Economic Regulation Authority

Final decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27

Attachment 6: Operating expenditure

31 March 2023

D259003

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Note

This attachment forms part of the ERA's final decision on proposed revisions to the access arrangement for the Western Power Network for the fifth access arrangement period (AA5). It should be read with all other parts of the final decision.

The final decision comprises all of the following attachments:

Final decision on proposed revisions to the access arrangement for the Western Power network 2022/23 – 2026/27 – Decision Overview

Attachment 1 – Price control and target revenue

Attachment 2 – Regulated asset base

Attachment 3A – AA4 capital expenditure

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1. Summary

This attachment deals with operating expenditure.

The ERA's draft decision:

- Accepted Western Power's proposed base operating costs for AA5 as being efficient. Base operating costs were derived from actual operating costs incurred in 2020/21, adjusted for non-recurrent costs that are not reflective of ongoing operational requirements and escalated to 2022 prices.
- Accepted most of Western Power's proposed step changes including where the supporting evidence was limited.
- Did not accept two of Western Power's proposed step changes and so the draft decision:
  - Removed the proposed increase in costs for the silicone treatment program as they are not required under the Energy Safety Order, and industry guidelines recommend alternative approaches.
  - Required that the costs of decommissioning overhead lines are treated as capital expenditure and depreciated over one year. This leaves target revenue unchanged for AA5 but enables the costs to be included in the Investment Adjustment Mechanism for undergrounding and stand-alone power systems so that any difference between forecast and actual decommissioning can be trued up at the next access arrangement.
- Made some adjustments to the escalation factors proposed by Western Power to better reflect growth in the network. The ERA also removed growth escalation from corporate and indirect costs because overhead costs do not vary with the size of the network.
- Applied a productivity factor of 2 per cent per annum to operating expenditure and indirect costs. This requires Western Power to deliver operating expenditure efficiencies more consistent with other network operators in Australia, as well as ensuring that an allowance for efficiencies for the AA4 investment and efficiencies from investment in new and enhanced systems during AA5 are embedded in the forecast.

In the draft decision, the ERA acknowledged some of the uncertainty Western Power faces in undertaking transformation activities over AA5 by accepting most of the step changes in operating costs proposed by Western Power. However, there are other mechanisms in the code to manage uncertainty, for example, Western Power can prioritise approved operating expenditure where required as it responds to transformational challenges.

In its revised proposal, Western Power accepted the transfer of decommissioning costs and adjustments to growth escalation factors, which have been retained in the final decision. However, there were some errors in Western Power's calculation of labour escalation and it did not reflect the latest data available, which resulted in labour escalation being overstated in the revised proposal.

Western Power did not accept the expenditure reduction for silicone treatment and the inclusion of a 2 per cent productivity factor. Instead, Western Power proposed additional expenditure for private pole inspections, silicone treatment and insurance in its revised proposal. Western Power also considered the productivity factor should be reduced to 0.5 per cent.

Summary of final decision

- In the final decision, the ERA has included:
  - The base operating costs in Western Power's revised proposal but with correctly applied inflation and labour cost escalation. This reduced base operating costs by $19 million over the AA5 period.
  - Step changes consistent with the draft determination.
  - Additional non-recurrent operating expenditure of $24.3 million for the initial establishment costs of inspecting private poles following a High Court ruling in December 2022 that confirmed Western Power's obligations for private power poles.
  - A new step change of $43 million for insurance to reflect higher premiums due to general insurer concerns around large claims that have arisen in recent years and bushfire risk and climate change.
  - Corrections and updates to the labour escalation factor reduce operating costs by $16.1 million. These corrections and updates also affect capital expenditure, which has been reduced by $28 million.
- To ensure Western Power continues to seek operating efficiencies the ERA has retained the two per cent productivity factor included in the draft decision. Western Power is required to deliver operating efficiencies consistent with other network operators in Australia.

Table 1 below compares the ERA's final decision with Western Power's proposed operating expenditure.

Table 1: Operating expenditure ($ million real at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Western Power initial proposal	423.9	434.9	434.3	440.1	449.5	2,182.7
ERA draft decision	411.7	414.4	403.9	400.6	401.3	2,032.0
Western Power revised proposal	437.9	447.3	449.9	456.2	459.0	2,250.3
ERA final decision	422.2	416.2	405.6	402.3	400.8	2,047.0

Source: Western Power and ERA target revenue model

The reasons for the ERA's final decision on forecast operation expenditure and details of required amendments are set out in this attachment.

2. Regulatory requirements

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

Forecast operating costs must only include those costs that would be incurred by a service provider efficiently minimising costs. This is defined in the Access Code as meaning the service provider incurs no more costs than would be incurred by a prudent service provider, acting efficiently in accordance with good electricity industry practice seeking to achieve the lowest sustainable cost of delivering services, and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services.

An extract of sections of the Access Code relevant to forecast operating expenditure is included in Appendix 1.

3. Western Power's initial proposal

Western Power forecast that operating expenditure of $2,183 million would be required for it to operate and maintain its network over the AA5 period.

Western Power used the "base-step-trend" method to forecast operating expenditure. It has used the penultimate year of AA4, 2020/21 to establish what it considers to be its efficient recurrent base operating expenditure. It has then forecast discrete step changes and changes in output and cost input trends over the AA5 period to forecast operating expenditure for each year of AA5. Table 2 summarises the results of Western Power's forecasting process.

Table 2 AA5 initial proposed operating expenditure (real $ million at June 2022)

Expenditure	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent network base costs	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 network costs	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
Efficiency	-0.9	-1.9	-2.8	-3.8	-4.8	-14.3
Non-recurrent network costs	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 network costs	34.7	35.8	35.5	37.5	39.9	183.4
Total	423.9	434.9	434.3	440.1	449.5	2,182.7

4. Submissions on initial proposal

Submissions on operating expenditure were received from Perth Energy, Synergy, WALGA and the WA Expert Consumer Panel. Matters raised included:

- Concerns about lack of information on the proposed expenditure.
- Questions about how Western Power benchmarked against other network service providers and whether it had included sufficient productivity improvements in its proposal.
- Concerns about the proposed changes to washing and applying silicone to insulators.
- Concerns about the LED streetlight replacement strategy.
- Questions about whether the proposed expenditure to support market reforms was related to the provision of covered services.
- Questions about whether expenditure for alternative options should be included.
- A view that the real labour cost increases should be set no greater than the assumed rate of productivity growth.

The matters raised were included in the ERA's draft decision below.

5. Draft decision

The process adopted by the ERA in considering the forecasts of operating expenditure was to:

- Assess the extent to which Western Power's proposed recurrent network base costs would be incurred by a service provider efficiently minimising costs, consistent with the requirements of section 6.40 of the Access Code.
- Assess whether Western Power had provided adequate justification that forecast trends and step changes in the level of operating expenditure over AA5 were consistent with those that would be incurred by a service provider efficiently minimising costs.

The ERA's technical consultant Engevity provided advice on the efficiency of Western Power's proposed operating expenditure and undertook a benchmarking exercise using the Australian Energy Regulator's (AER) benchmarking models and data from the National Electricity Market (NEM) network service providers.

5.1 Efficient base year operating expenditure

The ERA considered whether the actual operating expenditure for AA4 was consistent with a service provider efficiently minimising costs and therefore constituted a relevant cost base against which forecast operating expenditure for AA5 could be assessed.

The ERA assessed the efficiency of Western Power's base year (2020/21) operating expenditure by:

- Verifying records of actual operating expenditure for the AA4 period.
- Benchmarking against operating expenditure reported by other network service providers in Australia.
- Reviewing the incentives for Western Power to minimise its operating expenditure.
- Reviewing the base year operating expenditure line items (at a high level) for reasonableness.

