Economic Regulation Authority

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

Attachment 3B: AA5 Capital Expenditure

31 March 2023

D259006

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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. It should be read with all other parts of the final decision.

The final decision includes 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 forecast capital expenditure for AA5.

Target revenue for AA5 can include forecast capital costs that are reasonably expected to satisfy the new facilities investment test.

The new facilities investment test considers both the efficiency and purpose of an investment. The test ensures that prices increase only to the extent necessary to maintain the safety of the network and the reliability of provision of contracted covered services or, otherwise, there is a benefit to users that justifies an increase in prices.

In the draft decision the ERA determined that $3,712 million of $4,341 million capital expenditure proposed by Western Power in its revised proposal for AA5 was reasonably likely to meet the new facilities investment test.

In its revised proposal, Western Power has accepted the following reductions included in the draft decision:

- Network renewal undergrounding program - This relates to the conversion of overhead areas to underground power where the overhead assets have deteriorated and require replacement. Typically, this will require a contribution from local government to make up the cost difference between overhead and underground assets. The ERA agrees undergrounding can be a prudent management approach to overhead network renewal but the magnitude of the scale of work raises deliverability concerns. There were significant local government and contractor constraints in AA4 that would need to be overcome to deliver the proposed significant uplift in the size of the proposed program.
- Standalone power systems - The ERA agrees standalone power systems are a prudent long term transition strategy for the rural network but considers the proposed number of units is overly ambitious and risks the realisation of cost inefficiencies. Western Power delivered 187 units during AA4 and is proposing 10 times that level (1,861) for AA5. A slower ramp up will enable realisation of learning and technology cost efficiencies in AA6. The adjusted capital expenditure is based on 1,010 installations over AA5, consistent with State Government policy, compared with Western Power's proposal of 1,861.
- Other asset replacement - The ERA considered that the initial proposed replacement investment was not supported by actual asset condition. The ERA's technical consultant considered that the failure forecasts were based on age-risk relationships greater than observed historical performance. It considered this creates an upward bias in forecast failure rates. The adjustment aligns capital expenditure with actual expenditure incurred in AA4.
- Corporate real estate - A significant element of the forecast depot program costs was allocated to unplanned activities. The ERA has reduced this to reflect a more efficient cost.

The ERA's draft decision adjustments to undergrounding and standalone power systems reflected concerns about the deliverability and efficiency of the proposed level of expenditure. However, the ERA recognises these programs are integral to Western Power's strategy to address the transformation. Consequently, the ERA has made these investment categories subject to the investment adjustment mechanism.

The investment adjustment mechanism ensures that, if Western Power can scale up efficiently above the allowed level of expenditure during AA5, then the target revenue for AA6 will be adjusted to reflect the additional investment. It also ensures that if Western Power does not deliver its program to the approved level, target revenue for AA6 will be adjusted to reflect the underspend. This provides Western Power with the flexibility to focus activity and expenditure during AA5 to meet the challenges of the sector's transformation whilst protecting customers from incurring costs if these two programs are reduced during AA5.

The ERA has accepted the expenditure required to accelerate its advanced metering program so that most customers will have an advanced meter by the end of AA5. In its revised proposal, Western Power has identified that the expenditure required has reduced by $27.5 million to remove the cost of dual element metering.[1] The reduction in expenditure has been incorporated in the final decision.

Western Power proposed additional expenditure in its revised proposal. As set out in Table 1 below, the ERA has accepted some but not all of the proposed increases.

Table 1: Final decision on Western Power's revised proposed capital expenditure excluding forecast labour escalation and indirect costs (real $ million at June 2022)

Program	Final decision	Proposed	Reason
Transmission growth	$83.4 m	$83.4 m	The expenditure is for network expansion projects identified by Government to support the announced closures of coal fired generation. Approving the proposed expenditure is consistent with the Access Code objective to include consideration of the long-term interests of consumers in relation to reducing greenhouse gas emissions. As there is some uncertainty over the estimated costs and because some decisions about the projects will be made external to Western Power, the ERA has included the identified projects in the Investment Adjustment Mechanism. This will avoid any windfall gain to Western Power if it does not proceed with the projects or to cover any additional efficient costs if required during AA5 to deliver these projects. It is likely the projects will be identified in the next Whole of System Plan as "priority projects". If this does not occur, Western Power will need to demonstrate that the projects maximise the net benefit to consumers after considering all options and meet all aspects of the new facilities investment test.
Distribution growth	$29.1 m	$115.6 m	Western Power has not adequately considered other non-network options when determining the number of feeders requiring augmentation. The proposed unit costs do not reflect efficient costs and the new information provided with the proposed increase in expenditure, indicates that some of the original program included in the initial proposal (and draft decision) is no longer required.
Distribution reliability	$96.1 m	$190.1 m	Additional expenditure of $8.1 million for a program to replace insulators during 2022/23 in areas

1 A dual element meter can separately measure two things. For example total solar energy generated by a PV at the property and energy imported from the network.

Program	Final decision	Proposed	Reason
			currently experiencing poor reliability has been included in the final decision. Western Power's proposed expenditure of $183 million on six of the worst performing rural long feeders supplying approximately 6,000 customers has not been included in the final decision. The costs are high level based on desktop studies and assume that over half of the cost is for microgrids. The forecast improvement in reliability is between 25 to 50 per cent, which would still leave performance much worse than the legislated requirement and average performance. Instead, as discussed further in the section on service standards, an allowance of $88 million has been included to develop and implement an overall plan to address regional reliability including trialling different options, such as microgrids in some specific areas.
SCADA and IT	$0	$99.8 m	The revised proposal has not provided sufficient evidence of efficiency and prudency of investments. The expenditure included in the final decision for SCADA and IT provides an expenditure allowance that is already at the extreme upper end of expectations for Australian distributors and transmission service providers.
Decommissioning costs	$31.3 m	$31.3 m	This adjustment is consistent with the draft decision required amendment. As indicated in the draft decision, the decommissioning costs will be included in the standalone power system expenditure for the Investment Adjustment Mechanism.
Software as a service	$0	($28.2 m)	Western Power proposed to transfer $28.2 million from capital expenditure to operating expenditure based on an estimate of investment that 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.

In its revised proposal, Western Power proposed that distribution growth expenditure should be subject to the Investment Adjustment Mechanism due to uncertainties about electric vehicle take-up rates and potential changes to the distribution planning criteria. The ERA has not included distribution growth expenditure in the Investment Adjustment Mechanism because:

- Consistent with the price control determined in the framework and approach, it is important that Western Power is exposed to demand risk rather than just passing its costs through to customers. In the case of electric vehicle take-up, Western Power should be seeking ways to enable better utilisation of the existing network and reduce the need to expand the network to meet demand from electric vehicle charging.

- Any change to the planning criteria would be implemented through an amendment to the Technical Rules. The Access Code has provisions for dealing with cost increases or reductions due to amendments to the Technical Rules so that target revenue can be adjusted in the next period.

Table 2 below provides a comparison by investment category for AA5 and AA4. The final decision is $465 million or 14 per cent more than was approved for AA4 and $964 million or 33 per cent more than actual net expenditure in AA4.

Table 2: Final decision capital expenditure[2] (net real $ million at June 2022)

	AA5 Final decision $m	AA5 Western Power revised proposal $m	AA5 Draft decision $m	AA5 Western Power initial proposal $m	AA4 Actual $m	AA4 approved $m
Growth	563	667	441	436	385	641
Compliance (including reliability driven)	547	660	443	440	335	397
Asset replacement (includes undergrounding, standalone power systems and metering)	2,061	2,072	2,091	2,441	1,534	1,649
SCADA and IT	605	692	616	872	438	322
Corporate support	119	120	121	152	243	249
Total net capex	3,896	4,210	3,712	4,341	2,935	3,257

Source: ERA Analysis: Western Power and ERA target revenue model

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

2 Includes labour cost escalation and indirect costs.

2. Regulatory requirements

Section 6.51 of the Access Code provides for the target revenue for an access arrangement period to include forecast capital costs that are reasonably expected to satisfy the new facilities investment test.

The new facilities investment test considers both the efficiency and purpose of an investment. The test ensures that prices increase only to the extent necessary to maintain the safety of the network and the reliability of provision of contracted covered services or, otherwise, there is a benefit to users that justifies an increase in prices.

In the case of augmentations to the network for new demand, expenditure will meet the new facilities investment test when the investment is the efficiently delivered lowest cost option and the forecast additional revenue from the augmentation does not require an increase in prices.

As required under section 6.56 of the Access Code, the ERA published a guideline on factors that will be considered in new facilities investment test determinations.

An extract of the Access Code requirements relevant to the AA5 capital expenditure is included in Appendix 1.

3. Western Power's initial proposal

Western Power's initial total proposed capital expenditure for the AA5 period (net of capital contributions and including labour cost escalation and indirect costs) was $4,341 million. A summary of the proposed expenditure is set out in Table 3 below.

Table 3: Western Power's initial proposed net capital expenditure for AA5 (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5
Transmission network direct capital expenditure:						
Asset replacement and renewal	63.5	62.4	55.9	55.1	56.2	293.2
Growth	88.4	72.9	52.2	51.0	27.2	291.7
Improvement in service	0.0	0.0	0.0	0.0	0.0	0.0
Compliance	36.1	36.8	39.7	26.9	21.5	161.0
Total	**188.0**	**172.1**	**147.9**	**133.0**	**105.0**	**745.9**
Distribution network direct capital expenditure:						
Asset replacement and renewal	390.7	405.5	413.8	406.0	401.8	2,017.9
Growth	166.6	156.9	151.7	154.3	144.0	773.4
Improvement in service	0.2	0.0	0.0	0.0	0.0	0.2
Compliance	43.1	42.5	43.5	43.2	42.8	215.2
Total	**600.6**	**604.9**	**609.1**	**603.6**	**588.6**	**3,006.8**
SCADA & Telecommunications direct capital expenditure	72.0	72.4	84.3	80.1	84.4	413.1
Corporate direct capital expenditure	83.6	101.1	119.5	82.5	76.7	463.3
Total gross direct capital expenditure	**944.2**	**950.5**	**960.7**	**909.1**	**864.6**	**4,629.1**
Less contributions:						
Transmission growth	(57.5)	(31.3)	(31.3)	(31.3)	(11.7)	(163.0)
Distribution asset replacement	(27.3)	(35.5)	(45.5)	(54.4)	(56.4)	(219.2)
Distribution growth	(107.0)	(107.0)	(107.0)	(107.0)	(99.9)	(528.1)
Total contributions[3]	**(191.9)**	**(173.8)**	**(183.8)**	**(192.7)**	**(168.0)**	**(910.2)**
Total net direct capital expenditure	**752.3**	**776.7**	**776.9**	**716.4**	**696.6**	**3,718.9**
Add:						
Indirect costs	130.8	129.4	129.7	127.6	125.2	642.7
Labour escalation	11.1	16.5	21.9	25.8	29.4	104.7
Less allocations to contributions:						
Indirect costs	(22.3)	(19.3)	(20.5)	(22.7)	(19.7)	(104.6)
Labour escalation	(2.2)	(2.9)	(4.0)	(5.3)	(5.4)	(19.8)
Total gross capital expenditure	1,086.2	1,096.3	1,112.4	1062.5	1,019.2	5,376.5

3 Excludes labour cost escalation and indirect costs. Total contributions including labour cost escalation and indirect costs is $1,034.5 million.

