.10: AA5 forecast distribution compliance capex, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Bushfire management | 3.0 | 2.8 | 2.7 | 2.7 | 2.8 | 14.0 |
| Pole Management (Compliance) | 20.8 | 21.0 | 20.5 | 20.8 | 21.2 | 104.4 |
| Reliability Compliance | 9.9 | 7.7 | 9.4 | 9.3 | 8.7 | 45.0 |
| Power Quality | 4.4 | 5.8 | 5.8 | 5.9 | 6.0 | 27.9 |
| Conductor Management | 3.6 | 3.6 | 3.6 | 3.6 | 3.7 | 18.0 |
| Connection Management | 5.2 | 5.3 | 5.3 | 5.4 | 5.5 | 26.7 |
| Other | 3.0 | 3.0 | 3.2 | 2.9 | 2.9 | 15.1 |
| **Gross capex** | **49.8** | **49.2** | **50.6** | **50.7** | **50.7** | **251.1** |
| Less contributions | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **AA5 capex to be added to the RAB** | **49.8** | **49.2** | **50.6** | **50.7** | **50.7** | **251.1** |

951. The major distribution compliance programs for the AA5 period include:

- **bushfire management** ($14.0 million, 6 per cent): focused on mitigating the risk of overhead conductors coming into contact with each other (conductor clashing) and causing either conductor failure, damage to the conductor or causing sparks that could lead to ground fires. It includes, proactively installing LV spreaders on bays that are likely to clash, proactively treating spreader defects and reactively treating HV and LV bays that have clashed in service
- **pole management** ($104.4 million, 42 per cent): covers the replacement of cross arms, insulators and stays that support the overhead infrastructure. Failure of these assets may lead to range of adverse safety impacts including ground fire, electric shock, physical injury and property damage, as well as service disruption. The objective of this expenditure is to maintain safety & reliability at historical AA4 levels. The proposed expenditure is required to address:
  - deteriorating stay performance & condition
  - high proportion of cross arm failures in metro and urban areas with high public exposure
  - assisted and unassisted failures of insulators requiring reactive replacement.

- **reliability compliance** ($45.0 million, 18 per cent): covers projects to address locations with reliability performance well below the network category average and below the specified minimum service standards under the Access Code. Increased expenditure in AA5 is required to meet SSB requirements, which emerged in the later part of the AA4 period.
- **power quality compliance** ($27.9 million, 11 per cent): covers investment to address customers' power quality related complaints. These complaints typically stem from issues such as over voltage, undervoltage, overloading, voltage imbalance and harmonics on the LV network
- **connection management** ($26.7 million, 11 per cent): covers the replacement of overhead customer service connections (**OCSCs**) that have failed or are in poor condition as identified through routine inspections or through service connection condition monitoring (**SSCM**) using AMI. This expenditure also covers underground residential distribution (**URD**) pillars that are replaced under failure conditions and the maintenance of cable pits located in road reserves.

952. Service connections are the largest contributor to electric shock counts on the distribution network. The use of SSCM via AMI has been established as a prudent option to monitor and manage the electric shock risks posed by service connections. Investment in this technology in conjunction with the continuation of the AMI program has allowed Western Power to reduce expenditure required to manage public safety relating to service connections.

## 8.5 SCADA and Telecommunications network capex

953. Western Power's SCADA and Telecommunications assets provide the services required to protect, operate and manage the transmission and distribution networks and the WEM. The SCADA and Telecommunications system is comprised of:

- the SCADA master station – operated from the control centre from where Western Power centrally operates and manages the transmission and distribution networks
- substation SCADA and distribution automation – field monitoring and control of electronic equipment to operate plant and equipment at every substation (as well as across overhead and underground distribution networks)
- the telecommunications network – providing the voice and data infrastructure required to transfer information between the electricity network, substations, depots and the control centre.

954. The SCADA and Telecommunications network is integral to the safe, reliable and efficient operation of the Western Power Network by provision of services including protection, monitoring, control, operational voice, meter reading, remote management and maintenance. The SCADA and Telecommunication network consists of more than 10,000 assets and over 5,000 km of communication cables and links.

955. The information gathered and communicated via SCADA infrastructure effectively acts as the 'eyes and ears' of the network, informing system and network operators of vital details about how the network is performing. The information also allows for proactive management to maintain safety and reliability.

956. The SCADA and Telecommunications network has grown and evolved over the past 40 years through a combination of technological advancement and as a result of organic growth and augmentation of Western Power's networks. However, the infrastructure deployed during the 1980s was mainly analogue and now needs to be upgraded to integrate with the digital network.

957. Much of the early digital technology is also at end of its useful life or is no longer compatible with current requirements. In general, the MRL of SCADA communications assets is about one-third that of transmission

and distribution assets, so SCADA assets need to be renewed approximately three times during the life span of these other assets.

958. Compounding these factors are additional emerging factors, including customer demands and expectations, the uptake of DER (including solar PV, batteries and EVs), the expanding AMI fleet, technology standards and compliance requirements, and emerging cyber security threats.

959. As a result, the asset life cycles for SCADA communications assets are decreasing and will be expected to be required to be refreshed in ever-shorter cycles. Western Power needs to act now to invest in cycled refreshing of its SCADA assets.

960. Over previous regulatory periods, Western Power's SCADA and Telecommunications network has been maintained on a reactive basis. It has now reached the point where technical obsolescence has become an issue for almost 70 per cent of SCADA assets, meaning that support for the assets is becoming increasingly difficult to source. The rates of obsolescence vary between SCADA assets. For example, as at June 2021, the rate of obsolescence was:

- 94 per cent for grid automation assets in the CBD
- 68 per cent for UHF/VHF radio assets.

961. The condition of the SCADA and Telecommunications network has also impacted the reliability of those assets, with most operating will below their target availability. For example, the current availability of microwave radio, telecom multiplex, UHF/VHF radio and remote terminal unit (**RTU**) assets is around 97.56 per cent, against a target reliability of 99.99 per cent.

962. Extending the asset life further of these SCADA assets will lead to:

- lower reliability and asset availability
- higher opex and workforce impacts
- inability to meet emerging requirements relating to cyber security, DSO, DER and Technical Rules.

963. Accordingly, Western Power plans to invest $483.4 million in the SCADA network during the AA5 period. Table 8.11 summarises the AA5 period forecast distribution SCADA and Telecommunications capex.

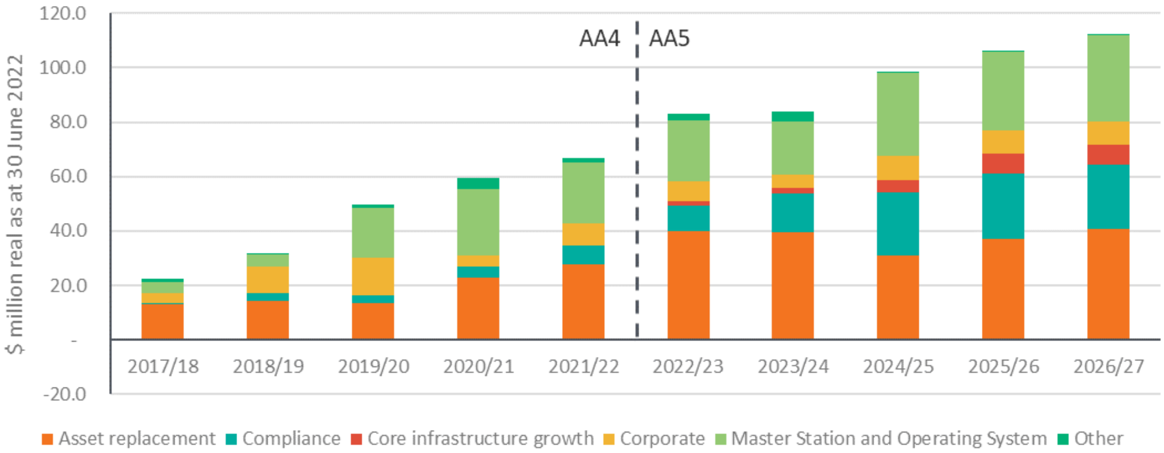
**Table 8.11: AA5 forecast SCADA and Telecommunications network capex, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Asset replacement | 39.9 | 39.7 | 31.1 | 37.1 | 40.6 | 188.4 |
| Compliance | 9.5 | 14.2 | 22.9 | 24.1 | 23.6 | 94.4 |
| Core infrastructure growth | 1.4 | 1.9 | 4.4 | 7.1 | 7.3 | 22.1 |
| Corporate | 7.4 | 5.1 | 9.3 | 8.7 | 8.9 | 39.4 |
| Master station and operating system | 22.4 | 19.3 | 30.2 | 28.7 | 31.4 | 132.0 |
| Other | 2.7 | 3.9 | 0.2 | 0.2 | 0.2 | 7.1 |
| **Gross capex** | **83.2** | **84.0** | **98.1** | **106.0** | **112.0** | **483.4** |
| Less contributions | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| **AA5 capex to be added to the RAB** | **83.2** | **84.0** | **98.1** | **106.0** | **112.0** | **483.4** |

964. Figure 8.7 shows forecast SCADA and Telecommunications capex for the AA5 period compared with historical levels.

**Figure 8.7: Comparison of AA4 actual and AA5 forecast SCADA and Telecommunications capex by regulatory category**




965. The following sections provide an overview of the forecast investment in the AA5 period for each subcategory. Further details of the forecast SCADA and Telecommunications capex is provided in the AA5 Forecast Capital Expenditure Report provided in Attachment 8.1.

### 8.5.1 Asset replacement (improvement in service)

966. During the AA5 period, Western Power proposes to invest $188.4 million to replace critical SCADA and Telecommunication network infrastructure that is obsolete and unsupported. Obsolete assets include pilot cables, microwave radio transceivers and remote terminal units.

967. Issues with obsolescence existed prior to AA4 and were noted in our AA4 regulatory proposal. Towards the end of AA4 it was necessary to increase investment and delivery to maintain historical performance and ensure a sustainable work program could be delivered across AA5.

968. The proposed investment in the AA5 period will replace assets predominantly within the telecommunication network access, radio systems, control automation cabling, DC power system and grid automation asset classes. A significant proportion of these assets are obsolete and have a “high” risk rating. The obsolete assets are no longer manufactured and are not supported by the supplier. Furthermore, spare parts are no longer available for purchase or refurbishment.

969. Western Power plans to undertake a range of projects during the AA5 period, including:

- a staged program of replacing the obsolete telecommunications network access, microwave and DC power systems assets
- complete the replacement of UHF/VHF radio systems (including the mobile radio) and associated infrastructure in the south west region of the SWIS

- commence the next stage of the replacement of UHF/VHF radio systems (including the mobile radio) and associated infrastructure in the northern and eastern regions of the SWIS

970. The asset replacement program is staged to optimise the asset life by retrieving spares to extend the life of assets, maximise Western Power project delivery capability and compliance to Western Power's IGF to ensure investments are prudent and efficient.

### 8.5.2 Master station and operating system

971. Master station systems provide critical services to maintain the safe and reliable supply of electricity to the community. The master station systems are responsible for the remote operations and management of the Western Power Network and the WEM.

972. The technology requirements to remotely operate and manage the evolving power system are increasing. Upgrades to operational technology systems are required to mitigate operational risk and deploy new capability.

973. The forecast SCADA master station and operating system investment for the AA5 period includes expenditure to:

- maintain the master station applications and infrastructure, including the Advanced Distribution Management System, the Transmission Management system (which is being replaced), the Communications Network Management System and the emergency telephone systems
- implement new capability to manage DER, including visibility of the low voltage network, capability for emergency curtailment or control and improved operational intelligence to support orchestration of DER, such as short term operational forecasting and operational analytics to maintain situational awareness
- implement new functionality that enable business improvements resulting in risk reduction or efficiencies such as the deployment of additional AMI-related modules to enable medium voltage distribution automation devices to communicate via the RF mesh communications network (where feasible) and enhancements to the communications network management system (CNMS).

974. The SCADA and Telecommunications network investment in the AA5 period is expected to deliver the following benefits:

- improved workforce safety (i.e. lower rate of injuries) resulting from a greater proportion of work being able to be actioned remotely and, where sites do need to be entered, greater awareness of site risks before entering the premises
- better management of residual service delivery risks, with improved circuit availability
- lower cost of service delivery through network optimisation and DER integration and management
- enable greater DER penetration
- being able to identify and respond to faults quickly, to improve network reliability
- improve asset, platform and systems integration.

975. The introduction of emerging technology will also provide long term reduction of capex in other parts of the network. The ability to analyse and support the network holistically will allow greater capacity to drive existing assets harder and potentially gain significant capital investment deferral opportunities.

### 8.5.3 Compliance

976. Western Power plans to invest $94.4 million in compliance capex for the SCADA and Telecommunications network. This investment is focused on the replacement and addition of SCADA and Telecommunications assets to achieve compliance with regulatory and legislative obligations, such as the WEM Rules and Technical Rules, and manage the associated residual risks to ALARP. This activity includes installing active electronic equipment such as remote terminal units, microwave radio, control cabling, telecommunications structures and shelters, and DC power systems.

977. Issues with obsolescence existed prior to AA4 and were noted in our AA4 regulatory proposal. Towards the end of AA4 it was necessary to increase investment and delivery to maintain historical performance and ensure a sustainable work program could be delivered across AA5.

978. Western Power will address anticipated cyber security requirements for in-service field assets as required by proposed amendments to the *Security of Critical Infrastructure Act 2018* and *Security Legislation Amendment (Critical Infrastructure) Bill 2020*. This investment will:

- address preparedness for, and ability to respond to, cyber security threats and incidents
- uplift asset availability to the required level as per technical regulation and industry best practices
- improve safety and ability to monitor and collect data for improved business and asset management.

### 8.5.4 Other SCADA and Telecommunications capex

979. Other investment proposed for the AA5 period for SCADA and Telecommunications includes:

- **development of Western Power's capability to meet DER and DSO integration requirements** ($22.1 million): this cannot be addressed with the existing renewal and replacement projects, including Project Symphony. This includes projects to address potential capability shortfalls relating to field automation, communications and the DSO operational platform. This investment is to ensure there is suitable SCADA and telecommunications infrastructure to support DER and DSO, including monitoring and control of primary assets (e.g. transformers, batteries, solar) on the medium and low voltage networks

  The evolving role of Western Power as the DSO and the technical specifications around the level of automation and control and how DSO / DER will be integrated is yet to be fully defined. Accordingly, the forecast capex requirement is based on Western Power's understanding of the future requirements of the DSO role and expected level of DER integration
- **replacement and addition of SCADA and Telecommunications assets** ($39.4 million): to support Western Power's Corporate Strategy to increase the asset output, reduce the asset costs and increase the asset reliability and life span. These investments are targeted at improving security at substations, supporting the Depot Optimisation and Consolidation Program (**Depot Program**), facilitating field automation and additional radio mesh equivalent to support the AMI deployment
- **addressing external technological changes** ($7.1 million): including actions by third parties, affecting SCADA and Telecommunications service delivery. This expenditure is required to react to changes outside of the electricity industry that have significant impacts on the asset base. The majority of planned investment for the AA5 period results from the Telstra's decision to discontinue the 3G service, which is currently used by a number of Western Power's devices. These devices will be transitioned from Telstra 3G services to Telstra NextG services. The planned investment for the AA5 period also includes expenditure related to the transition of copper telephony services at substations.

## 8.6 Corporate support capex

980. Western Power proposes to invest $540.7 million of capital in corporate support during the AA5 period. Corporate capex comprises business support investment and IT investment.

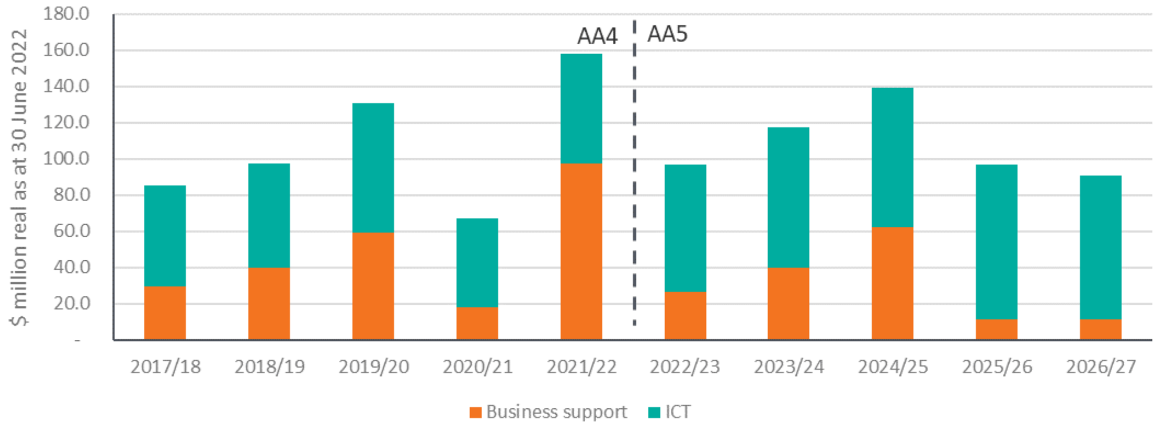
981. Table 8.12 summarises AA5 period forecast corporate capex by regulatory category.

**Table 8.12: AA5 forecast corporate capex by regulatory category, $ million real, 30 June 2022**

| Expenditure category | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total AA5 |
|---|---|---|---|---|---|---|
| Business support | 26.2 | 40.2 | 62.5 | 11.4 | 11.5 | 151.9 |
| IT | 70.4 | 77.0 | 76.6 | 85.4 | 79.4 | 388.8 |
| **Gross capex** | **96.7** | **117.2** | **139.1** | **96.9** | **90.9** | **540.7** |
| Less contributions | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **AA5 capex to be added to the RAB** | **96.7** | **117.2** | **139.1** | **96.9** | **90.9** | **540.7** |

982. Figure 8.8 shows forecast corporate support capex for the AA5 period compared with historical levels.

**Figure 8.8: Comparison of AA4 actual and AA5 forecast corporate support capex by regulatory category**




983. Forecast corporate capex for the AA5 period is comparable to that incurred in the AA4 period. However, the mix of investment has shifted, with a greater proportion of the corporate capex in the AA5 period being for IT projects.

### 8.6.1 Business support

984. The business support category includes expenditure on corporate real estate and property plant and equipment.

#### *Corporate real estate*

985. Forecast investment in corporate real estate is $145.8 million in the AA5 period. It is focused primarily on the Depot Program, which commenced at the at the start of the AA4 period. The Program has two key objectives:

- update Western Power's ageing depots to meet current workplace safety practices

- improve financial efficiency of Western Power's depots through redevelopment of regional depots and consolidation of the number of depots in the Perth Metropolitan and South West region of WA.

986. The Depot Program seeks to address safety risks and issues impacting the financial and operational efficiencies of Western Power depots. It contributes to Western Power's strategic direction through:

- improving safety and operational efficiency within depots through delivery of modern, fit-for-purpose depot facilities
- enhancing physical security measures to protect our personnel, property and network assets
- reducing on-going expenditure in the delivery and maintenance of facilities and accommodation
- provision of accommodation to meet future operational requirements in a changing economic environment
- consistent and efficient property management practices to reduce costs in delivery of property services
- setting up depots for the future, with an ability to expand operational capacity.

987. By the end of the AA4 period Western Power will have delivered three newly built depots under the Depot Program, being the Vasse, Pinjarra and Albany depots, and will have completed South Metro Depot within the first six months of AA5. In addition to these, the Depot Program has also delivered a significant rebuild and refurbishment of the Merredin and Northam Depots, respectively. During the AA5 period, Western Power will deliver the following depots:

- Balcatta Depot – redevelopment of Western Power's northern metropolitan depot
- Forrestfield Depot – the location of a new dedicated Western Power training facility to replace the aged Training Facility currently located in Jandakot
- Picton Depot – redevelopment of the Western Power depot in the major regional town of Bunbury
- A number of small regional depots, the location of which will be determined once the full impact of the modular grid is known.

988. Western Power has previously adopted a care and maintenance approach for the depots. However, this approach is no longer sustainable given the depots are exceeding their engineering life. This means that ongoing capital and operating expenditure will need to increase to extend the life of these depots. The proposed investment in the AA5 period will extend the economic life of Western Power depots by 50 years and will reduce the requirement for increasing levels of capex and opex to provide short term extensions to the life of the depots.

989. Other proposed investments in the AA5 period include:

- expanding the capacity of the Hope Road logistics facility in Jandakot, which currently has insufficient warehouse space available
- redeveloping regional depots and supporting accommodation for staff with the sequencing of these developments to align with operational requirements
- undertaking capital maintenance work on the head office building.

### *Property plant and equipment*

990. Western Power plans to invest $6.0 million in ongoing operational capex requirements to ensure the safe and efficient delivery of the works program during the AA5 period. The forecast is based on historical spend.

991. Investment in equipment is required to ensure both safe and effective delivery of Western Powers works program. The forecast investment is required for low value capital equipment that is used by Western Power's operational workforce in delivering the annual works program. The equipment is generally replaced at the end of its useful life or if new technology emerges that can be utilised in delivery. Examples of PPE include:

- specialist testing equipment used to analyse, test and recover sulphur hexafluoride gas (**SF6**) present within circuit breakers
- primary equipment used to test and commission protection assets
- three phase testing equipment for power and distribution transformer testing
- automated unit for locating both core and ground faults on LV cables
- portable power quality analyser used to measure a range of power quality parameters.

### 8.6.2 IT investment

992. As the use of digital technology expands, Western Power will maximise value from technology investments by increasing agility and reducing time to benefits, targeting operational efficiencies and effectively managing cyber security risk. Western Power is required to ensure that its systems, applications and hardware remain current, reliable and vendor supported to meet a changing market and new customer demands.

993. Forecast capex on IT during the AA5 period is $388.8 million, split between infrastructure and maintenance (34 per cent) and business driven (66 per cent), covering network planning and asset management, growth, corporate and customer.

994. IT applications require regular upgrades to remain within vendor support parameters, as well as to take advantage of improved functional and technological capabilities. Similarly, IT infrastructure must be regularly refreshed to remain current and supportable.

995. Western Power adopts a disciplined approach to IT application and infrastructure investment, consistent with the IT Strategic Plan[179] and IT Asset Management Guidelines. Western Power has established IT programs of work for the AA5 period to deliver the following goals:

- **Infrastructure**: to build a flexible and responsive infrastructure capability, focused on continuous improvement and improving productivity for Western Power's technology investment
- **Applications:** maintain currency of IT applications within vendor support parameters to leverage new and updated technology capabilities that deliver operation improvements and lower costs
- **Cyber Security:** contain cyber security risk within Western Power's corporate risk appetite by achieving an improved cyber security Maturity Indicator Level (**MIL**) across AESCSF domains, and consider additional amendments proposed to the *Security of Critical Infrastructure Act 2018* (Cth).

996. Western Power's proposed investment in IT for network planning and asset management will ensure this function has the right tools, systems and applications to extend the operating lives of existing assets and support transitional changes to the grid. Western Power proposes to update its existing asset management tools and systems to address current deficiencies and support the future network.

997. Western Power's proposed IT investment for the AA5 period supports the deployment of AMI with investment in the information and operational technology elements of the solution. These include the Network Management Solution that manages the last mile meter communications and services as the

[179] The IT Strategic Plan will be replaced with the Digital Capability Strategy from 1 July 2022

gateway to integrate to the meter as well as the integration and changes to the backend IT systems such as the Meter Data Management Systems and Billing Systems.

998. This investment is in alignment with Western Power's Corporate Strategy to support DER and other renewable energy devices to meet customer expectations. When fully implemented, AMI data will be fully integrated into Western Powers operations to reduce security risk and improve decision making outcomes.

999. Western Power will also invest in the information technology elements of metering for the mandated implementation of five-minute settlements in the WEM, which is due to commence in October 2025) (see section 8.4.1).

1000. Western Power will also enhance customer systems to ensure we have the right capabilities to operate in a more complex future where big data, visibility and online digital communications will be paramount. An assessment of current systems architecture and options for using existing tools to support the customer engagement outcomes has concluded that an investment is required to support the changing profile of customer services. The proposed investment will deliver improvements for large customer projects and continued enhancements to the customer management platforms including customer relationship management, customer data integration from AMI, self-service portal, improved view of the customer through near real time analytics and expanding the footprint of our digital offering for customer communications.

1001. Further details of forecast IT expenditure is provided in the AA5 Forecast Capital Expenditure Report provided in Attachment 8.1.

### *Cyber security*

1002. Due to an increase in the number and sophistication of cyber-attacks against critical infrastructure, the security and reliability of the network have fallen under increasing attention recently. In response to the increasing threat landscape, Western Power has aligned to the AESCSF as the primary control and maturity framework to manage cyber risks.

1003. Western Power has established its Cyber Security Program in 2018 as part of the Cyber Security Strategy to progress the delivery of projects to address cyber security risks and uplift our cyber security maturity. The program has established improved processes across scoping, planning and delivery to improve delivery outcomes for Western Power and help secure our energy transformation journey.