Verification of operating costs in AA4

In accordance with the ERA's Guidelines for Access Arrangement Information, Western Power provided regulatory accounts that reconciled costs of regulated activities with a set of base accounts for the business. A comparison of claimed operating costs with recorded operating costs is shown in Table 3 below.

Table 3: Reconciliation of claimed operating expenditure for AA4 with recorded operating expenditure for Western Power ($ million nominal)

	Base Account	Adjustments	Regulatory Account	Claimed non-capital costs
Transmission 2017/18	97.7	5.4	103.1	103.1
Transmission 2018/19	96.1	1.3	97.4	97.4
Transmission 2019/20	119.8	1.1	120.9	121.4
Transmission 2020/21	122.0	0.2	121.8	121.8

	Base Account	Adjustments	Regulatory Account	Claimed non-capital costs
Transmission 2021/22*				114.8
Distribution 2017/18	281.0	38.5	319.5	319.5
Distribution 2018/19	273.2	3.4	276.6	276.6
Distribution 2019/20	308.4	2.9	311.3	311.3
Distribution 2020/21	305.3	0.8	306.1	306.1
Distribution 2021/22*				338.5

** Western Power 2021/22 financial results are not yet available.*

There was a small difference ($0.5 million) in transmission expenditure for 2019/20 due to an input error in Western Power regulated revenue model. The draft decision noted this would be corrected in the final decision.

Adjustments over the AA4 period that were necessary to create the annual regulatory accounts included:

- Fleet depreciation to align Western Power's statutory accounting disclosures with its regulatory accounting disclosures. To achieve this, the unregulated fleet depreciation is disclosed as operating expenditure costs in the regulatory financial statements and not depreciation and amortisation.
- Aligning Western Power's statutory capital additions with the ERA's AA4 decision regarding statutory capital expenditure that does not meet the new facilities investment test, including amounts relating to:
  - Intellectual property for work completed in preparation for transition to the national regulatory regime.
  - Wood pole emergency replacements.
  - Provision for environmental and rehabilitation costs.
- Other operating expenditure costs that do not meet the non-capital costs requirements of the Access Code and which cannot be expensed to the regulatory profit and loss account.

Western Power's regulatory accounts are audited for Western Power by the Office of the Auditor General.

The ERA was satisfied that the regulatory accounts provided a true and correct indication of operating costs in the AA4 period.

Benchmarking Analysis

The ERA engaged Engevity to benchmark Western Power's performance against other service providers utilising the AER's benchmarking methods and data drawn from the AER's benchmarking report and averaged over five years.

Engevity's analysis demonstrated that Western Power performed relatively well in terms of expenditure against its peers in the NEM. However, it does not perform as well in terms of service performance, particularly for rural customers.

A detailed discussion of Engevity's findings is at section 5.7.1 of Engevity's report to the ERA.

Incentives to minimise operating expenditure

Western Power's regulatory framework provides incentives for it to minimise its operating expenditure and achieve efficiencies greater than those included in the approved target revenue.

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

These measures all contribute to giving Western Power an incentive to minimise its costs.

Base year network operating expenditure

Western Power used the operating expenditure for 2020/21, the penultimate year of AA4 as the base year for its AA5 forecasts because that is the most recent year for which audited results are available.

Western Power made the following adjustments to its 2020/21 actual costs to establish its AA5 recurrent network base cost of $348.1 million.

- Removed $20 million of revenue associated with non-revenue cap services.
- Removed indirect costs of $42.8 million. These have been removed because Western Power forecasts indirect costs separately and then allocates them between capital expenditure and operating expenditure.
- Removed non-recurrent expenditure that is not reflective of ongoing operational expenditure requirements of $14.6 million, including:
  - Design costs of $5.6 million for a project that did not proceed and which were subject to a customer contribution.
  - Actuarial adjustments of $4.2 million that were materially above the adjustment amount averaged over the previous five years.
  - Correction of unintentional underpayments of $1.8 million identified in an internal underpayments review.
  - Removal of $3.1 million that is associated with implementing phase one of the energy transformation program.
- Rolled forward the base year to account for inflation in the final year of the AA4 period.[1]

Western Power's recurrent network base costs of $348.1 million break down was as follows:

- $194.1 million of operating expenditure on the distribution network
- $60.6 million of operating expenditure on the transmission network
- $93.4 million of recurring corporate operating expenditure.

[1] Western Power states it engaged Synergies to determine the inflation rate for 2021/22. Synergies determined the inflation rate for 2021/22 to be 1.75 per cent based on the most recent WA Treasury forecast. The regulated revenue model used an inflation factor of 1.84 per cent based on the AA4 forecast inflation.

A review of operating expenditure by regulatory category was undertaken by Engevity who noted that, apart from corporate costs, Western Power's total operating expenditure appeared consistent with other similar networks. However, Western Power's corporate costs were relatively high and moving further away from comparable AER regulated network service providers over the term of AA5.[2]

Taking account of the information put forward by Western Power, the benchmarking undertaken by the technical consultant and the regulatory incentives for efficient expenditure, the ERA accepted Western Power's proposed base year expenditure.

5.2 Forecast changes in operating expenditure during AA5

Western Power's forecast changes in operating expenditure over the AA5 period were considered in the following order:

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

5.2.1 Step Changes

Western Power's proposed step changes are set out in Table 4 below.

Table 4: Initial proposed step changes (real $ million at June 2022)

Step change	Description	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Repair streetlight faults	Includes LED replacement.	4.5	4.5	4.5	4.5	4.5	22.5
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	22.0
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)

[2] Engevity Final Advice (August 2022), Attachment 7, p. 82.

Step change	Description	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Silicone treatment program	Changes to the silicone treatment program requiring the line to be de-energised	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 process 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
High Voltage 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**

Source: Western Power data

Stakeholder submissions raised the following specific concerns about the proposed step changes:

- WALGA considered the options assessment by Western Power for streetlighting LED replacements was deficient in that the published assessment only identified two options, replace like for like (which is not feasible as the globes cannot be procured or imported) and the proposed reactive replacement with LED globes. It noted the lifecycle cost and performance of a range other options had not been demonstrated. It was concerned that the approach is "piecemeal" and had not been rigorously and independently verified to provide the lowest lifecycle costs. WALGA was also concerned that the quality of the lighting outcomes resulting from the implementation of Western Power's LED replacement strategy had not been demonstrated.

- Silicone treatment program
  - Perth Energy was concerned about the change in approach and stated that supply reliability and Western Power's response to interruptions were critical performance indicators. Perth Energy relayed opinions from its customers that Western Power's response to outages caused by pole-top fires was slower than was considered reasonable.
  - WALGA was concerned that the proposed reduction in the volume of silicone treatments and the increased cost of these treatments due to the requirement to apply the treatment only on de-energised lines will lead to a decrease in network performance.
  - Given the cost, and the implications for consumer supply, the WA Expert Consumer Panel considered that an independent review of the new maintenance process was required, including the consideration of whether methods used by other utilities such as standby generators and temporary bypasses could be used to conduct the work with 'live-lines'.
- Synergy considered the step changes in operating expenditure for DSO capability and SCADA and communications was only efficient if it enabled alternative options as a substitute for higher capital expenditure with net savings achieved overall. In any case, Synergy questioned whether funding to develop new capabilities, systems and strategies such as DSO, digital substations, LiDAR programs, new data accessibility systems and additional response generators should be funded through recurrent revenue.