	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5
Total contributions	(216.4)	(196.00	(208.40	(220.7)	(193.1)	(1,034.5**)**
Total net capital expenditure	**869.7**	**900.2**	**903.8**	**841.6**	**825.8**	**4,341.1**

Source: ERA analysis derived from Western Power access arrangement information

A comparison of Western Power's initial proposed capital expenditure for AA5 with actual expenditure during AA4 is set out below.

Table 4: Comparison of initial proposed AA5 total net capital expenditure with AA4 actual expenditure (real $ million at June 2022)

Expenditure category	AA5 proposed	AA4 actual	Increase/ (Reduction)
Transmission network direct capital expenditure:			
Asset replacement and renewal	293.2	204.4	88.8
Growth	291.7	355.2	(63.5)
Improvement in service	0.0	2.7	(2.7)
Compliance	161.0	105.9	55.1
Total	**745.9**	**668.2**	**77.7**
Distribution network direct capital expenditure:			
Asset replacement and renewal	2,017.9	1,301.1	716.8
Growth	773.4	781.1	(7.7)
Improvement in service	0.2	13.9	(13.7)
Compliance	215.2	155.1	60.1
Total	**3,006.8**	**2,251.2**	**755.6**
SCADA & telecommunications direct capital expenditure	413.1	196.4	216.7
Corporate direct capital expenditure	463.3	477.1	(13.8)
Gross direct capital expenditure	**4,629.1**	**3,592.9**	**1,036.2**
Add indirect costs and labour escalation	747.0	505.3	241.7
Less capital contributions and gifted assets	(1,035.0)	(1,049.0)	14.0
Total net capital expenditure	**4,341.1**	**3,049.0**[4]	**1,292.1**

Source: ERA analysis derived from Western Power access arrangement information

Western Power provided the following reasons for increases in forecast capital expenditure compared to the AA4 actual expenditure:

4 Includes $103.2 million for AMI communications expenditure.

- Transmission network**:** forecast capex was expected to increase to continue to address the ageing asset base, facilitate additional capacity for customer connection (including connection of renewable generation and load to meet carbon reduction requirements) and rationalise voltages, whilst improving network utilisation.
- Distribution network: the increase in forecast capex was driven primarily by the installation of standalone power systems, undergrounding programs (such as the Network Renewal Undergrounding Program), acceleration of the AMI deployment and maintaining safety performance of the network (including addressing ring main unit safe operating risk issues).
- SCADA and Telecommunications**:** there was a significant increase in forecast capex 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).

Further details of Western Power's initial proposal are incorporated in the ERA's draft decision below.

4. Submissions on initial proposal

Matters raised in submissions relevant to the determination of the AA5 forecast capital base included:

- Insufficient information to justify the significant expenditure in areas such as SCADA and telecommunications, SPS, undergrounding and AMI.
- Concerns with the lack of investment in transmission capacity to cater to areas suitable for large renewable generation, large industrial loads and electrification of industrial and processing sectors.
- The importance of ensuring only efficient investment is approved.
- Questions over the robustness of the standalone power system business cases and seeking assurance that it was less expensive than the existing solution. Also, submissions questioned whether operating cost alternatives and outsourcing was considered by Western Power as alternatives.
- Ensuring Western Power has justified the long-term benefits and considered alternatives and the effect of obsolescence in its proposal for the SCADA and telecommunications expenditure.
- Mixed support for undergrounding expenditure, with concerns in ensuring long term benefits are demonstrated and that it is the lowest cost alternative.
- While there was some support for accelerating the rollout of advanced meters, concerns were raised whether the investment was efficient.
- Concerns about the level of spending in this proposal given the potential for additional costs during AA5.

5. Draft decision

Section 6.51 of the Access Code provides for the target revenue for an access arrangement period to include capital costs calculated for an amount of forecast new facilities investment that is reasonably expected to satisfy the test in section 6.51A of the Access Code.

Western Power determined amounts of forecast capital expenditure to be notionally added to the capital base by deriving a total amount of forecast capital expenditure and subtracting a forecast of capital contributions.

The approach taken by the ERA to assess whether the forecast capital expenditure satisfies the new facilities investment test was to:

- Assess whether the forecast capital expenditure was reasonably expected to satisfy the efficiency test under section 6.52(a) of the Access Code
- Assess whether Western Power had made a reasonable forecast of the amount of capital expenditure that would satisfy the new facilities investment in its entirety.

The ERA's consultant, Engevity, provided advice to assist the ERA in its review. Engevity's review included an assessment of Western Power's governance processes, asset management strategies and forecasts.

Engevity advised that its review of Western Power's investment governance framework (IGF) found that it was consistent with good industry practice and had appropriate check points and approvals for investment, which, if applied appropriately, should be capable of producing prudent and efficient outcomes.

Engevity specifically considered Western Power's performance on cost estimation. Engevity reported that its detailed reviews of Western Power's application of the IGF to the AA4 historical expenditure found that:

- For a number of significant investments, the project scope was not sufficiently defined at the time of the access arrangement to deliver a "50 per cent probability of exceedance" at a portfolio level to ensure that risk was shared appropriately between the business and customers under the regulatory incentive arrangements.
- The options analysis in business case documents dismissed reasonable alternatives on a qualitative basis as unsuitable, without appropriate analysis of cost, timing or benefits.[5]
- Some projects included explicit or implicit cost or scope contingencies in estimates that typically equate to 8-10 per cent of overall project costs and effectively change a +/- 10% estimate to a +0%/ -10% estimate.

Engevity acknowledged that the asymmetry in governance and change thresholds was designed to encourage delivery efficiencies to be realised by project managers, however, it also introduced a clear bias towards overstating project cost that becomes problematic for regulatory forecasts. Engevity considered that without an appropriate correction for this bias

5 For example, the HAY-MIL switchboard project initially dismissed a refurbishment option as unacceptable whilst noting that it would be significantly lower cost, instead Western Power Proposed a $29.9m replacement option which was included in the AA4 Further Financial Decision allowance. On further investigation, the preferred replacement option was costed in the Business Case at $62.1m, resulting in Western Power investigating and adopting a refurbishment option with the original equipment manufacturer with an actual cost of $12.3m over AA4, 80% under the reported market replacement cost, 59% under the Access Arrangement budget and 8.9% under the Gate 3 Business Case cost estimate for the refurbishment option.

in the regulatory capital expenditure forecasts, the total portfolio cost would also be overstated by a similar proportion.

Therefore, whilst the IGF itself represented sound governance processes, the quality of the project information and analysis unavoidably affected the accuracy of project costs and their suitability for regulatory forecasting purposes at a portfolio level.

In Engevity's opinion, the design of the stage gated approval system and change control management was comparable to processes employed by industry peers and appropriate for the works. However, the consistent application of the framework, associated processes and input information was a concern.

Engevity reviewed the application and effectiveness of the IGF through a review of audits done by Western Power and a spot check of supplied project information. Engevity made the following observations in relation to an internal audit report on the IGF undertaken in 2018:

- The Investment governance audit report supplied (assumed to be the most recent report) was from 2018. Given the central role of the investment governance system as a risk management tool, there is merit in more frequent audits at least every two years if not annual reviews.
- Basic metrics such as percentage of investments compliant with IGF requirements and objectives are not supplied in the audit report. Additional metrics relating to systems effectiveness including percentage of projects falling within IGF cost, schedule and benefits tolerances are not supplied. These IGF effectiveness metrics should be collated and analysed for continuous improvement opportunities.
- With these qualifications in mind, we note our previous observations on the impact of cost and scope contingencies, the relatively poor predictability of outturn costs within the Business Case accuracy and the need to correct the inherent bias that has been observed through our review of Western Power's CAPEX portfolio in AA4 and AA5.

Engevity noted that Western Power's internal audit reporting found that the IGF design was adequate and fit for purpose and was operating effectively. However, although the internal audit indicated no major issues with the application of the IGF, it was silent on the effectiveness of the framework in meeting cost, schedule and benefits realisation tolerances at key decision milestones.

Engevity also conducted a spot check of a sample of projects supplied by Western Power to evaluate compliance with IGF rules and IGF systems effectiveness. Its observations were as follows:

- Actual costs were within 10% of Gate 3 (detailed business case) estimates four times out of nine if costs were not adjusted for scope changes.
- Many of the projects experienced material and multiple scope changes during execution. If budget costs were adjusted for scope change, actual cost was within 10% of Gate 3 estimates for two projects out of nine and not within 10% of Gate 3 estimate for seven out of nine projects.
- Five of the nine projects were completed more than 12 months after the Gate 3 approved "Asset in Service". Four projects were delivered two years beyond their original completion date.
- Many of the projects experienced material and multiple scope changes during execution.
- In Engevity's opinion, the quality of the change control documentation and detail of the new facilities investment test (NFIT) 'look-back' reports was higher than many Australian

utilities.[6] However, the reconciliation of project costs and asset quantities to regulatory models was difficult, and in some cases not possible with the information provided.

Engevity considered that, while project costs were a mixture of underruns and overruns relative to the detailed business case, the project schedule was primarily overrun. Four of nine projects were completed two years after the completion data anticipated at the time of investment decision. Engevity noted these very long delays can distort the perspective of project outcomes when looking at spend within an access arrangement period and not considering the whole of project cost. Engevity noted that, while it had not analysed the full AA4 portfolio, a systemic bias to late delivery of projects (as suggested, but not proven by the 13 NFIT projects that were reviewed) would result in a significantly overstated AA5 capital expenditure forecast.

Engevity noted the asset management framework and systems used by Western Power had previously been reviewed against ISO 55000 and the ERA asset management system requirements and found to be compliant.

Engevity acknowledged achieving ISO 55001:2014 certification is a significant achievement and demonstrated Western Power's asset management system addressed all of the elements of the standard. However, the accreditation is for the system itself and focuses heavily on the documentation of appropriate systems and processes and less on the outcomes delivered by the system (which is essentially the focus of Engevity's review). It does not provide assurance over the outcomes or the quality of the inputs to the asset management system.

Engevity highlighted the following findings from the 2020 Asset Management System Review report completed by AMCL:

> "In general, it was observed that Western Power has developed a sophisticated, well-structured and disciplined Asset Management System. Through the documentation review and tele-interview process Western Power demonstrated clear intent in its application of the system and diligence in its upkeep. AMCL observes that attaining certification to the ISO55001 standard has clearly facilitated ongoing maturity development of Western Power's approach to asset management. Documentation for policies and procedures was both comprehensive and "useable", with few gaps observed. Where gaps were observed, they mostly (with some exceptions) tended to be around their currency and application as opposed to whether documentation was lacking for key asset management processes." [7]
>
> …
>
> "… Western Power were unable to effectively demonstrate that non-asset options were routinely considered, identified and appropriately investigated at the planning stages of project development. It was not clear that the concept of non-asset options was well understood or applied consistently. Western Power were unable to demonstrate that an effective Demand Management Policy, or framework was established and operating…
>
> …Western Power were unable to provide a consistent view on the application of lifecycle costing at network investment decision making level.
>
> The ability of Western Power to demonstrate how operational costs were factored into reinvestment decisions was not clear. There appeared to be limited policy and guidance around the costing principles to be used whilst evaluating life cycle costs. This should

[6] Engevity expect that this is mainly due to the ex-post review of historical investment under the WA regulatory framework. In comparison the incentive arrangements under the AER regulated businesses are designed to reward outperformance on both total CAPEX and total OPEX. They limit the scope for ex-post CAPEX reviews to material overspends of the total regulatory CAPEX allowance – which has generally been avoided by networks since the introduction of the possible ex-post review.