1004. The Cyber Security Program has two key objectives:

- drive an improvement in our foundational cyber security controls to contain our cyber security risk within our corporate risk appetite
- achieve an improved cyber security MIL across AECSF domains, consistent with Western Power's adopted cyber security framework, which is also expected to be consistent with proposed reforms to the *Security of Critical Infrastructure Act 2018* (Cth).

1005. The Cyber Security Program commenced delivery of Phase 1 in 2018 as part of the Cyber Security Strategy. Over the course of 2019 and 2020, the program has progressed in the delivery of projects to address cyber security risks and uplift Western Power's cyber security maturity. Strategic risk has been contained to a rating of 'High' (down from 'Extreme'), and progress on maturity uplift was assessed in December 2021 (following completion of Phase 2) and is anticipated to reach MIL2.

1006. Successful projects include the design of the Functional Operating Model, which will provide significant capability to improve cyber security in the organisation and sustain AESCSF requirements. The Cyber

Security function will operate as a Centre of Excellence and support the business to manage cyber security as well as provide end-to-end cyber security services.

1007. Cyber security investment relates to various aspects of Western Power's proposed investment for the AA5 period, including:

- providing an uplift in cyber security as part of the Depot Program
- replacement and augmentation of SCADA and Telecommunications assets to mitigate risks arising through obsolescence and meet prevailing cyber security needs
- considering proposed future amendments to the *Security of Critical Infrastructure Act* (Cth)
- enabling a secure transformation to a modular grid, by improving our foundational cyber security controls and adopting a secure by design approach to the introduction to new and emerging technologies.

# 9. Expenditure incentives and adjustment mechanisms

1008. This chapter provides an overview of the incentive mechanisms to apply to Western Power over the AA5 period. It details the methodology for calculating expenditure incentives, the investment adjustment mechanism and demand management innovation allowance mechanism and explains how they represent the interests of customers. A discussion of the SSAM is set out in Chapter 6.

**Key Messages**

- The expenditure incentives and adjustment mechanisms proposed for the AA5 period are consistent with the ERA's Framework and Approach.
- The investment adjustment mechanism will no longer include categories of growth and customer driven capital expenditure to strengthen incentives for efficiency and retaining only the provision for any current or succeeding state underground power program
- The gain sharing mechanism will now provide a symmetrical financial incentive, include uncontrollable costs and will not require satisfaction of service standard performance which strengthens the incentives for efficiency without relieving the incentives to maintain services. This is consistent with the recent changes to the Access Code
- We will introduce a new demand management innovation allowance to offset the incentive to continue to invest in traditional network solutions when alternative solutions may be efficient. This aims to reduce long term costs by providing a revenue allowance for research and development of innovative solutions
- We included an adjustment in the D Factor mechanism for any additional operating expenditure incurred in relation to the procurement of NCESS triggered by the Coordinator of Energy under recent amendments to the WEM Rules
- We are retaining the existing mechanisms for any unforeseen and trigger events and for changes to the Technical Rules to allow the recovery of costs during the AA5 period should these events occur.

## 9.1 Overview of expenditure incentive and adjustment mechanisms proposal

1009. The regulatory framework was amended during the AA4 period including introducing the framework and approach process to facilitate early public consultation and stakeholder agreement on incentive mechanisms and other matters. The changes to the regulatory framework are provided in Chapter 3.

1010. The ERA's Final Decision on the framework and approach[180] makes changes to the IAM and gain sharing mechanism (**GSM**) that applied in the AA4 period, and applies a DMIA in the AA5 period as follows:

- retain the existing IAM, with adjustments to remove growth and customer driven expenditure from the investment adjustment mechanism to improve incentives for Western Power to seek efficiencies in capex
- retain the existing GSM from the AA4 period, with amendments to reflect the changes made to the GSM requirements in the Access Code
- include a DMIA in our access arrangement for the AA5 period.

1011. As noted in Chapter 3, Western Power's AA5 proposal is consistent with the decisions set out in the ERA's framework and approach. The changes required to be implemented are summarised in Figure 9.1.

[180] ERA, *Framework and approach for Western power's fifth access arrangement review*, Final Decision, 9 August 2021.

1012. All other aspects of the expenditure incentive schemes and adjustment mechanisms will remain unchanged from the AA4 period. The reasons for the proposed amendments are discussed in the following sections.

**Figure 9.1: Summary of the changes to the incentive schemes and adjustment mechanisms for the AA5 period and the application of the demand management innovation allowance mechanism**

| | Description | Summary of changes |
|---|---|---|
| Investment adjustment mechanism | The IAM provides for an adjustment to target revenue for differences between actual and forecast capital expenditure in certain expenditure categories.<br>The IAM exists to ensure customers do not pay for forecasting errors in these nominated expenditure categories by providing a true-up of revenue in the next access arrangement period. | Removed following categories from the IAM set out in clause 7.3.7 of the current access arrangement, consistent with the ERA's framework and approach:<br>• Connection of new generation capacity<br>• Connection of new load<br>• Augmentations to provide additional capacity<br>Clarified the inclusion applies to any state government fully or partially funded program, such as the current and any subsequent SUPP |
| Gain sharing mechanism | The GSM provides a financial incentive to reduce non-capital costs or improve productivity over the access arrangement period by allowing Western Power to keep operating expenditure efficiencies for a longer period. This means that Western Power can keep the benefits of operating cost efficiencies for five years regardless of the year during the access arrangement period the efficiency was made. | Retain the existing GSM from the AA4 period, with the following amendments , consistent with the ERA's framework and approach:<br>• Removed reference to service standard benchmark performance (Note: This is incentivised separately under service standard benchmark incentives and the service standard adjustment mechanism)<br>• Introduced a symmetrical GSM with rewards and penalties<br>• GSM efficiency and innovation benchmarks to reflect approved forecast operating costs including updates to forecast network growth and customer growth escalation factors |
| Demand management innovation allowance mechanism | The key purpose of the DMIA is to overcome barriers and constraints within the regulatory framework that would prevent investment in innovation which would deliver benefits to customers. The DMIA mechanism enables funding for innovation that would not otherwise be available under the regulatory framework. | Include a DMIA mechanism with the objective to incentivise the pursuit of valuable innovative projects that deliver benefits to customers for the AA5 period, with the following features :<br>• Target revenue for AA5 will include an annual allowance based on 0.08 per cent of approved target revenue (excluding the allowance) for each pricing year<br>• The allowance can be used during the AA5 period for projects that meet the eligibility requirements set out in the Access Code and guidelines published by the ERA |

## 9.2 Incentive adjustment mechanism

1013. The IAM provides for an adjustment to target revenue for differences between actual and forecast capex in certain expenditure categories. The IAM exists to ensure customers do not pay for forecasting errors in these nominated expenditure categories by providing a true-up of revenue in the next access arrangement period.

### 9.2.1 Regulatory requirements

1014. Section 6.15 of the Access Code requires Western Power's access arrangement to include an IAM where the proposed price control is based on Western Power's total costs. The IAM indicates how any difference between forecast and actual capex (the investment difference) will be treated for the next access arrangement review.

1015. The IAM is defined as follows:

> *6.13 An "investment adjustment mechanism" is a mechanism in an access arrangement detailing how any investment difference for the access arrangement period is to be treated by the Authority at the next access arrangement review.*
>
> *6.14 In sections 6.13 and 6.16, "investment difference" for an access arrangement period is to be determined at the end of the access arrangement period by comparing:*
>
> *(a) the nature (including amount and timing) of actual new facilities investment which occurred during the access arrangement period;*
>
> *with*
>
> *(b) the nature (including amount and timing) of forecast new facilities investment which at the start of the access arrangement period was forecast to occur during the access arrangement period.*

1016. Sections 6.16 to 6.18 of the Access Code provide further details on the application of an IAM:

> *6.16 Without limiting the types of investment adjustment mechanism which may be contained in an access arrangement, an investment adjustment mechanism may provide that:*
>
> *(a) adjustments are to be made to the target revenue for the next access arrangement in respect of the full extent of any investment difference; or*
>
> *(b) no adjustment is to be made to the target revenue for the next access arrangement in respect of any investment difference.*
>
> *6.17 An investment adjustment mechanism must be:*
>
> *(a) sufficiently detailed and complete to enable the Authority to apply the investment adjustment mechanism at the next access arrangement review; and*
>
> *(b) without limiting this Code, consistent with the gain sharing mechanism (if any) in the access arrangement;*
>
> *(c) consistent with the Code objective.*
>
> *6.18 An investment adjustment mechanism in an access arrangement applies at the next access arrangement review.*

### 9.2.2 Proposed investment adjustment mechanism to apply in the AA5 period

1017. Western Power's IAM for the AA4 period allows an adjustment to our target revenue in the AA5 period that corrects any economic loss or gain due to differences between forecast and actual capex for the following types of capex:

- connecting new generation capacity
- connecting new loads
- augmentation of the network to provide covered services
- the SUPP.

1018. The AA4 IAM is consistent with the revenue cap price control that applied prior to 2019/20. The revenue cap price control insulated Western Power from revenue risk if demand was different from forecast. The investment adjustment mechanism sheltered Western Power 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.

1019. However, the price control for the AA5 period includes an adjustment mechanism. As Western Power receives more revenue if demand is greater than forecast and less revenue if demand is less than forecast, there is less need for the investment adjustment mechanism to include expenditure for growth and customer demand.

1020. As such, the ERA's Final Decision on the framework and approach removed growth and customer driven expenditure from the investment adjustment mechanism to improve incentives for Western Power to seek efficiencies in capex.[181]

1021. For the AA5 period, Western Power has adopted the ERA's Final Decision on the framework and approach to remove the following capex categories from the IAM:

- connecting new generation capacity
- connecting new loads
- augmentation of the network to provide covered services.

1022. The IAM will continue to apply to the SUPP. The SUPP is an initiative that replaces overhead lines in established areas with underground power infrastructure. It is retained in the IAM as the SUPP is co-funded between the program partners – the State Government, Western Power and local government authorities. During the AA5 period, other state government programs could apply including a succeeding state underground power program. Investment and volumes of the current and succeeding SUPPs during the AA5 period are highly dependent on community and local government support and funding. The IAM ensures that customers pay only for actual investment in state government programs, including the current or succeeding SUPP, during the AA5 period.

1023. Accordingly, we have amended section 7.3.7 of our current access arrangement to remove all capex categories, except for the SUPP for the AA5 period, which has been clarified to include any state government program including the current or succeeding SUPP.

## 9.3 Gain sharing mechanism

1024. The GSM provides a financial incentive to reduce non-capital costs or improve productivity over the access arrangement period by allowing Western Power to keep opex efficiencies for a longer period. This means that Western Power can keep the benefits of operating cost efficiencies for five years regardless of the year during the access arrangement period the efficiency was made. Western Power is unable to recover any opex that is incurred above the allowance set by the ERA in the access arrangement and as such is penalised for any inefficiency.

### 9.3.1 Regulatory requirements

1025. Under section 6.20 of the Access Code, Western Power's access arrangement is required to include a GSM as follows:

> *6.19 A "gain sharing mechanism" is a mechanism:*

[181] ERA, *Framework and approach for Western power's fifth access arrangement review*, Final Decision, 9 August 2021, pg. 41

> (a) *in an access arrangement which the Authority must apply at the next access arrangement review to determine an amount to be included in the target revenue for one or more of the following access arrangement periods; and*
>
> (b) *which operates as set out in sections 6.20 to 6.28.*
>
> *6.20 An access arrangement must contain a gain sharing mechanism unless the Authority determines that a gain sharing mechanism is not necessary to achieve the objective in section 6.4(a)(ii).*

1026. Section 6.21 of the Access Code sets out the objective of the GSM as:

> (a) *achieving an equitable allocation over time between users and the service provider of innovation and efficiency gains or losses relative to efficiency and innovation benchmarks; and*
>
> (b) *being objective, transparent, easy to administer and replicable from one access arrangement to the next; and*
>
> (c) *giving the service provider an incentive to reduce costs or otherwise improve productivity in a way that is neutral in its effect on the timing of such initiatives.; and*
>
> *{For example, a service provider should not have an artificial incentive to defer an innovation until after an access arrangement review.}*
>
> (d) *minimising the effects of the mechanism on incentives for the implementation of alternative options.*

1027. Section 6.27 of the Access Code sets out how the ERA is to apply the GSM:

> *The Authority 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.*

1028. The requirements for the efficiency and innovation benchmarks used for the purposes of determining the benchmark surplus and benchmark deficit under the GSM are set out in section 5.26 of the Access Code, as follows:

> *Efficiency and innovation benchmarks must:*
>
> (a) *if the access arrangement contains a gain sharing mechanism, be sufficiently detailed and complete to permit the Authority to make a determination under section 6.25 at the next access arrangement review; and*
>
> (b) *provide an objective standard for assessing the service provider's efficiency and innovation during the access arrangement period; and*
>
> (c) *be reasonable.*

1029. On 18 September 2020, the Access Code was amended to support the delivery of the State Government's Energy Transformation Strategy. The amendments to the Access Code included the following changes to the GSM:

- expanded the requirements to include both an above-benchmark surplus and below-benchmark deficit to ensure the GSM is symmetrical

- removed the requirement that the above-benchmark surplus does not exist to the extent it was achieved by Western Power failing to maintain a service standard at least equivalent to the service standard benchmark
- introduced a requirement to minimise the effects of the GSM on incentives for the implementation of alternative options.

### 9.3.2 Proposed gain sharing mechanism to apply in the AA5 period

1030. Western Power's AA4 GSM 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 (the year the efficiency was made plus four additional years) regardless of which year the efficiency was made.

1031. The GSM increases the incentive to Western Power to achieve operating cost efficiencies during an access arrangement period as it ensures that Western Power retains the efficiency saving for the same period of time, regardless of which year during the access arrangement period the efficiency was made.

1032. Without this mechanism, 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 incentive to make efficiency savings in the latter years of an access arrangement period.

1033. For the AA5 period, Western Power has adopted the ERA's Final Decision on the framework and approach to retain the existing GSM in the AA4 period, with the following amendments:

- remove the link to service standard performance
- adjust the GSM formulas to provide symmetrical incentives
- include uncontrollable costs in the GSM.

1034. These changes were introduced in response to the amendments made to the GSM requirements in the Access Code. These changes to the GSM for the AA5 period are discussed below.

#### *Service standards*

1035. The amendments to the Access Code in September 2020 removed the requirements that the above benchmark surplus does not exist to the extent it was achieved by Western Power failing to maintain a service standard at least equivalent to the SSB.

1036. Western Power is proposing to amend the existing GSM to reflect these changes in the Access Code by deleting sections 7.4.4 to 7.4.6 of the current access arrangement.

1037. Western Power has both an opex incentive scheme (the GSM) and a financial services incentive scheme (SSAM). As both of these schemes are symmetrical in the AA5 period, together they already provide the financial incentive to seek operating cost efficiencies balanced with maintaining service performance. This removes the need for the link between the GSM and service standard performance.

#### *The GSM to provide symmetrical incentive*

1038. Western Power has amended the existing GSM to reflect the amendments to the Access Code in September 2020 to require the GSM to be symmetrical. We are proposing the following amendments to the GSM:

- remove all references to 'above-benchmark surplus' and replace them with 'above-benchmark surplus or below benchmark deficit'

- amend the formula in section 7.4 of the current access arrangement that sets out how to calculate the GSM so the adjustment can be less than zero.

1039. The amendments result in a higher-powered GSM compared to the AA4 period, as it is symmetrical with both rewards and penalties (the AA4 GSM included rewards only). This aligns the GSM with common regulatory practice to have a symmetrical incentive scheme.

### *Uncontrollable costs*

1040. The existing GSM for the AA4 period excludes expenditure categories that are outside of Western Power's control, including licence fees, the energy safety levy, ERA fees, and superannuation costs for defined benefit schemes.

1041. For the AA5 period, Western Power has adopted the ERA's Final Decision on the framework and approach to remove these exclusions from the GSM for the AA5 period.

### *Application of network growth factors*

1042. The existing GSM for the AA4 period included an ex-post adjustment to adjust the efficiency benchmarks for actual, independently audited growth of the network, rather than forecast network growth.

1043. For the AA5 period, Western Power has adopted the ERA's Final Decision on the framework and approach, to reflect the network growth and customer growth escalators approved in the ERA's determination of forecast network growth factors in the GSM.

1044. This is also aligned with the overall philosophy applied by the AER under the base-step-trend approach which is to avoid adjustment to opex for uncontrollable costs, on the basis that under the right incentive framework, differences between actual and forecast costs will balance out over time. As such, under the AER's equivalent GSM, the Efficiency Benefit Sharing Mechanism (EBSS), there is no ex-post adjustment to the forecast opex to account for actual network growth[182].

1045. Table 9.1shows the transmission and distribution network growth factors that we have used to escalate the AA5 opex forecasts.

**Table 9.1: Network growth factors, per cent**

| Growth factor | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Customer numbers | 1.50% | 1.52% | 1.50% | 1.49% | 1.49% |
| Circuit length | 0.60% | -1.33% | 1.02% | -0.22% | -0.22% |
| Ratcheted maximum demand | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **Transmission weighted average network growth** | **0.66%** | **-0.29%** | **0.87%** | **0.25%** | **0.25%** |
| **Distribution** | | | | | |
| Customer numbers | 1.50% | 1.52% | 1.50% | 1.49% | 1.49% |
| Circuit length | -0.27% | -0.20% | 1.07% | 0.94% | -0.34% |

182 KPMG, *Western Power Network Growth Factors Final Report*, October 2021, pg. 20

| Growth factor | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Ratcheted maximum demand | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **Distribution weighted average network growth** | **0.80%** | **0.82%** | **1.00%** | **0.97%** | **0.78%** |

## 9.4 Demand management innovation allowance mechanism

1046. A requirement for a DMIA mechanism to be included in Western Power's access arrangement was introduced as part of the amendments to the Access Code to support the delivery of the State Government's Energy Transformation Strategy.

1047. The key purpose of the DMIA is to overcome barriers and constraints within the regulatory framework that would prevent investment in innovation which would deliver benefits to customers. The DMIA mechanism enables funding for innovation that would not otherwise be available under the regulatory framework.

### 9.4.1 Regulatory requirements

1048. The Access Code defines the DMIA as follows:

> *6.32B The demand management innovation allowance is an annual, ex-ante allowance provided to service providers in the form of a fixed amount of additional revenue at the commencement of each pricing year of an access arrangement period.*
>
> *6.32C The objective of the demand management innovation allowance mechanism is to provide service providers with funding for research and development in demand management projects that have the potential to reduce long term network costs ('demand management innovation allowance objective').*

1049. The Access Code clarifies that:

> *6.32F Any amount of allowance not used by the service provider or not approved by the Authority over the access arrangement period must not be carried over into the subsequent access arrangement period or reduce the amount of the allowance for the subsequent access arrangement period.*

1050. Section 6.32G of the Access Code provide further details on the application of an DMIA mechanism:

> *6.32G In developing and applying any demand management innovation allowance mechanism, the Authority must take into account the following:*
>
> *(a) the mechanism should be applied in a manner that contributes to the achievement of the demand management innovation allowance objective;*
>
> *(b) projects the subject of the allowance should:*
>
> *(i) have the potential to reduce long term network costs; and*
>
> *(ii) be innovative and not otherwise efficient and prudent alternative options that a service provider should have provided for in its proposed access arrangement; and*
>
> *(iii) comply with the demand management innovation allowance guidelines*
>
> *(c) the level of the allowance:*

*(i) should be reasonable, considering the long term benefit to consumers; and*

*(ii) should only provide funding that is not available from any other source; and*

*(iii) may vary over time; and*

*(d) the allowance may fund projects which occur over a period longer than an access arrangement period.*

*6.32H A service provider must submit a compliance report to the Authority in accordance with the demand management innovation allowance guidelines.*

### 9.4.2 Proposed demand management innovation allowance mechanism for the AA5 period

1051. Western Power has included a DMIA mechanism in our access arrangement for the AA5 period, consistent with the amendments to the Access Code. Our view is that the application of the DMIA should be flexible enough to adapt to the circumstances and progression of an energy market in transition to ensure that the scheme achieves its intended outcomes.

1052. Under Section 4.A2(D) of the Access Code, the ERA is required to determine the DMIA mechanism as part of the framework and approach. The ERA determined the allowance level of the DMIA for Western Power in the Final Decision on the framework and approach. The form of the DMIA, eligibility criteria and the compliance and reporting requirements are set out in the ERA's DMIA guideline.[183]

1053. Western Power notes that the objective of DMIA is to incentivise the pursuit of valuable innovative projects that deliver benefits to customers. In our feedback to the ERA through the development of the DMIA guideline we highlighted our view that the eligibility criteria and process of ex-post assessment should not create unnecessary risks and administrative complexity that may prevent some valuable innovative projects from being considered and lead to under-utilisation of the DMIA. Ex-post review should evaluate the eligibility requirements in a proportionate, flexible, transparent, and objective manner to ensure the scheme achieves the desired objectives.

1054. We have adopted the ERA's Final Decision on the framework and approach to include an annual innovation allowance for research and development in demand management initiatives in our target revenue. Consistent with the ERA's Final Decision on the framework and approach, we propose to include an allowance of 0.08 per cent of our target revenue approved (excluding the allowance) for each pricing year in the AA5 period for demand management initiatives that meet the eligibility requirements in the Access Code and the ERA guidelines.

1055. Based on the target revenue in our AA5 proposal, an allowance of 0.08 per cent is approximately $6 million over the AA5 period, or $1.2 million each year.

## 9.5 Unforeseen events

### 9.5.1 Regulatory requirements

1056. The Access Code allows the target revenue to be adjusted for efficient costs incurred as a result of an unforeseen force majeure event, as follows:

*6.6 If:*

*(a) during the previous access arrangement period, a service provider incurred capital-related costs or non-capital costs as a result of a force majeure event; and*

[183] ERA, *Demand management innovation allowance guideline – Decision*, 14 September 2021

*(b) the service provider was unable to, or is unlikely to be able to, recover some or all of the costs ("unrecovered costs") under its insurance policies; and*

*(c) at the time of the force majeure event the service provider had insurance to the standard of a reasonable and prudent person (as to the insurers and the type and level of insurance),*

*then subject to section 6.8 an amount may be added to the target revenue for the covered network for the next access arrangement period in respect of the unrecovered costs.*

*6.7 Nothing in section 6.6 requires the amount added under section 6.6 in respect of unrecovered costs to be equal to the amount of unrecovered costs.*

*6.8 An amount must not be added under section 6.6 in respect of capital-related costs or non-capital costs, to the extent that they exceed the costs which would have been incurred by a service provider efficiently minimising costs.*

### 9.5.2 Proposed unforeseen and trigger events for the AA5 period

1057. Section 6.6 of the Access Code allows Western Power to recover prudent and efficient capex and opex incurred during a previous access arrangement period as a result of a force majeure event[184] that are unable to be recovered under Western Power's insurance policies[185].

1058. Western Power is not proposing any unforeseen and trigger events for the AA5 period.

## 9.6 D factor

### 9.6.1 Proposed D Factor mechanism change for the AA5 period

1059. Western Power's D Factor mechanism for the AA4 period allows an adjustment to our target revenue in the AA5 period so that Western Power can be financially neutral in relation to incurring additional operating expenditure during the period:

- as a result of deferring a capital expenditure program; or
- in relation to demand management initiatives or network control services

1060. Western Power is proposing that the AA5 D Factor mechanism include an adjustment for any additional operating expenditure incurred in relation to the procurement of NCESS triggered by the Coordinator of Energy under the amendments gazetted to the WEM Rules in December 2021. The amendments to the WEM Rules introduce a new section 3.11A for the triggering of procurement of NCESS which will come into effect from 1 February 2022.

1061. The D Factor provides a mechanism to ensure that Western Power has an incentive to consider both operating and capital expenditure options. The D Factor ensures that Western Power is not penalised for choosing an operating expenditure solution where it is the more prudent and efficient investment decision during the AA5 period. Inclusion of NCESS in the D Factor enables the appropriate recovery of the actual costs of procurement of NCESS where the Coordinator of Energy triggers this under the WEM Rules and deems that Western Power, as the Network Operator, shall pay for the service. Customers will only pay for

[184] Under the Access Code 'force majeure' is defined as: *a fact or circumstance beyond the person's control and which a reasonable and prudent person would not be able to prevent or overcome*.

[185] Insurances must reflect the type and level of cover held by a reasonable and prudent person.

the actual additional operating expenditure through a true-up of revenue in the next access arrangement period.

1062. Accordingly, we have amended section 7.6.3 of our current access arrangement to include the additional adjustment for the procurement of NCESS as directed by the Coordinator of Energy under the WEM Rules.

## 9.7 Technical Rule changes

### 9.7.1 Regulatory requirements

1063. Section 6.9 of the Access Code provides that revenue in the next period can be adjusted for unforeseen costs relating to changes to the Technical Rules.