Engevity advised that Western Power had not provided sufficient information to demonstrate that the proposed step changes were efficient expenditure and that any offsetting savings had been incorporated in the proposal. Its findings were as follows:

> - **Streetlight repairs ($4.5m p.a):** Additional volumes of streetlights to be serviced. Western Power has not provided evidence to demonstrate the proposed cost is efficient.
> - **DSO capability ($4.4m p.a.):** Western Power has not provided evidence to demonstrate the proposed cost is efficient.
> - **Meter Reading ($4.5m p.a. by 2026/27):** While it is clear savings can be achieved by remote readings rather than manual reads, Western Power has not provided evidence to verify the forecast saving.
> - **Silicone Treatment Program ($5.3m p.a.):** This program was justified in AA4 and has increased in cost due to the decision to conduct the procedure while de-energised which will incur substantially higher switching and planning costs in addition to lowering the daily unit rate of completions. [Engevity] note that the move away from live line work is not required under the Energy Safety Order 01 – 2021 which instead recommends improved equipment testing, compliance and work practices for live line insulator washing. This is largely consistent with the Victorian Electricity Supply Industry guidelines[3] and recent awareness publications involving

[3] Victorian Electricity Supply Industry, VESI Fieldworker Handbook, updated 2008, pp. 15-16.

washing equipment condition[4]. On this basis, [Engevity] do not consider that the step change is efficient.

- **Digital Substation ($1m p.a.):** The concept of such substations is well known in other utilities. Details relating to Western Power's planned implementation are not clear beyond equipment condition monitoring. Condition monitoring may prevent failures and assist in overall system performance. There may be savings in the reactive and planned maintenance categories. However, these targeted savings are not noted by Western Power.[5]
- **SCADA & Telecommunications ($3.9m p.a.):** Both programs of expenditure are coupled with major CAPEX spends proposed in the AA5 period. Additionally, they build on previously approved programs from AA4. Western Power has not provided evidence to demonstrate that the proposed cost is efficient.
- **SPS Maintenance ($2.4m p.a. by 2026/27):** Cost estimations here are seen to ramp up reflecting the ambition to install approximately 1,800 SPS units in the AA5 period. Total estimated expenditure is projected to be in excess of $6.4M with built-in additional expenditure planned for the next period. While the strategy is self-evident in terms of reliability improvement it provides Western Power with several OPEX savings in the areas of pole maintenance, replacement, line patrols, fire mitigation, emergency response and line hardware maintenance. It is not clear if the estimates are net of these benefits.
- **Governance & Safety Assurance ($0.8m p.a.):** Engevity has examined these programs and it appears that much of the proposed AA5 activity is consistent with broad industry practice.
- **LiDAR program ($1.2m p.a.):** LiDAR is a sophisticated inspection methodology used by the majority of DNSP's and TNSP's as a cost-effective way to inspect geographically spread assets. The proposal here is for additional costs to increase the frequency of inspections. This should result in improvements in reliability and cost savings associated with corrective maintenance, but these do not appear to have been included in the proposal.
- **Power Quality ($0.4m p.a.):** Large local demand variations attributable to local generation will expose Western Power connections to unacceptable voltage variations and increasingly power quality issues. Investments in Power Quality monitoring are prudent and necessary. At a system level Western Power is investing heavily in control and monitoring equipment (e.g., AMI) as well as SCADA in order to manage these issues. While the overall strategy seems necessary it is not clear how the information will be focused, and the measured effects managed in real time. Nor is it clear how the OPEX associated with the initiative will be offset if at all by actions taken as a result of the information gained.
- **High Voltage Emergency Generator ($1m p.a.):** In recent periods many DNSP's have utilised High Voltage generators to provide local network support in the event of outages or as a temporary augmentation to local load carrying capacity. It is assumed that this is the Western Power strategy. Such equipment is available from the market on a hire basis, and it appears that Western Power intends to pursue this strategy along with an ownership strategy. Long term supply contracts with service providers may be more efficient.

4 Victorian Electricity Supply Industry, VESI HV Live Work Committee & VESI Work Practices Committee – Awareness Bulletin Live Work Equipment. A copy of this document can be found here.

5 In some cases, the benefits from condition monitoring will not be realised until the equipment develops faults or deterioration indicators. As this typically does not occur until later in the asset life, the monitoring the condition of the more reliable newer assets that have communications capabilities is of limited immediate benefit compared to the older plant with greater accumulated wear from operation and deterioration from environmental conditions.

ERA assessment

The assessment of the proposed step changes was difficult due to limited information to demonstrate that the proposed step changes were efficient and that any offsetting savings had been incorporated.

The ERA considered some specific matters below before setting out its overall view.

Repair streetlight faults

The repair streetlight faults activity is the non-routine repair of streetlight faults and predominantly responds to customer reports of faulty streetlights. Streetlights that have failed in service are identified by the public or workforce and faults are remediated.

As part of this, Western Power developed a strategy to 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.

The strategy aimed 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. Replacing mercury vapour globes with LED involved a higher material cost, with the added benefit of reducing maintenance expenditure due to a longer life of globes, reduced energy consumption and better environmental outcomes.

Western Power stated that it assessed various options to address the identified need in developing the step change forecast. It considered the assessment demonstrated that reactive replacement of streetlights with LED globes was the most cost-effective option.

In relation to the concerns raised by WALGA about streetlights, in the draft decision the ERA amended the streetlighting reference service to require Western Power to ensure it meets current streetlighting standards if it changes the type of luminaire.[6] The ERA considered this should address WALGA's concern that Western Power may install luminaires that do not meet current streetlighting standards.

The draft decision noted that converting streetlights to LED is an important component of Western Power's plans to reduce its carbon emissions as well as meet its obligations under the Minamata Convention. WALGA raised concerns that the reactive approach Western Power had chosen did not have the lowest lifecycle cost. The draft decision required Western Power to ensure it meets current streetlighting standards if it changes the type of luminaire installed. The draft decision noted Western Power would need to review its planned strategy if it was not based on meeting current streetlighting standards and ensure that the option it has chosen has the lowest lifecycle cost.

Draft decision required amendment 1

Provide evidence that the proposed reactive replacement of streetlights with LED globes will meet current streetlighting standards and has the lowest lifecycle cost.

Silicone treatment program

To reduce the likelihood of pole top fires, Western Power applies silicone grease on insulators periodically on its distribution overhead network. Historically, the silicone application process was applied while the line was energised. A review of work practices undertaken in 2020/21 by Western Power determined that the application of silicone treatments would only be

6 There are two standards identified by WALGA in its submission: AS/NZS 1158 - Pedestrian Area Lighting Standard; and AS/NZS 4282 – Control of the obtrusive effects of outdoor lighting.

undertaken on de-energised lines. Consequently, the AA5 proposal included lower volumes of silicone treatments compared to AA4 due to the requirement to get planned outages for silicone treatment on de-energised lines. The unit cost for silicone treatments was higher as a result of the change in work practice.

The ERA's technical consultant advised that the Energy Safety Order issued following an incident in 2020 did not require Western Power to de-energise lines for silicone treatment and that industry guidelines recommend alternative approaches.

In addition to the increased costs, stakeholders were concerned the proposed reduction in the volume of silicone treatments due to the requirement to apply the treatment only on de-energised lines will lead to a decrease in network performance.

Taking account of stakeholder submissions and the technical consultant advice, the ERA removed the proposed step change for the silicone treatment program. Given the implications for customer supply, the ERA expected Western Power would review its work practices as suggested by the Expert Consumer Panel to enable it to work safely with "live-lines".

Overall

As identified in Synergy's submission, the proposed step changes include items relating to transformation programs. The ERA considered it was important to ensure that Western Power can respond to the rapidly evolving technologies and more frequent and severe weather events from a changing climate.

On balance, the ERA accepted the proposed step changes (apart from the silicone treatment program) for inclusion in the forecast capital expenditure.

Draft decision required amendment 2

Remove the proposed step change in operating expenditure for the silicone treatment program.

5.2.2 Network Growth Escalation

Western Power proposed that its recurrent operating expenditure forecasts for AA5 would be adjusted for the forecast growth in the customer base and the physical size of the transmission and distribution networks.

Western Power's proposed network growth escalation factors are set out in Table 5.