[7] AMCL, Western Power 2020 Asset Management System Review Report, Version: v4-0, 30 November 2020, Page 6 of 204.

> include consideration of ongoing or escalating operational costs and risk costs associated with time view of investment.
>
> In particular, no overarching documentation by way of a framework or guideline was able to be identified that provided guidance on the application of lifecycle costs in asset class strategies, options analysis, investment decisions, equipment procurement, or other decisions where this should be a consideration." [8]

Engevity reviewed the inputs and forecast outcomes or the asset management plans and made the following observations:

- The risk-based approach to asset management used by Western Power is consistent with the principles of good industry practice. Western Power has applied data driven methods and expert judgement to attempt to quantify the likelihood of failure events. The conversion of failures to consequences is built on historical data but forecast trends do not reasonably align with recent performance. Monetisation of the consequences has used industry recognised methods and references, however in the case of the financial analysis prepared for the AMI program, the VCR assumption of $50k/MWh is approximately twice the AER's most recent NEM residential average. The outcomes of the risk-based approach are prioritised and optimised using a process that engages appropriate subject matter experts and executive level management.
- The risk-based approach is data intensive. In a self-assessment Western Power has indicated gaps in underlying data are contributing to conservatism in asset management planning. This has been a persistent problem and it is unclear from the current submission the extent to which it will be resolved.

Based on Engevity's analysis and advice, the ERA considered Western Power's governance and planning processes were generally good. However, application of the processes in some cases was lacking and some data (particularly in relation to the risk-based planning tools) required improvement. The ERA considered this had particular implications for the assessment of forecast expenditure on new activities such as standalone power systems, the network renewal and undergrounding program and SCADA/IT expenditure.

In making its assessment of the level of expenditure for AA5 reasonably likely to meet the requirements of the new facilities investment test, the ERA considered the level of historical expenditure, information provided by Western Power, stakeholder submissions and advice from Engevity.

The ERA determined some of Western Power's forecast expenditure was not reasonably likely to satisfy the new facilities investment test. In addition, for some proposed investments further evidence was needed to demonstrate the forecast expenditure was reasonably likely to satisfy the new facilities investment test. The ERA's assessment of forecast capital expenditure for growth, asset replacement, improvement in service, compliance, SCADA and corporate services is addressed below.

Consistent with the approach taken by Western Power in its initial proposal, the forecast values are presented as direct capital costs – without indirect costs and labour escalation.

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[8] AMCL, Western Power 2020 Asset Management System Review Report, Version: v4-0, 30 November 2020, Page 141 of 204.

5.1 Growth

Western Power's initial proposed growth capital expenditure is set out in Table 5 below.

Table 5: Western Power's initial proposed growth capital expenditure for AA5 – excluding forecast labour escalation and indirect costs (real $ million at June 2022)

Expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actuals
Transmission network							
Capacity expansion	27.4	38.9	18.2	16.9	12.8	114.2	88.2
Customer driven	61.0	34.0	34.0	34.0	14.5	177.6	267.0
Total	88.4	72.9	52.2	51.0	27.2	291.7	355.2
Less contributions	(57.5)	(31.3)	(31.3)	(31.3)	(11.7)	(163.0)	(239.0)
Net capital expenditure	**30.8**	**41.7**	**21.0**	**19.7**	**15.6**	**128.8**	**116.2**
Distribution network							
Capacity expansion	34.0	24.3	19.1	21.7	18.4	117.5	59.5
Customer driven	95.0	95.0	95.0	95.0	87.9	468.0	457.2
Gifted assets	37.6	37.6	37.6	37.6	37.6	188.0	264.3
Total	166.6	156.9	151.7	154.3	144.0	773.4	781.1
Less contributions	(107.0)	(107.0)	(107.0)	(107.0)	(99.9)	(528.1)	(631.2)
Net capital expenditure	**59.6**	**49.9**	**44.7**	**47.3**	**44.0**	**245.4**	**149.9**
Total network							
Gross capital expenditure	255.0	229.8	203.9	205.3	171.2	1,065.1	1,136.3
Net capital expenditure	90.4	91.6	65.7	67.0	59.6	374.2	266.1

Source: ERA analysis of Western Power data

Western Power stated that the transmission capacity expansion investment was focused on optimising against asset condition and regional strategies.

The transmission customer driven expenditure category comprises all the capital expenditure 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.

For the distribution network, Western Power stated that the number of over-utilised feeders was forecast to increase compared to previous years that had flat or negative growth in areas. Dependent on customer responses to hot weather events, it considered investment would be required to cater for load growth and avoid premature asset ageing. Additionally, Western Power expected to continue to see PV uptake on rooftops, resulting in a continued decline in daytime minimum load that increased the probability of localised over-voltages and required investment to mitigate the risk of non-compliance.

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. As this category of investment generally includes high volumes of low-cost works, Western Power considered historical expenditure tends to be a good indicator of future investment.

Several concerns in relation to growth expenditure were raised in stakeholder submissions:

- Alinta Energy supported the interim and 2050 emissions reduction targets but noted that without plans for investment in transmission capacity to enable the connection of large-scale renewable generation, these targets would be untenable, especially considering the long lead times of transmission infrastructure and generation projects. Alinta also noted that the access arrangement did not include a plan for the investments required to electrify transport. Alinta noted that Western Power mentioned that hydrogen and sector coupling can help decarbonise hard to abate sectors but had not detailed how the network would need to evolve to enable this.[9]
- The Australian Energy Council expressed concern about the lack of transmission network augmentation to support large renewable projects. It noted that its consultant Marsden Jacobs Associates had recommended a review of Western Power's transmission planning process and giving consideration to significant network upgrades to support the creation of renewable energy zones in the North Country, East Country, and the Muja region to facilitate efficient grid connection of large-scale renewable generators and decrease the risk of congestion.[10]
- The Chamber of Minerals and Energy sought further clarity on how Western Power planned to support the growth and decarbonisation requirements of large industrial consumers and generators on both the transmission and distribution network, particularly as companies seek to further electrify operations, and consider expansion opportunities or new connections.[11]
- Collgar Windfarm noted that even with declining operational demand, the location of that demand was likely to vary from current patterns. It also noted that renewable resource availability is an important factor in locating new facilities, which may not align with network availability. Given this, it stated that it was foreseeable that investment in transmission infrastructure would be required to service new loads and generation facilities.[12]
- Synergy wanted further clarity on why there was an increase in capacity expansion expenditure. It noted the increase in transmission capacity expansion expenditure between the AA4 and AA5 periods and given Western Power's statement that it expected peak demand would fall over the AA5 period, it sought to understand why Western Power was forecasting a pick-up in capacity expansion capex relative to that in AA4.[13]

9 Alinta Energy, 20 April 22, Public submissions on issues paper, p. 3.

10 AEC, 20 April 22, Public submissions on issues paper, pp. 3, 4, online.

11 The Chamber of Minerals and Energy of WA, 22 April 22, Public submissions on issues paper, p. 3.

12 Collgar Wind Farm, 20 April 22, Public submissions on issues paper, p. 3.

13 Synergy, 20 April 22, Target Rev and price control submission, Public submissions on issues paper, p. 61.

The ERA's technical consultant identified issues with Western Power's demand forecasts and planning for growth.

Engevity considered the near-term tasks to sustain the existing transmission network were robust but that long-term planning was less developed.

The ERA noted the Government had commenced a comprehensive assessment of electricity demand to inform future network requirements that would be undertaken ahead of the next Whole of System Plan, which is required by 2025.[14] The draft decision noted that if the Whole of System Plan identified that significant expenditure was required before June 2027 the access arrangement could be re-opened.

In relation to the customer and demand forecasts Engevity considered:[15]

> Western Power's energy forecasts are driven by historical relationships – for example between energy consumption and economic activity, electricity prices, and substitution factors. However, this forecasting approach is not consistent with Western Power's proposal to undertake a network transformation program to respond to the major changes in its operating environment.
>
> Western Power has not adequately considered the 'structural changes' in demand, including the adoption of new technologies like EVs [electric vehicles] and battery storage, that are not reflected in the historical data. Other factors such as:
>
> - the expected size of newly installed solar PV [photovoltaic] systems, which has increased significantly over time, with 6-10kW systems typical and 13kW+ not uncommon. Five years ago, 3-7kW systems were typical. 10 years ago, 1.5kW systems were the norm.
> - the level of saturation of rooftop PV and other forms of DER within different areas of the network, for example, it is not plausible that penetration exceeds the number of residential buildings in the area.
> - the consumption behaviour of new customers, as compared to existing.
> - customers' response to new tariff structures being proposed by Western Power.
>
> also mean assuming historical relationships will largely continue through the AA5 and AA6 periods is clearly a flawed approach.
>
> For example, increasing uptake of behind-the-meter batteries and EVs is likely to offset some of the impact of the higher solar PV penetration that is driving lower minimum demand periods. This impact will be more significant if cost reflective pricing structures are implemented to smooth demand for consumption and export services as much as possible. Western Power proposes a very low, 'super off-peak' energy price for consumption to encourage more use of the network during periods when solar panels are exporting renewable energy to the grid.[16] By design, this will encourage customers to shift load to and charge their EVs during the middle of the day where they are able.
>
> Western Power proposes new investment to overcome minimum demand issues but does not account for the above factors, nor does it include sensitivity analysis. This is a significant error. The benefits of Western Power's proposed CAPEX will be overstated – all other things being equal.
>
> Further, Western Power's approach and input assumptions do not appear to:
>
> - align with AEMO's latest forecasts (2021 ESOO) of DER [Distributed Energy Resources] uptake (e.g., PV);

[14] Government media statement published 24 August 2022– Assessment of electricity demand to inform WA's future network.

[15] Engevity, August 2022, Western Power AA5 Expenditure Proposal Review Executive Summary, pp. 28-29.

[16] Western Power access arrangement proposal, Tariff Structure Statement Overview, Appendix F.1, p. 3.

- account for potential changes in the size of future PV systems (as compared to historical);
- contemplate how the spatial take up of PV may change over time (relative to history).

Engevity noted the effect was unlikely to be material in the near term (< 5 years) but had implications for the asset management plans prepared for AA5 for long lived assets. Further, as noted in Attachment 1 on target revenue and Attachment 11 on network tariffs, updated demand forecasts were also required for tariff modelling purposes. The ERA expected Western Power to provide updated customer and demand forecasts with its response to the draft decision that addressed the issues identified.

As the proposed growth expenditure was at a similar level to AA4 actual expenditure, the ERA did not amend the growth expenditure in the draft decision.

5.2 Asset replacement and renewal

Western Power's initial proposed asset replacement and renewal expenditure is set out in Table 6 below.