> *6.9 If, during the previous access arrangement period, the technical rules for the covered network were amended under section 12.53 with the result that the service provider, in complying with the amended technical rules:*
>
> *(a) incurred capital-related costs or non-capital costs:*
>
> *(i) for which no allowance was made in the access arrangement; and*
>
> *(ii) which the service provider could not have reasonably foreseen at the time of the approval of the previous access arrangement;*
>
> *and*
>
> *(b) did not incur capital-related costs or non-capital costs for which allowance was made in the access arrangement,*
>
> *then subject to sections 6.10 to 6.12 an amount may be added to the target revenue for the covered network for the next access arrangement period in respect of the costs.*
>
> *6.10 The amount (if any) to be added under section 6.9(a) must be positive, and the amount (if any) to be added under section 6.9(b) must be negative.*
>
> *6.11 A positive amount must not be added under section 6.9(a) in respect of capital-related costs or non-capital costs, to the extent that they exceed the costs which would have been incurred by a service provider efficiently minimising costs.*
>
> *6.12 A negative amount added under section 6.9(b) must have regard to the savings that would have been made by a service provider efficiently minimising costs even if the service provider did not actually achieve that level of savings.*

### 9.7.2 Proposed Technical Rule change mechanism for the AA5 period

1064. Sections 6.9 to 6.12 of the Access Code provide a mechanism to adjust Western Power's AA6 target revenue for any differences in actual capex or opex as against the AA5 forecast expenditure required to meet its Technical Rules obligations arising from amendments during the AA5 period.

1065. Western Power is proposing to retain the existing Technical Rules changes provisions for the AA5 period. The retention of the current revenue adjustment mechanism for Technical Rules changes means customers will pay only for actual costs associated with approved Technical Rules changes during the AA5 period rather than forecasts.

# 10. Weighted average cost of capital

1066. This chapter outlines Western Power's estimate of the WACC for the AA5 period.

**Key Messages**

- The regulated rate of return (also known as the weighted average cost of capital – WACC) is the return we earn on investment in our network. It is intended to provide incentives to undertake efficient investment by ensuring we recover the efficient cost of capital
- We have followed the approach in the Access Code and the ERA's current practice in calculating the WACC for the AA5 period and, in relation to the return on debt, we propose a change more consistent with the approach adopted by many regulators which reflects standard commercial practices and ensures sustainability over time
- Our proposed average regulated rate of return is 4.73 per cent in the AA5 period, nearly 20 per cent lower than in the AA4 period. This comprises a return on debt of 3.9 per cent and equity of 5.73 per cent compared to 5.03 per cent and 6.57 per cent in the AA4 period respectively
- The fall in the regulated rate of returns has resulted from changes in market conditions that have mostly affected the risk-free rate which drives both the return on debt and equity provided

1067. Section 6.65 of the Access Code allows for the ERA to make a determination of the "*preferred methodology for calculating the weighted average cost of capital in access arrangements*". The ERA is yet to make such a determination at the time of preparing this submission.

1068. As such, for the AA5 period, our WACC estimate has broadly adopted the same method for determining the cost of equity and debt that the ERA applied to gas businesses under the 2018 Rate of Return Guidelines[186] with some variations, which are detailed further below. Western Power considers that this approach is consistent with section 6.66 of the Access Code (which sets out the requirements for a determination under section 6.65).

1069. The WACC is the rate of return on investment a company is expected to pay on average to all its security holders to finance its assets. For a regulated business, the WACC is determined using a weighted average of the estimated cost of equity and cost of debt to be incurred over the regulatory period. The cost of equity estimates the return required by shareholders to invest in the network. The cost of debt estimates the interest rate required by debt holders on issued debt (or the interest rate on loans). The weighting reflects that of a theoretical efficient benchmark electricity business and does not necessarily reflect Western Power's actual debt portfolio or ownership structure.

1070. The WACC is multiplied by Western Power's RAB to derive the return on assets revenue building block. For asset-intensive businesses such as electricity networks, the return on assets is typically one of the largest building blocks used to calculate target revenue. During the AA4 period, return on assets accounted for 25 per cent of Western Power's revenue.

1071. Western Power's return on asset revenue building block for the AA5 period relates to financing investment in an electricity network that connects our 2.3 million customers' homes, businesses and essential community infrastructure to an increasingly renewable energy mix. Achieving a reasonable rate of return is essential to attract the necessary funding from investors and debt providers, so we can best meet community expectations and move as safely and affordably as possible to a modular grid.

186 ERA, *Final Rate of Return Guidelines (2018)*, December 2018

1072. Western Power engaged Frontier Economics to undertake an industry scan and provide an expert opinion on key issues relating to the allowed rate of return. The Frontier Economics report, provided as Attachment 10.1 – Considerations for the regulatory rate of return allowance, includes extensive research conducted for Western Power and helped inform our submission and provides the supporting arguments for our proposed approach to estimating the allowed rate of return.

## 10.1 Approach to the allowed return on capital

1073. Western Power proposes that the allowed return on capital should be set on the basis of a vanilla WACC defined as:

$$WACC = \frac{E}{V} r_e + \frac{D}{V} r_d$$

where:

- $\frac{E}{V}$ and $\frac{D}{V}$ represent the proportions of equity and debt financing, respectively
- $r_e$ and $r_d$ represent the required return on equity and debt financing, respectively.

1074. Western Power also proposes that the required return on equity should be set on the basis of the Sharpe-Lintner Capital Asset Pricing Model (**CAPM**) defined as:

$$r_e = r_f + \beta_e \left( E[r_m] - r_f \right)$$

where:

- $r_f$ is the rate of return on a risk-free asset
- $\beta_e$ is the equity beta for the benchmark efficient firm, defined as:

$$\beta_e = \frac{Cov(r_e, r_m)}{Var(r_m)}$$

- $\left( E[r_m] - r_f \right)$ is the market risk premium
- $r_m$ represents the expected return on a broadly diversified 'market' portfolio.

1075. Western Power notes that this CAPM-based WACC approach is the standard approach adopted by the ERA in its previous regulatory decisions.

1076. In this AA5 proposal, Western Power proposes to follow the approach adopted by the ERA in its AA4 decision for Western Power and in its 2018 Rate of Return Guidelines in all but two respects:

- Western Power proposes that the risk-free rate should be set using the yield on 10-year Commonwealth government bonds, rather than the 5-year term applied for the AA4 period
- Western Power proposes that the allowed return on debt should be set using the 10-year trailing average approach that is now adopted by all other Australian regulators.

1077. The rationale for these two changes is explained below, with more details provided in the detailed report prepared for Western Power by Frontier Economics (see Attachment 10.1).

1078. It is worth noting that even after incorporating the changes that are proposed to the estimation of the risk-free rate and allowed return on debt, the resulting WACC allowance is materially lower than the current allowance set in AA4 due to reductions in parameters that are driven by financial market estimates.

## 10.2 Required return on equity

### 10.2.1 Nominal risk-free rate

1079. Western Power proposes that the risk-free rate should be set on the basis of the yield on 10-year Commonwealth government bonds, as opposed to the current AA4 approach of using a 5-year term for the risk-free rate.

1080. Western Power considered detailed analysis of the term of the risk-free rate as set out in the Frontier Economics report which concluded that a 10-year term should be adopted for the risk-free rate as:

- the use of a 10-year rate reflects the standard practice adopted by market investors, valuation professionals and academics
- the net present value (**NPV**)=0 principle requires that the regulatory allowance is set to match the return that investors require – which is based on a 10-year risk-free rate
- all other Australian regulators[187] now adopt a 10-year risk-free rate, matching the regulatory approach with the approach adopted by market investors.

1081. Taking into consideration the analysis presented in the Frontier Economics report, Western Power believes there is no compelling basis for maintaining a 5-year risk-free rate.

1082. Western Power notes the ERA's recent final decision on the Pilbara networks rate of return[188], released on 21 November 2021, has adopted the yield of a 10-year Commonwealth Government bond to estimate the risk-free rate.

### 10.2.2 Equity beta

1083. Western Power proposes an equity beta of 0.7, consistent with the equity beta allowance for Western Power in the AA4 period and the equity beta allowance in the ERA's 2018 Rate of return Guidelines.

1084. We consider the proposed equity beta of 0.7 is conservative given allowances made by other comparable regulators. For example, the AER has recently documented the equity betas used by comparable regulators.[189] Those comparable equity beta allowances, re-levered to reflect the ERA's 55 per cent gearing assumption, are set out in Table 10.1 below.

1085. Western Power does not propose that the current AA4 equity beta allowance be increased on the basis of the information set out in this table, but simply notes that maintaining the current allowance of 0.7 is conservative in light of the allowances of the other regulators recently considered by the AER.

**Table 10.1: International equity beta allowance[190]**

| Regulator | Original equity beta | Gearing | Re-levered equity beta |
|---|---|---|---|
| Authority for Consumers and Markets | 0.74 | 50% | 0.82 |
| Federal Energy Regulatory Commission | 0.84 | 60% | 0.75 |

187 Western Power notes that at the time of writing, the AER is currently assessing their approach to the rate of return: https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022

188 Determination of Pilbara networks rate of return, page 11, paragraph 124 https://www.erawa.com.au/cproot/22308/2/Pilbara-networks-rate-of-return-final-decision-For-publication.pdf

189 AER, December 2020, *International regulatory approaches to rate of return*, Table 5, pp. 26-27

190 AER, December 2020, *International regulatory approaches to rate of return*, Table 5, pp. 26-27, re-levered to 55 per cent

| Regulator | Original equity beta | Gearing | Re-levered equity beta |
|---|---|---|---|
| Surface Transportation Board | 1.11 | 16.92% | 2.05 |
| New Zealand Commerce Commission | 0.71 | 44% | 0.88 |
| New Zealand Commerce Commission* | 0.60 | 42% | 0.77 |
| Italian Regulatory Authority for Energy, Networks & the Environment | 0.65 | 42% | 0.84 |
| Office of Gas and Electricity Markets | 0.76 | 55% | 0.76 |
| Office of Gas and Electricity Markets* | 0.71 | 55% | 0.71 |
| Office of Water Services | 0.71 | 54.5% | 0.72 |
| Office of Water Services (CMA) | 0.76 | 54.5% | 0.77 |

### 10.2.3 Market risk premium

1086. Western Power proposes no change to the approach used for the AA4 period for estimating the market risk premium (**MRP**). We have adopted the current estimate of 6 per cent in our AA5 proposal, recognising that the ERA's approach to the MRP is not a mechanistic one, but requires the exercise of the ERA's judgment at the time of each determination. We note that a 6 per cent MRP allowance was adopted in the AA4 period and in the ERA's 2018 Rate of Return Guidelines.

1087. The Frontier Economics report prepared for Western Power recommends that consideration should be given to a wider range of evidence when estimating the MRP (see Attachment 10.1). Frontier Economics has particular regard to the analysis and recommendations on this point set out in the reports recently commissioned by the AER.

1088. In its report for Western Power, Frontier Economics makes two specific recommendations on the MRP:

1. No weight should be applied to the geometric mean of historical excess returns.

   The primary reason for this recommendation is the substantial body of evidence that concludes that it is inappropriate to place any reliance on the geometric mean of historical excess returns. Leading textbooks and case studies prepared by Professors at Harvard, Stanford, MIT, Wharton and London Business School not only report that they recommend the use of arithmetic means, but explain why it is wrong to use a geometric mean for the purpose of estimating forward-looking expected returns.

2. Real weight should be applied to the dividend growth model (**DGM**) estimate and the total market return approaches that allow for a negative relationship between the risk-free rate and the MRP.

   The primary reason for this recommendation is the substantial body of evidence that supports the existence of a negative relationship between the risk-free rate and the MRP. Frontier Economics' view is that the required return on equity has not fallen one-for-one with the decline in government bond yields that has occurred since 2018. Rather, it is their view that the evidence indicates that the MRP has increased to at least partially offset the decline in government bond yields.

A key component of this body of evidence is the recent expert reports commissioned by the AER. Those reports advise that there is "*no good evidence*" to support the historical excess returns approach[191] and that such an approach is "*not as effective as the approaches of other regulators*"[192]. The AER's consultants have advised that consideration should be given to applying more weight to forward-looking DGM estimates and the total market return approach.

1089. Although Western Power considers that there are strong reasons to support these recommendations, we are not proposing any changes to the approach to the MRP for this AA5 proposal. Nevertheless, we request that the ERA consider the issues raised in the report.

## 10.3 Required return on debt

### 10.3.1 Benchmark credit rating

1090. Western Power proposes a benchmark credit rating of BBB+, consistent with the benchmark credit rating for Western Power in the AA4 period and the benchmark credit rating in the ERA's 2018 Rate of return Guidelines.

### 10.3.2 Term of debt

1091. Western Power proposes a term of debt of 10 years consistent with the benchmark term of debt for Western Power in the AA4 period and the benchmark credit rating in the ERA's 2018 Rate of return Guidelines.

### 10.3.3 Benchmark efficient financing strategy

1092. Western Power proposes that the allowed return on debt should be set to reflect the costs of a benchmark efficient financing strategy whereby the firm raises 10 per cent of its debt financing requirements each year in the form of 10-year fixed-rate BBB+ debt. Under that approach, the cost of servicing debt is reflected in the 'trailing average' return on debt allowance that is now used by all other Australian regulators.

1093. This represents a departure from the current approach applied in the AA4 period of setting the return on debt allowance to reflect the costs of a financing strategy whereby the benchmark firm:

- issues 10-year floating rate debt on a staggered maturity basis (i.e., refinancing 10 per cent of its debt portfolio each year)
- uses interest rate swaps to lock in the base risk-free rate at the beginning of each regulatory period.

1094. A detailed analysis of the approach to the allowed return on debt is set out in the report prepared by Frontier Economics for Western Power, (see Attachment 10.1).

1095. Frontier Economics recommends that the allowed return on debt should be set using the standard 10-year trailing average approach adopted by all other Australian regulators. The primary reasons for that conclusion are:

- the current approach to the allowed return on debt reflects a financing strategy that a business would be unlikely to consider adopting, other than to replicate the allowance provided to it under the current approach. Consequently, it is difficult to support the notion that such a strategy is prudent and efficient

191 CEPA, June 2021, *Relationship between RFR and MRP*, pp. 6, 44.
192 Brattle, June 2020, *A review of international approaches to regulated rates of return*.

- all other Australian regulators now use the standard 10-year trailing average approach applied to the entire return on debt, matching the regulatory approach with the approach generally observed in the market. It is now the case that no other Australian regulator:
  - adopts the ERA's hybrid approach
  - considers that the NPV=0 principle prevents it from adopting the standard 10-year trailing average approach.

1096. Western Power notes that the standard trailing average approach also best reflects our own (prudent and efficient) approach to managing our debt portfolio.

1097. For all of the reasons set out above and in the attached Frontier Economics report, we propose that the allowed return on debt should be set using the standard trailing average approach.

1098. Western Power notes the ERA's recent final decision on the Pilbara networks rate of return[193], released on 21 November 2021, has adopted a full 10-year trailing average debt approach to estimate the return on debt.

### 10.3.4 Debt issuing costs

1099. Western Power proposes to adopt debt issuing costs of 10 basis points per annum, consistent with the benchmark term of debt for Western Power in the AA4 period and the benchmark term of debt in the ERA's 2018 Rate of return Guidelines.

### 10.3.5 Debt hedging costs

1100. Western Power proposes to adopt no debt hedging costs on the basis that no hedging via swap contracts would be required under the standard trailing average approach. Under that approach, the benchmark efficient firm issues a tranche of 10-year fixed-rate debt each year, so there are no swaps required to fix rates at the beginning of each regulatory period.

### 10.3.6 Annual update

1101. The current approach for the implementation of a trailing average cost of debt is to require an annual update of the data set – for Western Power this occurs at the time of the annual Price List. Western Power recommends this approach is maintained in the AA5 period under the proposed move to a standard trailing average approach. Under this method, Western Power is required to confidentially nominate an averaging period to be used for each year of the AA5 period.

### 10.3.7 Implementing the trailing average

1102. In considering changes to the methodology for the cost of debt, Western Power has also considered how best to implement the standard trailing average approach. This is particularly important in the current environment where rates are at or close to historical lows and expected to stay low for some time. This means that any trailing average approach will likely start the AA5 period relatively 'high' and decrease over the period.

1103. From a revenue and price outcome, this would mean that initial projections of revenue and price outcomes would be overstated and each annual update to the WACC (and hence revenue and prices) will likely be a downwards adjustment.

193 Determination of Pilbara networks rate of return, page 31, paragraph 201 https://www.erawa.com.au/cproot/22308/2/Pilbara-networks-rate-of-return-final-decision-For-publication.pdf

1104. To mitigate this impact, Western Power has sought to incorporate the methodology adopted by the AER whereby the most recent observation is used as a placeholder value for each year of the regulatory period. This essentially pre-empts where the trailing average is most likely to move over the period and reduces potential volatility in revenue and prices.

1105. This approach appears to be a good fit for the standard trailing average approach, which is impacted slightly more than the ERA's hybrid approach by the annual update process.

## 10.4 Other rate of return parameters

### 10.4.1 Gearing

1106. Western Power proposes a gearing parameter of 55 per cent, consistent with the gearing parameter for Western Power in the AA4 period and the benchmark gearing parameter in the ERA's 2018 Rate of return Guidelines.

### 10.4.2 Gamma

1107. Western Power proposes a gamma of 0.5, consistent with the benchmark gamma for Western Power in the AA4 period and the benchmark gamma in its 2018 Rate of return Guidelines.

### 10.4.3 Corporate tax rate

1108. Western Power proposes a corporate tax rate of 30 per cent, consistent with the ERA's determination for Western Power in AA4 and the rate used in the 2018 Rate of return Guidelines.

### 10.4.4 Inflation

1109. Western Power proposes an inflation rate of 2.03 per cent, determined using the same methodology as the ERA's determination for Western Power in AA4 and in the 2018 Rate of return Guidelines.

## 10.5 Comparative WACC allowance

1110. Placeholder values for each of the WACC parameters have been calculated using data up to 30 June 2021. Western Power will separately, confidentially provide to the ERA a future dated period to use for the calculation of the parameters for the draft and final decisions. The placeholder WACC allowance is compared with the ERA's AA4 allowance in Table 10.2 below. The table shows that, even after incorporating the changes that are proposed to the estimation of the risk-free rate and allowed return on debt, the WACC allowance is materially lower than the current allowance set in AA4.

1111. Note that while there are values for all five years of the AA5 period, and the cost of debt varies each year as set out in section 10.3.7.

**Table 10.2: WACC outcome in AA4 compared with AA5 proposed**

| Parameter | Final for AA4 period | Placeholder values for AA5 period | | | | |
|---|---|---|---|---|---|---|
| | | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
| **Cost of equity parameters** | | | | | | |
| Nominal risk-free rate (per cent) | 2.37 | 1.53 | 1.53 | 1.53 | 1.53 | 1.53 |
| Equity beta | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |

| Parameter | Final for AA4 period | Placeholder values for AA5 period | | | | |
|---|---|---|---|---|---|---|
| | | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
| Market risk premium (per cent) | 6 | 6 | 6 | 6 | 6 | 6 |
| Nominal after tax return on equity (per cent) | 6.57 | 5.73 | 5.73 | 5.73 | 5.73 | 5.73 |
| **Cost of debt parameters** | | | | | | |
| Five-year interest rate swap (effective yield) (per cent) | 2.59 | n/a | n/a | n/a | n/a | n/a |
| Debt risk premium (per cent) | 2.487 | n/a | n/a | n/a | n/a | n/a |
| Trailing average return on debt | n/a | 4.40 | 4.00 | 3.73 | 3.52 | 3.37 |
| Benchmark credit rating | BBB+ | BBB+ | BBB+ | BBB+ | BBB+ | BBB+ |
| Term of debt for debt risk premium | 10 years | 10 years | 10 years | 10 years | 10 years | 10 years |
| Debt issuing costs (per cent) | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Debt hedging costs | 0.114 | n/a | n/a | n/a | n/a | n/a |
| Nominal cost of debt (return on debt) (per cent) | 5.29 | 4.50 | 4.10 | 3.83 | 3.62 | 3.47 |
| **Other parameters** | | | | | | |
| Inflation (per cent) | 1.84 | 2.03 | 2.03 | 2.03 | 2.03 | 2.03 |
| Debt proportion (gearing) | 55 | 55 | 55 | 55 | 55 | 55 |
| Franking credits (gamma) (per cent) | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate tax rate (per cent) | 30 | 30 | 30 | 30 | 30 | 30 |
| **Weighted average cost of capital** | | | | | | |
| Nominal after-tax WACC (per cent) | 5.87 | 5.05 | 4.83 | 4.69 | 4.57 | 4.49 |

# 11. Annual revenue requirement

1112. This chapter describes how Western Power has calculated its revenue requirement for the AA5 period. It includes the forecast target revenue and outlines the form of price control and revenue components, including calculation of Western Power's RAB, tax asset base (**TAB**), adjustments under regulatory incentive/adjustment mechanisms and other revenue items.

**Key Messages**

- We have complied with the Access Code and the ERA's current practice in calculating our annual revenue requirement which is similar to the AA4 period
- Our revenue requirement is $7,472.6 million over the AA5 period, 6.5 per cent less than revenue recovered over the AA4 period. This is primarily due to the lower regulated rate of return which has fallen from 5.72 per cent to 4.73 per cent and lower incentive scheme revenues
- We will retain the modified revenue cap form of price control consistent with the Framework and Approach and the AA4 period
- Our target revenue includes:
  - $953 million (nominal) in TEC consistent with the gazetted amount
  - $182.9 million in deferred revenue recovery consistent with the recovery approach in the AA4 period
  - $66.5 million for AAMI communications expenditure consistent with amendments to the access code and
  - $9.1 million in adjustments under the financial incentive schemes, investment adjustment mechanism and recovery of access reform costs
- Our regulated asset base will grow from $10.4 billion to $12.3 billion
- We have aligned the economic life used for depreciation with the most recent tax ruling and proposed three new asset categories for transmission secondary systems, SPS and energy storage

## 11.1 Regulatory framework

1113. Section 6.1 of the Access Code allows an access arrangement to include any form of price control, as long as it meets the price control objectives set out in section 6.4 of the Access Code. The price control objectives are that the price control provides the service provider with sufficient revenue to:

- recover efficient costs of providing covered services, including a return on investment
- reward the service provider for outperformance of efficiency and innovation benchmarks under the GSM
- recover deferred revenue
- recover AMI communications expenditure
- recover costs resulting from unforeseen events and Technical Rule changes in the prior access arrangement period
- reward (or penalise) the service provider under the IAM and the SSAM
- recover the cost of access reform work

- recover the cost of the Tariff Equalisation Contribution (**TEC**).

while allowing the service provider to predict likely changes in target revenue during the access arrangement period and minimising the variance between expected revenue in the final pricing year of the access arrangement period and the target revenue for final pricing year.

1114. Sections 6.32A and 6.32B of the Access Code also require an access arrangement to include a DMIA mechanism, which is to be in the form of a fixed amount of additional revenue each year. Through the framework and approach for the AA5 period[194], the ERA has determined that the DMIA should be set at 0.08 per cent of approved target revenue (before the allowance) each year.

1115. Section 6.2 of the Access Code notes that the target revenue may be set by:

- reference to total approved costs, such as a revenue cap, or
- reference to prior year prices, such as a price cap, or
- a combination thereof.

1116. Through the framework and approach, the ERA has determined that the form of the price control set for the AA4 period (i.e. a modified revenue cap, with target revenue based on approved total costs) should be retained for the AA5 period, with the following two amendments:

- a single price control (rather than separate controls for transmission and distribution)
- removal of the side constraint (which restricted price increase for each reference service to 2 per cent above the overall average increase in total revenue).

1117. The price control applied by Western Power in this AA5 proposal reflects the ERA's decision in the framework and approach for the AA5 period.

## 11.2 Overview of revenue requirement

1118. Western Power proposes to recover $7,472.6 million of revenue via reference tariffs over the AA5 period. While the framework and approach determined that there will be a single price control for Western Power for the AA5 period, the following table shows the split between the distribution and transmission revenues to enable comparison with previously published information. The price control will apply only to the total target revenue amount shown in Table 11.1.