Table 5: Western Power initial proposed network growth escalation factors

Expenditure	Weighting	2022/23	2023/24	2024/25	2025/26	2026/27
Distribution						
Customer Numbers	55.70%	1.50%	1.52%	1.50%	1.49%	1.49%
Circuit Length	15.50%	-0.27%	-0.20%	1.07%	0.94%	-0.34%
Annual average growth in highest maximum demand	28.80%	0.00%	0.00%	0.00%	0.00%	0.00%
Distribution Growth	**100%**	**0.80%**	**0.82%**	**1.00%**	**0.97%**	**0.78%**

Expenditure	Weighting	2022/23	2023/24	2024/25	2025/26	2026/27
Transmission						
Customer Numbers	24.10%	1.50%	1.52%	1.50%	1.49%	1.49%
Circuit Length	49.30%	0.60%	-1.33%	1.02%	-0.22%	-0.22%
Annual average growth in highest maximum demand	26.60%	0.00%	0.00%	0.00%	0.00%	0.00%
Transmission growth	**100.00%**	**0.66%**	**-0.29%**	**0.87%**	**0.25%**	**0.25%**

Source: Western Power data

Western Power also applied growth escalation to corporate costs and indirect costs.

The forecast values for the circuit length distribution scale escalation factor proposed by Western Power increased over the AA5 period. This forecast conflicted with Western Power's plan to remove lines as a result of the installation of SPS systems over the period.

In the draft decision, the ERA removed the circuit length element to be more consistent with Western Power's plans to convert parts of the network to stand-alone power systems.

Draft decision required amendment 3

Amend the circuit lengths in the distribution network growth escalation factor to be consistent with Western Power's plans to convert parts of the network to stand-alone power systems.

For the transmission growth factors, Western Power proposed a change to the AA4 method for customer numbers. For AA5 Western Power proposed that the total number of end-use customers should be used instead of the number of transmission connections.

The ERA did not consider that total customer numbers were more closely aligned with transmission related recurrent expenditure than the number of transmission related connections. Engevity had advised that adopting this change would also lead to a one-off step up in growth.

In the draft decision, the ERA retained the method approved for AA4.

Draft decision required amendment 4

Amend the customer numbers transmission network growth escalation factor to use the number of transmission connections.

Western Power also applied growth escalation to corporate costs. The ERA considered business support activities such as information technology, levies, fees and insurance are not proportional to growth in service outputs that may result from changes in customer demand. Consequently, no growth escalation should be applied to corporate costs.

Draft decision required amendment 5

Remove growth escalation factors from corporate costs.

5.2.3 Non-recurrent network costs

Western Power forecast it would spend $72.5 million of non-recurrent operating costs during the AA5 period.

Table 6: AA5 initial proposed non-recurrent costs (real $ million at 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**

Source: Western Power data

In relation to the two items associated with the removal of overhead lines, the ERA considered there was a risk that the decommissioning may not go ahead at the dates planned. The regulatory framework does not enable differences in operating expenditure to be adjusted at the next access arrangement period. This could result in customers paying for decommissioning that does not occur. In contrast, the opening regulated asset base is adjusted at each access arrangement review to reflect actual capital expenditure during the previous period so ultimately only actual expenditure is passed through to customers.

The draft decision noted that, with the planned levels of undergrounding and standalone power systems over AA5 and future regulatory periods, costs associated with the removal of overhead lines were likely to be significant. The ERA considered the decommissioning expenditure associated with the removal of overhead lines would be better managed in the regulatory framework by including them in the capital costs of the project that leads to the need to remove the lines.

Treating the expenditure as part of the capital cost of the project ensures that customers ultimately pay only for decommissioning expenditure that is incurred. Depreciating such expenditure over one year ensures there is no difference in forecast target revenue regardless of whether it is treated as operating expenditure or capital expenditure. In the case of the East Perth substation, this would also better ensure that the decommissioning costs are netted off against any payment for the land.[7]

As there was no difference in target revenue, for the purposes of the draft decision the ERA did not adjust operating expenditure. It noted that an adjustment to transfer decommissioning costs to capital expenditure would be made in the final decision.

Draft decision required amendment 6

Decommissioning costs associated with the removal of overhead lines should be included in the capital costs of the project that leads to the need to remove the lines and should be deprecated over one year.

[7] Proceeds from regulated asset disposals are deducted from the regulatory asset base.

The ERA did not adjust Western Power's forecast costs for continuation of the regulatory reform program.

5.2.4 Productivity improvements

In its initial proposal, Western Power incorporated a productivity improvement of 0.25 per cent per year in its forecast operating expenditure. Western Power engaged Synergies to forecast operating expenditure productivity estimates for its AA5 proposal. Synergies used a Multilateral Total Factor Productivity model to generate productivity estimates using data from the AER's 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.

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.

Western Power applied the average of the forecast productivity growth calculated by Synergies, which resulted in a 0.25 per cent per annum productivity adjustment over the AA5 period.

Submissions queried whether Western Power had included a reasonable productivity factor in its proposal:

- The WA Expert Consumer Panel submitted that it had not seen evidence of an ongoing, strong focus on productivity improvement. It noted that the forecast efficiency trend of $14 million is relatively low when compared with the level of operational expenditure over AA5 and recommended seeking relevant benchmark information from other jurisdictions.

The ERA's technical consultant reviewed the analysis presented by Synergies and relied on by Western Power to establish its proposed annual efficiency value. Engevity was able to access more recent benchmarking data and to review the assumptions and methods applied by Synergies to arrive at its proposed range. Based on the updated data available, the average productivity of the five distribution networks assessed by Synergies was between zero and 2.6 per cent per annum.

Engevity also noted that Synergies had not fully adopted the AER's approach. The AER considered the productivity growth factor should only capture the productivity growth that would be achieved by a distributor on the 'efficiency frontier', so it based its estimate on the highest ranked distributors in the NEM. This helps to control for the scope for other distributors' performance to include an element of 'catch-up productivity'.[8]

Engevity identified Endeavour Energy as a similar network business to Western Power based on customer locations (albeit without a long rural category). Endeavour Energy was not used to inform Synergies selection of proposed value for annual productivity improvement. It had achieved an annual productivity growth of seven per cent per annum from 2016 to 2020, and two per cent per annum over 2006 to 2020.

Engevity also considered there may be scope for Western Power to achieve greater operating expenditure efficiencies than it had included in its base operating expenditure as it had not identified "capex/opex trade-offs" in its base operating expenditure forecast from the transformation programs it is undertaking.

[8] AER, Forecasting productivity growth for electricity distributors, Final decision, March 2019, p. 8.

Engevity considered, on balance, that Western Power should be able to target an efficiency improvement across the AA5 period of two per cent per annum. It considered this outcome was more consistent with Western Power's stated approach to estimating the productivity growth factor – using the most recent benchmarking data available and distinguishing between movements in the efficiency frontier versus 'catch up'.

Taking account of the analysis provided by the technical consultant, the ERA considered it was reasonable to expect a service provider efficiently minimising costs would seek to achieve a productivity factor of two per cent per annum. This required Western Power to deliver operating expenditure efficiencies more consistent with other network operators in Australia.

Draft decision required amendment 7

Amend the productivity factor to two per cent per annum.

5.2.5 Indirect Costs

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

Western Power's initial proposed indirect expenditure for AA5 is set out in Table 7 below.

Table 7: AA5 initial proposed indirect expenditure (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent network base	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	(0.4)	(0.8)	(1.2)	(1.7)	(2.1)	(6.2)
Non-recurrent costs	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	167.2	167.8	168.5	169.2	169.9	842.6

Source: Western Power data

The initial proposed recurrent network base costs were based on actual indirect costs (excluding those attributable to non-revenue capital expenditure) incurred in 2020/21.

The proposed step changes were for:

- Increased support services to support the capital program of $6.3 million each year.
- Increased IT contract support costs of $3.8 million each year.
- Cyber security program costs of $3.5 million each year.

The ERA considered the proposed step changes were reasonable to support the changes needed to manage the transformation programs.