Table 6: Western Power's proposed asset replacement and renewal capital expenditure for AA5 – excluding forecast labour escalation and indirect costs (real $ million at June 2022)

Expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actuals
Transmission asset replacement and renewal							
Primary plant	26.3	23.0	21.9	22.0	22.0	115.1	60.3
Protection	15.0	15.0	15.0	15.0	15.0	74.8	33.2
Power transformers	14.1	15.0	12.0	11.6	11.9	64.5	42.9
Switchboards	5.7	9.4	3.4	2.4	1.6	22.5	27.8
Other	2.5	0.0	3.7	4.2	5.8	16.3	40.3
Total	**63.5**	**62.4**	**55.9**	**55.1**	**56.2**	**293.2**	**204.4**
Distribution asset replacement and renewal							
Pole management	77.7	77.9	67.1	70.1	69.9	362.7	637.7
Asset replacement	119.7	107.7	80.3	67.6	66.1	441.5	402.5
Standalone power systems	51.9	53.2	52.4	62.3	63.5	283.3	38.2
Network renewal undergrounding program	70.5	97.8	138.4	137.8	138.9	583.4	12.6
Metering	60.9	59.0	65.6	58.2	53.4	297.0	159.6
Streetlights	10.0	10.0	10.0	10.0	10.0	49.9	50.4
Total gross capital expenditure	**390.7**	**405.5**	**413.8**	**406.0**	**401.8**	**2,017.9**	**1,301.1**

Expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actuals
Less contributions	(27.3)	(35.5)	(45.5)	(54.4)	(56.4)	(219.2)	(76.5)
Total net capital expenditure	**363.4**	**370.0**	**368.3**	**351.6**	**345.5**	**1,798.7**	**1,224.6**
Total asset replacement and renewal							
Gross expenditure	454.2	467.9	469.7	461.1	458.0	2,311.1	1,505.5
Net expenditure	426.9	432.4	424.2	406.7	401.6	2,091.9	1,429.0

Source: ERA analysis of Western Power data

The proposed transmission asset replacement and renewal expenditure was $88.8 million (43 per cent) higher than actual AA4 expenditure. It included increased expenditure for primary plant, protection and power transformers offset by reduction in switchboards and other.

The proposed distribution asset replacement and renewal net expenditure was $574.1 million (47 per cent) higher than actual AA4 expenditure. This was primarily due to programs related to transformation initiatives – standalone power systems, the network renewal undergrounding program and accelerating the rollout of advanced meters.

The ERA did not consider all the proposed asset replacement and renewal expenditure was reasonably likely to meet the new facilities investment test. The adjustments the ERA made in the draft decision are set out in Table 7 below.

Table 7: ERA draft decision adjustments to proposed asset replacement and renewal capital expenditure – excluding forecast labour escalation and indirect costs (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Proposed expenditure:						
Transmission	63.5	62.4	55.9	55.1	56.2	293.2
Distribution	390.7	405.5	413.8	406.0	401.8	2,017.9
Total	**454.2**	**467.9**	**469.7**	**461.1**	**458.0**	**2,311.1**
Adjustments						
Standalone power systems	(32.6)	(25.4)	(16.3)	(17.7)	(10.6)	(102.6)
Network renewal undergrounding program	(8.5)	(11.3)	(16.8)	(15.1)	(15.0)	(66.8)
Other asset replacement:						
Transmission	(18.5)	(18.2)	(16.3)	(16.0)	(16.4)	(85.3)
Distribution	(16.2)	(15.0)	(11.5)	(9.9)	(9.7)	(62.3)
Total	**(34.7)**	**(33.2)**	**(27.8)**	**(25.9)**	**(26.1)**	**(147.6)**
Draft decision:						
Transmission	45.1	44.2	39.7	39.1	39.9	207.9
Distribution	333.4	353.7	369.2	363.3	366.6	1,786.2

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Total	**378.4**	**398.0**	**408.8**	**402.4**	**406.3**	**1,994.1**

Source: ERA analysis

The reasons for the ERA's adjustments are set out below.

5.3 Standalone power systems

Western Power stated that, consistent with its Grid Strategy and Corporate Strategy, standalone power systems (SPS) would be deployed during the AA5 period where the SPS solution was determined to be the least cost solution over the long term, as an alternative option to replacing the overhead network.

It noted that 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.

Western Power noted that SPS has a higher upfront cost in the period it is installed, however, it considered that it was cheaper than traditional network over the lifetime. Western Power considered that, not only was this solution lower cost over the long term, but it also provided greater benefits for customers in both safety and reliability performance.

Western Power planned to transition 4,000 existing connection points to either SPS or proactive supply abolishment by 2031. Approximately 1,861 units or equivalent were scheduled for deployment in the distribution area over the AA5 period. This included 1,630 SPS equivalents for the SPS program and 230 SPS equivalents to enable microgrids.

Western Power noted that that cost efficiency would be facilitated through competitive tendering processes to select vendors for the provision of turnkey SPS solutions.

Western Power stated that 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.

There were several stakeholder submissions on SPS:

- The WA Expert Consumer Panel strongly agreed with the strategy of a modular grid over time but considered that the business cases should be assessed in detail to ascertain whether a time delay would result in more optimal outcomes. For example, the ERA should consider if the overhead lines connecting the SAP need to be replaced today or in ten years' time, as this is critical for justifying the business case.[17]
- Synergy's view was that it is essential WP tests the contract market to determine whether operating cost provision of SPS solutions can be delivered at a lower cost than WP capex solutions.[18]
- Perth Energy's submission suggested that SPS should be regularly reviewed to assess whether the capital outlays can be justified based on savings gained during the AA5

[17] WA Expert Consumer Panel, 29 April 22, Attachment 1, Public submissions on issues paper, p. 12.

[18] Synergy, Target Rev and price control submission, 20 April 22, Public submissions on issues paper, p. 63.

period. If the savings are longer term, then perhaps the programs should be slowed or deferred as part of holding down prices through the coming five years.[19]

- The AEC's view was that:
  - Standalone power systems should only be installed in parts of the network where it is cheaper than maintaining the existing network.
  - The focus should be on minimising the forward-looking costs and not on historical investment costs. Even if standalone power systems are cheaper than maintaining the existing network they should not be installed if the assets they replace have not been fully depreciated and need to be written down.
  - Competition should be encouraged in the provision of stand-alone power systems and the ERA should closely scrutinise the installation of the standalone power systems to ensure that Western Power undertakes a competitive tendering process to select vendors.[20]
- Change Energy supported any initiative that reduced the cost of supply of electricity sustainably over the long term. However, it did not consider Western Power had adequately demonstrated that disconnecting customers from the network, and creating smaller, disconnected networks was in fact in the long-term interests of end use consumers. Change Energy recommended that the ERA seeks an economic assessment of Western Power's proposed network strategy, together with the alternative options considered. In particular, Change Energy expected Western Power to fully consider and calculate the costs and benefits of building out the network constraints, and presented an unbiased comparison against a similar cost benefit analysis of the modular network. Given the potential cost and implications of making such a dramatic shift in network strategy, Change Energy considered a robust business case, tested with stakeholders, was a reasonable prerequisite.[21]
- Collgar generally supported the approach to transition to a modular network as it provides the most cost-effective solution to meet future requirements. However, Collgar had concerns about Western Power's proposed execution approach.[22]
- The Australian Microgrid Centre of Excellence considered it was questionable whether the number of SPS systems being proposed for this Access Arrangement Period represented value for money to WA consumers. It considered the development of microgrids proper would unlock economies of scale when compared to the large number of SPS systems being proposed in locations adjacent on the grid. It was unclear how Western Power was planning the actual transition to a hybrid network in regional areas in WA.[23]

The ERA's technical consultant considered that the standalone power system program was justified in principle but had concerns around the deliverability and efficiency of the proposed investment:

- The proposed expenditure had not been demonstrated to be efficient due to comparatively high unit costs for the SPS units and lack of evidence that SPS's currently offer a more cost-effective solution for supply to customers than like-for-like replacement of overhead distribution network assets.

[19] Perth Energy, 20 April 22, Public submissions on issues paper, p. 61.

[20] AEC, 20 April 22, Public submissions on issues paper, p. 3.

[21] Change Energy, 20 April 22, Public submissions on issues paper, p. 3.

[22] Collgar Wind Farm, 20 April 22, Public submissions on issues paper, p. 3.

[23] Australian Microgrid Centre of Excellence, 20 April 22, Public submissions on issues paper, p. 2.

- A reasonable range of alternative options had not been considered for the proposed investment. Engevity has not been provided with sufficient information, such as net present value (NPV) models and options assessments, to be confident that Western Power had undertaken options analysis for autonomous overhead distribution replacement that had considered the costs, risks and benefits of all options. The information provided had not shown that the scope and timing of the AA5 proposed SPS program was the most efficient solution to providing reliable, high quality supply to its customers.
- Western Power engaged Mainsheet Capital over two phases to quantify the potential costs and benefits of the SPS program, with phase two being completed in February 2021. In phase one, Mainsheet Capital found that a 30 year SPS program to transition 6000 connections had the lowest net present cost (NPC) of the options assessed. In phase two, Mainsheet Capital set out options to improve the efficiency of the SPS program, including potential justifications for an accelerated program. In Mainsheet Capital's words:[24]
  - Aggressive assumptions needed to be applied to justify SPS acceleration from a financial perspective. If more conservative assumptions were applied, a longer transition timeframe is likely to be optimal, whilst actively continuing to progress cost reductions and supply abolishment.
- Engevity found systemic issues with Western Power's approach to asset and risk management resulting in potential premature replacement of network assets. Engevity viewed this as further reason to reduce the scope of AA5 SPS investment such that Western Power can demonstrate a more robust approach to identifying efficient areas of the autonomous distribution network to replace with SPSs when proposing further investment in AA6 and beyond.
- Overall, Engevity found the SPS program not cost efficient due to high unit costs and lack of evidence that SPSs currently offer a more cost-effective solution for supply to customers than like-for-like replacement of overhead distribution network assets. Engevity's concerns with the cost efficiency of the AA5 SPS program can be grouped into three categories:
  - SPS base unit costs are very high considering the components involved and compared to similarly sized SPS units available on the retail market.
  - Per customer costs for SPS customers not evidenced to be less than current costs based on Western Power's cost to serve (CTS) metric.
  - No evidence has been provided that the cost of AA5 SPS program is materially recovered from reduced distribution replacement costs or other benefits in AA5 or beyond.

The ERA agreed standalone power systems are a prudent long term transition strategy for the rural network but considered the proposed number of units as overly ambitious and risks the realisation of cost inefficiencies. On that basis, the ERA did not consider the proposed expenditure as reasonably likely to meet the requirements of the new facilities investment test.

As set out in Table 7, the ERA reduced expenditure for standalone power systems by $102.6 million. The adjusted capital expenditure is based on 1,010 installations over AA5 compared with Western Power's proposal of 1,861.

The ERA did not reduce Western Power's proposed unit costs in the draft decision. As identified in Engevity's report, the proposed unit costs are high compared to similarly sized

[24] Mainsheet Capital, Feb 2021, Phase two: Portfolio Benefits Evaluation, p. 22.

units available on the retail market. However, the costs are not well understood at this point. The reduction in the number of standalone power systems provided for in the draft decision will enable realisation of learning and technology cost efficiencies. This applies to both the cost of the standalone power systems and the ability to identify parts of the network where it is more efficient to replace overhead lines with standalone power systems.

The adjustment to expenditure reflects concerns about the deliverability and efficiency of the proposed level of expenditure. However, the ERA recognised that the standalone power program is integral to Western Power's strategy to address the transformation. Consequently, standalone power expenditure is subject to the Investment Adjustment Mechanism.

The Investment Adjustment Mechanism ensures that, if Western Power can scale up efficiently during AA5, the target revenue for AA6 will be adjusted to reflect the additional investment. It also ensures that if Western Power does not deliver its program target, revenue for AA6 will be adjusted to reflect the underspend. This provides Western Power with the flexibility to focus activity and expenditure during AA5 to meet the challenges of the sector's transformation whilst protecting customers from incurring costs if the programs are reduced during AA5.

Actual expenditure during the AA5 period will be subject to an ex-post review at the next access arrangement review. Western Power will need to demonstrate that its actual unit costs are least cost and that it has only installed standalone power systems where it is more efficient to do so than maintain the overhead network. If Western Power cannot demonstrate this, it will not be permitted to recover the costs from customers through network tariffs.