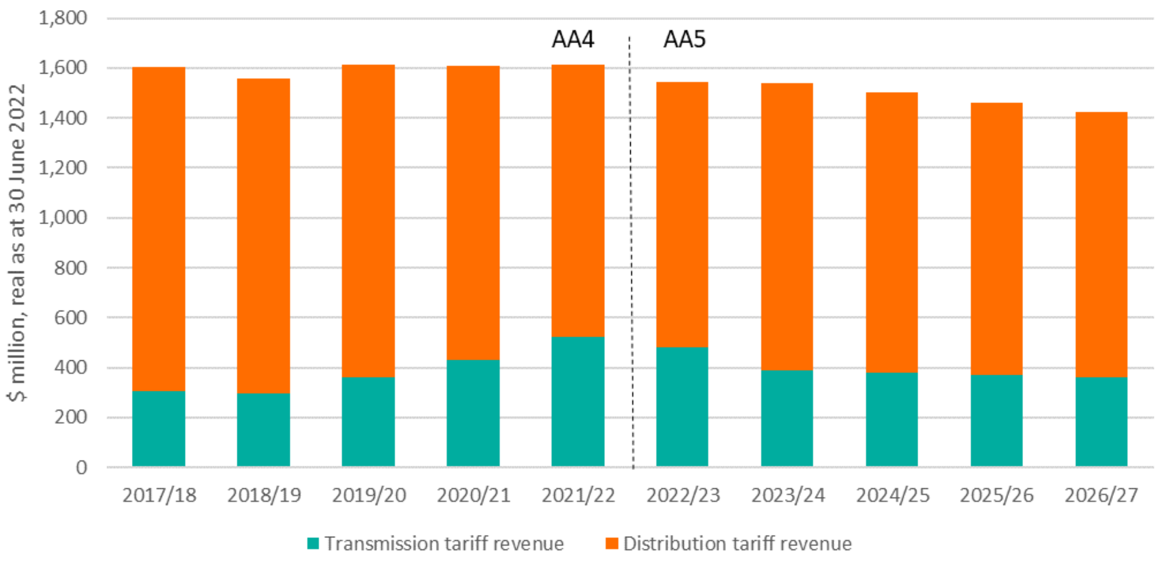
**Table 11.1: AA5 target revenue, $ million real at 30 June 2021**

| Target revenue | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | Total |
|---|---|---|---|---|---|---|
| Transmission tariff revenue | 482.1 | 388.3 | 378.3 | 368.6 | 359.2 | 1,976.6 |
| Distribution tariff revenue | 1,062.9 | 1,150.5 | 1,121.9 | 1,094.0 | 1,066.7 | 5,496.0 |
| **Total AA5 target revenue** | **1,545.1** | **1,538.8** | **1,500.2** | **1,462.6** | **1,425.9** | **7,472.6** |

1119. The target revenue for the AA5 period is $519.2 million (6.5 per cent) less than tariff revenue recovered during the AA4 period, as shown in Figure 11.1.

[194] Economic Regulation Authority, *Framework and approach for Western Power's fifth access arrangement review*, Final decision, 9 August 2021

**Figure 11.1: Tariff revenue for the AA4 and forecast AA5 periods, $ million real at 30 June 2022**




1120. The ERA has determined that the modified revenue cap form of price control will be retained for the AA5 period. Western Power proposes the building block methodology, using a post-tax modelling approach, be used to calculate the target revenue. This is consistent with the approach approved for the AA4 period.

1121. The target revenue for the AA5 period includes $953.0 million (nominal) for the TEC. Western Power pays the TEC to the State Government under Part 9A of the *Electricity Industry Act 2004* "*to contribute towards maintaining the financial viability of [Horizon Power] while enabling the regulated retail tariffs for electricity that is not supplied form the South West interconnected system to be, so far as is practicable, the same as the regulated retail tariffs for electricity that is supplied from that system*." The TEC amount is gazetted by State Government each year and is included in target revenue under sections 6.4(a)(vii) and 6.37A of the Access Code.

1122. The target revenue for the AA5 period also includes:

- $182.9 million in deferred revenue recovery. This amount relates to target revenue that was under-recovered in prior access arrangement periods
- $66.5 million for AMI communications expenditure. The Access Code was amended in September 2020 to include an allowance in the target revenue for the recovery of AMI communications expenditure over a 10-year period commencing from the next access arrangement period.

1123. Target revenue for the AA5 period includes adjustments of $92.6 million from the adjustment mechanisms that were in place during the AA4 period. This revenue adjustment is made up of:

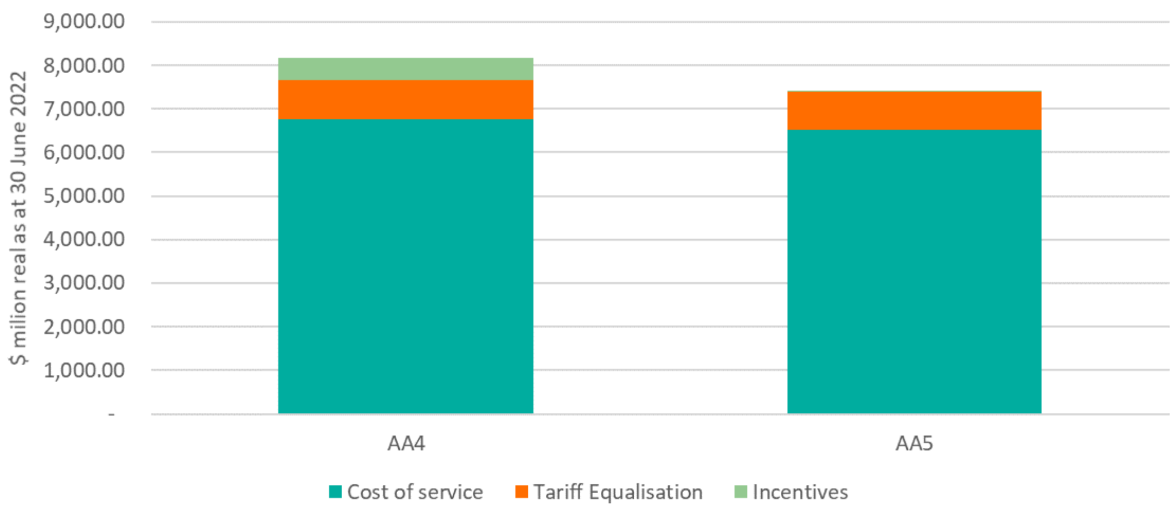
- $48.1 million from the GSM, as a result of opex budget underspends in 2019 and 2021
- $42.2 million under the D-factor, for network control services in Ravensthorpe, Bremer Bay, North Country, Eastern Goldfields and Meadow Springs
- $2.3 million for revenue related to access reform costs relating to access reform work undertaken during the AA4 period.

1124. These positive adjustments under the GSM and D-factor are offset by a $83.5 million negative adjustment, made up of:

- $39.2 million under the IAM, to return depreciation and return on asset revenue recovered for $280.9 million underspend in growth capex categories
- $44.2 million under the SSAM, to return revenue for underperformance against service standard adjustment mechanism targets (SSTs).[195]

1125. The target revenue associated with Western Power's cost of service is $6,510.3 million for the AA5 period, which is 3.7 per cent lower than the cost of service during the AA4 period (see Figure 11.2).

**Figure 11.2: Comparison of target revenue for the AA4 and AA5 periods, $ million real at 30 June 2021**




1126. Cost of service revenue excludes TEC and adjustments from prior periods. It represents the forecast revenue that results from the proposed access arrangement and services Western Power intends to provide during the AA5 period, including return on and return of capital.

1127. The decrease in the cost of service is primarily due to the lower rate of return applied to the RAB (see Section 11.4.2), which is offsetting the larger RAB and opex step changes. As described in Chapter 7 and 8, forecast opex and capex for the AA5 period is higher than that incurred during the AA4 period.

1128. Details of the revenue building blocks are provided in sections 11.4 – 11.12 of this chapter.

## 11.3 Overview of approach to annual revenue requirement

### 11.3.1 Form of price control

1129. Consistent with the ERA's determination under the framework and approach for the AA5 period, Western Power will apply a modified revenue cap form of price control with the following amendments:

- a single price control (rather than separate controls for transmission and distribution)
- removal of the side constraint (which restricted price increase for each reference service to 2 per cent above the overall average increase in total revenue).

1130. Western Power will retain the charging criteria form of price control for ancillary services, such as high load escorts.

[195] Further information on Western Power's performance in the AA4 period is provided in Chapter 5.

1131. Consistent with the approved approach for the AA4 period, the revenue cap will apply to all services Western Power provides to transmit and distribute electricity, whether they are reference or non-reference services. The revenue cap will also cover some metering services required under the Metering Code, such as scheduled meter reading.[196]

1132. Non-reference services that are covered by the revenue cap are those covered services provided by Western Power at the request of a customer but which do not meet the eligibility criteria to qualify for a reference service. For clarity, we define all reference and non-reference services that fall under the revenue cap as revenue cap services. These services are:

- connection services
- exit services
- entry services
- bi-directional services
- standard metering services as defined in the most recent Model Service Level Agreement (2020) approved by the ERA under the *Electricity Industry (Metering) Code 2012*
- streetlight maintenance on Western Power owned assets.

1133. Ancillary services (such as high load escorts) are defined as non-revenue cap services, as the revenue associated with these services are not covered by the revenue cap. Non-revenue cap services are always non-reference services.

1134. The form of price control for the AA5 period is detailed in the proposed access arrangement, including the price control formulae required to give effect to the modified revenue cap.

1135. Western Power will charge non-revenue cap services directly to the customer that is receiving the service. Charges for non-revenue cap services are set using the criteria detailed in clause 5.1.2(b) of the proposed access arrangement, which requires that charges are:

- negotiated in good faith
- consistent with the Access Code objective
- reasonable.

1136. This approach is consistent with sections 2.8(b) and 6.1 of the Access Code and is the same approach that was approved for non-revenue cap services in the AA4 period.

1137. The ERA is not required to approve tariffs or charges for non-revenue cap services. The forecast costs for providing non-revenue cap services are not included in the building blocks for the target revenue used to calculate the annual revenue caps for revenue cap services.

1138. Where possible, for commonly requested non-revenue cap services, we set standard fees and charges in line with the charging criteria and publish them on our website. Prices for extended metering services are detailed in the metering code model service level agreement. For other non-revenue cap services, we will negotiate individually with customers consistent with the charging criteria.

### 11.3.2 Use of the building blocks method

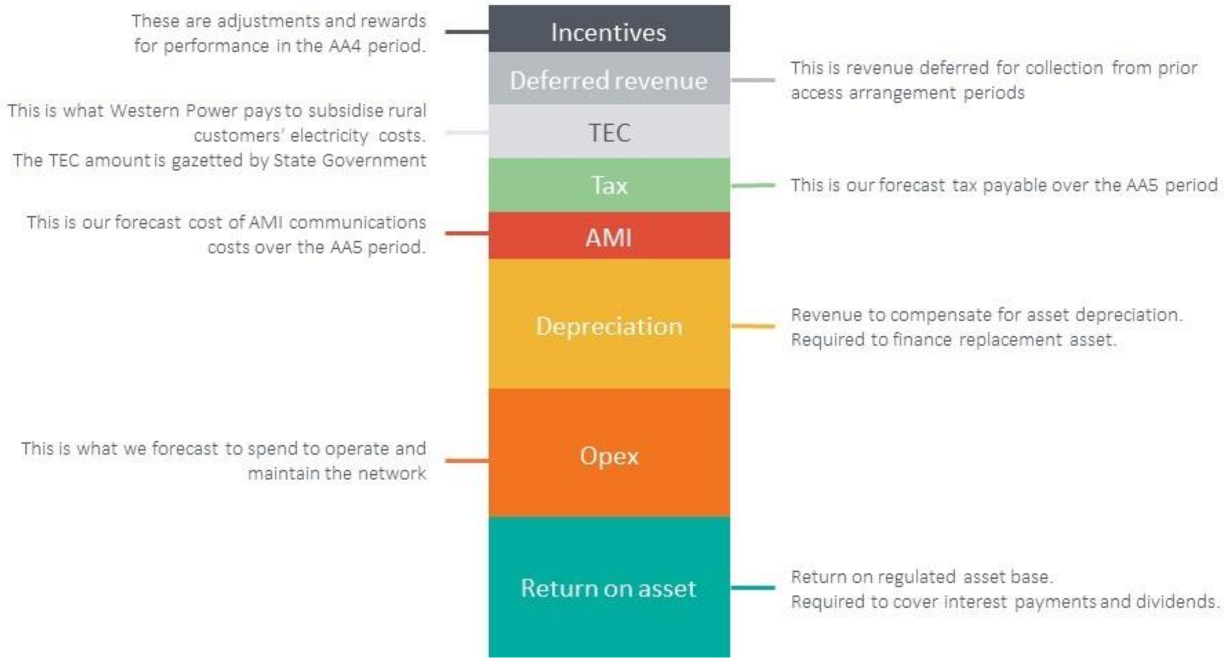
1139. Western Power has applied the building blocks method to determine target revenue and the revenue caps for the AA5 period. This same method was used to determine target revenue for prior access arrangement

[196] Extended metering services under the Model Service Level Agreement (2020), such as de-energising a metering point, are considered to be non-revenue cap access services.

periods. The building blocks method is commonly used by regulated businesses and economic regulators to determine the target revenue that meets the price control objective detailed in section 6.4(a) of the Access Code.

1140. Western Power has determined the target revenue in each year of the AA5 period with reference to approved total costs, as provided for in section 6.2(a) of the Access Code. The building block method determines the total approved costs (and thus the target revenue) as the sum of the building blocks. Target revenue is determined separately for the transmission and distribution system. We determine target revenue on a post-tax basis. Figure 11.3 outlines the revenue building blocks.

**Figure 11.3: Western Power's revenue building blocks**




1141. Table 11.2 provides the cross-references to the sections of this AA5 proposal that discuss and justify our proposal for each of the building blocks.

**Table 11.2: Cross-reference to building block information in this proposal**

| Revenue building block | Section of this AA5 proposal |
|---|---|
| Return on assets (RAB x WACC) | Chapter 10<br>Chapter 11, section 11.4 |
| Return on working capital | Chapter 11, section 11.5 |
| Forecast opex | Chapter 7<br>Chapter 11, section 11.7 |
| Return of capital (depreciation) | Chapter 11, section 11.6 |
| Tax | Chapter 11, section 11.12 |
| Revenue from AA4 adjustment mechanisms | Chapter 11, section 11.8 |
| Revenue deferred from prior access arrangement periods | Chapter 11, section 11.11 |
| Recovery of AMI communications costs | Chapter 11, section 11.9 |

| Revenue building block | Section of this AA5 proposal |
|---|---|
| Recovery of TEC | Chapter 11, section 11.10 |

### 11.3.3 Revenue modelling

1142. At a high level, Western Power's revenue model determines a revenue requirement for each building block:

- required return on assets
- required return on working capital
- depreciation
- forecast opex
- deferred revenue recovery
- AMI communications cost recovery
- regulatory adjustments (incentives and forecast vs actual adjustments)
- forecast tax calculation
- TEC.

1143. A price path is then applied to determine the annual revenue caps such that the revenue caps are equal (in present value terms) to the building block revenue requirement. For the AA5 period, Western Power has proposed a price path that includes an initial step increase in the tariffs in 2022/23, followed by no growth in average tariffs for the remainder of the AA5 period.

1144. The revenue model is based on the following high-level assumptions:

- revenue modelling occurs on a nominal post-tax basis
- all expenses are modelled on an as-incurred basis
- revenue and expenses are assumed to occur at the end of the year
- transmission system and distribution system revenue requirements are modelled separately.

1145. The revenue model is provided at Attachment 11.1 – AA5 Regulatory Revenue Model.

## 11.4 Return on assets

1146. Western Power receives a return on the value of its RAB, which is one of the largest revenue building blocks. The return on assets is determined by multiplying the value of the opening RAB in each year by the rate of return, in the form of the WACC, for that year.

### 11.4.1 Regulated asset base

1147. The RAB is used to derive both the return on assets and depreciation building blocks. In determining the forecast RAB for the AA5 period, we have calculated the value of the closing RAB for the AA4 period using the same roll forward method used in previous access arrangement periods.

1148. The AA4 closing RAB calculation uses the following method:

- start with the opening RAB at the commencement of the AA4 period
- adjust this RAB to account for:

– the difference between any estimated capex included in that value and actual capex undertaken in the preceding access arrangement period
– the difference between any forecast inflation included in that value and actual inflation observed in the preceding access arrangement period

- add the value of capex (net of contributions) incurred from 1 July 2017 to 30 June 2022
- deduct the value of disposals that occurred from 1 July 2017 to 30 June 2022
- deduct forecast depreciation from 1 July 2017 to 30 June 2022.

1149. The estimate of the closing RAB for the AA5 period follows this approach, taking into consideration:

- forecasts of new facilities investment (capex)
- forecasts of capital contributions
- inflation assumptions
- forecasts of depreciation
- economic lives of assets.

1150. Table 11.3 shows the closing AA4 RAB and our estimate of the closing RAB for the AA5 period, split by transmission and distribution.

**Table 11.3: Western Power closing RAB for the AA4 and AA5 period, $ million real at 30 June 2022**

| Regulated asset base | Estimated closing value for the AA4 period (as at 30 June 2022) | Estimated closing value for the AA5 period (as at 30 June 2027) |
|---|---|---|
| Transmission RAB | 3,465.2 | 3,715.9 |
| Distribution RAB | 7,004.3 | 8,598.4 |
| **Total RAB** | **10,469.5** | **12,314.3** |

1151. Details of the RAB calculations are provided in Attachment 11.1 – AA5 Regulatory Revenue Model. The key assumptions made in estimating the closing RAB for the AA5 period include:

- the RAB is rolled forward over the AA5 period based on Western Power's forecast of new facilities investment and capital contributions
- the economic life for various asset classes have been adjusted to better reflect the life of these assets for new facilities investment undertaken in the AA5 period (see section 11.6.1)
- new asset classes have been added to reflect the changing technology and innovative solutions being implemented in the Western Power Network (see section section 11.6)
- there are no asset disposals forecast over the AA5 period.

1152. Table 11.4 shows the roll forward of the RAB for the Western Power Network for the AA5 period, broken down between the transmission and distribution networks.

**Table 11.4: RAB roll forward, $ million real at 30 June 2022**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Opening RAB | 3,465.2 | 3,547.7 | 3,632.3 | 3,694.6 | 3,713.8 |

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Net capex | 229.3 | 249.8 | 237.9 | 203.8 | 195.0 |
| Less forecast depreciation | 146.7 | 165.2 | 175.5 | 184.7 | 192.9 |
| **Closing Transmission RAB** | **3,547.7** | **3,632.3** | **3,694.6** | **3,713.8** | **3,715.9** |
| **Distribution** | | | | | |
| Opening RAB | 7,004.3 | 7,356.6 | 7,716.5 | 8,057.4 | 8,347.3 |
| Net capex | 640.5 | 650.5 | 665.9 | 637.8 | 630.8 |
| Less forecast depreciation | 288.2 | 290.6 | 324.9 | 347.9 | 379.7 |
| **Closing Distribution RAB** | **7,356.6** | **7,716.5** | **8,057.4** | **8,347.3** | **8,598.4** |
| **Total** | | | | | |
| Opening RAB | 10,469.5 | 10,904.3 | 11,348.8 | 11,752.1 | 12,061.1 |
| Net capex | 869.7 | 900.2 | 903.8 | 841.6 | 825.8 |
| Less forecast depreciation | 435.0 | 455.8 | 500.5 | 532.6 | 572.6 |
| **Closing Total RAB** | **10,904.3** | **11,348.8** | **11,752.1** | **12,061.1** | **12,314.3** |

1153. See chapter 8 for further information on our capex estimate and section 11.6 below for further information on the estimate of forecast depreciation.

### 11.4.2 WACC estimate

1154. During the AA5 period, the WACC will vary each year as a result of the annual update of the cost of debt under the trailing average cost of debt approach.

1155. For the purposes of this AA5 proposal, we have estimated the WACC each year using the most recent observation of the cost of debt as a placeholder value for each year of the regulatory period. The impact of actual annual changes in the WACC during the AA5 period will be reflected in Western Power's annual revenue adjustment and resulting price list.

1156. Further information on Western Power's estimated WACC is provided in Chapter 10.

### 11.4.3 Required return on assets

1157. Table 11.5 show Western Power's indicative return on assets allowance.

**Table 11.5: Return on assets allowance, $m nominal**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Opening RAB | 3,465.2 | 3,619.7 | 3,781.3 | 3,924.2 | 4,024.6 |
| Post-tax nominal WACC | 5.05% | 4.83% | 4.69% | 4.57% | 4.49% |
| **Indicative return on assets** | **175.1** | **174.9** | **177.2** | **179.3** | **180.6** |
| **Distribution** | | | | | |

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Opening RAB | 7,004.3 | 7,505.9 | 8,033.0 | 8,558.2 | 9,046.0 |
| Post-tax nominal WACC | 5.05% | 4.83% | 4.69% | 4.57% | 4.49% |
| **Indicative return on assets** | **353.9** | **362.7** | **376.5** | **391.0** | **405.9** |
| **Total** | | | | | |
| Opening RAB | 10,469.5 | 11,125.7 | 11,814.2 | 12,482.4 | 13,070.7 |
| Post-tax nominal WACC | 5.05% | 4.83% | 4.69% | 4.57% | 4.49% |
| **Indicative return on assets** | **529.0** | **537.6** | **553.7** | **570.3** | **586.5** |

### 11.4.4 Removing the double count of inflation

1158. Under the building block method applied by Western Power, the RAB is rolled forward in real terms, then converted to nominal dollars to derive the return on assets and depreciation building blocks. When determining the return on assets, the calculation applies a nominal WACC on a nominal RAB. This effectively applies inflation twice on the RAB.

1159. An amount representing the inflationary gain on the RAB from the building blocks is deducted from the target revenue to offset the double count of inflation. These amounts are shown below.

**Table 11.6: Inflation deductions for distribution and transmission, $m nominal**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Transmission | 70.3 | 73.5 | 76.8 | 79.7 | 81.7 |
| Distribution | 142.2 | 152.4 | 163.1 | 173.7 | 183.6 |
| **Total** | **212.5** | **225.9** | **239.8** | **253.4** | **265.3** |

## 11.5 Return on working capital

1160. Working capital refers to a stock of funds that Western Power must maintain to pay costs as they fall due. The cost of this stock of working capital (being the required return on the capital investment) is incurred during the everyday business operation and the provision of covered services. The efficient financing costs, including a return on investment commensurate with the commercial risks involved, can be calculated on a forward-looking basis and incorporated within our target revenue as provided for in section 6.4 of the Access Code.

1161. We propose to continue using the same method for determining the cost of working capital as approved by the ERA for the AA4 period. This cost has been calculated as the difference between the implicit cost incurred by providing credit to users of services (accounts receivable) and the implicit benefit of receiving credit from suppliers (accounts payable). The working capital estimate is based on three core assumptions:

- inventory – 4.0 per cent
- accounts receivable – 45 days
- accounts payable – 20 days.

1162. The assumption for inventory and accounts receivable are consistent with those applied for the AA4 period. The accounts payable has been reduced to 20 days (down from 24.2 days in the AA4 period) reflecting a change in Western Power's policies to 20-day standard terms for all creditors to reflect government policy.

1163. Return on working capital has been included in target revenue for the AA5 period. Working capital requirements over the AA5 period are shown in Table 11.7.

**Table 11.7: Forecast working capital, $m nominal**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Transmission | 51.3 | 39.8 | 39.9 | 39.9 | 39.5 |
| Distribution | 106.2 | 118.7 | 117.1 | 115.9 | 114.2 |
| **Total** | **157.5** | **158.5** | **157.0** | **155.8** | **153.6** |

## 11.6 Forecast return of capital (depreciation)

1164. Depreciation is an allowance provided to Western Power so capital investors recover the cost of their investment over the economic life of the asset. RAB depreciation is modelled in two parts:

- initial capital base - depreciating the opening capital base when Western Power was first disaggregated in 2006
- new capex - depreciating the capex incurred each year in the access periods following disaggregation.

1165. In order to depreciate new capex it must be allocated into asset categories with matching asset lives. Western Power does this in a two-step process, whereby capex is first allocated to regulatory activity categories as follows:

- growth (capacity expansion, customer driven, gifted assets)
- asset replacement and renewal (asset replacement, SPS, NRUP, metering, wood pole management)
- improvement in service (reliability driven, SCADA and Telecommunications)
- compliance (safety, environment and statutory)
- corporate (IT and business support).

1166. The activity categories are then allocated to the transmission and distribution regulatory asset categories set out in the following table.

**Table 11.8: Transmission and distribution asset types**

| Transmission | Distribution |
|---|---|
| • Transmission cables | • Wooden pole lines |
| • Transmission steel towers | • Underground cables |
| • Transmission wood poles | • Transformers |
| • Transmission metering | • Switchgear |
| • Transmission transformers | • Street lighting |
| • Transmission reactors | • Meters and services |
| • Transmission capacitors | • IT |
| • Transmission circuit breakers | • SCADA and Telecommunications |
| • SCADA and Telecommunications | • Other distribution non-network |
| • IT | • Distribution land and easements |
| • Other non-network | • Equity raising costs |
| • Land and easements | • Standalone power systems |
| • Equity raising costs | • Storage |
| • Transmission secondary systems | |

1167. Western Power is proposing three new asset classes for the AA5 period: Transmission secondary systems, Distribution SPS and Distribution Storage. As we adopt new technology and innovative solutions the asset categories used to track and depreciate our RAB need to be updated to accommodate new asset types.

1168. Annual capex in each of these transmission and distribution regulatory asset categories is depreciated over its approved economic life on a real straight-line basis. We propose to maintain this depreciation methodology for all investments in the AA5 period.

1169. Each asset category also has an opening value and remaining life assigned for the initial capital base. Depreciation on these values is also done on a straight-line basis for the number of years specified (counting from 2006).

1170. Table 11.9 shows the forecast depreciation for distribution and transmission assets for the AA5 period. More detail on the depreciation calculation can be found in Attachment 11.1 – AA5 Regulatory Revenue Model.