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

Consistent with its proposed operating expenditure, Western Power included a 0.25 per cent per annum productivity improvement negative adjustment in its proposed indirect costs. As discussed in section 5.2.4, the ERA considered a productivity factor of two per cent is reasonable.

For the reasons above, the ERA did not consider Western Power's proposed indirect expenditure was consistent with a service provider efficiently minimising costs and required it to be amended as set out in Table 8 below.

Table 8: Draft decision indirect expenditure (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent Network Base	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 network costs	165.4	165.4	165.4	165.4	165.4	827.1
Network growth escalation	0.0	0.0	0.0	0.0	0.0	0.0
Productivity factor	(3.3)	(6.6)	(9.7)	(12.8)	(15.9)	(48.3)
Non-recurrent costs	0.0	0.0	0.0	0.0	0.0	0.0
Total[9]	162.1	158.9	155.7	152.6	149.6	778.8

Source: ERA analysis

The ERA's estimate of the allocation of indirect expenditure, after taking account of the adjustments to operating and capital expenditure set out in the draft decision, is shown in Table 9 below.

Table 9: Draft decision indirect expenditure allocation (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Total	162.1	158.9	155.7	152.6	149.6	778.8
Capitalised	125.9	122.7	121.5	117.7	113.9	601.7
Expensed	36.2	36.2	34.2	34.9	35.7	177.1

Source: ERA analysis

[9] Before labour escalation.

Draft decision required amendment 8

Forecast indirect expenditure must be amended to be consistent with the ERA's draft decision including:

- Removing growth escalation.
- Amending the productivity factor to two per cent.

5.2.6 Labour cost escalation

Western Power included labour cost escalation of 0.77 per cent for each year of AA5. Western Power engaged Synergies to provide a forecast of the annual rate of growth in the wage price index for Western Australian electricity, gas, water and waste water services.[10]

Western Power stated it had applied the AER benchmark methodology to determine the proportion of labour costs of a benchmark efficient business rather than using its actual proportion of labour costs.

The ERA considered including a labour cost escalation factor was consistent with ensuring operating expenditure only includes those costs that would be incurred by a service provider efficiently minimising costs, providing the escalation factor is based on a reasonable forecast and is no higher than the assumed rate of productivity growth.

Western Power's forecasts were out of date. However, as the labour costs escalation is a relatively small component of Western Power's proposed costs the ERA did not amend the labour escalation component for the purposes of the draft decision. The ERA required Western Power to update its forecasts to reflect current data and noted it would review the forecast in the final decision, including ensuring that it is no higher than the assumed rate of productivity growth.

Draft decision required amendment 9

The labour escalation factor must be updated to reflect the latest forecast data and must be no higher than the forecast rate of productivity growth included in forecast operating costs.

10 A copy of Synergies report can be found here.

6. Western Power's revised proposal

In its revised proposal, Western Power has sought an increase in operating expenditure in comparison to its initial proposal and the ERA's draft decision.

Western Power's revised proposed operating expenditure forecast is set out in Table 10 below.

Table 10: Western Power's revised proposed operating expenditure forecast

	Initial proposal	ERA draft decision	Revised proposal	Western Power's notes
Recurrent network base costs	1,740.5	1,740.5	1,813.3	Rolled forward the base year to account for actual inflation in the final year of AA4.
Step changes	104.9	78.6	214.3	Since submitting its initial proposal Western Power states it is experiencing increasing challenges and cost pressures from external factors and has adjusted the operating expenditure forecast to reflect step changes for the new challenges.
Total recurrent network costs	1,845.4	1,819.0	2,027.6	
Network growth escalation	52.9	32.3	30.5	Western Power amended the circuit length in the distribution network growth escalation factor and updated circuit length in the transmission network growth escalation factor to reflect the latest forecast growth. Western Power amended the customer numbers transmission network growth escalation factor to use the number of transmission connections and updated it to reflect the latest customer numbers. Western Power also amended the customer numbers distribution network growth escalation factor to reflect the most recent forecast of customer numbers for the AA5 period.
Productivity	(14.3)	(108.4)	(31.1)	Western Power has updated its position to include an operating expenditure productivity factor of 0.5 per cent per annum. Western Power states it is facing a number of challenging external factors impacting its costs. It considers imposing a higher productivity factor than 0.5 per cent per annum would set an unrealistic productivity target and is inconsistent with other regulator approaches.
Non-recurrent costs	72.5	72.5	11.5	Western Power has shifted the costs associated with the decommissioning of distribution overhead lines from operating

	Initial proposal	ERA draft decision	Revised proposal	Western Power's notes
				expenditure to capital expenditure, consistent with the Draft Decision required amendment.
Labour cost escalation	42.7	39.4	24.3	Western Power has updated the labour escalation rate to reflect the latest forecast data.
Expensed indirect costs	183.4	177.1	187.5	Western Power has removed growth escalation factors from the forecast corporate costs for the AA5 period, Western Power has amended forecast indirect expenditure to adjust the growth escalation and productivity factor consistent with the approach adopted for direct operating expenditure outlined above.
Total	2,182.7	2,032.0	2,250.3	

Source: Western Power's revised proposal access arrangement information

The increase in step changes Western Power is seeking is set out in Table 11 below.

Table 11: Western Power's revised proposed step changes

Step change	Initial proposal	ERA Draft decision	Revised proposal	Western Power's notes
Silicone treatment program	26.4	-	40.3	To mitigate the risk associated with pole top fires due to the accumulated backlog caused by a pause on the live-line silicone treatment program during the AA4 period.
Insurance costs	-	-	43.0	Significant increases in premiums forecast across the energy sector due to recent extreme claim events.
SaaS	-	-	28.2	Movement from ICT capital expenditure to operating expenditure for cloud based software as a service solutions.
Private pole inspections	-	-	24.3	Management of private pole attachment points (PPAP) in line with a holistic full inspection cycle, driven by obligations placed upon Western Power from a court judgment issued by the Supreme Court of Western Australia, Court of Appeals in July 2021.

7. Submissions on the revised proposal and draft decision

Submissions on Western Power's revised operating expenditure forecasts were received from the WA Local Government Association, Australian Energy Council, Change Energy, Synergy and the WA Expert Consumer Panel. Matters raised included:

- Requests for the ERA to review information on proposed expenditure, including for projects and programs that were new or for which forecast expenditure increased when compared with Western Power's initial proposal.
- Support for the ERA's draft decision requiring the inclusion of a two per cent productivity factor to apply over the AA5 period.
- Requests for the ERA to confirm that Western Power has provided evidence that the proposed reactive replacement of streetlights with light-emitting diode (LED) globes will meet current streetlighting standards and has the lowest lifecycle cost.
- Concern that the proposed labour escalation premium is too high.

The matters raised are included in the ERA's considerations below.

8. Considerations of the ERA

The ERA has considered the extent to which Western Power has complied with the draft decision required amendments and considered the new information Western Power has put forward in relation to the cost increases it is seeking in its revised proposal against the requirements of section 6.40 of the Access Code.

The ERA sought advice from its technical consultant, Engevity, on the efficiency of Western Power's proposed increases to operating expenditure.

8.1 Base year network operating expenditure

In the draft decision, the ERA accepted Western Power's proposed base year network operating expenditure.

In its revised proposal, Western Power has adjusted base operating expenditure to reflect actual inflation for the 2021/22 year. Western Power's initial forecast base operating expenditure assumed inflation of 1.84 per cent for 2021/22. Actual inflation for 2021/22 was 6.1 per cent. Incorporating actual inflation for 2021/22 increased base operating expenditure by $72.8 million over the AA5 period compared with the ERA's draft decision.

The ERA agrees that updating for actual inflation is consistent with the base-step-trend method. However, Western Power has not taken account of actual labour escalation during 2021/22.