5.4 Network Renewal Undergrounding Program

The Network Renewal Undergrounding Program (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.

Where a funding gap in proposed projects is identified, Western Power stated that it will seek to underground the network through financial partnerships with local communities (via the relevant local governments).

Western Power considered the need for this investment was driven by a significant part of the metropolitan overhead network reaching the end of its service life. Western Power stated that it 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. 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.

Stakeholder submissions included the following comments:

- The WA Expert Consumer Panel's experience was that undergrounding costs could be 5 to 10 times higher than overhead construction. While the costs were being shared with councils, the panel was concerned that WA citizens could be paying too high a price for undergrounding.[25]

- WALGA understood the many positives that undergrounding brought but noted that the ratepayer contribution was increasing.[26]
- The Australian Energy Council considered the undergrounding expenditure should be justified as the least cost solution, otherwise work should be deferred.[27]

The ERA's technical consultant advised that Western Power experienced significant cost and delivery time over-runs during the AA4 period due to inaccurate scoping estimates of costs, local council challenges to deliver multiple projects, local government approval processes and contractor pricing and availability issues.[28]

The ERA considered that, although the NRUP could be a prudent management approach to overhead network renewal, the magnitude of the scale up raised deliverability concerns. Deliverability encompasses both the ability to undertake the works required and that the relevant council is able to pay the contribution needed. Information provided by Western Power on potential undergrounding projects indicated undergrounding would be more costly than like for like replacement in most cases and a contribution would be required. There were significant local government and contractor constraints in AA4 that would need to be overcome to deliver the proposed significant uplift in the size of the proposed program. On that basis, the ERA did not consider the proposed expenditure was reasonably likely to meet the requirements of the new facilities investment test.

As set out in Table 7, the ERA reduced expenditure for the NRUP by $66.8 million. This adjustment brought the proposed expenditure in line with actual expenditure during AA4 on undergrounding.

The adjustment reflected concerns about the deliverability of the proposed level of expenditure. However, the ERA recognised the NRUP was integral to Western Power's strategy to address the transformation so made the NRUP expenditure subject to the Investment Adjustment Mechanism similar to standalone power system expenditure.

5.5 Metering

Western Power commenced deployment of advanced meters in 2019.[29] 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.

Western Power considered advanced meters play a key role in a range of emerging network requirements which require increased visibility (and potentially control) of the distribution network. It considered advanced meters are 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.

25 WA Expert Consumer Panel, 29 April 22, Attachment 1, Public submissions on issues paper, p. 12.

26 WALGA, 20 April 22, Public submissions on issues paper, p. 9.

27 AEC, 20 April 22, Public submissions on issues paper, p. 8.

28 Engevity, August 2022, Western Power AA5 Expenditure Proposal Review Executive Summary, p. 13.

29 Western Power describes advanced meters as being digital meters with a communication device installed. Western Power stated that the advanced meters can automatically and remotely read electricity flows and provide early detection of connection faults and supply issues including power quality data, voltage and current levels and how much renewable energy is being fed back into the network.

Western Power proposed to accelerate its advanced metering program so that most customers will have an advanced meter by the end of AA5. Under its business-as-usual approach (i.e. installing advanced meters in new properties, meter replacements and meter exchanges initiated by customers) most properties would have an advanced meter by the end of AA6 (2032). The proposed acceleration will bring that date forward by five years to 2027.

Western Power's business case for the accelerated advanced metering program indicated the incremental capital expenditure for acceleration was $115. 6 million and that the difference in net present cost when comparing full deployment by 2027 (based on the accelerated program) and 2032 (based on business as usual) was $21 million. The business case described benefits that would arise from acceleration but did not include quantification of such benefits.

The ERA's technical consultant considered Western Power had not justified the benefits of accelerating the advanced metering program and that it had included contingency allowances in its cost estimate. The consultant was also concerned that Western Power would not be able to deliver the full program during AA5.

Given the relatively small difference in net present cost terms and time-period, the ERA's draft decision included the accelerated metering costs. However, it was subject to Western Power quantifying and demonstrating the benefit of the acceleration in its response to the draft decision, removing any contingency allowance and demonstrating that it would be able to deliver the program in AA5.

5.6 Other asset replacement and renewal

As discussed above, a large part of the increase in proposed asset replacement and renewal compared with actual AA4 expenditure was due to expenditure for standalone power systems, NRUP and accelerating the rollout of advanced meters. In relation to the remaining asset replacement and renewal expenditure, the ERA's technical consultant's analysis suggested that the need for asset replacement was overstated and that assets were being replaced earlier than required.

Similar views were expressed by the WA Expert Consumer Panel's consultant, Dynamic Analysis, who considered that the level of replacement expenditure increase was very high for distribution assets, and the replacement rate appeared to be higher than networks in the NEM. Evidence of prioritisation based on risk quantification was not observed and Dynamic Analysis considered there may be opportunities to 'sweat assets' which have low consequences of failure.[30]

The ERA's technical consultant's advice included the following points:[31]

- Western Power uses a risk-based approach to determine when assets require replacement, balancing criticality and condition and basing decisions on risk reduction and whole of lifecycle costs.
- Engevity was concerned about Western Power's approach to risk management and the identification of assets to be replaced. From the information provided, Engevity found Western Power's risk and failure volume forecasting algorithms consistently output increased asset risk and failure volumes on almost every transmission and distribution asset category. This was not consistent with the experience of other networks in which each asset class followed different failure curves that ranged between a propensity for early failure, increasing end of life failures and relatively

30 WA Expert Consumer Panel, 29 April 22, Attachment 1, Public submissions on issues paper, p. 12.

31 Engevity, August 2022, Western Power AA5 Expenditure Proposal Review Executive Summary, p. 14.

> constant failures over an asset's life. Whist Engevity were not provided with the models or details of the algorithms, the outputs of the modelling suggested that asset aging significantly outweighs condition information in the calculation.

Engevity analysed the trends in forecast failure rates and how the actual failures for each asset class compared to Western Power's asset management targets. Its key findings included:[32]

> - Failure rates without Western Power network intervention were expected to increase over almost all Tx and Dx asset classes. In some cases, the failure rates were expected to double or more.
> - As of June 2020, most asset classes were experiencing actual failure rates at or below Western Power's asset management targets. This suggested that there was no imminent need for asset replacements to occur across most asset classes, yet Western Power's proposed REPEX across both transmission and distribution is relatively flat across AA5.
>
> Engevity recognised that accurate failure and risk forecasting is a difficult task, however the field experience of actual failure rates and failure trends should outweigh expert assumptions and the output of predictive tools used by networks. In most cases, assets degrade gradually, and periodic inspections will identify and prioritise emerging issues. Where inspections are occurring, defect rates are stable, failure rates are stable and field condition is reported as sound, there is little reason to expect a step change in replacement requirements other than factors such as common issues affecting a certain type of asset. Even so, in cases where the failure mode is not inherently dangerous or the reliability value of the asset is low, assets could remain in service until failure, inspection defects, or demonstrable economic obsolescence render them unserviceable. This approach would tend to maximise the life of assets and minimise the cost to customers as the value provided by older, fully depreciated assets is maximised. These operational practices could be coupled with properly calibrated predictive tools to further refine the forecasting approach – indeed that is what most network businesses do.

Consequently, Engevity considered that Western Power's risk management algorithms that inform the asset replacement programs were underestimating asset condition and therefore overstating the scope of replacement required.

Engevity recommended:[33]

> … an overall adjustment to the total proposed replacement expenditure for transmission and distribution to align it with actual expenditure incurred in AA4. This is supported by the fact that Western Power's AA4 expenditure has been found sufficient to meet it network performance requirements and to maintain a level of safety and reliability that is high enough such that customers are content and, on the whole, do not value additional investment to improve these levels.

Based on the advice of its consultant, the ERA did not consider the proposed asset replacement and renewal expenditure was reasonably likely to meet the new facilities investment test. As set out in Table 7, the ERA reduced the proposed transmission and distribution asset replacement and renewal expenditure by $85.3 million and $62.3 million respectively in line with Engevity's recommendation.

32 Engevity, August 2022, Western Power AA5 Expenditure Proposal Review Attachments, pp. 285, 286.

33 Engevity, August 2022, Western Power AA5 Expenditure Proposal Review Attachments, p. 291.

5.7 Compliance

Transmission - compliance

Western Power's initial proposed transmission compliance capital expenditure is set out in Table 8 below.

Table 8: Western Power's proposed transmission compliance capital expenditure for AA5 – excluding forecast labour escalation and indirect costs (real $ million at June 2022)

Expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actuals
Poles & towers	9.3	9.3	9.3	9.3	9.3	46.3	52.4
Substation security	6.9	6.7	6.7	6.7	4.8	31.8	21.3
Substation building upgrades	4.8	2.3	2.3	2.3	2.4	14.0	4.3
Cables	1.5	4.0	6.5	2.0	0.0	14.0	0.0
Cross-arm replacement	1.9	1.9	1.9	1.9	1.9	9.3	7.4
Transformer compliance	2.1	1.5	1.1	1.0	1.0	6.7	11.1
Other	9.7	11.2	12.0	3.8	2.2	38.9	9.5
Total capital expenditure	36.1	36.8	39.7	26.9	21.5	161.0	105.9

Source: ERA analysis of Western Power data

The forecast investment was $55.1 million more than that was incurred during the AA4 period. The increase in transmission compliance capex during the AA5 period was due mainly to increases in transmission cable compliances and other transmission compliance (such as asbestos removal and substation security).

The proposed expenditure related to compliance requirements and obligations. The ERA's technical consultant did not recommend any adjustments. While the ERA noted that that the expenditure proposed by Western Power for AA5 was 52.1 per cent higher than the AA4 actual expenditure, it recognised that the actual expenditure in AA4 was ~34 per cent lower than forecast due to reprioritisation to deal with unexpected transformer issues and substation security improvements being delayed.[34,35] The ERA also recognised the dynamic environment that Western Power needs to deal with in relation to grid stability. As such, the ERA considered the proposed expenditure would reasonably be expected to meet the requirements of the new facilities investment test.

[34] Western Power, Feb 2022, AAI – Attachment 5.1 – AA4 Capital Expenditure Report, p. 22.

[35] Western Power, Feb 2022, AAI – Attachment 8.1 – AA5 Forecast Expenditure Report, p. 37.

Distribution - compliance

Western Power's proposed distribution compliance capital expenditure is set out in Table 9 below.

Table 9: Western Power's proposed distribution compliance capital expenditure for AA5 – excluding forecast labour escalation and indirect costs (real $ million at June 2022)

Expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actuals
Bushfire management	2.6	2.4	2.3	2.3	2.3	12.0	10.3
Pole management	18.0	18.2	17.6	17.8	17.9	89.4	54.1
Reliability compliance	8.5	6.7	8.1	7.9	7.3	38.6	14.8
Power quality compliance	3.8	5.0	5.0	5.1	5.1	23.9	16.5
Conductor management	3.1	3.1	3.1	3.1	3.1	15.5	9.3
Connection management	4.5	4.5	4.6	4.6	4.7	22.9	43.2
Other distribution compliance	2.6	2.6	2.8	2.5	2.5	12.9	6.9
Total	43.1	42.5	43.5	43.2	42.8	215.2	155.1

Source: ERA analysis of Western Power data

The major distribution compliance programs for the AA5 period included:

- bushfire management: 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 included, 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: covered the replacement of cross arms, insulators and stays that supported 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. Western Power stated that 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: 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. Western Power submitted increased expenditure in AA5 was required to meet service standard benchmark requirements, which emerged in the latter part of the AA4 period.