**Table 11.9: Forecast depreciation, $m nominal**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---:|---:|---:|---:|---:|
| Transmission | 149.7 | 172.0 | 186.5 | 200.1 | 213.3 |
| Distribution | 294.1 | 302.5 | 345.1 | 377.0 | 419.8 |
| **Total forecast depreciation** | **443.8** | **474.4** | **531.6** | **577.1** | **633.1** |

### 11.6.1 Economic life

1171. We propose the same economic lives that were applied in the AA4 period for most of the asset groups. The exceptions are as follows:

- for transmission assets:

- transmission reactors, where the economic life is proposed to be decreased to 40 years (previously 50 years)
- transmission circuit breakers, where the economic life is proposed to be decreased to 40 years (previously 50 years)
- equity raising costs, where the economic life is proposed to be decreased to 46 years (previously 49 years)
- transmission secondary systems, which is new asset class that has been assigned a proposed economic life of 30 years

- for distribution assets:
  - underground cables (for distribution), where the economic life is proposed to be decreased to 50 years (previously 60 years)
  - switchgear (for distribution), where the economic life is proposed to be decreased to 30 years (previously 35 years)
  - equity raising costs, where the economic life is proposed to be decreased to 39 years (previously 43 years)
  - SPS, which is new asset class that has been assigned a proposed economic life of 15 years
  - storage, which is new asset class that has been assigned a proposed economic life of 10 years.

1172. The changes in economic life for the existing asset classes reflect the most recent tax ruling (TR 2021/3) on the effective life of depreciating assets. For the new asset classes, the proposed economic life is based on Western Power's assessment of the MRL for these assets.

1173. These changes will affect only the calculation of the depreciation for new facilities investment undertaken during the AA5 period. New facilities investment undertaken in previous access arrangements will continue to be depreciated based on the economic lives that applied at the time the depreciation forecast was developed for the investment.

1174. Table 11.10 and Table 11.11 show the proposed economic lives for transmission and distribution assets for the AA5 period.

**Table 11.10: Economic lives for transmission assets for the AA5 period**

| Asset class | AA4 Economic Life | AA5 Economic Life |
|---|---|---|
| Transmission cables | 55.0 | 55.0 |
| Transmission steel towers | 60.0 | 60.0 |
| Transmission wood poles | 45.0 | 45.0 |
| Transmission metering | 40.0 | 40.0 |
| Transmission transformers | 50.0 | 50.0 |
| Transmission reactors | 50.0 | 40.0 |
| Transmission capacitors | 40.0 | 40.0 |
| Transmission circuit breakers | 50.0 | 40.0 |
| SCADA and Telecommunications | 11.0 | 11.0 |
| IT | 6.0 | 6.0 |

| Asset class | AA4 Economic Life | AA5 Economic Life |
|---|---|---|
| Other non-network assets | 27.0 | 27.0 |
| Land & Easements | 0.0 | 0.0 |
| Equity raising costs | 49.0 | 46.0 |
| Transmission secondary systems | N/A | 30.0 |

**Table 11.11: Economic lives for distribution assets for the AA5 period**

| Asset class | AA4 Economic Life | AA5 Economic life |
|---|---|---|
| Wooden Pole Lines | 41.0 | 41.0 |
| Underground Cables | 60.0 | 50.0 |
| Transformers | 35.0 | 35.0 |
| Switchgear | 35.0 | 30.0 |
| Street lighting | 20.0 | 20.0 |
| Meters and Services | 15.0 | 15.0 |
| IT | 6.0 | 6.0 |
| SCADA and Telecommunications | 10.2 | 10.2 |
| Other Distribution Non-Network | 27.0 | 27.0 |
| Distribution Land & Easements | 0.0 | 0.0 |
| Equity Raising Costs | 43.0 | 39.0 |
| Standalone Power Systems | N/A | 15.0 |
| Storage | N/A | 10.0 |

## 11.7 Forecast operating expenditure

1175. Western Power is proposing to spend $2,185.3 million of opex in the AA5 period. Under the building blocks method, this expenditure is added to target revenue in the year it is forecast to be incurred.

1176. Chapter 7 provides a detailed explanation of how the opex forecast was derived.

### 11.7.1 Access reform costs

1177. Sections 6.8.1 to 6.83 of the Access Code permit Western Power to apply to the ERA for 'access reform costs' to be included in its target revenue. Access reform costs are defined in the Access Code as *"costs incurred by a service provider to undertake and deliver the access reform work, including costs incurred prior to the commencement of the commencement of the 2020 (No. 2) amendments"*.[197]

1178. Western Power is seeking a revenue adjustment of $2.3 million for access reform work undertaken during the AA4 period relating to the WOSP and limit advice. This non-capital adjustment is included in the forecast opex for the transmission network.

[197] The amendments referenced in this definition came into effect in September 2020.

### *Whole of System Plan*

1179. The Energy Transformation Strategy launched the development of the WOSP for the SWIS in May 2019 and the inaugural WOSP was launched in August 2020. The WOSP presents four scenarios of how the SWIS may evolve to 2040 and key findings that inform the forecast for renewables uptake, the growth of storage and opportunities for non-network solutions. Western Power provided network operator guidance and network modelling support to Energy Policy WA to develop the WOSP.

1180. The revenue adjustment of $0.5 million for this access reform work is classified as business overheads opex and covers the resource effort to prepare the inputs, undertake the modelling and prepare the guidance for Energy Policy WA. The Western Power regulatory reform business case for this expenditure was approved in August 2019.

### *Limit advice*

1181. Western Power is required to provide AEMO with non-thermal limit and 41$^{o}$ thermal limit advice. These are new requirements introduced to support the commencement of the new WEM in October 2022 and are the result of a formal request in May 2019 by the Energy Transformation Implementation Unit[198] for Western Power to provide this advice to AEMO.

1182. Non-thermal limits are typically related to network voltages and stability, and depend on asset, equipment or network section specifications. The development of non-thermal limit advice is a new capability for Western Power and is required for the introduction of security constrained economic dispatch. The advice will be required on an ongoing basis to account for changes in the transmission network, connections and network outage scenarios.

1183. The 41$^{o}$ thermal limit advice is required to support the first Network Access Quantity (**NAQ**) based Reserve Capacity Cycle in early 2022 and will continue on an ongoing basis.

1184. The revenue adjustment of $1.9 million for this access reform work is classified as opex and covers the resource effort to prepare the advice for AEMO. In March 2020, Western Power submitted an investment change control against the Western Power regulatory reform business case (approved in August 2019) to fund the delivery of this advice.

## 11.8 Revenue adjustments

1185. Western Power will incur a $6.8 million adjustment in the AA5 period as a result of various revenue adjustment mechanisms in place during the AA4 period.

1186. The adjustment mechanisms applied in the AA5 period result in a $90.2 million positive adjustment to reflect efficiency rewards (GSM) and demand management services (D-factor). This is offset by a $83.5 million negative adjustment for variance in forecast capex (IAM) and service performance (SSAM).

1187. Table 11.12 summarises the financial implications of the adjustment mechanisms on the target revenue for the AA5 period.

[198] The Energy Transformation Implementation Unit was established in May 2019 to support the delivery of the Energy Transformation Strategy. It concluded in May 2021.

**Table 11.12: Revenue adjustments under the AA4 adjustment mechanisms, $ million real at 30 June 2022**

| Adjustment mechanism | Present value adjustment to transmission revenue in the AA5 period | Present value adjustment to distribution revenue in the AA5 period | Present value adjustment to total target revenue in the AA5 period |
|---|---|---|---|
| IAM | -9.6 | -29.6 | -39.2 |
| GSM | 11.5 | 36.6 | 48.1 |
| SSAM | 2.4 | -46.6 | -44.2 |
| D-Factor | 34.0 | 8.2 | 42.2 |
| Unforeseen events | 0.0 | 0.0 | 0.0 |
| Technical rule changes | 0.0 | 0.0 | 0.0 |
| **Total** | **38.2** | **-31.4** | **6.8** |

1188. The following sections describe the revenue adjustments under each mechanism.

### 11.8.1 IAM

1189. We have subtracted $39.2 million from target revenue for the AA5 period in line with the requirements of the IAM. This amount has been calculated in accordance with section 7.3 of the current access arrangement.

1190. The IAM provides for an adjustment to target revenue that ensures Western Power and its customers are financially neutral as a result of differences between actual and forecast capex in certain expenditure categories in the AA4 period. These capex categories were:

- connecting new generation capacity
- connecting new loads
- augmentation of the network to provide additional capacity for the provision of covered services
- the SUPP.

1191. The IAM is calculated by comparing the forecast capex with the actual capex incurred that meets the requirements of section 6.51A of the Access Code. The adjustment amount is calculated using the revenue building blocks methodology to calculate the return on and return of capex in the IAM expenditure categories. The revenue adjustment is the difference between the building blocks adjusted for the time value of money and inflation.

#### *Transmission*

1192. Western Power will return $9.6 million to customers due to differences between actual and forecast capex on the transmission network during the AA4 period. Table 11.13 shows the transmission revenue adjustment.

**Table 11.13: Transmission adjustment due to the IAM, $ million real at 30 June 2022**[199]

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| **Forecast IAM transmission capex (net of capital contributions)** | | | | | |

[199] 2021/22 adjustments based on forecast performance.

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Total IAM transmission capex | 39.0 | 35.5 | 13.7 | 15.0 | 11.7 |
| Revenue - return on and return of | 0.0 | 2.1 | 3.9 | 4.5 | 5.2 |
| **Actual IAM transmission capex (net of capital contributions)** | | | | | |
| Total IAM transmission capex | -19.9 | -18.4 | 94.3 | 19.9 | 56.9 |
| Revenue - return on and return of | 0.0 | -0.2 | -0.4 | 3.3 | 4.2 |
| **Revenue adjustment under IAM** | 0.0 | -2.3 | -4.2 | -1.2 | -1.0 |

***Distribution***

1193. Western Power will return $29.6 million to customers due to differences between actual and forecast capex on the distribution network during the AA4 period. Table 11.14 shows the distribution revenue adjustment.

**Table 11.14: Distribution adjustment due to the IAM, $ million real at 30 June 2022**[200]

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| **Forecast IAM distribution capex (net of capital contributions)** | | | | | |
| Total IAM distribution capex | 135.1 | 137.2 | 120.0 | 101.0 | 108.9 |
| Revenue - return on and return of | 0.0 | 8.5 | 16.5 | 23.4 | 29.3 |
| **Actual IAM distribution capex (net of capital contributions)** | | | | | |
| Total IAM distribution capex | 43.1 | 50.2 | 79.6 | 71.6 | 58.9 |
| Revenue - return on and return of | 0.0 | 4.9 | 9.8 | 15.3 | 20.1 |
| **Revenue adjustment under IAM** | 0.0 | -3.6 | -6.7 | -8.1 | -9.2 |

### 11.8.2 GSM

1194. The target revenue for the AA5 period includes $48.1 million as a result of performance under the GSM during the AA4 period. The GSM provides Western Power an incentive to make operating cost efficiencies by allowing the business to add a share of efficiency gains achieved during one access arrangement period to target revenue for the next access arrangement period. Efficiency improvements must not be made at the expense of service performance. Therefore, GSM rewards are applied only if Western Power achieves a defined set of minimum service standards. Customers receive the majority of the benefits as a result of the significantly lower opex in future periods.

1195. Western Power has applied the GSM in accordance with section 7.4 of the current access arrangement. The current GSM accounts for the receipt of efficiency rewards based on the proportion of SSBs met in each financial year. Western Power has calculated the reduction in the GSM revenue (**GSMR**) based on the proportion of SSBs that have not been met in each financial year (i.e. the SSB Deficiency Proportion) of the five-year AA4 period.

1196. The formulation detailed in section 7.4 is summarised in the following tables. The values for $EIB_t$ and $A_t$ for each year will be updated for actual audited scale escalation factors at the end of the AA4 period.

200 2021/22 adjustments based on forecast performance.

1197. A detailed calculation is shown in the revenue model (Attachment 11.1). The following tables summarise the calculation of the GSM adjustment.

**Table 11.15: Calculation of GSM inputs and output, $ million real at 30 June 2022[201]**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | Total |
|---|---|---|---|---|---|---|
| **Input calculations** | | | | | | |
| Efficiency and innovation benchmark ($EIB_t$) | 386.9 | 393.0 | 392.8 | 403.9 | 401.6 | |
| $A_t$ (actual non-capital costs) | 424.8 | 358.1 | 422.2 | 397.5 | 409.7 | |
| Above Benchmark Surplus (ABSt) ($EIB_t - A_t$) | -37.9 | 72.8 | -64.3 | 35.8 | -14.5 | |
| **Output** | | | | | | |
| **Total GSMAt** | 0.0 | 29.8 | 0.0 | 21.3 | 0.0 | 51.1 |
| GSM revenue Adjustment[202] | | | | | | -3.0 |
| **GSMR** | | | | | | 48.1 |

### 11.8.3 SSAM

1198. The target revenue for the AA5 period includes a $44.2 million deduction as a result of performance under the SSAM. This amount has been calculated in accordance with section 7.5 of the access arrangement.

1199. The SSAM provides an incentive to maintain and/or improve service above the service standard benchmarks for the AA4 period by providing financial rewards for performance improvements or penalties for underperformance. The present value of the adjustment under the SSAM is calculated as if the rewards or penalties in each year immediately follow the relevant performance year. Service performance over the AA4 period is detailed in Chapter 5.

#### *Adjustment against transmission service standard targets*

1200. Western Power has incurred an overall $2.4 million reward under the SSAM for performance against the transmission network service standard targets during the AA4 period. Table 11.16 shows performance compared with the service standard target and the associated financial penalty or reward for each measure.

**Table 11.16: Transmission adjustment due to the SSAM, $ million real at 30 June 2022[203]**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| **Circuit availability (% of time)** | | | | | |
| Target | 0.0 | 0.0 | 98.5 | 98.5 | 98.5 |
| Performance | 99.1 | 98.7 | 98.8 | 98.5 | 98.5 |

201 2021/22 service standard performance is assumed to the same as 2020/21 performance. This will be updated to include the actual 2021/22 service standard performance at the end of the AA4 period.

202 Reduction in the GSM revenue (GSMR) based on the proportion of SSBs that have not been met in each financial year (i.e. the SSB Deficiency Proportion) of the five-year AA4 period as per section 7.4.4.

203 2021/22 service standard performance is assumed to the same as 2020/21 performance. This will be updated to include the actual 2021/22 service standard performance at the end of the AA4 period.

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Penalty / reward | 0.0 | 0.0 | 1.5 | 0.0 | 0.0 |
| **Loss of supply event frequency >0.1** | | | | | |
| Target | 0.0 | 0.0 | 17.0 | 17.0 | 17.0 |
| Performance | 11.0 | 13.0 | 15.0 | 14.0 | 14.0 |
| Penalty / reward | 0.0 | 0.0 | 0.2 | 0.3 | 0.3 |
| **Loss of supply event frequency >1** | | | | | |
| Target | 0.0 | 0.0 | 3.0 | 3.0 | 3.0 |
| Performance | 6.0 | 2.0 | 3.0 | 2.0 | 2.0 |
| Penalty / reward | 0.0 | 0.0 | 0.0 | 0.2 | 0.2 |
| **Average outage duration** | | | | | |
| Target | 0.0 | 0.0 | 784.0 | 784.0 | 784.0 |
| Performance | 560.0 | 523.0 | 751.0 | 976.0 | 976.0 |
| Penalty / reward | 0.0 | 0.0 | 0.2 | -0.3 | -0.3 |

### *Adjustment against distribution service standard targets*

1201. Western Power has incurred an overall $46.6 million penalty under the SSAM for performance against the distribution network service standard targets during the AA4 period. Table 11.17 shows performance compared with the service standard target and the associated financial penalty or reward for each measure.

**Table 11.17: Distribution adjustment due to the SSAM, $ million real at 30 June 2022[204]**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| **SAIDI – CBD (minutes per annum)** | | | | | |
| Target | 0.0 | 0.0 | 17.7 | 17.7 | 17.7 |
| Performance | 1.3 | 14.7 | 22.8 | 14.1 | 14.1 |
| Penalty / reward | 0.0 | 0.0 | -0.2 | 0.1 | 0.1 |
| **SAIDI – Urban (minutes per annum)** | | | | | |
| Target | 0.0 | 0.0 | 106.8 | 106.8 | 106.8 |
| Performance | 104.5 | 104.2 | 134.3 | 118.0 | 118.0 |
| Penalty / reward | 0.0 | 0.0 | -11.6 | -5.5 | -5.5 |
| **SAIDI – Rural Short (minutes per annum)** | | | | | |
| Target | 0.0 | 0.0 | 188.6 | 188.6 | 188.6 |
| Performance | 151.9 | 178.3 | 218.3 | 210.2 | 210.2 |

[204] 2021/22 service standard performance is assumed to the same as 2020/21 performance. This will be updated to include the actual 2021/22 service standard performance at the end of the AA4 period.

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Penalty / reward | 0.0 | 0.0 | -4.2 | -3.4 | -3.4 |
| **SAIDI – Rural Long (minutes per annum)** | | | | | |
| Target | 0.0 | 0.0 | 677.7 | 677.7 | 677.7 |
| Performance | 718.1 | 663.5 | 737.7 | 713.5 | 713.5 |
| Penalty / reward | 0.0 | 0.0 | -3.4 | -2.1 | -2.1 |
| **SAIFI – CBD (interruptions per annum)** | | | | | |
| Target | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Performance | 0.0 | 0.1 | 0.2 | 0.3 | 0.3 |
| Penalty / reward | 0.0 | 0.0 | -0.3 | -0.3 | -0.3 |
| **SAIFI – Urban (interruptions per annum)** | | | | | |
| Target | 0.0 | 0.0 | 1.1 | 1.1 | 1.1 |
| Performance | 1.0 | 1.0 | 1.1 | 1.1 | 1.1 |
| Penalty / reward | 0.0 | 0.0 | -1.6 | -1.3 | -1.3 |
| **SAIFI – Rural Short (interruptions per annum)** | | | | | |
| Target | 0.0 | 0.0 | 2.0 | 2.0 | 2.0 |
| Performance | 1.6 | 1.8 | 2.1 | 1.9 | 1.9 |
| Penalty / reward | 0.0 | 0.0 | -1.5 | 0.2 | 0.2 |
| **SAIFI – Rural Long (interruptions per annum)** | | | | | |
| Target | 0.0 | 0.0 | 4.3 | 4.3 | 4.3 |
| Performance | 4.0 | 3.8 | 3.8 | 4.3 | 4.3 |
| Penalty / reward | 0.0 | 0.0 | 2.9 | 0.2 | 0.2 |

### *Adjustments against call centre SSAM targets*

1202. Western Power has incurred an overall $0.2 million penalty under the SSAM for performance against the call centre service standard targets during the AA4 period. Table 11.18 shows performance compared with the service standard target and the associated financial penalty or reward.

**Table 11.18: Call centre performance due to the SSAM adjustments, $ million real at 30 June 2022[205]**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| **Call centre performance (per cent of calls responded to within 30 seconds)** | | | | | |
| Target | 0.0 | 0.0 | 92.0 | 92.0 | 92.0 |
| Performance | 91.7 | 91.7 | 92.6 | 91.9 | 91.9 |
| Penalty / reward | 0.0 | 0.0 | 0.2 | 0.0 | 0.0 |

205 2021/22 service standard performance is assumed to the same as 2020/21 performance. This will be updated to include the actual 2021/22 service standard performance at the end of the AA4 period.

### 11.8.4 D-factor

1203. Section 7.6 of the current access arrangement permits Western Power, in certain circumstances, to recover non-capital costs through the D-factor scheme. Western Power seeks an adjustment to target revenue for the AA5 period of $42.2 million. This is to recover the costs associated with network control services in Ravensthorpe, Bremer Bay, North Country, Eastern Goldfields and Meadow Springs.

1204. In accordance with the requirements of the access arrangement, the opex associated with these network control services relates to demand management or a generation solution that would otherwise require network augmentation. We consider this opex is compliant with the requirements of Sections 6.40 and 6.41 of the Access Code. Further information on the network control services is included in the D-factor compliance summaries provided as Confidential Attachments 11.2 through to 11.6.

**Table 11.19: D-factor adjustment, $ nominal[206]**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Ravensthorpe | 0.6 | 0.6 | 0.6 | 0.5 | 0.5 |
| North Country | 0.0 | 2.7 | 4.2 | 5.3 | 3.8 |
| Eastern Goldfields | 0.0 | 2.5 | 3.2 | 4.0 | 4.0 |
| Bremer Bay | 0.2 | 0.5 | 0.3 | 0.3 | 0.3 |
| Meadow Springs | 0.0 | 0.0 | 0.3 | 0.1 | 0.0 |
| **Total adjustment** | **0.8** | **6.3** | **8.5** | **10.2** | **8.6** |

### 11.8.5 Unforeseen events

1205. Section 6.6 of the Access Code and section 7.1 of the current access arrangement permit Western power, in certain circumstances, to include unforeseen costs resulting from a force majeure event in the target revenue for the next access arrangement period.

1206. Western Power has assessed the costs related to unforeseen force majeure events that occurred over the AA4 period and determined there is no need for an adjustment to target revenue for the AA5 period.

### 11.8.6 Technical Rules changes

1207. Western Power has assessed the Technical Rules changes that occurred over the AA4 period and determined there is no need for an adjustment to target revenue for the AA5 period.

## 11.9 AMI communications

1208. Western Power proposes an adjustment of $66.5 million for AMI communications expenditure incurred prior to 30 June 2022.

1209. The Access Code was amended in September 2020 to include an allowance in the target revenue for the recovery of prior AMI communications expenditure over a 10 year period commencing from the next access arrangement period.

1210. Section 6.5G of the Access Code states that:

206 2021/22 adjustments based on forecast performance.

*6.5G An amount in respect of AMI communications expenditure must be added to the target revenue for the Western Power Network for each access arrangement period in the AMI recovery period until the full amount referred to in section 6.5F(a) (subject to any adjustments under section 6.5H) has been added.*

1211. Section 6.5F sets out the relevant definitions:

*(a) "AMI communications expenditure" means all expenditure incurred prior to30 June 2022 on and in relation to communications equipment (such as communication access points, modems and network interface cards), information technology systems and supporting equipment and services that are required to enable advanced metering functionality. For the purposes of this section, AMI communications expenditure is $115.36 million (expressed in real dollar values as at 30 June 2017); and*

*(b) "AMI recovery period" means a period of 10 years commencing on the next revisions commencement date following the date of the 2020 (No. 2) amendments.*

*{Note: The 2020 (No. 2) amendments came into effect on 18 September 2020.}*

1212. The proposed adjustment represents the amount specified in the Access Code, adjusted for the time value of money and inflation, consistent with the requirements of section 6.5H of the Access Code.

## 11.10 TEC

1213. The target revenue for the AA5 period includes $953.0 million (nominal) for the TEC in line with the requirements of sections 6.4(a)(vii) and 6.37A of the Access Code. Section 6.37A and 7.12 of the Access Code enables the TEC to be recovered from users of Western Power's distribution network.

1214. Consistent with the approach approved for the AA4 period, Western Power proposes to recover the TEC from distribution customers with demand less than 7,000 kVA. Customers with demand greater than 7,000 kVA do not pay the TEC as these customers can usually choose between being connected to the transmission or the distribution network. Charging the TEC to distribution-connected users with demand greater than 7,000 kVA may create an incentive for those users to change to being connected to the transmission network in order to avoid being charged for the TEC. A high number of customers switching from the distribution to the transmission network could result in additional costs that would ultimately be paid for by the wider customer base.

1215. The State Government periodically gazettes the TEC amounts. Given the potential changes that may occur to the TEC over the AA5 period, the price control formula for the distribution system includes an explicit pass-through element for the TEC.

1216. The forecast TEC over the AA5 period aligns with the TEC forecast in the State Budget and is shown in Table 11.20. At the time of this submission the TEC requirement for the entire AA5 period has not been gazetted by the Government.

**Table 11.20: Forecast TEC for the AA5 period, $ million nominal**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| TEC | 189.0 | 188.0 | 192.0 | 192.0 | 192.0 |

## 11.11 Recovery of deferred revenue

1217. As part of the ERA's access arrangement decision for the AA2 period, revenue amounts were deferred to future access arrangement periods for both distribution and transmission. Western Power proposes to recover $182.9 million of this deferred revenue during the AA5 period. This amount has been determined on the recovery methodology previously approved in prior access arrangement periods.

1218. Amendments to the Access Code were gazetted in July 2021 to allow Western Power to expedite the recovery of this revenue from network users during the AA5 period, up to a level that results in flat nominal prices for customers. The ERA's decision on Western Power's forecast expenditure and WACC will determine the level of AA2 deferred revenue that will be recovered during the AA5 period.[207] Therefore, the proposed value for the deferred revenue recovery is subject to change.