Western Power's forecast base operating expenditure assumed labour escalation of 0.88 per cent for 2021/22. This value was calculated by Western Power using data drawn from the 2021-22 Budget which was delivered 9 September 2021.[11] Actual labour escalation for 2021/22 was negative (-2.66 per cent). After adjusting for actual labour escalation, Western Power's revised proposed base operating expenditure over the AA5 period reduces by $19.3 million.

A similar adjustment applies to base costs for indirect costs.

Required Amendment 1

Amend base operating expenditure and base indirect costs to reflect actual labour escalation in 2021/22.

8.2 Step Changes

Western Power is seeking increased costs compared to the step changes included in the draft decision for the following items:

- Silicone Treatment Program ($40.3 million)
- Insurance ($43.0 million)
- Private pole inspections ($24.3 million)

[11] Government of Western Australia (2021), Western Australia State Budget 2021-22 – Budget Paper No. 3 Economic and Fiscal Outlook, p. 3. Available here

- Transferring cloud-based Software as a Service (SaaS) solutions ($28.2 million) from capital expenditure to operating expenditure.

In addition, the draft decision approved a step change for Western Power's proposed strategy to manage a transition to LED globes and luminaires in line with the cessation of the use of mercury vapour as required by the Minamata Convention on mercury. In response to concerns raised by stakeholders about the screw-in LED globes Western Power was proposing to use, the draft decision required Western Power to provide evidence that the globes meet current streetlighting standards and that the proposed strategy had the lowest lifecycle cost.

As set out in Engevity's advice to the ERA, when assessing step changes, consideration must be given to whether the costs are already accounted for by other components of the base-step-trend forecasting method to avoid the risk of double counting. For example:

- Costs associated with increased volume or scale are accounted for through the network growth escalation factors.
- Forecast productivity growth accounts for material increases in network service provider's input costs over time, so higher cost inputs caused by exogenous factors that impact the broader industry, including potentially new regulatory obligations, are assumed to be accounted for through a lower productivity estimate.

Furthermore, to maximise the level of approved revenue it can collect from users through network charges, a network service provider has an incentive to identify new costs not reflected in base operating expenditure or costs that are increasing at a greater rate than the rate of change. However, there is no corresponding incentive to identify those costs that are decreasing or will not continue.

Therefore, a network service provider simply demonstrating that a new cost will be incurred – that is, a cost that was not incurred in the base year – is not necessarily sufficient justification to introduce a step change. There is a risk that including such costs would upwardly bias the total operating expenditure forecast.

Engevity recommends that only exceptional circumstances would warrant the inclusion of a step change in the operating expenditure forecast and notes this is generally consistent with the approach adopted by Australian regulators. Engevity provides the following examples of circumstances it considers would warrant inclusion as a step change:

- A step change may be required in circumstances where it is prudent and efficient for a network service provider to increase its operating expenditure in order to reduce its capital costs. The network service provider would need to demonstrate the opex–capex trade-off will lead to improved or at least neutral outcomes for consumers.
- A step change in a network service provider's operating expenditure forecast may be justified if a material step-up in expenditure is required to prudently and efficiently comply with a new, binding regulatory obligation that is not otherwise reflected in the productivity growth forecast. If so, the network service provider may be expected to incur such costs into future regulatory periods – so an increase in its operating expenditure forecast may be warranted. A step change can also include the removal of a regulatory obligation on the network service provider that means it will no longer incur the associated costs in future regulatory periods.

Western Power's proposed step changes are considered below.

Streetlighting costs

Western Power has not adequately demonstrated that its proposed screw-in globe replacement strategy has the lowest lifecycle cost. As discussed in Attachment 8, the draft decision requires Western Power to obtain independent testing of new equipment that is likely to affect lighting performance. The testing against standards may have implications for the deployment of the screw-in globe. Western Power will need to ensure that its final strategy is based on the lowest lifecycle cost. This matter is discussed further in Attachment 8.

Silicone treatment program

In its initial proposal, Western Power noted it had decided to only apply silicone treatment on de-energised lines. This was due to a safety incident that had occurred in 2020. Consequently, although the AA5 proposal included lower volumes of silicone treatments compared to AA4, due to the requirement to get planned outages for silicone treatment on de-energised lines, the unit cost for silicone treatments was higher as a result of the change in work practice. Western Power proposed a step change of $26.5 million over the AA5 period to cover this cost increase.

For the draft decision, the ERA's technical consultant advised that the Energy Safety Order issued following the incident in 2020 did not require Western Power to de-energise lines for silicone treatment and that industry guidelines recommended alternative approaches.

In addition to the increased costs, stakeholders were concerned the proposed reduction in the volume of silicone treatments due to the requirement to apply the treatment only on de-energised lines would lead to a decrease in network performance.

Taking account of stakeholder submissions and the technical consultant advice, the ERA removed the proposed step change for the silicone treatment program in the draft decision. Given the implications for customer supply, the ERA expected Western Power would review its work practices as suggested by the WA Expert Consumer Panel to enable it to work safely with live-lines.

In its revised proposal, Western Power notes that due to cessation of the live-line treatment program in 2020, there is a backlog of structures requiring treatment and this will continue to increase.

Prior to cessation of the live-line treatment program, Western Power washed and silicone treated about 20,000 structures per annum. Western Power states that the pole top fire strategy for AA5 requires treatment of 20,000 structures per annum from 2022/23 but only approximately 5,000 can be delivered using de-energised washing and silicone treatments with existing funding. It states this will result in a cumulative backlog of about 50,000 by June 2023.

Western Power states it has undertaken trials and conducted further investigations which have provided a potential live-line washing and siliconing option through the use of helicopters. Western Power notes that when it introduces a new work practice it is required to assess and implement adequate controls to mitigate workforce safety risk. As a result, Western Power considers it will likely start the live-line silicone program from 2023/24.

Western Power states that the primary driver for the step change is to mitigate the risk associated with pole top fires due to the accumulated backlog caused by the pause on the live-line silicone treatment program. Taking account of the backlog, Western Power considers it will need to address 135,000 structures over AA5. It is seeking $40.3 million over the AA5 period.

As noted in Engevity's advice to the ERA, AA4 and prior periods included live-line insulator washing and silicone treatment works. Therefore, the value of these works is implicitly considered in base operating expenditure.

Prior to the safety incident Western Power refers to, Western Power had a live-line treatment program in place that treated 20,000 structures per annum. The backlog has arisen, and will continue to increase, due to cessation of that program by Western Power.

The ERA notes Western Power incurred a fine in November 2022 for the incident that occurred in 2020. The District Court found that Western Power had breached the Electricity (Network Safety) Regulations 2015 by failing to ensure, so far as reasonably practicable, that a prescribed activity on its network was carried out safely. An investigation by the State's electrical safety regulator, Building and Energy, found the wand provided to the employee did not comply with the required standards for washing sticks used near live electricity.[12]

As stated in Engevity's advice to the ERA, there is no prohibition on live-line washing and silicone treatment providing that appropriately certified foam filled, fibreglass wands are used. Western Power has discretion to investigate alternative methods of delivering its insulator washing program, including by helicopter, drone or when deenergised. In doing so, these alternatives would typically need to provide a more efficient delivery than the historical live-line washing practices, or otherwise contribute network reliability, operational or other tangible benefits that would justify the incremental expense.

Cessation of the live-line washing and silicone treatment program has had an adverse effect on reliability. This needs to be addressed as soon as possible.

As described above, for AA4 and prior periods, live-line insulator washing and silicone treatment costs were included in base operating expenditure. Western Power has chosen to cease live-line silicone treatment and move to a more costly practice that adversely affects reliability. It is evident that a live-line program can be done safely and is more efficient. The ERA does not accept Western Power's proposed cost increase. Western Power should reprioritise its work programs to meet its safety obligations. If there is a backlog or catchup needed due to its cessation of the live-line program, it needs to deal with the highest risks first.