- power quality compliance: 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: 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. Western Power noted that service connections are the largest contributor to electric shock counts on the distribution network. It considered 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 (also refer to noted that under AMI for further context).

The proposed expenditure related to compliance requirements and obligations. The ERA's technical consultant did not recommend any adjustments.

While the ERA noted that the expenditure proposed by Western Power for AA5 is 38.8 per cent higher than the AA4 actual expenditure, it is required to meet reliability and compliance obligations. The largest increase in proposed expenditure from AA4 levels was in the reliability and pole management compliance subcategories, which are focus areas for Western Power to improve service standards. On that basis, the ERA considered the proposed expenditure would reasonably be expected to meet the requirements of the new facilities investment test.

5.8 SCADA and corporate ICT

Western Power's initial proposed SCADA and telecommunications capital expenditure and corporate ICT expenditure is set out in Table 10 below.

Table 10: Western Power's proposed SCADA and corporate ICT capital expenditure for AA5 – excluding forecast labour escalation and indirect costs (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actuals
SCADA and telecommunications							
Asset replacement	34.5	34.2	26.7	31.5	34.2	161.2	77.5
Master station and operating system	19.4	16.6	26.0	24.5	26.5	112.9	64.0
Compliance	8.2	12.2	19.7	20.5	19.9	80.4	13.9
Other	9.9	9.4	11.9	13.6	13.8	58.6	41.0
Total SCADA and telecommunications	**72.0**	**72.4**	**84.3**	**90.1**	**94.4**	**413.1**	**196.4**
Corporate ICT	60.9	66.4	65.8	72.7	66.9	332.8	255.9

	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actuals
Total SCADA and corporate IT	**132.9**	**138.8**	**150.1**	**162.8**	**161.3**	**745.9**	**452.3**

Source: ERA analysis of Western Power data

Western Power's SCADA and Telecommunications assets provide the services required to protect, operate, and manage the Western Power Network 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.

Corporate ICT covers investment in various enterprise systems used by Western Power as well as investment in core IT infrastructure including computers, operating systems and desk top applications.

Western Power stated that that the SCADA and Telecommunications network had grown and evolved over the past 40 years through a combination of technological advancement and because of organic growth and augmentation of Western Power's networks. However, the infrastructure deployed during the 1980s was mainly analogue and now needed to be upgraded to integrate with the digital network.

Western Power considered much of the early digital technology was also at the end of its useful life or was no longer compatible with current requirements. It noted that that, in general, the mean replacement life of SCADA communications assets was about one-third that of transmission and distribution assets, so SCADA assets needed to be renewed approximately three times during the life span of those other assets.

Western Power stated that that its SCADA and Telecommunications network had historically been maintained on a reactive basis. It considered it had now reached the point where technical obsolescence had become an issue for almost 70 per cent of SCADA assets, meaning that support for the assets was becoming increasingly difficult to source. Western Power considered the condition of the SCADA and Telecommunications network had also affected the reliability of those assets, with most operating will below their target availability.

Forecast capital expenditure on corporate ICT during the AA5 period was split between infrastructure and maintenance (34 per cent) and business driven (66 per cent), covering network planning and asset management, growth, corporate and customer.

Western Power had 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 Australian Energy Sector Cyber Security Framework domains, and consider additional amendments proposed to the *Security of Critical Infrastructure Act 2018* (Cth).

Stakeholder submissions included the following matters relevant to SCADA and telecommunications expenditure and corporate ICT expenditure:

- The Chamber of Minerals and Energy recommended further information was shared regarding the relative benefits of the proposed level of investment (e.g. 110 per cent increase) in SCADA and Telecommunication and any analysis of the supporting business case against alternatives, such as increasing the level of investment in transmission infrastructure. It also sought to understand what provisions were employed to mitigate risks of rapidly changing technologies rendering assets obsolete or unsupported.[36]
- Synergy was concerned whether all the SCADA expenditure met the criteria of expenditure for covered services. They sought clarity as to the extent to which some of WP’s investment program was proposed to support WEM reforms, given that the WEM reform activities may require significant investment in SCADA and communications systems.[37]
- Perth Energy noted the proposed expenditure of around $500 million on SCADA and the telecommunications network. Around 40 per cent of this was stated as being required to replace equipment that is obsolete or unsupported. It is important that expenditure of the remaining $300 million is task-driven rather than technology-driven. That is, this sum is necessary to continue providing long term cost reductions to customers rather than being nice-to-have.[38]
- The Australian Energy Council submitted that Western Power is proposing to update its SCADA and Telecommunications network during the AA5 period to support the digital network and enable the integration of distributed energy resources. Western Power say that this investment will enable the introduction of new and emerging technologies. The AA5 proposal includes $483.4 million of capital expenditure of which only $188.4 million is needed to replace equipment that is obsolete and unsupported. Given the uncertainties of the future electricity system and the possibility of a large amount of additional costs during AA5, the AEC encouraged the ERA to consider whether the full SCADA upgrade was necessary at this time or if a portion of the proposed SCADA works could be delayed, limiting some of the price increases during the AA5 period.[39]
- Alinta Energy was concerned by the proposed increase in capex net of asset replacement costs, especially on SCADA and IT infrastructure, and its effect on customers. They considered that it was not clear whether this expenditure had a business case and would be in the long-term interest of customers per the ENAC objective. Further, they noted that the equipment’s short asset life, and flow-on effects to operating costs amplified the costs to customers. Finally, Alinta Energy questioned whether the significant capex allocated to introducing more “sophisticated operating

[36] The Chamber of Minerals and Energy of WA, 22 April 22, Public submissions on issues paper, p. 3.

[37] Synergy, 20 April 22, Target Rev and price control submission, Public submissions on issues paper, p. 63.

[38] Perth Energy, 20 April 22, Public submissions on issues paper, p. 4.

[39] AEC, 20 April 22, Public submissions on issues paper, p. 8.

systems to enable increasing levels of renewable and distributed energy resources" as part of the "modular network", and "support orchestration of DER" would be efficient.[40]

- The AEC noted that that IT costs are forecast to significantly increase during the AA5 period. Western Power's proposal showed that IT capex would jump 32.2 per cent from $251.8 million in AA4 to $332.8 million in AA5. The majority of this investment is in various enterprise systems used by Western Power. This is a substantial increase in capex that needs to be justified. If any portion of this IT capex is not necessary at this time then it was suggested that the expenditure is delayed. The AEC also noted that that if so many systems are replaced in one period, then it is likely they will be due for replacement in another single period in 10 to 15 years.[41]
- Change Energy noted that cyber security had become a significant risk in the energy industry, in particular with an increase in remote operations[42] such as remote disconnections. The upgrades proposed by Western Power appeared prudent, but Change Energy submitted that it had seen, across the industry, IT projects are prone to scope creep and cost blowouts. Change Energy recommended that the ERA satisfied itself that the proposed costs were market tested and reflected a prudent scope of works.[43]
- Perth Energy noted the emphasis being placed on cyber security and was supportive of this. The move to advanced metering meant that cyber security needed to include protection of metering data being transferred from customers. The cyber implications of remotely curtailing output of domestic solar PV systems would also need to be considered. However, Perth Energy did not want "safety issues" to be used as justification for any over-expenditure. All expenditures should be based on the need to meet real issues and to comply with legislative obligations.[44]
- WA Expert Consumer Panel's consultant Dynamic Analysis noted that ICT had the greatest impact on short term prices. It considered that only projects with maximum value should be approved.[45]

The ERA's technical consultant provided the following advice:[46]

- Western Power was forecasting a significant increase of 73 per cent in ICT program actual expenditure from AA4 or 171 per cent increase on the approved expenditure in the same period.
- Engevity recognised and supported the intent of Western Power's ICT strategy as well the moderate increase in the volume of works delivered by Western Power to date in AA4. However, Engevity considered the scale of the AA5 ICT program was excessive and not adequately justified. Most notably, there was an absence of a clearly defined scope for the program that is aligned to identified network needs beyond the assertion that systems need to be modernised or need replacement once they are no longer supported by the vendor. There was also a clear issue that the accelerated timing of the current ICT program and increased expenditure was not aligned with a prudent and cost-efficient approach to electricity network ICT

40 Alinta Energy, 20 April 22, Public submissions on issues paper, p. 1.

41 AEC, 20 April 2022, Public submissions to Issues paper, p. 9.

42 For example, an increase in the use of remote disconnections increases the risk of a cyber-attack resulting in the disconnection of a significant number of connections in the SWIS.

43 Change Energy, 20 April 22, Public submissions to Issuer paper, p. 5.

44 Perth Energy, 20 April 22, Public submissions to Issuer paper, p. 6.

45 WA Expert Consumer Panel, 29 April 22, Public submissions to Issuer paper, Attachment 1, p. 12.

46 Engevity, August 2022, Western Power AA5 Expenditure Proposal Review Executive Summary, pp.15-16.

delivery and it was not clear how this acceleration minimised costs to customers. For example:

- Engevity's review found that assets are forecast to be replaced on a conservative asset age basis, rather than an actual asset condition or risk basis. Western Power had not demonstrated that ICT cost forecasts have been estimated with reference to efficient industry benchmarks or comparable implementations of major ICT systems in other networks. These are fundamental market assessment measures that would have clearly highlighted that the scale of the program is excessive for an Australian network.
- Engevity also found that the acceleration of SPS and AMI deployment was not supported and is reasonably expected to face deliverability issues over AA5. The associated adjustment to these programs reduces the need and timing for some of Western Power's ICT capex program.
- The Project Symphony trials were still at an early stage and Western Power should not pre-empt this project's findings by including substantial expenditure for large scale implementation. Should further expansion of Project Symphony be required, the system would likely provide benefits that are partially, or completely funded out of OPEX and capex efficiencies. Noting Western Power's demonstrated ability to reprioritise its AA4 network replacement program to accommodate over $180 million of SCADA additional investment beyond the level approved by ERA for AA4, Engevity considered that there was sufficient flexibility in the overall capex portfolio to manage both network risk and prioritise emergent ICT capex needs.

- Western Power had not demonstrated the capability and resources to deliver its proposed ICT program for the AA5 period in a cost-efficient manner – especially given the scale of approved expenditure overruns experienced in AA4. Whilst Engevity recognised the need for investment in ICT systems to support the network transformation strategy, it is critical that they are delivered in an efficient manner to ensure that the substantial investment in ICT systems delivers the expected benefits for customers whilst managing costs within the business case forecast that was justified by those benefits.

The ERA considered the information provided by Western Power, Engevity's advice and stakeholder comments and noted the following:[47]

- A clear case that reliability was falling below acceptable levels due to obsolescence and non-compliance of IT, SCADA and Communication assets had not been made. Engevity pointed to the Network Management Plan[48] which showed a relatively flat historic availability of SCADA and Telecommunication networks and forecast an increase in reliability for CBD automation in the future.
- Engevity noted that there was limited evidence of business case/investment evaluation plans for the total AA5 SCADA and ICT investment program.
- Engevity's benchmarking study showed that Western Power's forecast was significantly higher than other regulated networks.
- Engevity found systemic issues with Western Power's approach to asset and risk management. Engevity noted that that mean replacement age (MRL) was heavily relied on as the indicator of replacement need for an asset, not the asset's current condition or performance.[49] This would mean that some ICT assets may be considered for replacement prematurely.