1219. Western Power considers that accelerated recovery of AA2 deferred revenue will be treated as a balancing item in the ERA's Final Decision adjusting the weighted average tariff outcome to be flat to compensate for potential reductions in other building blocks. That is, if the weighted average tariff outcome results in prices lower than existing rates, an amount of AA2 deferred revenue that brings prices back in line with existing rates will be permitted to be added to the target revenue for the AA5 period.

1220. The roll forward of these amounts from the opening of the AA4 period to the closing of the AA5 period is shown in the tables below, along with the revenue being recovered in the AA5 period.

**Table 11.21: Transmission deferred revenue roll forward over the AA4 period, $ million real as at 30 June 2021**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Opening deferred revenue | 101.4 | 100.6 | 99.7 | 98.7 | 97.7 |
| Less principal recovered | 0.8 | 0.9 | 1.0 | 1.0 | 1.1 |
| **Closing deferred revenue value** | **100.6** | **99.7** | **98.7** | **97.7** | **96.7** |

**Table 11.22: Transmission deferred revenue roll forward over the AA5 period, $ million real as at 30 June 2021**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Opening deferred revenue | 96.7 | 95.4 | 94.0 | 92.5 | 91.0 |
| Less principal recovered | 1.3 | 1.4 | 1.5 | 1.6 | 1.6 |
| **Closing deferred revenue value** | **95.4** | **94.0** | **92.5** | **91.0** | **89.3** |
| Revenue recovered through tariffs | 4.2 | 4.0 | 3.9 | 3.9 | 3.8 |

**Table 11.23: Distribution deferred revenue roll forward over the AA4 period, $ million real as at 30 June 2021**

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| Opening deferred revenue | 748.7 | 739.4 | 729.8 | 719.4 | 708.5 |
| Less principal recovered | 9.3 | 9.6 | 10.4 | 10.9 | 11.3 |

207 Consistent with section 6.5D of the *Electricity Networks Access Code 2004.*

| | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 |
|---|---|---|---|---|---|
| **Closing deferred revenue value** | **739.4** | **729.8** | **719.4** | **708.5** | **697.2** |

**Table 11.24: Distribution deferred revenue roll forward over the AA5 period, $ million real as at 30 June 2021**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Opening deferred revenue | 697.2 | 683.8 | 669.6 | 654.6 | 638.9 |
| Less principal recovered | 13.4 | 14.3 | 15.0 | 15.7 | 16.2 |
| **Closing deferred revenue value** | **683.8** | **669.6** | **654.6** | **638.9** | **622.6** |
| Revenue recovered through tariffs | 34.0 | 33.0 | 32.4 | 32.0 | 31.6 |

## 11.12 Tax allowance

1221. Western Power's revenue requirement for the AA5 period includes an allowance for expected corporate income tax. A notional whole of business AA5 tax expense is calculated taking into consideration forecast revenue, opex, interest on debt, tax depreciation and TEC allowances.

### 11.12.1 Tax asset base

1222. The TAB is a key input into the calculation of the tax building block, as it determines the depreciation deduction for tax purposes. Western Power has calculated the TAB using the roll-forward method, consistent with the approach for the RAB.

1223. The estimate of the closing TAB for the AA5 period takes into consideration:

- forecasts of new facilities investment (capex)
- forecasts of capital contributions
- inflation assumptions
- forecasts of depreciation
- economic lives of assets.

1224. The estimate of the closing TAB for the AA5 period uses the same inflation assumptions as used for determining the WACC for the AA5 period. Forecast capex over the AA5 period is in real dollars at 30 June 2022. Depreciation for the TAB is calculated using the diminishing value method.

1225. Table 11.25 shows the closing AA4 TAB and our estimate of the closing TAB for the AA5 period, split by transmission and distribution.

**Table 11.25: Western Power closing TAB for the AA4 and AA5 period, $ million nominal**

| Regulated tax asset base | Estimated closing value for the AA4 period (as at 30 June 2022) | Estimated closing value for the AA5 period (as at 30 June 2027) |
|---|---|---|
| Transmission TAB | 2,551.9 | 2,870.1 |
| Distribution TAB | 5,900.3 | 7,432.5 |
| **Total Western Power TAB** | **8,452.2** | **10,302.5** |

1226. Details of the TAB calculations, including the associated forecast depreciation and asset lives, are provided in Attachment 11.1 – AA5 Regulatory Revenue Model.

### 11.12.2 Estimate of tax allowance

1227. To estimate the cost of corporate income tax, we have used the current corporate tax rate of 30 per cent, and a value for imputation credits (gamma) of 0.50.

1228. The following table show the Western Power income tax expense for target revenue services.

**Table 11.26: Estimated cost of corporate income tax for the AA5 period, $ nominal**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Western Power taxable income | 233.0 | 139.2 | 128.9 | 109.7 | 120.6 |
| Estimated cost of corporate income tax | 82.2 | 49.1 | 45.5 | 38.7 | 42.6 |
| Less value of imputation credits | **-41.1** | **-24.6** | **-22.7** | **-19.4** | **-21.3** |

## 11.13 Target revenue

1229. Western Power's target revenue for the AA5 period is set out in Table 11.27.

**Table 11.27: Target revenue for the AA5 period, $ million nominal**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Operating expenditure | 435.1 | 452.7 | 461.2 | 477.0 | 497.1 |
| Depreciation | 231.3 | 248.6 | 291.8 | 323.7 | 367.8 |
| Deferred Revenue Recovery | 39.0 | 38.6 | 38.6 | 38.8 | 39.2 |
| AMI communications | 13.8 | 13.9 | 14.1 | 14.3 | 14.6 |
| Tax Payable | 82.2 | 49.1 | 45.5 | 38.7 | 42.6 |
| Less Value of Imputation Credits | -41.1 | -24.6 | -22.7 | -19.4 | -21.3 |
| Tariff Equalisation Contribution | 189.0 | 188.0 | 192.0 | 192.0 | 192.0 |
| Return on Assets | 529.0 | 537.6 | 553.7 | 570.3 | 586.5 |
| Return on Working Capital | 8.3 | 7.6 | 7.4 | 7.2 | 7.0 |
| IAM Revenue Adjustment | -40.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SSAM Revenue Adjustment | -45.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| Technical Rule Change Revenue Adjustment | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| D-Factor Revenue Adjustment | 43.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GSM Revenue Adjustment | 49.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Target revenue for revenue cap services (unsmoothed)** | **1,494.6** | **1,512.8** | **1,582.8** | **1,644.0** | **1,726.8** |

### 11.13.1 Annual revenue cap

1230. The revenue to be recovered under the revenue cap for each year of the AA5 period reflects the target revenue and the price control formula. The proposed access arrangement specifies formulae that outline how the actual revenue allowances in each year of the AA5 period are built up based on the revenue cap initially determined in the revenue model.

1231. These formulae take the base revenue cap number and adds on the adjustments required for each year, namely for the TEC, to ensure a smooth price path these adjustments are included within the target revenue when setting the price path.

1232. The single price control formula for the AA5 period:

$$TNR_t = NR_t + TEC_t$$

where:

- $TNR_t$ is the maximum total network revenue cap services revenue for each year, t, of the AA5 period
- $NR_t$ is the annual revenue cap services revenue in year t
- $TEC_t$ is an explicit pass-through element to recover the gazetted amounts of TEC.

1233. Table 11.28 shows the network revenue annual parameters for the AA5 period.

**Table 11.28: Total smoothed annual revenue, $ million nominal**

| | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 |
|---|---|---|---|---|---|
| Annual revenue cap services revenue ($NR_t$) | 1,387.4 | 1,413.9 | 1,401.5 | 1,393.0 | 1,384.6 |
| *plus* TEC | 189.0 | 188.0 | 192.0 | 192.0 | 192.0 |
| Maximum total network revenue cap services revenue ($TNR_t$) ($ million real at 30 June 2022) | 1,545.1 | 1,538.8 | 1,500.2 | 1,462.6 | 1,425.9 |
| % change in $TNR_t$ | | 0.41% | 2.51% | 2.51% | 2.51% |

1234. Western Power proposes an adjustment to target revenue in the year ended 30 June 2025 to require Western Power to recover the difference, be it higher or lower, between the approved target revenue for the first year of AA5, being the year ended 30 June 2023, and the actual revenue received from applying the price list for the year ended 30 June 2022 in that first year of AA5. This adjustment is required due to the target commencement date of AA5 being 1 July 2023 and the framework and approach decision that Western Power's current price list will apply until the advised access arrangement comes into effect.

### 11.13.2 Annual update of WACC

1235. The use of a trailing average cost of debt means the WACC will need to be updated annually over the course of the AA5 period.[208] This means the revenue caps outlined above are subject to change each year.

1236. Consistent with the approach to an annual WACC update adopted for the AA4 period, it is expected that when Western Power is preparing a Price List for the coming financial year a new cost of debt and hence WACC is calculated. The revenue model will then re-determine the revenue caps for the remaining years of the AA5 period.

1237. Part of this re-determination will include updated values for $NR_t$ needed to determine pricing.[209] The first year that this process is likely to occur is 2024/25. The updated values for each of the terms will be specified in the relevant Price List Information.

1238. It is not expected that the annual updating process will materially change the $NR_t$ value. The debt risk premium (**DRP**) is a 10-year rolling average, which means that only one of the 10 years that make up the overall value is being updated each year. Therefore, it is not proposed to update the revenue at risk amounts for the determination of the SSAM rewards and penalties. The values approved in the access arrangement will remain in place for the AA5 period, despite the revenue caps changing.

208 As discussed in Chapter 10 of this AA5 proposal.

209 Note that the terms $TX_t$ and $DX_t$ are discussed in Chapter 12 of this AA5 proposal.

# 12. Price path and network tariffs

1239. This chapter outlines Western Power's tariff structure statement, providing an overview of network tariffs and average price path for the AA5 period. It also includes discussion of reference services and the corresponding reference tariff changes as well as the introduction of new tariffs.

**Key Messages**

- Our access arrangement now includes a tariff structure statement (TSS) that provides information on the tariff structure and charging parameters, the approach applied to set tariffs and a forecast of how tariffs are expected to change over the period
- We are seeking to improve the efficiency of our tariff structures to enable customers to benefit from using our network more efficiently and better inform decisions about adopting new technologies. This should reduce the costs to all customers over time.
- Average price changes over the period will be less than inflation or less than 1 per cent per annum in nominal terms

## 12.1 Overview of price path and network tariffs proposal

1240. Amendments to the Access Code as part of the Energy Transformation Strategy included new requirements for Western Power to include certain information on tariffs in our access arrangement and the principles we are required to follow when setting reference service tariffs. The new requirements are intended to provide greater flexibility and clarity for setting tariffs for all our customers and greater transparency on how costs are allocated to each of our reference services.

1241. Consistent with the changes to the Access Code, Western Power is required to include a tariff structure statement (**TSS**) in our access arrangement. When developing and setting our tariffs, Western Power is required to:

- include a reference tariff change forecast that sets out the forecast change in each tariff for each year of the AA5 period. The forecast facilitates consultation during the AA5 review on the price path for each reference service tariffs. The TSS will be the reference point against which the ERA will evaluate each of our price lists for the AA5 period
- ensure that each tariff is cost reflective
- accommodate the reasonable preferences of our customers when designing our tariff structures and ensure the structures can be understood by our customers in context of information provided to them during our engagement program. Western Power conducted consultation with stakeholders in the preparation of the TSS for the AA5 period, as summarised in section 12.3.

1242. This chapter outlines Western Power's TSS, providing an overview of network tariffs and average price path for the AA5 period. The full TSS is provided at Appendix F.1 – Tariff Structure Statement Overview and Appendix F.2 – Tariff Structure Statement Technical Summary.

## 12.2 Regulatory requirements

1243. The Access Code requires Western Power's access arrangement to include a TSS and reference tariff change forecast. The TSS must include:

- the structure and charging parameters for each distribution reference tariff

- a description of the approach that will be applied to set each distribution reference tariff during the access arrangement period
- evidence that the approach complies with the Access Code
- a forecast weighted average annual price change over the period for each distribution reference tariff.

1244. While the Access Code only includes a requirement for the TSS to include distribution tariffs, Western Power has also included transmission and ancillary services in the TSS for completeness.

### 12.2.1 Elements of a TSS

1245. Section 7.1A specifies the requirements of a TSS.

> *7.1A A tariff structure statement of a service provider of a covered network must set out the service provider's pricing methods, and must include the following elements:*
>
> *a) the structures for each proposed distribution reference tariff*
>
> *b) the charging parameters for each proposed distribution reference tariff, and*
>
> *c) a description of the approach that the service provider will take in setting each distribution reference tariff in each price list of the service provider during the relevant access arrangement period in accordance with sections 7.2 to 7.12.*
>
> *7.1B A tariff structure statement must comply with:*
>
> *a) the pricing principles, and*
>
> *b) any applicable framework and approach.*
>
> *7.1C A network service provider must comply with the tariff structure statement approved by the Authority and any other applicable requirements in this Code when the service provider is setting the reference tariffs for reference services.*
>
> *7.1D A tariff structure statement must be accompanied by 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.*

### 12.2.2 Pricing methods

1246. Section 4.3 of the Access Code requires Western Power to include:

> *a) information detailing and supporting the price control in the access arrangement; and*
>
> *b) information detailing and supporting the pricing methods in the access arrangement, including:*
>
> *(i) a description (with supporting materials) of how the proposed tariff structure statement complies with the pricing principles including:*
>
> *A. a description of where there has been any departure from the pricing principles set out in sections 7.3D to 7.3H, and*
>
> *B. an explanation of how that departure complies with section 7.3B, and*
>
> *(ii) a description of how the service provider has engaged with users and end-use customers in developing the proposed tariff structure statement and has sought to address any relevant concerns identified as a result of that engagement, and*

*c) if applicable, information detailing and supporting the measurement of the components of approved total costs in the access arrangement, and*

*d) information detailing and supporting the service provider's system capacity and volume assumptions, and*

*e) any other information specified in the guidelines made under section 4.5.*

1247. Section 7.2 of the Access Code allows Western Power to include any pricing methods in our TSS as long as they collectively meet the Access Code's pricing objectives and comply with other pricing method and TSS requirements.

1248. Section 7.3 of the Code defines the pricing objective:

*7.3 Subject to sections 7.7 and 7.12, the pricing methods in a tariff structure statement must have the objective (the "pricing objective") that the reference tariffs that a service provider charges in respect of its provision of reference services should reflect the service provider's efficient costs of providing those reference services.*

1249. While the Access Code allows Western Power to use any pricing methods to structure reference service tariffs as long at the methods meets the pricing objectives and other relevant Access Code pricing method requirements, Western Power is expected to apply certain methods unless alternative methods would better achieve the Access Code objective. Section 7.6 of the Access Code specifies:

*7.6 Unless a tariff structure statement containing alternative pricing methods would better achieve the Code objective, for a reference service:*

*a) the incremental cost of service provision should be recovered by tariff components that vary with usage or demand, and*

*b) any amount in excess of the incremental cost of service provision should be recovered by tariff components that do not vary with usage or demand.*

### 12.2.3 Pricing principles

1250. The Access Code requires our reference service tariffs to comply with the pricing principles. Recent amendment to the Access Code revised the pricing principles.

1251. The revised pricing principles are outlined below:

*7.3G Each reference tariff must be based on the forward looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:*

*a) The additional costs likely to be associated with meeting demand from end-use customers that are currently on that reference tariff at times of greatest utilisation of the relevant part of the service provider's network, and*

*b) The location of end-use customers that are currently on that reference tariff and the extent to which costs vary between different locations in the service provider's network.*

*7.3H The revenue expected to be recovered from each reference tariff must:*

*a) Reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff* *b) When summed with the revenue expected to be received from all other reference tariffs, permit the service provider to recover the expected revenue for the reference services in accordance with the service provider's access arrangement, and*

*c) Comply with sections 7.3H(a) and 7.3(b) in a way that minimises distortions to the price signals for efficient usage that would result from reference tariffs that comply with the pricing principle set out in section 7.3G.*

*7.3I The structure of each reference tariff must be reasonably capable of being understood by customers that are currently on that reference tariff, including enabling a customer to predict the likely annual changes in reference tariffs during the access arrangement period, having regard to:*

*a) the type and nature of those customers*

*b) the information provided to, and the consultation undertaken with, those customers.*

## 12.3 Approach to developing prices

1252. Western Power's TSS explains our approach to setting prices under the new pricing framework, as set out in the Access Code. The key amendments to the pricing framework require Western Power to comply with a single pricing objective that our reference tariffs should reflect our efficient costs of providing our reference services, and new pricing principles.

1253. We have developed our reference tariffs to promote economic efficiency by signalling to our customers the future network costs that can be avoided through their behaviour. Economic efficiency is focused on future costs because it is only future network costs that can be avoided.

1254. Signalling to customers our future network costs through efficient price signals will:

- encourage customers to use our network more when it does not increase our costs
- empower customers to decide whether an installation behind their meter (e.g. solar panels, batteries or more efficient appliances), participation in community battery schemes or some other change in their behaviour will better meet their needs, or the needs of other customers, at a lower cost
- promote the role of our network as a platform for sharing and accessing electricity, while meeting customers' evolving needs
- promote fairness between adopters and non-adopters of new technologies
- indicate the areas where customers value further investment in network capacity or capability, i.e. where there is not a lower cost non-network solution
- enable the connection of more renewable generation, supporting jobs, growth, and decarbonisation.

1255. We explain how our tariffs achieve these outcomes in the TSS.

1256. Achieving these outcomes through efficient tariffs has never been more important since:

- customers have more control over their electricity use (and bills) than ever before
- the way customers use our network is changing, as customers support the transition to renewable energy by adopting DER
- the drivers of our future efficient costs are changing

- there is some uncertainty as to the future services and technology mix that will best meet our customers' needs and how the new technologies will interact.

1257. It is therefore imperative that our tariffs reflect our role as a network service provider, while also best meeting customers' evolving needs. In practice, this means signalling to customers the network benefits and future costs that arise from their decisions.

1258. Consistent with the Access Code, Western Power's methodology for designing our tariff structures aligns with the new pricing principles in sections 7.G-I of the Access Code. Figure 12.1 sets out the key principles we applied in developing our TSS.

**Figure 12.1: Key principles underlying the TSS**

| | |
|---|---|
| Marginal cost | Each tariff must be based on forward-looking efficient costs |
| Revenue recovery | The revenue recovered from a tariff must:<br>• reflect the total efficient cost of serving the customer<br>• minimise distortions to price signals for efficient use |
| Bounds | The revenue recovered from each tariff must fall between the standalone and avoidable cost of serving those customers |
| Customer preferences | Tariff structures must reflect the reasonable requirements of users and end-use customers, so far as is consistent with the code objective |
| Simplicity | Tariff structures must be reasonably capable of being understood by customers |

### 12.3.1 Methodology for determining distribution costs and setting our distribution tariffs

1259. The methodology we apply to set prices for reference tariffs has no effect on the level of revenue we expect to recover from our customers, which is based on our efficient costs and is approved by the ERA. However, setting prices is important for our customers because it is how we:

- promote the efficient use of our network, which benefits all our customers
- determine the share of our efficient costs to be recovered from different customers, i.e. the network component of each customer's electricity bill.

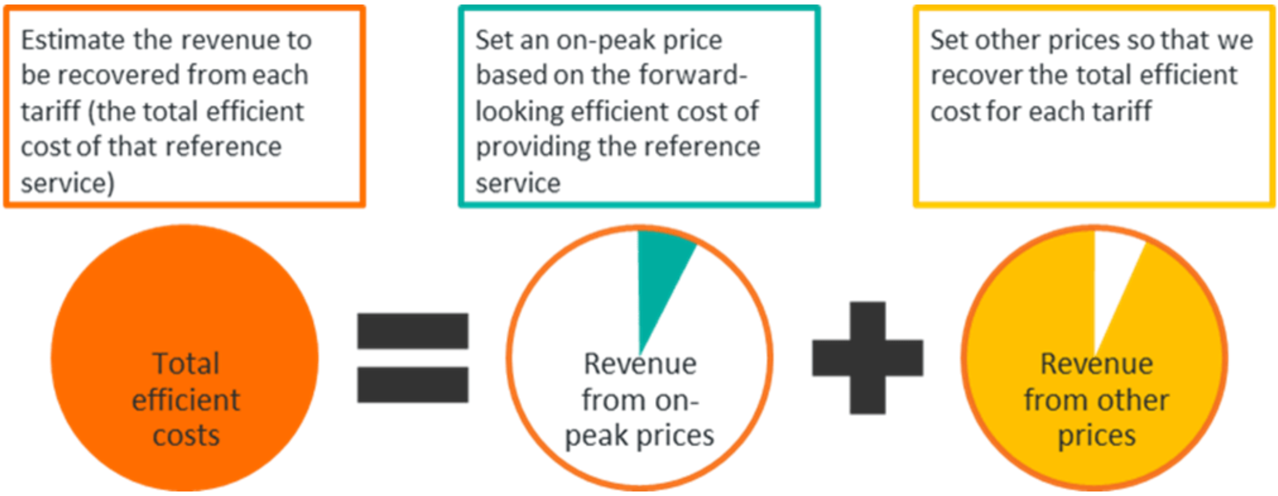
1260. At the highest level, our approach involves:

- setting a price for each reference tariff – typically the on-peak price[210] – based on the future network costs that can be avoided (or caused) by changing the use of our network during the on-peak period and
- setting the remaining prices for a reference tariff – e.g. fixed and other variable charges – so that we can (in total) recover the total efficient cost of providing the applicable reference service.

210 Outside of periods of very high demand, additional demand typically does not cause an increase in our future costs, because it can be served by existing, excess capacity.

1261. We illustrate this framework and the relationship between these steps, in Figure 12.2

**Figure 12.2: Illustration of new tariff framework**




1262. We describe the application of this framework in the TSS.

### 12.3.2 Our engagement with customers and stakeholders to develop our prices

1263. Consultation was a key element when developing our TSS. Western Power is required to accommodate the reasonable preferences of our customers when designing our tariff structures and ensure the structures can be understood by our customers in context of information provided to them during our engagement program.

1264. Western Power conducted consultation with stakeholders in the preparation of the TSS for the AA5 period. During Western Power's engagement with our customers on the development of our TSS, we focused on:

- elements that users and end-use customers can influence in the TSS
- explaining network tariffs in simple terms and their relationship to retail tariffs
- clearly communicating what a TSS is and why Western Power is required to develop one
- providing an explanation on how the TSS process will improve bill certainty.

1265. Table 12.1 summarises the key themes raised by customers during consultation, and how we have responded.

**Table 12.1: What our customers told us and how we responded**

| Key theme | What users told us | What end-use customers told us | How we responded |
|---|---|---|---|
| Tariffs | Would like more information on:<br>• the cost breakdown for tariffs<br>• ability to explain to customers how their network tariffs are developed<br>• how network tariffs are able to accommodate the variable nature of renewables.<br>A key challenge identified was that the move to more fixed costs means some users will pay more. | • Tariffs can be very confusing and Western Power needs to provide information that is easy to understand.<br>• Little awareness and knowledge of how costs are structured in power bills.<br>• Fairness is important – don't want to pay more than their fair share.<br>• Equity is important – would higher fixed costs impact all customers equitably? | • Our TSS is intended to provide accessible information to all network users and end-use customers<br>• Our TSS will provide transparent information on the methodology that we will apply to develop tariff structures and price levels, including in relation to facilitating the uptake of new technologies |
| Cost reflectivity | • Cost reflectivity is very important. Encourages efficient network usage, efficiency of supply and fairness. | • Not clear on the benefits of cost reflectivity.<br>• Questions were raised around solar PV no longer being incentivised and equity across customer groups.<br>• A positive was that it would potentially encourage better energy use behaviours. | • The TSS is designed to improve cost reflectivity. We are transitioning our variable charges down to levels that signal our future costs, offset by only gradual increases in fixed charges<br>• We are introducing new tariff structures that encourage solar soaking to facilitate more generation from solar PV<br>• We are signalling our future costs to customers through variable charges |
| Transition path | • Split 50/50 on how quickly to transition to cost reflectivity, depending on the size of the increase.<br>• A small percentage thought there should not be any change at all. | • The first reference group session was strongly in favour of transitioning quickly.<br>• After this was tested further with specific customer scenarios, the feedback changed to a slow and gradual increase, and the need for Western Power to clearly explain any changes. | • Western Power supports a slower transition to avoid any sudden price movements for its Users<br>• We are transitioning our allocation of costs to reference tariffs slowly, since these changes can have material effects on customer's network bills |

| Key theme | What users told us | What end-use customers told us | How we responded |
|---|---|---|---|
| Cap on annual transition | • Users support a transition cap that applies to a users' total, or bundled network bill, with regard also given to the contribution of the revenue target to changes in price.<br>• Most users support a slower transition cap | • The first reference group session was strongly in favour of the annual percentage change being applied all at once.<br>• After this was tested further with specific customer scenarios, the feedback changed to a slow and gradual increase, and the need for Western Power to clearly explain any changes. | • We have adopted a cap of 2 per cent in the TSS |

## 12.4 Average price path

1266. Target revenue for the AA5 period is $7,472.6 million. We have translated the target revenue for revenue cap services into an average price path over the five years of the AA5 period. The price path is determined by smoothing the revenue over the AA5 period while retaining the net present value of the total target revenue.