Required Amendment 2

The proposed step change for silicone treatment costs must be removed.

Insurance

Western Power is seeking a step change of $43 million for increased insurance costs over the AA5 period. It notes its 2022/23 premium has increased by 43 per cent compared to its 2020/21 premium and expects its premiums will continue to rise over the AA5 period. It notes external factors that affect its insurance premiums:

[12] As set out in a notice on the Department of Mines, Industry Regulation and Safety website, when the washing stick, or wand, was near a live 22,000 volt conductor, an electrical discharge ran through the equipment and the worker's left hand, arm and shoulder. The resulting severe burns required specialist treatment at Fiona Stanley Hospital.

The standards require live-work sticks to have insulating rods or foam-filled tubes made from fibreglass-reinforced plastic insulation. The live-work stick provided to the worker was hollow and had an aluminium rod, which failed to protect against the electrical discharge. The stick was also overdue for mandatory testing.

- increasing inflation, and the resulting impact on replacement values, as well as supply chain issues
- recent claims activity of other insured businesses (nationally and globally)
- the increased frequency and severity of natural catastrophes
- demand from other utility companies and government entities for the same types of insurance, such as bushfire liability coverage in Australia
- market capacity available, which depends on the amount of available insurer capital and willingness or appetite to deploy capital
- capital requirements.

Engevity considers allowing these costs as a step change will risk an over-allowance in the total operating expenditure forecast. It considers that as other network businesses in Australia would be affected by the external factors identified by Western Power, the proposed step change could be adequately accounted for through the productivity growth factor component of the operating expenditure forecast. It notes Western Power has not demonstrated its insurance costs are increasing at a greater rate than the rate of change experienced by the broader industry.

The ERA agrees that other network businesses would also be affected and that the increased costs should flow through to the productivity factor. However, the ERA has reviewed recent network service provider proposals submitted to the AER and notes that evidence was provided by the service providers of significant increases in insurance costs due to general insurer concerns around large claims that have arisen in recent years and bushfire risk and climate change.

In its draft decisions on the most recent round of transmission price reviews published in September 2022, the AER has allowed cost increases for insurance. The AER adjusted the transmission network companies proposed costs to include only forecast costs for the price review period and to remove any expenditure captured by the network growth escalation factor.[13]

The forecast increases proposed by Western Power relate to the AA5 period and forecast network growth escalation is minimal. Taking account of the evidence from the AER's reviews, the ERA has included Western Power's proposed cost increase in the final decision despite limited and very late evidence provided by Western Power to support its claim.

Private pole inspections

Western Power is proposing an additional operating expenditure step change of $24.3 million for the management of private poles over the AA5 period. The requirement for this expenditure is driven by obligations placed upon Western Power from the court judgment issued by the Supreme Court of Western Australia, Court of Appeals in July 2021 with regards to the Parkerville private pole failure case. The Court found that Western Power breached its existing duty to have a system for undertaking the periodic inspection of wooden point of attachment poles (PPAP) owned by customers and used to support live electrical apparatus.

Western Power lodged an appeal with the High Court and was awaiting the outcome when it submitted its revised proposal. The High Court dismissed Western Power's appeal on 7 December 2022.

13 Some companies had sought to include increases in premiums that related to the current pricing period.

Under the obligation imposed by the Court decision, Western Power submits its responsibilities include:

- Performing the necessary inspections on PPAPs in order to understand their condition.
- Utilising this information to assess the likelihood of failure, potential consequences of failure and level of risk represented by these assets in accordance with the engineering practices that Western Power applies to its own assets.
- Issuing a notice to the owner of the pole on the required maintenance to perform on the pole, up to and including replacement. In the most serious cases, or where the notice period has expired and the pole condition has not been rectified, this includes the immediate disconnection of the service, and reconnection after the remediation works have been carried out.

Engevity considers allowing these costs as a step change will risk an over-allowance in the total operating expenditure forecast. It notes similar PPAP management obligations have been implemented by other comparable network businesses in Australia over the last five to ten years so the proposed step change could be adequately accounted for through the productivity growth factor component of the operating expenditure forecast.

While the ERA agrees in theory that these costs may at least partially be reflected in the productivity factor, it is clear that prior to the Supreme Court decision in July 2021, Western Power did not consider it had an obligation in respect of private poles. Consequently, its base costs do not include expenditure for inspecting private poles.

As it has now been made clear that Western Power is responsible, it is important that the initial inspections are undertaken as quickly as possible and that an efficient ongoing inspection program is put in place. The ERA has included the expenditure Western Power is seeking as non-recurring operating expenditure for the initial establishment costs of inspecting private poles.

Software as a service

Western Power proposes to transfer $28.2 million from capital expenditure to operating expenditure based on an estimate of investment that it considers could be delivered through software as a service solutions.

Given uncertainties and lack of historical data to inform a likely split between capital expenditure and operating expenditure, the ERA has retained the expenditure in capital expenditure. If any such expenditure is treated as operating expenditure in the financial accounts during AA5, an adjustment can be made in the regulatory accounts to ensure actual expenditure is treated consistently with the assumption made in the final decision for regulatory purposes.

8.3 Network growth escalation

The draft decision required Western Power to:

- Amend the circuit lengths in the distribution network growth escalation factor to be consistent with Western Power’s plans to convert parts of the network to standalone power systems.
- Amend the customer numbers in the transmission growth escalation factor to use the number of transmission connections.
- Remove growth escalation factors from corporate costs.

The ERA has reviewed Western Power's revised operating expenditure model and is satisfied the amendments have been made consistent with the draft decision.

8.4 Non-recurrent network costs

The draft decision required Western Power to transfer decommissioning costs associated with the removal of overhead lines from operating expenditure to capital expenditure. The expenditure was required to be included in the capital costs of the project that led to the need to remove the lines and was required to be depreciated over one year.

The ERA has reviewed Western Power's revised operating expenditure model and target revenue model and is satisfied the amendment has been made consistent with the draft decision.

8.5 Productivity improvements

The draft decision required Western Power to amend its proposed productivity factor of 0.25 per cent to two per cent.

Western Power has updated its position to include a productivity factor of 0.5 per cent per annum. Western Power states it is facing a number of challenging external factors impacting its costs. It considers imposing a higher productivity factor than 0.5 per cent per annum would set an unrealistic productivity target and is inconsistent with other regulator approaches.

Submissions from the Australian Energy Council, Synergy and the WA Expert Consumer Panel all supported the ERA's draft decision on productivity. The WA Expert Consumer Panel considered it would ensure Western Power works towards targets that reflect best practice for comparable networks in other parts of Australia and overseas. The Australian Energy Council suggested that potentially the productivity factor should be higher given the considerable size of Western Power's proposed capital expenditure and lack of innovation in the provision of covered services.

Based on advice from its consultant Synergies, Western Power initially proposed a productivity factor of 0.25 per cent using a method that it considered was similar to the approach used by the Australian Energy Regulator in its 2019 decision on productivity factors, updated for more recent data.[14]

As outlined in the draft decision, Engevity was able to access more recent benchmarking data than was used by Synergies and reviewed the assumptions and methods applied by Synergies to arrive at its proposed range. Based on the updated data available, the average productivity of the five distribution networks assessed by Synergies was between zero and 2.6 per cent per annum.

Engevity also noted that Synergies had not fully adopted the AER's approach. The AER considered the productivity growth factor should only capture the productivity growth that would be achieved by a distributor on the 'efficiency frontier', so it based its estimate on the

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14 Australian Energy Regulator, 2019, Forecasting productivity growth for electricity distributors – Final Decision paper. Available here. The decision was to use a productivity factor of 0.5 per cent.

highest ranked distributors in the NEM. This helps to control for the scope for other distributors' performance to include an element of 'catch-up productivity'.[15]

Engevity identified Endeavour Energy as a similar network business to Western Power based on customer locations (albeit without a long rural category). Endeavour Energy was not used to inform Synergies selection of proposed value for annual productivity improvement. It had achieved an annual productivity growth of seven per cent per annum from 2016 to 2020, and two per cent per annum over 2006 to 2020.