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[47] Ibid, pp. 304 -318.

[48] AAS - Attachment 8.2 - Network Management Plan, pp. 317-319.

[49] Western Power, 2021, Distribution Structures Asset Management Strategy, p. 10.

Taking account of these issues and Engevity's advice, the ERA did not consider the proposed expenditure for SCADA and telecommunications and corporate ICT was reasonably likely to meet the new facilities investment test. Based on the benchmarking and other analysis provided by Engevity, the ERA considered the proposed expenditure should be reduced by $223.7 million in total as set out in Table 11 below. The ERA considered the draft decision included sufficient expenditure to allow Western Power to comply with its cyber security requirements. If Western Power considered additional funds were needed to ensure cyber security, it could provide details and evidence to support this in its response to the draft decision.

Table 11: ERA adjustments to Western Power's proposed SCADA & telecommunications expenditure and corporate ICT expenditure - excluding forecast labour escalation and indirect costs (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5
Proposed expenditure:						
SCADA & telecommunications	72.0	72.4	84.3	90.1	94.4	413.1
Corporate ICT	60.9	66.4	65.8	72.7	66.9	332.8
Total	132.9	138.8	150.1	162.8	161.3	745.9
Adjustments:						
SCADA & telecommunications	(21.6)	(21.7)	(25.3)	(27.0)	(28.3)	(123.9)
Corporate ICT	(18.3)	(19.9)	(19.7)	(21.8)	(20.1)	(99.8)
Total	(39.9)	(41.6)	(45.0)	(48.8)	(48.4)	(223.7)
Draft decision						
SCADA & telecommunications	50.4	50.7	59.0	63.1	66.1	289.2
Corporate ICT	42.6	46.5	46.1	50.9	46.8	233.0
Total	93.0	97.2	105.1	114.0	112.9	522.2

Source: ERA analysis

5.9 Corporate

Western Power's proposed corporate capital expenditure is set out in Table 12 below.

Table 12: Western Power proposed corporate capital expenditure for AA5 - excluding forecast labour escalation and indirect costs (real $ million at June 2022)

Expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actual
Business support	22.7	34.6	53.7	9.7	9.7	130.5	221.2
ICT	60.9	66.4	65.8	72.7	66.9	332.8	255.9
Total capital expenditure	83.6	101.1	119.5	82.5	76.7	463.3	477.1

Source: ERA analysis of Western Power data

The business support category included expenditure on corporate real estate and property plant and equipment.

Forecast investment in corporate real estate is focused primarily on the Depot Program, which commenced at the start of the AA4 period. During the AA5 period, Western Power was proposing to 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.

Other proposed corporate real estate investments in the AA5 period included:

- 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.

The proposed investment in property, plant and equipment was based on historical spend. The forecast investment was required for low value capital equipment used by Western Power's operational workforce to deliver 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.

In its review of Western Power's proposed depot expenditure, Engevity identified that approximately $42.8 million (32 per cent of the total corporate real estate regulatory activity) had been assigned to unplanned or general projects. Engevity recommended it be reduced by $27.6 million to retain approximately $15 million for unplanned or general depot projects to be more in line with industry practice.

Based on Engevity's advice, the ERA considered the level of unplanned or general project expenditure included in the proposed depot expenditure was not reasonably likely to meet the requirements of the new facilities investment test. As set out in Table 13 below, the ERA required that the business support expenditure be reduced by $27.6 million.

The ERA's total adjustments to the proposed corporate expenditure are set out in Table 13 below. The adjustment to ICT was discussed in section 5.8.

Table 13: ERA adjustments to Western Power's proposed corporate capital expenditure - excluding forecast labour escalation and indirect costs (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5
Total proposed by Western Power	83.6	101.1	119.5	82.5	76.7	463.3
Reductions:						
Business support	(0.1)	(8.1)	(8.2)	(5.7)	(5.6)	(27.6)
IT	(18.3)	(19.9)	(19.8)	(21.8)	(20.1)	(99.8)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5
Total	**(18.4)**	**(28.0)**	**(28.0)**	**(27.5)**	**(25.7)**	**(127.4)**
Draft decision	65.3	73.1	91.6	55.0	50.9	335.9
Allocated to:						
Transmission	23.9	25.8	30.0	16.7	14.4	110.7
Distribution	41.5	47.3	61.6	38.2	36.5	225.2

Source: ERA analysis

5.10 Summary of draft decision capital expenditure

The ERA calculated revised values for AA5 forecast capital expenditure in accordance with the ERA's determination under the draft decision on whether the forecast of new facilities investment may, under section 6.50 of the Access Code, be taken into account in the determination of total costs and target revenue.

As discussed in the operating expenditure attachment, the ERA revised Western Power's proposed indirect costs. In addition, the ERA's amendments to direct capital expenditure and operating expenditure affect the allocation of indirect costs and labour escalation across different categories of expenditure.

The revised values determined for the draft decision are shown in Table 14 below.

Table 14: Draft decision capital expenditure for AA5 (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total	Western Power initial proposal
Transmission direct capital expenditure							
Asset replacement and renewal	45.1	44.2	39.7	39.1	39.9	207.9	293.2
Growth	88.4	72.9	52.2	51.0	27.2	291.7	291.7
Improvement in service	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compliance	36.1	36.8	39.7	26.9	21.5	161.0	161.0
Total	**169.5**	**154.0**	**131.6**	**116.9**	**88.6**	**660.6**	**745.9**
Distribution direct capital expenditure							
Asset replacement and renewal	333.4	353.7	369.2	363.3	366.6	1,786.2	2,017.9
Growth	166.6	156.9	151.7	154.3	144.0	773.4	773.4
Improvement in service	0.2	0.0	0.0	0.0	0.0	0.2	0.2
Compliance	43.1	42.5	43.5	43.2	42.8	215.2	215.2
Total	**543.3**	**553.1**	**564.4**	**560.8**	**553.4**	**2,775.1**	**3,006.8**

	2022/23	2023/24	2024/25	2025/26	2026/27	Total	Western Power initial proposal
SCADA and Telecommunications							
Transmission	27.9	28.5	33.5	33.1	34.9	157.9	225.6
Distribution	22.5	22.2	25.5	30.0	31.1	131.3	187.5
Total	**50.4**	**50.7**	**59.0**	**63.1**	**66.0**	**289.2**	**413.1**
Corporate							
Transmission	23.9	25.8	30.0	16.7	14.4	110.7	158.3
Distribution	41.5	47.3	61.6	38.2	36.5	225.2	305.0
Total	**65.3**	**73.1**	**91.6**	**55.0**	**50.9**	**335.9**	**463.3**
Total gross direct capital expenditure	**828.6**	**830.8**	**846.6**	**795.8**	**758.9**	**4,060.8**	**4,629.1**
Contributions (direct costs)							
Transmission growth	(57.5)	(31.3)	(31.3)	(31.3)	(11.7)	(163.0)	(163.0)
Distribution asset replacement	(27.3)	(35.5)	(45.5)	(54.4)	(56.4)	(219.2)	(219.2)
Distribution growth	(107.0)	(107.0)	(107.0)	(107.0)	(99.9)	(528.1)	(528.1)
Total	**(191.9)**	**(173.8)**	**(183.8)**	**(192.7)**	**(168.0)**	**(910.2)**	**(910.2)**
Total net direct capital expenditure	**636.7**	**657.0**	**662.8**	**603.1**	**591.0**	**3,150.6**	**3,718.9**
Indirect costs							
Transmission	38.3	35.6	33.8	28.7	24.4	160.8	
Distribution	87.6	87.0	87.8	89.0	89.4	440.9	
Total	**125.9**	**122.6**	**121.5**	**117.7**	**113.9**	**601.7**	**642.7**
Labour escalation							
Transmission	3.5	5.0	6.6	6.6	6.7	28.3	
Distribution	6.4	9.5	12.8	16.0	19.0	63.7	
Total	**9.9**	**14.5**	**19.4**	**22.6**	**25.7**	**92.0**	**104.7**

	2022/23	2023/24	2024/25	2025/26	2026/27	Total	Western Power initial proposal
Indirect costs allocated to contributions							
Transmission	(9.2)	(4.8)	(4.7)	(4.9)	(1.8)	(25.4)	
Distribution	(15.4)	(16.2)	(17.3)	(19.2)	(18.7)	(86.9)	
Total	**(24.6)**	**(21.1)**	**(22.0)**	**(24.1)**	**(20.6)**	**(112.3)**	**(104.6)**
Labour escalation allocated to contributions							
Transmission	(0.8)	(0.6)	(0.8)	(1.0)	(0.5)	(3.7)	
Distribution	(1.5)	(2.3)	(3.2)	(4.3)	(5.0)	(16.2)	
Total	**(2.2)**	**(2.9)**	**(4.0)**	**(5.3)**	**(5.4)**	**(19.9)**	**(19.8)**
Total AA5 capital expenditure							
Gross capital expenditure	964.4	967.9	987.5	936.1	898.5	4,754.4	5,376.5
Contributions	(218.7)	(197.8)	(209.8)	(222.1)	(194.0)	(1,042.3)	(1,034.5)
Net capital expenditure	745.7	770.2	777.7	714.0	704.5	3,712.1	4,341.1

Source: ERA analysis

6. Western Power's revised proposal

In the draft decision the ERA determined that $3,712 million of $4,341 million capital expenditure proposed by Western Power in its revised proposal for AA5 was reasonably likely to meet the new facilities investment test.

In its revised proposal, Western Power accepted the following reductions included in the draft decision:

- network renewal undergrounding program ($66.8 million)
- standalone power systems ($102.6 million)
- other asset replacement ($147.6 million)
- corporate real estate ($27.6 million).

Western Power's revised proposal includes additional expenditure and some adjustments to its initial proposal as summarised in Table 15.

Table 15: Western Power's revised proposal increases to capital expenditure - excluding forecast labour escalation and indirect costs (real $ million at June 2022)

Program	Proposed	Description
Transmission growth	$83.4 m	The Whole of System Plan will not be published until 2025 but Western Power states that early planning has identified a need for the following projects during the AA5 period: • Upgrades to maximise the utilisation of the 220kV transmission line to the Eastern Goldfields (scoping costs of $11.8 million in 2022/23-2023/24 and planning to execution costs of $49 million in 2024/25-2026/27). • Scoping and planning of potential network augmentations for the North Region (scoping and planning costs of $22.6 million in 2022/23-2026/27).
Distribution growth	$115.6 m	Western Power considers several significant events have occurred since the preparation of its original proposal and demand forecast that increase the required investment. This includes: • The impact of the 2021 Christmas heatwave on energy forecasts under existing planning criteria. • The Shepherd Report and resulting recommendations. • Preliminary results of modelling EV adoption and charging behaviour scenarios prepared in conjunction with EPWA as part of the Western Australian EV Action Plan. Western Power's proposed additional expenditure is based on a forecast increase in investment to address overloaded feeders and transformers arising from an updated demand forecast that incorporates the impacts of the December 2021 heatwave. Due to uncertainty regarding EV adoption rates and potential changes to the planning criteria, Western Power proposes the distribution capacity expansion category be subject to the investment adjustment mechanism.