1267. The smoothed revenue in any year may not reflect the underlying building block components of that year, however the total value of revenue is retained over the AA5 period in present value terms. This smoothed revenue profile may be affected by the following:

- forecast energy consumption over the AA5 period
- the average price path over the AA4 period
- predictable changes in average price during the AA5 period.

1268. It is normal regulatory practice to adjust the building blocks target revenue to enable a more predictable (and less volatile) price path by smoothing the revenue. Smoothing is required because the target revenue calculated through the building block methodology may result in the revenue moving up or down throughout the period.

1269. The smoothing process benefits customers by providing greater visibility of future pricing and minimising price volatility within period. A new requirement in section 7.3H of the Access Code requires Western Power to minimise distortions to price signal for efficient usage. This effectively enables any tariff-rebalancing required to bring tariffs in line with efficient costs to be smoothed over the AA5 period. Smoothing also ensures that, in present value terms, over the course of the access arrangement period target revenue is equivalent to the sum of the revenue cap allowed in each year.

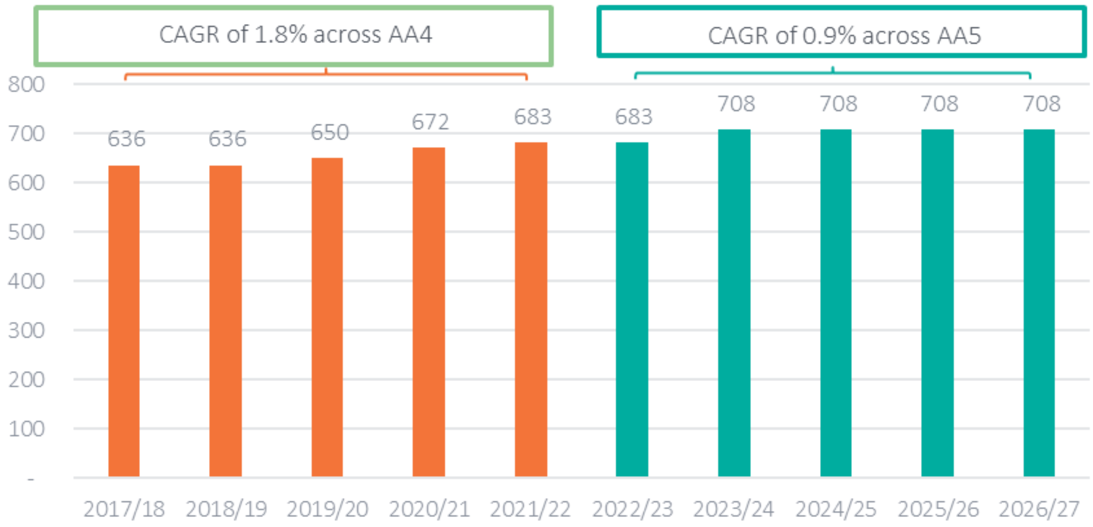
### 12.4.1 Average nominal price movement

1270. This AA5 period proposal results in an average nominal price increase of 0.9 per cent per cent per year[211]. For the AA4 period, the nominal increase in average nominal prices was 1.8 per cent per cent each year.

[211] Combined average of transmission and distribution tariffs.

1271. Figure 12.3 shows the estimated average nominal price path over the AA4 and AA5 periods for the average residential customer.[212]

**Figure 12.3: Estimated average nominal network price movements over the AA4 and AA5 periods for residential customers, excluding the TEC[213]**




### 12.4.2 Transition path for prices in the AA5 period

1272. For the AA5 period, there will be a single price control, consistent with the ERA's Final Decision on the framework and approach. That is, individual tariff movements are governed by a single constraint, which is a change from the AA4 period where we had separate price controls for the transmission and distribution network.

1273. Our single price path has been developed to transition towards cost-reflective tariffs. Our proposed path:

- has been developed in line with customer preference and regulatory precedent
- increases the proportion of fixed charge compared to variable charges
- results in a moderate move towards cost reflective prices.

1274. Changes in the prices that comprise each tariff are generally driven by:

- the total efficient cost of operating our network (our target revenue), as approved by the ERA
- our forecast of customer numbers, energy and demand
- improving the efficiency of our tariffs, which we propose to implement gradually to manage the effects on customers.

1275. To manage the potential effects on customers of moving to more efficient tariffs, we will aim to limit the increase in the average price of a tariff to no more than 2.0 per cent on top of the change that is required to recover our ERA-approved efficient costs (or revenue target).

1276. The methodology in our TSS will only be applied in the second year of the AA5 period (from 1 July 2023) and, in the first year of the AA5 period, our prices will remain unchanged from the final year of the AA4 period. We expect that this will not lead to the recovery of our total efficient costs in year one, which will in

212 Excluding the TEC

213 Final pricing will be subject to updated information as it becomes available prior to final determination.

turn require the difference to be made up in year two, i.e. through a 3.7 per cent increase in our target revenue.

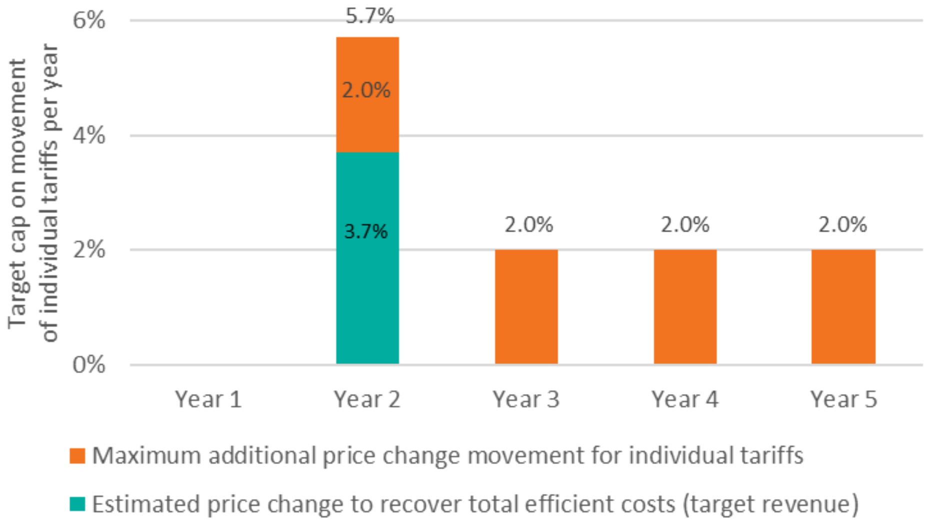
1277. We expect our efficient costs (or target revenue) to be flat from year two onwards.

1278. As a consequence, we will aim to limit the average change in price in constant dollar terms, for any tariff to no more than:

- 5.7 per cent in year two (2023/24) – i.e. 3.7 per cent plus 2.0 per cent
- 2.0 per cent in each subsequent year.

1279. Figure 12.4 shows the proposed average nominal network price path and the tariff movement cap over the AA5 period.

**Figure 12.4: Proposed maximum nominal network price path and tariff movement cap, excluding TEC**




1280. It is important to highlight that the target maximum caps above would apply only to tariffs that need to increase in price, and not all tariffs that need to increase in price will increase up to the cap. Some tariffs will decrease during AA5. The average expected movement by tariff is provided in the TSS Overview at Appendix F.1.

1281. The network tariffs are only one component of the electricity bill customers pay, the other key components being the generation and retailer costs. Excluding the TEC, the Western Power network tariff accounts for one of three core total costs associated with the electricity supply chain[214].

1282. The actual impact on customers' retail tariffs resulting from changes in Western Power's network tariffs will depend on how much of any network tariff retailers choose to pass through to customers. Many customers (including all non-contestable residential and small business customers) in the SWIS purchase their electricity supply from Synergy. Synergy's retail tariffs are also subject to State Government policy and may not reflect increases in the network tariffs.

[214] The TEC is a cost collected by Western Power and then passed through to Horizon Power. The TEC is designed to help keep prices for regional electricity customers in line with customers services by the Western Power Network and is mandated by State Government.

## 12.5 Reference services and tariffs for the AA5 period

1283. References services are the services Western Power offers to customers who wish to connect to our electricity network. For Western Power, reference services are those services associated with transmitting or distributing electricity. The prices, standards, and terms and conditions for these services are covered by Western Power's access arrangement. Our reference services for the AA5 period are consistent with the ERA's Final Decision on the framework and approach[215], and are discussed in detail in Chapter 6.

1284. Reference services covered by an access arrangement must have an associated reference tariff, SSBs and a standard access contract. Therefore, reference services are only offered to customers who hold a standard access contract. At Western Power the standard access contract is the Electricity Transfer Access Contract (**ETAC**).

1285. ETAC holders are typically generators, retailers and large loads. Though residential and small business customers are users of the network, these customers do not have an ETAC. Instead, the electricity retailer holds the ETAC on behalf of customers.[216] Where a customer wishes to access the network, the retailer nominates the reference service Western Power is to provide. The retailer then pays the associated network reference tariff and passes those costs on to the end customer via the retail tariff.

1286. Although the retailer is the ETAC holder (and pays the reference tariff), Western Power is still providing transmission and distribution services to all customers. Consistent with the ERA's Final Decision on the framework and approach and as outlined in Chapter 6, Western Power will retain most of the same reference services as provided during the AA4 period. We are consolidating six AA4 reference services into two reference services and will be providing 16 new reference services in the AA5 period. Each reference service has a corresponding reference tariff in the proposed access arrangement.

1287. We are proposing the following changes to reference tariffs, based on the reference service changes, for the AA5 period:

- introducing four new tariffs with a super off-peak period
- introducing three new tariffs for grid-connected batteries
- introducing two new tariffs for dedicated EV charging stations.

1288. Table 12.2 shows the reference tariffs for the AA5 period.

**Table 12.2: Summary of reference tariffs for the AA5 period**

| Service | Reference tariff | Reference service | Existing, consolidated or new services |
|---|---|---|---|
| A1 | RT1 | Anytime Energy (Residential) Exit Service | Existing |
| A2 | RT2 | Anytime Energy (Business) Exit Service | Existing |
| A3 | RT3 | Time of Use Energy (Residential) Exit Service | Existing |
| A4 | RT4 | Time of Use Energy (Business) Exit Service | Existing |
| A5 | RT5 | High Voltage Metered Demand Exit Service | Existing |

215 ERA, *Framework and approach for Western Power's fifth access arrangement review – Final Decision*, 9 August 2021, pg. 24.

216 Reference services provided to residential and small use customers are administered in this way because it enables Western Power to provide reference services to many customers via a single ETAC. It is common in the energy sector to use a standard contract. The alternative would be to have one ETAC per residential customer and small user, which would require more than one million contracts that would largely be the same. This would not be an efficient approach.

| Service | Reference tariff | Reference service | Existing, consolidated or new services |
|---|---|---|---|
| C5 | | High Voltage Metered Demand Bi-directional Service | Existing |
| A6 | RT6 | Low Voltage Metered Demand Exit Service | Existing |
| C6 | | Low Voltage Metered Demand Bi-directional Service | Existing |
| A7 | RT7 | High Voltage Contract Maximum Demand Exit Service | Existing |
| C7 | | High Voltage Contract Maximum Demand Bi-directional Service | Existing |
| A8 | RT8 | Low Voltage Contract Maximum Demand Exit Service | Existing |
| C8 | | Low Voltage Contract Maximum Demand Bi-directional Service | Existing |
| A9 | RT9 | Streetlighting Exit Service (including streetlight maintenance) | Existing |
| A10 | RT10 | Unmetered Supplies Exit Service | Existing |
| A11 | TRT1 | Transmission Exit Service | Existing |
| B1 | RT11 | Distribution Entry Service | Existing |
| B2 | TRT2 | Transmission Entry Service | Existing |
| B3 | RT23 | Entry Service Facilitating a Distributed Generation or Other Non-Network Solution | Existing |
| C1 | RT13 | Anytime Energy (Residential) Bi-directional Service | Existing |
| C2 | RT14 | Anytime Energy (Business) Bi-directional Service | Existing |
| C3 | RT15 | Time of Use Energy (Residential) Bi-directional Service | Existing |
| C4 | RT16 | Time of Use Energy (Business) Bi-directional Service | Existing |
| A12 | R17 | 3 Part Time of Use Energy (Residential) Exit Service | Existing |
| C9 | | 3 Part Time of Use Energy (Residential) Bi-directional Service | Existing |
| A13 | RT18 | 3 Part Time of Use Energy (Business) Exit Service | Existing |
| C10 | | 3 Part Time of Use Energy (Business) Bi-directional Service | Existing |
| A14 | RT19 | 3 Part Time of Use Demand (Residential) Exit Service | Existing |
| C11 | | 3 Part Time of Use Demand (Residential) Bi-directional Service | Existing |
| A15 | RT20 | 3 Part Time of Use Demand (Business) Exit Service | Existing |
| C12 | | 3 Part Time of Use Demand (Business) Bi-directional Service | Existing |
| A16 | RT21 | Multi Part Time of Use Energy (Residential) Exit Service | Existing |
| C13 | | Multi Part Time of Use Energy (Residential) Bi-directional Service | Existing |
| A17 | RT22 | Multi Part Time of Use Energy (Business) Exit Service | Existing |
| C14 | | Multi Part Time of Use Energy (Business) Bi-directional Service | Existing |
| B3 | RT23 | Entry Service Facilitating a Distributed Generation or Other Non-Network Solution | Existing |

| Service | Reference tariff | Reference service | Existing, consolidated or new services |
|---|---|---|---|
| C15 | RT24 | Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution | Existing |
| D1 | RT25 | Supply Abolishment Service | Existing |
| D2 | N/A[217] | Capacity Allocation Service | Consolidated from existing D2, D3, D4 and D5 |
| D6 | RT26 | Remote Load / Inverter Control Service | Consolidated from existing D6 and D7 |
| D8 | RT28 | Remote De-energise Service | Existing |
| D9 | RT29 | Remote Re-energise Service | Existing |
| D10 | RT30 | Streetlight LED Replacement Service | Existing |
| D11 | RT31 | Site visit to support remote re-energise service[218] | New |
| D12 | RT32 | Manual De-energise Service | New |
| D13 | RT33 | Manual Re-energise Service | New |
| A18 | RT34 | Super Off-peak Energy (Residential) Exit Service | New |
| A19 | RT35 | Super Off-peak Energy (Business) Exit Service | New |
| C16 | RT36 | Super Off-peak Energy (Residential) Bi-directional Service | New |
| C17 | RT37 | Super Off-peak Energy (Business) Bi-directional Service | New |
| C18 | RT38 | Low Voltage Distribution Storage Service | New |
| C19 | RT39 | High Voltage Distribution Storage Service | New |
| C20 | TRT3 | Transmission Storage Service | New |
| C21 | RT40 | Low Voltage Electric Vehicle Charging Service | New |
| C22 | RT41 | High Voltage Electric Vehicle Charging Service | New |
| M1 | M1 | Unidirectional, accumulation, bi-monthly, manual | Existing |
| M2 | M2 | Unidirectional, accumulation (TOU), bi-monthly, manual | Existing |
| M3 | M3 | Unidirectional, interval, bi-monthly, manual | Existing |
| M4 | M4 | Unidirectional, interval, monthly, manual | Existing |
| M5 | M5 | Unidirectional, interval, bi-monthly, remote | Existing |
| M6 | M6 | Unidirectional, interval, monthly, remote | Existing |
| M7 | M7 | Unidirectional, interval, daily, remote | Existing |
| M8 | M8 | Bidirectional, accumulation, bi-monthly, manual | Existing |

217 Applicable Reference Tariff: Any applicable lodgement fees payable in accordance with the Applications and Queuing Policy

218 This service is proposed to complement the remote re-energise service, for circumstances where the controller/end-use customer requires on-site support to commence the flow of electricity behind a connection point.

| Service | Reference tariff | Reference service | Existing, consolidated or new services |
|---|---|---|---|
| M9 | M9 | Bidirectional, accumulation (TOU), bi-monthly, manual | Existing |
| M10 | M10 | Bidirectional, interval, bi-monthly, manual | Existing |
| M11 | M11 | Bidirectional, interval, monthly, manual | Existing |
| M12 | M12 | Bidirectional interval, bi-monthly, remote | Existing |
| M13 | M13 | Bidirectional, interval, monthly, remote | Existing |
| M14 | M14 | Bidirectional, interval, daily, remote | Existing |
| M15 | M15 | Unmetered supply, accumulation, bi-monthly, manual | Existing |
| M16 | M16 | One off manual interval read | Existing |
| M17 | M17 | Unidirectional, interval, weekly, manual | New |
| M18 | M18 | Unidirectional, interval, weekly, remote | New |
| M19 | M19 | Bidirectional, interval, weekly, manual | New |
| M20 | M20 | Bidirectional, interval, weekly, remote | New |

1289. The proposed changes to reference tariffs for the AA5 period are outlined below.

### 12.5.1 New tariffs with a super off-peak period

1290. Consistent with the ERA's Final Decision on the framework and approach, we propose to introduce four new super off-peak time of use energy tariffs for residential and business customers using either an exit or bi-directional reference service in the AA5 period.

1291. These tariffs enable a customer-led solution to address the changing drivers of our network costs. They achieve this by including a super off-peak period with a very low variable energy price which encourages customers to shift load to times when supply significantly exceeds demand on our network, i.e. minimum demand events and utilise the network more efficiently.

1292. The super off-peak period will apply for six hours, from 9am to 3pm every day and involve a price that is significantly lower than the peak charge.

1293. The structure of the following tariffs are detailed in the TSS Overview and Technical Summary provided as Appendix F.1 and F.2:

- Super Off-peak Energy (Residential) Exit service – RT34
- Super Off-peak Energy (Business) Exit service – RT35
- Super Off-peak Energy (Residential) Bi-directional service – RT36
- Super Off-peak Energy (Business) Bi-directional service – RT37.

### 12.5.2 New tariffs for grid-connected batteries

1294. Grid-connected batteries can play a key role in the energy market transformation since they can provide a range of services to the wholesale market and assist in avoiding network costs, e.g.:

- exporting during periods of peak demand

- importing during periods of peak energy.

1295. The range of value streams available to grid-connected batteries and their large size also means that they can impose significant costs on the network if the value of those other streams exceeds the future cost they impose on our network.

1296. Consistent with the ERA's Final Decision on the framework and approach, we have included the following tariffs for grid-connected batteries to ensure they operate efficiently on our network:

- LV distribution storage service tariff – RT38; and
- HV distribution storage service tariff – RT39; and
- Transmission storage service tariff – TRT3.

1297. It is important to recognise that efficiency is promoted by a battery (or any customer) providing the service that is most highly valued by the electricity supply chain, which may not necessarily be network services. That is, there may be greater value for using the battery for non-network services.

1298. In this context, the role of our tariffs is to provide the battery with a price signal that enables it to decide whether the provision of network services or other services will produce the highest benefit to the electricity market.

1299. The potential for grid-connected batteries to provide non-network services also means that the battery owners should contribute to the cost of maintaining and operating our network, just as other business customers do.

1300. We describe the structure of our transmission and distribution-connected grid-scale battery tariffs in detail in the TSS Overview and Technical Summary provided as Appendix F.1 and F.2.

### 12.5.3 New tariffs for dedicated EV charging stations

1301. Consistent with the ERA's Final Decision on the framework and approach, we are including a new, technology specific tariff for dedicated Electric Vehicle (EV) charging stations, which will play a key role in the decarbonisation of the transport sector:

- Low Voltage Electric Vehicle Charging Service tariff – RT40; and
- High Voltage Electric Vehicle Charging Service tariff – RT41.

1302. A key challenge with dedicated EV fast-charging stations arises from the tension between:

- their potential to impose significant future network costs due to their very high demand; and
- their low utilisation during the initial uptake of EVs, which can inhibit their ability to pay for the costs they impose on the network.

1303. We describe the structure of our tariffs for dedicated EV fast-charging stations in detail in the TSS Overview and Technical Summary provided as Appendix F.1 and F.2.

### 12.5.4 Transitional time of use services

1304. We are providing 16 transitional time of use services. Our intention, which is consistent with our approach in previous access arrangements, is to continue providing users with our existing time of use reference services if:

- the services were provided at the relevant connection points at the date the AA5 period takes effect, and
- those services continue from the AA5 period effective date.

However, from the AA5 period effective date, the current (transitional) time of use services will be closed for new nominations. Existing connection points under those services will transition to the new time of use service over time as the users transition connection points to alternative services.

## 12.6 Prudent discounts

1305. Western Power proposes no changes to the prudent discounting policy. The current policy will apply for the AA5 period. The prudent discounting policy is provided at section 6.6 of the proposed access arrangement.

1306. Our policy is that a prudent discount may be offered to a user or applicant seeking access to the Western Power Network where they can demonstrate that an alternative option will provide a comparable service at a lower price than that offered by reference services and reference tariffs.

1307. Where a user can demonstrate with sufficient detail[219] that an alternative option will provide a comparable service at a lower price, we may offer a discounted price that is equal to the higher of the:

- cost of the alternative option
- incremental cost of service provision.

1308. This restriction means that the discounted price will not fall below the incremental cost of service provision and in doing so not impose an additional cost on the other users of the covered network.

## 12.7 Discounts for distributed generation

1309. Western Power proposes no changes to the policy on discounts for distributed generation. The current policy will apply for the AA5 period. The policy on discounts for distributed generation is contained in section 6.7 of the proposed access arrangement.

1310. Our policy is that discounted tariffs can be provided where network costs are reduced as a result of an embedded generator connecting to the network. We believe it is appropriate to encourage distributed generation where this leads to a net saving in providing network services to customers.

1311. The discount given to distributed generation is based on our avoided costs from a NPV calculation of the total costs incurred if the generator does not connect, less the total costs incurred if the generator connects. Our policy states that the NPV calculation of total costs should assess the operating and capex requirements under the *'with'* and *'without'* generator connection scenarios over a period of at least 10 years.[220]

1312. Our policy on discounts for distributed generation states that the NPV of the avoided cost is converted to an equivalent annualised discount for a defined period of time. A discount will only be available if the avoided cost calculated from the connecting generator is greater than zero. Our policy on discounts for distributed generation does not prevent the discount exceeding 100 per cent of the user's tariff.

[219] The user or applicant must provide Western Power with sufficient details of the cost of the alternative option to enable the calculation of the annualised cost.

[220] The NPV calculation would ideally extend to 20 years, however data limitations may dictate that a shorter period is more appropriate. A period of no less than 10 years is required by the policy.

# 13. Policies and contracts

1313. This chapter summarises proposed changes to the standard access contract and three policies that form part of Western Power's proposed access arrangement. The Access Code sets out the policies and contracts that must be included in an access arrangement. They include a:

- Standard Access Contract – section 5.1(b)
- Applications and Queueing Policy – section 5.1(g)
- Contributions Policy – section 5.1(h)
- Multi-function Asset Policy – section 5.1(m)

**Key Messages**

- Changes to the Access Code in July 2021 led by Energy Policy WA resulted in amendments being made to the Standard Access Contract, Applications and Queuing Policy and Contributions Policy during the AA4 period
- We have used these transitional polices and contract as the basis for the policies and contract for this AA5 proposal and propose minor amendments to improve clarity and applicability and better deliver outcomes for customers
- The amendments to the Access Code require Western Power to develop a Multi-function Asset Policy as part of its access arrangement to guide how we may use regulated assets to provide new unregulated services. We support the introduction of this policy to share the benefits from multi-function assets with end-use customers, who ultimately pay for the shared network

## 13.1 Overview of policies and contracts proposal

1314. Following stakeholder consultation led by Energy Policy WA in April and May 2021, amendments were made to the Access Code in July 2021 to support the introduction of the constrained network access regime. This reform will facilitate the entry of new generation capacity and technologies that will increase competition with the aim of ultimately benefitting electricity consumers through cheaper and cleaner energy. Constrained network access for entry services (generators) is scheduled to commence from 1 October 2023.

1315. The Access Code amendments resulted in Western Power making consequential changes to the Standard Access Contract[221], AQP and Contributions Policy, which were approved by the ERA.[222]

1316. Changes to the Access Code in September 2020 [223] as part of the Energy Transformation Strategy removed the concept of bare transfers from the Transfer and Relocation Policy and the remaining provisions of that Policy being absorbed into the AQP.[224] The definition of transfer and relocation policy has been retained but amended to refer to the relevant parts of the AQP, to ensure that existing references to the transfer and relocation policy in existing ETACs remain effective.

221 The Standard Access Contract used by Western Power is the Electricity Transfer Access Contract

222 Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code - Improving access to the Western Power network

223 West Australian Government Gazette No 157, 18 September 2020

224 The concept of bare transfers and relocations has been removed as a result of the introduction of the constrained network access regime. Amendments were made to clauses 2.2 and 2.2(e) in the Applications and Queuing Policy to reflect this. Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code - Improving access to the Western Power network, pg. 35.