For the final decision, the ERA asked Engevity to provide advice on Western Power's revised proposal. Engevity notes in its updated advice that it weighed the following factors in arriving at its view for the draft decision:

- The average productivity of the five distributors selected by Synergies in its initial advice increased – using more recent benchmarking data not available at the time of Western Power's initial proposal – to between roughly zero and 2.6 per cent per annum over a five and 10-year period, respectively.
- [Engevity] considered Western Power's spread of customers is highly comparable to Endeavour Energy's profile, which was not included in Synergies analysis. Endeavour Energy achieved an average productivity growth of 7 per cent per annum from 2016 to 2020, and 2 per cent per annum over 2006–20.
- Of the five networks selected by Synergies, only Powercor and SA Power Networks are at the efficiency frontier. The average productivity of these two 'frontier distributors' was between roughly zero and 4 per cent per annum over a five- and 10-year period, respectively.
- [Engevity] considered there may be scope for Western Power to achieve greater OPEX efficiencies than what was included in its base OPEX forecast. Western Power's forecast had not identified additional CAPEX–OPEX trade-offs that are expected from its proposed SPS and AMI capex programs.
- Productivity changes for NEM transmission networks are less stable and do not show a strong trend over time relative to distribution OPEX productivity. So, [Engevity] had not sought to rely on the transmission data.

In its updated advice, Engevity acknowledges that making comparisons between Western Power and the NEM distributors based on reflective reporting periods is challenging – noting the productivity data is highly variable from year to-year. Considerable judgement is required by the ERA to estimate what Western Power can reasonably achieve acting prudently and efficiently in AA5.

Engevity advises that the most recent productivity trends of NEM distributors – using a range of estimates and comparisons from the AER's 2022 benchmarking report, is more consistent with its recommendation of two per cent, than Western Power's revised proposal of 0.5 per cent per annum.

> A productivity growth factor of 2 per cent is squarely within the range of performance of six highly comparable network businesses (1.6 – 2.5 per cent), the five best performing NEM distributors (1.7 – 2.4 per cent) and all 13 NEM distributors (1.7 – 2.4 per cent), over a 10 and five year period.

Taking account of the updated analysis provided by Engevity, the ERA maintains its position in the draft decision that it is reasonable to expect a service provider efficiently minimising

15 Ibid, p. 8.

costs would seek to achieve a productivity factor of two per cent per annum consistent with other network operators in Australia.

Required Amendment 3

Amend the productivity factor to two per cent per annum.

8.6 Indirect costs

The draft decision required Western Power to:

- Remove growth escalation
- Amend the productivity factor to two per cent.

The ERA has reviewed Western Power's revised operating expenditure model and is satisfied that growth escalation has been removed from indirect costs consistent with the draft decision.

However, Western Power has applied a productivity factor of 0.5 per cent. This is not consistent with the draft decision. As set out in the section above on the productivity factor, the ERA has maintained its draft decision requirement that a productivity factor of two per cent must be applied.

Required Amendment 4

Forecast indirect costs must be amended to be consistent with the ERA's final decision including:

- Amending base direct costs to adjust for 2021/22 actual labour escalation.
- Amending the productivity factor to two per cent.

8.7 Labour Cost Escalation

The draft decision noted that Western Power's forecasts to estimate labour escalation were out of date. However, as labour cost escalation is a relatively small component of Western Power's proposed costs the ERA did not amend the labour escalation component for the purposes of the draft decision. The ERA required Western Power to update its forecasts to reflect current data and noted it would review the forecast in the final decision, including ensuring that it is no higher than the assumed rate of productivity.

The labour escalation factor is calculated using the following formula:

$$Labour\ escalation\ factor = ((1 + WPI + EGWWS\ Premium)/(1 + CPI)) - 1$$

Where:

- WPI is the average of Wage Price Inflation forecast by WA Department of Treasury.
- EGWWS Premium is a premium that reflects a rate of wage price inflation for workers in the Electricity, Gas, Water and Waste Services Industry over the average of WPI for all workers. This is determined with reference to quarterly data published by the ABS.

- CPI is the average of the Consumer Price Inflation forecast by WA Department of Treasury.

In its initial proposal, Western Power used a labour escalation factor of 0.77 per cent.

In its revised proposal, Western Power has adopted a labour escalation factor of 0.29 per cent.

In its calculations for both the initial and revised proposal Western Power has applied an EGWWS premium of 0.4 per cent.

Synergy considers the assumption of 0.4 per cent is too high and not supported by the analysis presented in Western Power's access arrangement information. Synergy highlights a statement in the consultant's report that Western Power commissioned to estimate the labour escalation factor:

> … there is evidence that the EGWWS premium over All Industries growth has narrowed over time ….

As noted in Synergy's submission, the ERA allowed an EGWWS premium of 0.2 per cent for AA4. The actual premium over the AA4 period has been 0.1 per cent.

The ERA has reviewed the most recent quarterly data available from the ABS and considers it does not provide evidence to support a premium of 0.4 per cent. In this final decision, the ERA has amended the premium to 0.1 per cent based on the most recent data available.

The ERA has also updated the labour escalation factor to use the most recent forecast published by the WA Department of Treasury in December 2022. The combined effect of these adjustments results in a labour escalation factor of 0.218 per cent.

The ERA has also corrected Western Power's operating expenditure model which was erroneously applying labour escalation for the 2021/22 year to forecast changes during the AA5 period. As noted above, the ERA adjusted base operating expenditure (which is stated in June 2022 $) to reflect actual labour escalation for the 2021/22 year.

Required Amendment 5

The labour escalation factor must be amended to 0.218 per cent.

8.8 Total operating expenditure

For the reasons set out above, the ERA considers that Western Power's revised proposed forecast of operating expenditure is not consistent with the requirements of section 6.40.

The ERA's final decision on forecast operating expenditure is set out in Table 12 below.

Table 12: Final decision operating expenditure (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent network base costs	358.8	358.8	358.8	358.8	358.8	1,794.0
Step changes	19.1	21.8	24.1	26.8	29.8	121.6

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Total recurrent network costs	377.9	380.6	382.9	385.6	388.6	1,915.5
Network growth escalation	2.8	3.7	5.6	7.3	8.8	28.2
Productivity	(7.6)	(15.2)	(22.8)	(30.5)	(38.2)	(114.4)
Non-recurrent costs	10.9	10.2	5.0	4.9	4.9	35.8
Expensed Indirect costs	37.7	35.7	33.3	32.9	34.0	173.7
Labour cost escalation	0.6	1.1	1.6	2.2	2.7	8.2
Total	422.2	416.2	405.6	402.3	400.8	2,047.0

Source: ERA analysis

The ERA's final decision on indirect costs is set out in Table 13 below.

Table 13: Final decision indirect costs (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent network base costs	156.4	156.4	156.4	156.4	156.4	782.2
Step changes	13.6	13.6	13.6	13.6	13.6	68.2
Total recurrent network costs	170.1	170.1	170.1	170.1	170.1	850.4
Productivity	(3.4)	(6.7)	(10.0)	(13.2)	(16.3)	(49.7)
Total	166.7	163.4	160.1	156.9	153.7	800.8

Source: ERA analysis

Required Amendment 6

Forecast operating expenditure and indirect costs must be amended to be consistent with the ERA's final decision.

Appendix 1 Extract of relevant provisions from Access Code

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

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 cost; 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.

"**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*.

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

"**alternative options**" means alternatives to part or all of a *major augmentation* or *new facilities investment*, including *stand-alone power systems, storage works*, demand-side management and *generation* solutions (such as distributed *generation*), either instead of or in combination with *network augmentation*.