1317. The updated policies and contract replaced the policies and contract under Western Power's AA4 and apply as transitional documents until the commencement of Western Power's AA5.[225] Western Power has used the transitional polices and contract as the basis for its policies and contract for this AA5 proposal and proposed minor amendments. In most instances, the proposed changes are designed to improve clarity and applicability. Additional changes have been proposed to better deliver outcomes for customers.

1318. Revisions to the policies and contract are discussed in the following sections. Changes to policies and the contract have been identified both internally during the AA4 period and via feedback from external stakeholders.

1319. Change summary reports for each document are provided in Attachments 13.1 to 13.4.

1320. Marked-up versions of the policies and the contract detailing all amendments are provided with the proposed access arrangement.

1321. The changes to the Access Code made in September 2020[226] also included amendments to:

- increase opportunities for new technologies to connect to the Western Power Network
- maximise utilisation of existing network infrastructure
- improve the access arrangement process.

1322. These changes enable the sharing of benefits from multi-function assets. As part of these amendments to the Access Code, Western Power is required to develop a Multi-function Asset Policy as part of its access arrangement to guide how Western Power may use regulated assets to provide new unregulated services.

1323. We have proposed a Multi-function Asset Policy for the AA5 period, consistent with the requirements of the Access Code.

## 13.2 Standard Access Contract

1324. The Standard Access Contract used by Western Power for the provision of reference services to customers is the ETAC. The ETAC outlines the terms and conditions in relation to services, tariffs, invoicing and payment, a customer's provision of financial security, technical compliance, and liability.

1325. The Access Code defines that a standard access contract must be:

*(a) reasonable; and*

*(b) sufficiently detailed and complete to:*

*(i) form the basis of a commercially workable access contract; and*

*(ii) enable a user or applicant to determine the value represented by the reference service at the reference tariff.*

### 13.2.1 Changes to the ETAC during the AA4 period

1326. The ETAC was updated in July 2021 to reflect the new changes made to the Access Code. The updated ETAC is applied as a transitional document until the commencement of Western Power's AA5 (**Transitional ETAC**).

225 Following the commencement of the AA5 period, the transitional documents become the model documents.

226 West Australian Government Gazette No 157, 18 September 2020

1327. The major changes implemented for the Transitional ETAC are summarised below: [227]

- **Constrained network access** – a number of amendments were made in the Transitional ETAC to provide increased certainty to enable Western Power and AEMO to perform their functions under a constrained network access regime, to align the operation of the WEM Rules and the Access Code, and provide clarity for the user. This included amending:
  - clause 3.1 to make it clear that entry services are provided on a constrained basis
  - clause 16.1 to require Western Power to provide network constraint information to AEMO constraints in order for AEMO to operate the constrained market
  - clause 16.2 to allow AEMO to issue directions to users and Western Power in order to perform its functions
  - clauses 16.3 and 25 to allow Western Power to issue directions to users in order to preserve Power System Reliability (as defined in the WEM Rules) and the supply of electricity to customers, which will require the management of emerging network stability issues that will not be managed by security constrained economic dispatch, including voltage and system strength
  - clause 16.4(a) to limit Western Power's liability for the curtailment of users, either by Western Power or by AEMO acting on advice or information from Western Power, except to the extent Western Power has not acted in good faith
  - clause 16.4(b) to limit Western Power's liability where it is performing activities for the operation of the electricity market such as assessments, analysis, or any other work was used in connection with the determination of users' Capacity Credit entitlements (and other entitlements under the WEM Rules)
- **Generator performance standards** – amending the ETAC provisions to:
  - require Western Power and each user to comply with the Technical Rules, registered generator performance standards and associated generator performance standards monitoring plan, so as to incorporate the additional technical obligations of a user who is a transmission connected generator (clause 12.1)
  - permit Western Power to immediately suspend a user if breaches by the user of its registered generator performance standards or the ETAC threaten Power System Reliability or the supply of electricity – but only at the point where Western Power considers this suspension necessary to avoid these impacts (clause 27.3).
- **Bare transfers and assignments** – the changes to the Access Code gazetted on 18 September 2020 removed the concept of bare transfers. For consistency, the following changes to the ETAC were made:
  - clauses 31.1 to 31.3 which addressed the concept of bare transfers were removed
  - application of the provisions of the Transfer and Relocation Policy (part of the Transitional AQP, discussed below) for assignments by a user, which will allow a user to assign the ETAC with Western Power's consent, not to be unreasonably withheld or delayed
  - addition of an assignment clause typical of commercial contracts for assignments by Western Power, which will allow Western Power to transfer rights and obligations under the contract with the consent of the user (which is not to be unreasonably withheld or delayed).

[227] Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code - Improving access to the Western Power network

### 13.2.2 Summary of proposed amendments to the ETAC for the AA5 period

1328. As part of this AA5 proposal Western Power has undertaken a review of the Transitional ETAC. Western Power has proposed minor amendments to the proposed new ETAC for the AA5 period to remove inconsistencies between the AQP and ETAC. This will improve the clarity of both documents, benefitting customers.

1329. All changes and the rationale for the changes are outlined in the change summary report provided in Attachment 13.1. A marked-up version of the ETAC is also provided as Appendix A to the proposed access arrangement.

## 13.3 Applications and Queuing Policy

1330. The AQP details the processes, procedures and requirements for customers seeking and obtaining access to the Western Power Network. The AQP helps Western Power manage customer access applications in an orderly, transparent and fair manner.

1331. The objectives of the AQP are as follows:

(a) *To provide an equitable, transparent and efficient process for assessing the suitability of plant and equipment to connect to Western Power's network and to make access offers based on that assessment; and*

(b) *To undertake assessments and to provide shared network access offers that facilitate access by generators and loads to the WA Electricity Market (WEM) on an economically efficient and non-discriminatory basis that is consistent with WEM requirements, and uses a process that is equitable, transparent and efficient; and*

(c) *Where feasible and cost-effective, to facilitate joint solutions for connection applications.*

### 13.3.1 Changes to the AQP during the AA4 period

1332. During the AA4 period, the AQP was updated to reflect changes made to the Access Code to introduce the constrained network access regime. The updated AQP will apply as a transitional documents until the commencement of Western Power's AA5 (**Transitional AQP**).

1333. The major changes implemented as part of the Transitional AQP are summarised below: [228]

- **Confidential information and publication of information relating to projects –** new confidential information and publication of information provisions were introduced in the Transitional AQP to provide more visibility of generation projects, facilitate transparency, and increase investment confidence:
  - new provisions introduced to allow the following information to be made available to all generation applicants where a connection application is related to generation (including connecting a new facility, modifying an existing facility, or amending the contracted capacity):
    - the requested (and, if applicable, existing) contracted capacity (as appropriate)
    - the location, voltage and arrangement of the proposed/upgraded connection point
    - the fuel type
    - the priority date of the application.

[228] Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code - Improving access to the Western Power network

- new provisions introduced to allow Western Power to share information with AEMO where a connection application is related to generation or large loads (including connecting a new facility, modifying an existing facility, or amending the contracted capacity), including technical information required for AEMO to undertake its system management function.

- **Capacity-related concepts –** the concept of spare network capacity has limited relevance to generators and entry services in a constrained access regime. Accordingly, the following amendments were made in the Transitional AQP:
  - clauses 2.2 and 2.2(e) were updated to incorporate the remaining provisions of the transfer and relocation policy in relation to transfers that are not bare transfers
  - references to spare capacity in clauses 18.2A, 19.3 and 23 were amended to apply only to applications for an exit service
  - clause 18.2A(a)(iii) was amended to limit its application to exit services
  - clause 19.3 was amended to allow Western Power to assess the potential asset configurations (and their cost) to provide the contracted capacity requested by a generator (i.e. the maximum capacity in the absence of constraints) and the contracted capacity (if any) available in the absence of such works instead of assessing spare capacity
  - clauses 24.1, 24.6(c) and 24.8 were amended to limit the references to constraints and spare capacity to exit services only
  - clause 24.6(c) was amended in respect of entry services to replace Western Power's obligation to make offers of spare capacity in the order of priority dates for competing applications with a reference to making access offers in priority date order to the extent Western Power is able having regard to the issue that resulted in applications being deemed competing in the first place
- **Competing application groups** – the concept of competing application groups was retained but modified for constrained network access. The concept is required to accommodate circumstances where one connection application may impede the ability to provide services sought in a second connection application.
- **Applicant specific solutions –** clause 20.3 was amended so that an objection cannot be made on the basis that the applicant specific solution would increase constraints on the network. That is, existing users or applicants would need to point to some impedance other than just greater constraints.
- **Technical Rules –** the definition of the Technical Rules in the Transitional AQP was expanded to include the registered generator performance standards which a transmission connected generator is required to comply with under the WEM Rules. Further, a new provision was added (clause 26(b)) that makes clear that for a generator proposing to connect to the transmission system, Western Power is not obliged to make an access offer until the registered generator performance standards have been determined in accordance with the WEM Rules.

### 13.3.2 Summary of proposed amendments to the AQP in the AA5 period

1334. We have proposed four key changes to the AQP for the AA5 period to improve its application. These amendments have been developed based on our experience and feedback from our customers through the AA4 period.

1335. The main changes address the following matters:

- changing the process to allow a Competing Applications Group (**CAG**) applicant to be transferred to the Applicant Specific Solution
- speed up process involving bypass by an Applicant Specific Solution of competing applicants

- removing inconsistencies between the AQP and ETAC.

1336. All changes and the rationale for the changes are outlined in the change summary report provided in Attachment 13.2. A marked-up version of the AQP is also provided as Appendix B to the proposed access arrangement.

#### *Change process to allow a Competing Applications Group applicant to be transferred to the Applicant Specific Solution*

1337. The CAG process in the AQP details how customers are managed when there are multiple applicants competing for access to the network. The current process does not consider the situation where all but one applicant decides not to proceed in the CAG, negating the requirement for a CAG.

1338. Western Power proposes to introduce a new clause (clause 24.7A(a)(ii)) to the AQP to address this situation. The proposed clause will allow Western Power to provide a notice to the customer advising:

> *(iii) Western Power determines that only one applicant is remaining in a competing applications group [(due to the other applications having been withdrawn or deemed to have been withdrawn or otherwise)] and it gives notice of this to the remaining applicant.*

1339. In this case, the competing applications group may be terminated if the applicant elects to withdraw from the CAG by giving at least 60 days' notice to Western Power.

#### *Speed up process involving bypass by an Applicant Specific Solution of a competing applicant*

1340. The applicant specific solution option (clause 20.3(c)) details how an existing user and competing applicant with an earlier priority date may object to a Western Power provided application- specific solution, on the grounds that it will impede on Western Power's ability to provide covered services to that existing user. The current process and timeframes prevent Western Power from progressing active applications expeditiously and diligently.

1341. Western Power proposes to remove the right of objection from a competing applicant for whom no work has been undertaken for 12 months and to reduce the time limits in each step after completion of the requested study which will result in a cumulative reduction of 40 business days (160 to 120 business days).

#### *Remove inconsistencies between the AQP and ETAC*

1342. Western Power has proposed minor amendments to the AQP to remove inconsistencies between the AQP and ETAC. This will improve the clarity and alignment of both documents, benefitting customers.

## 13.4 Contributions Policy

1343. The Contributions Policy details how Western Power charges customers seeking to establish a new, or upgrade an existing connection to the network.

1344. It is important that the Contributions Policy meets the needs and interests of Western Power as well as our customers and stakeholders. The objectives of the Contributions Policy as defined in the Access Code are that:

> *(a) in respect of a required augmentation, it strikes a balance between the interests of:*
>
> *(i) the contributing user; and*
>
> *(ii) other users; and*

*(iii) consumers;*

*and*

*(b) it does not constitute an inappropriate barrier to entry.*

### 13.4.1 Changes to the Contributions Policy during the AA4 period

1345. During the AA4 period, the Contributions Policy was updated to reflect changes made to the Access Code to introduce the constrained network access regime. [229] The updated Contributions Policy will apply as a transitional document until the commencement of Western Power's fifth access arrangement (**Transitional Contributions Policy**).

1346. The changes implemented as part of the Transitional Contributions Policy are summarised below: [230]

- **Compliance with Technical Rules and WEM Rules –** clause 7.4(b) was amended to provide that applicants must pay their own costs of ensuring their facilities and equipment comply with the WEM Rules including any Registered Generator Performance Standard
- **Definitions –** various amendments were made to ensure consistency between the Transitional Contributions Policy and the Access Code.

### 13.4.2 Proposed amendments to the Contributions Policy for the AA5 period

1347. In preparation for the AA5 period, Western Power has undertaken a comprehensive review of the Transitional Contributions Policy and identified minor amendments for the proposed new Contributions Policy for the AA5 period to better achieve the intent of existing provisions. The proposed changes have been included to improve readability and ensure consistency throughout the Contributions Policy.

1348. All changes and the rationale for the changes are outlined in the change summary report provided in Attachment 13.3. A marked-up version of the Contributions Policy is also provided as Appendix C.1 to the proposed access arrangement.

### 13.4.3 Distribution low voltage connection headworks scheme

1349. The distribution low voltage connection headworks scheme (DLVCHS) forms part of the Contributions Policy and was developed to allow the cost of infrastructure required for connection upgrades to be shared more evenly by all customers using the installed network.[231]

1350. In the AA4 proposal, Western Power proposed changes to the Contributions Policy that will allow more discretion to use more than 12 months of data for developing prices under the DLVCHS however this was not approved by the ERA. The ERA's decision in September 2018 stated that 12 months was a reasonable period of time for a review of prices.

1351. However, Western Power believes that a longer data period must be considered in order to better meet the objectives of the Contributions Policy.[232] Western Power proposes to develop prices under the DLVCHS based on modelling of connections over the immediately preceding 36-month period. This will better meet the policy objective of providing price stability and certainty to enable network users to make informed investment decisions.

---

[229] Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code May 2020

[230] Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code - Improving access to the Western Power network

[231] The DLVCHS covers connections within 25 km of the nearest zone substation

[232] The objectives of the Contributions Policy are outlined in clause 5.12 of the Access Code. Western Power believes that a longer data period will result in outcomes that better balance the interests of all users.

1352. All changes and the rationale for the changes are outlined in the change summary report provided in Attachment 13.4. A marked-up version of the DLVCHS Methodology is also provided as Appendix C.2 to the proposed access arrangement.

## 13.5 Multi-function Asset Policy

1353. Multi-function assets are those that are utilised to provide both regulated network support services and other services. These assets have become increasingly relevant as technology has evolved. For example, distribution-connected storage might now be used for both network purposes and provide unregulated (for the purposes of the Access Code) essential system services and/ or energy services.

1354. Amendments were made to the Access Code in September 2020[233] that enable the sharing of benefits from multi-function assets, to ensure that:

- the network service provider is incentivised to increase the use of the existing network; and
- a share of benefits of this increased utilisation are passed through to end-use customers, who ultimately pay for the shared network.[234]

1355. As part of these amendments to the Access Code, a new requirement was placed on Western Power to develop a Multi-function Asset Policy as part of its access arrangement. The Access Code also outlines the requirements the Multi-function Asset Policy must meet.

> *5.37 A multi-function asset policy must:*
>
> *(a) to the extent reasonably practicable, accommodate the interests of the service provider and of users and applicants; and*
>
> *(b) be sufficiently detailed to enable users and applicants to understand in advance how the multi-function asset policy will operate; and*
>
> *(c) set out the method for determining net incremental revenue; and*
>
> *(d) be consistent with the multi-function asset guidelines.*

1356. The Access Code includes a list of principles that Western Power must take into consideration in developing the Multi-function Asset Policy:

> *6.86 The multi-function asset principles are as follows:*
>
> *(a) the service provider should be encouraged to use assets that provide covered services for the provision of other kinds of services where that use is efficient and does not materially prejudice the provision of covered services;*
>
> *(b) a multi-function asset revenue reduction should not be dependent on the service provider deriving a positive commercial outcome from the use of the asset other than for covered services;*
>
> *(c) a multi-function asset revenue reduction should be applied where the use of the asset other than for covered services is material;*
>
> *(d) regard should be had to the manner in which costs of multi-function assets have been recovered or revenues of multi-function assets have been reduced in respect*

233 West Australian Government Gazette No 157, 18 September 2020

234 Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code May 2020

*of the relevant asset in the past and the reasons for adopting that manner of reduction; and*

*(e) any reduction effected under section 6.84 should be compatible with other incentives provided under this Code.*

1357. In October 2021, the ERA published the Multi-function Asset Guideline to provide more detail about the approach to be taken by Western Power in drafting this Policy. [235] The Guideline sets out the required content of this Multi-function Asset Policy to be comprised of the following components:

- identification of multi-function assets
- determination of net incremental revenue
- calculation of reduction to target revenue.

1358. The Access Code objectives and principles, together with the Guideline establish the regulatory arrangements for the Multi-function Asset Policy.

### 13.5.1 Proposed Multi-function Asset Policy for the AA5 period

1359. Western Power's Multi-function Asset Policy sets out the approach to sharing incremental revenue earned where regulated assets are used in the provision of non-covered services. Non-covered services refer to services that are not covered services. Covered services relate to the provision of electricity network services that are paid for by the broad electricity network customer base and subject to price regulation by the ERA under the Access Code. Non-covered services are also not excluded services. An example is services provided by batteries owned by Western Power to provide network support.

1360. Under this policy, a proportion of the incremental revenue earned by Western Power in such situations is transferred to regulated customers subject to the conditions set out in the Multi-function Asset Policy. Customers using the Western Power Network will benefit from the Multi-function Asset Policy by receiving reductions to future network charges.

1361. Western Power's Multi-function Asset Policy includes:

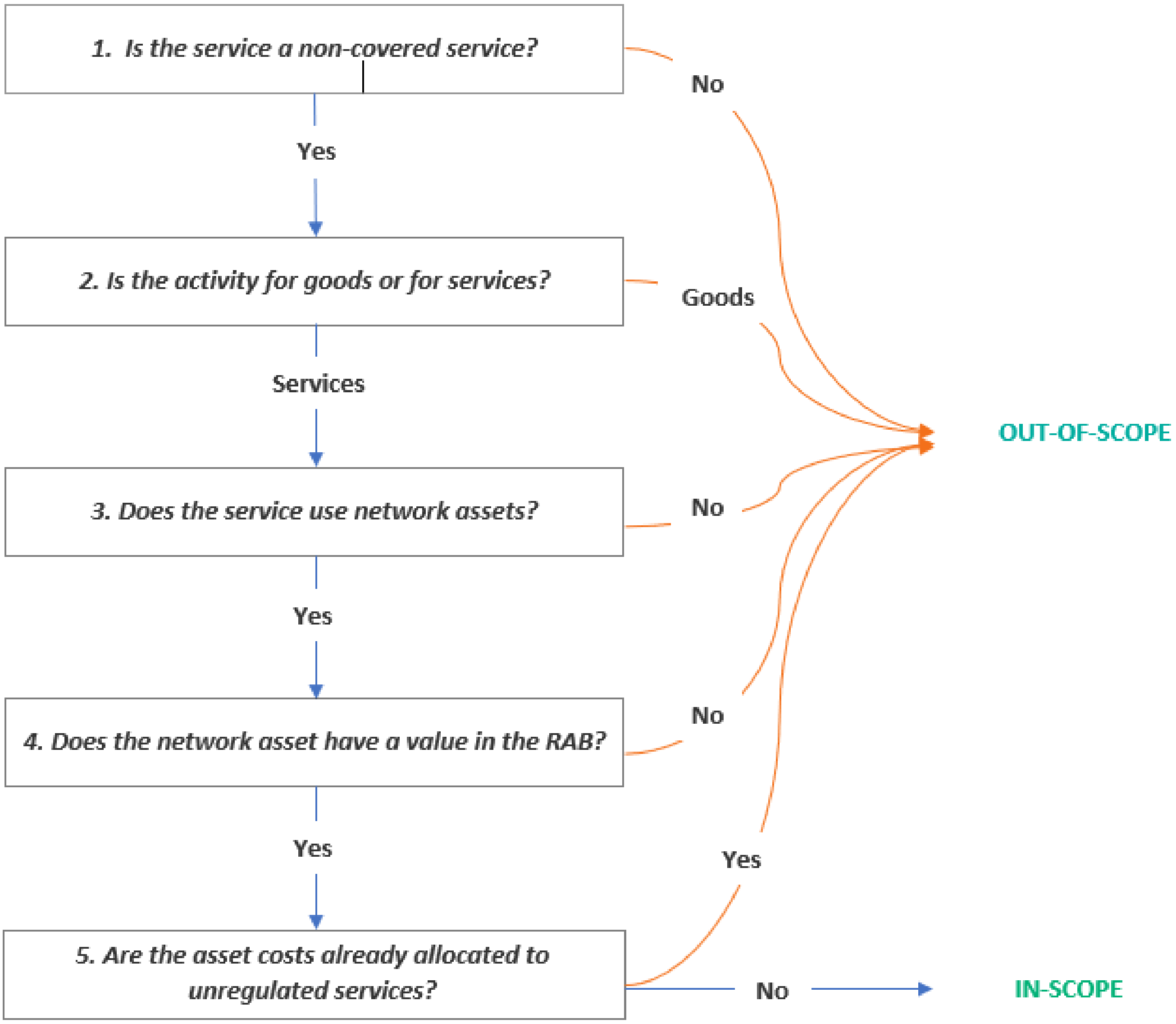
- the details for identification of the applicable non-covered services that use multi-function assets
- the methodology used to calculate net incremental revenue
- the methodology for calculating the deduction to target revenue.

#### *Decision-making framework for identifying non-covered services*

1362. Western Power's Multi-function Asset Policy includes a decision-making tool compromised of five steps to identify the applicable non-covered services that use multi-function assets. Figure 13.1 summarises the steps in the process as a decision tree.

[235] ERA (October 2021) *Multi-function asset guideline- Decision*

**Figure 13.1: Decision tree for the process of identifying applicable non-covered services**




### *Net incremental revenue methodology*

1363. The Multi-function Asset Policy provides a broad description of the methodology of calculating the net incremental revenue. The methodology removes from total payments the costs associated with acquiring additional assets, modifying existing assets and the cost of materials supplied.

1364. The reason for deducting these costs is that they are costs incurred to supply non-covered services that are not paid for by customers using network assets in the RAB. There is no over payment for these assets. The costs of these assets are fully recovered directly from the customers receiving non-covered services and therefore it is appropriate for such costs to be taken into account prior to any revenue adjustment.

1365. The equation below provides the calculation of the Net Incremental Revenue:

$$\sum NIR_t^n = \sum P_t^n - \sum A_t^n - \sum M_t^n - \sum Q_t^n - \sum O_t^n$$

Where:

NIR = net incremental revenue

n = applicable non-covered services identified using the decision-making framework set out in Figure 13.1

t= a year of the access arrangement

P = payments for applicable non-covered services recorded in accounting systems for the years as set out in Section 4 of the Multi-function Asset Policy and resulting from using the decision-making framework set out in Figure 13.1

A = cost of additional assets

M = cost of modifications to existing assets

Q = cost of materials used to supply the services

O = costs directly attributed to the applicable non-covered services

1366. Each component of the equation that is a deduction from payments is described in the Multi-function Asset Policy. The proposed Multi-function Asset Policy is provided as Appendix D to the proposed access arrangement and the accompanying explanatory document is provided as Attachment 13.5.

# 14. Supplementary matters

1367. This chapter addresses the supplementary matters required to be covered by the Access Code.

1368. Supplementary matters are those arrangements and activities Western Power undertakes in addition to its core electricity connection and transfer services that need to be addressed in order to facilitate its core services.

## 14.1 Regulatory Framework

1369. The supplementary matters relevant to the Western Power network are listed in section 5.27 of the Access Code being:

*a) balancing*

*b) line losses*

*c) metering*

*d) ancillary services*

*e) stand-by*

*f) trading*

*g) settlement*

*h) any other matter in respect of which arrangements must exist between a user and a service provider to enable the efficient operation of the covered network and to facilitate access to services, in accordance with the Code objective.*

1370. Section 5.28 of the Access Code requires an access arrangement to deal with supplementary matters in a manner which is consistent with and facilitates the treatment of the supplementary matter in accordance with the WEM Rules, Technical Rules, Access Code objective, enactments under Part 9 of the *Electricity Industry Act 2004* and in *written law*.[236]

## 14.2 Changes to supplementary matters

1371. The scope of Western Power's responsibility for some supplementary matters has changed since the AA4 period, most notably in respect to:

- changes to the WEM Rules and Metering Code to facilitate five-minute settlements
- changes to the WEM Rules requiring the preparation and provision of limit advice to AEMO.

1372. These changes, however, do not require any amendments to section 9 of the current access arrangement.

## 14.3 Proposed amendments

1373. Western Power's access arrangement has been prepared on the basis that all relevant supplementary matters including those identified above that are applicable as at the date of this submission will be undertaken in accordance with the Access Code requirements.

[236] Written law is a defined term in the Access Code.

1374. Western Power proposes to make minor amendments to the access arrangement to update references to the *Electricity Industry (Metering) Code* to reflect the current 2021 version.

1375. Except for this minor amendment, Western Power proposes to retain the supplementary matters in section 9 of the current access arrangement.