Program	Proposed	Description
Distribution reliability	$190.1 m	This relates to the required amendment to ensure the service standard benchmark for rural long SAIDI is no worse than the NQ&R Code requirement of 290 minutes. Western Power proposes to undertake a bespoke program of investigation and investment into service reliability and performance improvements on the rural long feeders that are exhibiting the worst levels of performance. It proposes a targeted program that focuses on the most under-performing rural long feeders irrespective of other factors such as accessibility and customer densities. Where savings are made and spare capacity exists within the program budget over the course of the AA5 period, other priority areas will be investigated for additional targeted investment. It notes that these targeted investments will not deliver significant movements on overall SAIDI and SAIFI due to the low number of customers on the feeders it is planning to address.
SCADA and IT	$99.8 m	Western Power considers the expenditure included in the draft decision is not sufficient to meet its SCADA and IT needs, particularly to address cyber security requirements and has proposed an increase.
Decommissioning costs	$31.3 m	This relates to the transfer of overhead line decommissioning costs from operating expenditure to capital expenditure (depreciated over one year) as required by the draft decision.
Software as a service	($28.2 m)	Western Power proposes to transfer costs of cloud-based software as a service costs from capital expenditure to operating expenditure.
Metering	($27.5 m)	Western Power has reduced its proposed metering expenditure to remove costs that had been included for dual element metering.

Source: Western Power revised proposal access arrangement information

7. Submissions on the revised proposal and draft decision

Submissions received on Western Power's forecast capital expenditure from the Australian Energy Council, Change Energy, Synergy and the WA Expert Consumer Panel raised concerns about the increases in expenditure that Western Power is seeking.

Submissions from Alinta, the Australian Energy Council, Collgar, and Perth Energy raised concerns that Western Power had not included sufficient investment for the transmission network.

Energy Policy WA provided a submission confirming that the proposed expenditure Western Power is seeking for additional transmission investment is needed to support the Government's decision to retire state-owned coal-fired generation facilities and replace them with new wind generation and storage capacity, over the period to 2030.

The Australian Energy Council queries the late inclusion of expenditure increases. It considers these costs should have been reasonably foreseen at the time of Western Power's initial proposal and questions what has materially changed since then to warrant such a large capital expenditure increase.

It notes Western Power claims additional expenditure is necessary to address the increasing threat of cyber security risks but considers Western Power should have already had a comprehensive cyber security business case irrespective of what has subsequently happened at other organisations.

It asks the ERA to:

- Review the justification for the proposed additional cyber security expenditure and consider if it is fit for purpose.
- Ensure that Western Power quantifies and demonstrates the benefit of the metering acceleration during AA5, and that it has removed any contingency allowance and demonstrated that it will be able to deliver the program in AA5.
- Assess if any of the proposed increases to capital expenditure can be deferred to a later period.
- Consider whether alternative options can reduce the capital expenditure. The network operator should be required to provide details of whether it has tested the market, the outcome of the process, and if any alternative options will be used in AA5.

It considers the ERA should closely monitor the standalone power system program so that:

- Standalone power systems are only installed in parts of the network where it is cheaper than maintaining the existing network.
- Standalone power systems are not installed if the assets they replace have not been fully depreciated and need to be written down.
- Competition is encouraged in the provision of stand-alone power systems and Western Power undertakes a competitive tendering process to select vendors.

Change Energy considers that, while Western Power has accepted many of the ERA's reductions to forecast expenditure, it appears to have done little to address the ERA's finding that many of the programs and projects lacked justification. Where it has accepted expenditure reductions, in most instances, Western Power has merely substituted these projects and programs for new ones. For example, Western Power accepted a ~$120 million reduction in proposed standalone power system expenditure only to introduce a new program to improve long rural service performance. This more than offsets the ERA's reduction at ~$180 million and is a program Western Power admits is not valued by end users.

In the current economic environment, and with a view to help moderate prices, Change Energy expected Western Power would have been conservative in developing its investment plans. However, Western Power has in many instances instead increased its forecasts by adding new projects and programs. Change Energy asks the ERA to apply the same scrutiny to these new projects and programs as it has done in its draft decision.

Synergy asks the ERA to ensure the additional $465.4 million capex that Western Power is requesting is evidenced, based in terms of need and, if so, costs are efficient. It notes that Western Power has proposed $182.0 million in capex to support compliance with the ERA's required amendment to the service standard benchmark for customers on rural long feeders but has not accepted the required amendment to the service standard benchmark.

The WA Expert Consumer Panel considers one of the most effective ways to manage project execution risks - and to manage costs in an inflationary environment - is to find smart ways to avoid the need to upgrade the physical infrastructure through non-network solutions, which include empowering consumers to manage their usage and take pressure off the grid. Western Power is required to consider non-network solutions as part of the Access Code requirements, but WA ECP considers it is yet to see the organisation pursue these sorts of opportunities at scale.

Alinta Energy is concerned that the revised proposal does not include plans indicating how Western Power will address the urgent need for transmission capacity to enable the energy transition and maintain reliability.

Alinta notes that the revised proposal includes proposals to investigate investments in the North and East Regions to support government policy, states that: "Western Power is cognisant of the delivery challenges presented by the current global workforce and supply chain challenges and has developed targeted strategies to mitigate these accordingly." However, given the urgent need for investment, Alinta recommends further work and analysis is required within this access arrangement period to give assurance that transmission bottlenecks will not cause substantial barriers to investment, undue delays, and cost pressures in the energy transition.

It considers that Western Power must identify and pursue "no regrets" transmission investments immediately and that if it identifies regulatory impediments to this work, (for example, the restrictions imposed by the NFIT, or the implications of such investments for network costs to customers), these must be articulated quickly to deliver timely regulatory changes.

The Australian Energy Council is concerned there is a disconnect between the amount of generation that Western Power forecasts being required by 2030 and the absence of transmission projects in AA5. It notes that in a study the AEC commissioned Marsden Jacobs and Associates (MJA) to undertake on whether the WEM provides revenue adequacy for generators and to recommend measures to minimise investor uncertainty and promote new investment, the lack of transmission planning and investment was identified as one of the key reasons for investor uncertainty.

It notes that transmission planning and construction is a lengthy process. It would already be ambitious to connect the required amount of generation over the next seven years, but the lack of planning and funding for transmission in AA5 will make this task harder and is misaligned with industry and State Government decarbonisation targets. It encourages the ERA to challenge Western Power on the transmission requirements during AA5 and how they will facilitate the amount of generation needed by 2030.

Collgar remains very concerned about the lack of transmission investment included in AA5. It provides details of the potential size and urgency of this investment. It appreciates that the State Government deferred the second Whole of System Plan (WOSP) to 2025 and that the results of the interim SWIS Demand Assessment (SWISDA) have not yet been released. However, these processes do not remove the need for Western Power to undertake its own network planning and, in accordance with clause 3.15(d) of the applications and queuing policy, 'make a good faith assessment as to the likelihood that specific projects will proceed'.

Collgar states it is pleased the revised proposal includes additional capital expenditure for network planning and that Western Power's Draft Transmission System Plan (TSP) identified some network investment is needed. But it considers the scale of the proposed investment is very underwhelming in the context of likely future requirements.

Collgar supports substantial additional network investment being included in AA5. While more detailed planning and analysis is to be undertaken, it considers there are various 'least regrets' projects that are essential to support the energy transition, regardless of whether specific generation or load projects proceed. One example is augmenting the network to Kalgoorlie, which will be needed as the various miners electrify their operations to achieve their often publicly stated decarbonisation objectives. Such projects must be commenced as a priority given the scale of the challenge Western Power, and the sector more broadly, is facing over the coming years.

Collgar encourages the ERA to use, where available, discretion in considering such proposals as the urgency of the need for transmission investment does not allow for lengthy regulatory processes. It considers alternative funding models will also be needed given the scale of investment required, including funding network investment from State Government consolidated revenue, and creating frameworks that encourage private sector investment.

Perth Energy questions whether the activities proposed for AA5, and the associated work in parallel areas, will allow Western Power to meet the obligations which it will face over the coming few years to enable the energy transition. It notes responsibility for various parts of the transformation process lie within Western Power, AEMO, Energy Policy and the Government more generally. No single entity has overall responsibility or the authority to ensure that the process is progressed on the current timetable. Any backtracking on the announced Synergy closure programme for their coal fired generators would be a failure for the whole energy industry. Given the issues with coal supplies, deferral of closures may not even be practical. It encourages the relevant parties to consider how this can be avoided.

EPWA notes it has been working closely with Western Power in relation to the network requirements to support the Government's decision to retire state-owned coal-fired generation facilities and replace these with new wind generation and storage capacity, over the period to 2030.

It states the proposed additional transmission investment in the revised proposal is consistent with work that was undertaken to support this decision, and EPWA supports the ERA granting a waiver for Western Power to undertake a Regulatory Investment Test for this work due to the reasons outlined by Western Power.

EPWA notes Western Power has also been an integral member of the Treasury-led Taskforce overseeing the SWIS Demand Assessment, with the Taskforce's formal advice due to be provided to Government shortly. It is likely that further network investment will be required following government consideration of this advice. Energy Policy WA will consult with the ERA on this as soon as is practicable and/or appropriate to do so.

8. Considerations of the ERA

The ERA has considered whether Western Power's proposed increases and amendments to the expenditure accepted in the draft decision are reasonably likely to satisfy the new facilities investment test.

The ERA's consultant, Engevity, provided advice to assist the ERA in its review.

8.1 Transmission Growth expenditure

Stakeholders are concerned that the level of proposed transmission investment in the access arrangement period is not sufficient to enable transformation at the pace necessary to meet industry requirements.

The ERA is aware that the State Government is currently working to identify future electricity demand in the South West Interconnected System, the volume of generation required to meet this demand and subsequently the transmission investment required to support ongoing decarbonisation.

While the Whole of System Plan will not be published until 2025 Western Power states that early planning has identified a need for the following projects during the AA5 period:

- Upgrades to maximise the utilisation of the 220kV transmission line to the Eastern Goldfields (scoping costs of $11.8 million in 2022/23-2023/24 and planning to execution costs of $49 million in 2024/25-2026/27).
- Scoping and planning of potential network augmentations for the North Region (scoping and planning costs of $22.6 million in 2022/23-2026/27).

The expenditure is for network expansion projects identified by Government to support the announced closures of coal fired generation.

EPWA has advised that the projects Western Power has requested expenditure for in its revised proposal are network expansion projects identified by Government to support the announced closures of coal fired generation.

The ERA considers that approving the proposed expenditure is consistent with the Access Code objective to include consideration of the long-term interests of consumers in relation to reducing greenhouse gas emissions.

As there is some uncertainty over the estimated costs and because some decisions about the projects will be made externally to Western Power, the ERA has included the identified projects in the Investment Adjustment Mechanism. This will avoid any windfall gain to Western Power if it does not proceed with the projects or to cover any additional efficient costs if required during AA5 to deliver these projects.

It is likely the projects will be identified in the next Whole of System Plan as "priority projects". If this does not occur, Western Power will need to demonstrate that the projects maximise the net benefit to consumers after considering all options and meet all aspects of the new facilities investment test.

The work currently underway by the State Government will inform transmission augmentation requirements and Western Power may need to make additional funding requests to the ERA prior to 2027, the final year in this access arrangement period.

8.2 Distribution growth expenditure

Western Power considers several significant events have occurred since the preparation of its original proposal and demand forecast that increase the required investment. These include:

- The impact of the 2021 Christmas heatwave on energy forecasts under existing planning criteria.
- The Shepherd Report and resulting recommendations.
- Preliminary results of modelling EV adoption and charging behaviour scenarios prepared in conjunction with EPWA as part of the Western Australian EV Action Plan.

Western Power's proposed additional expenditure of $115.6 million is based on a forecast increase in investment to address overloaded feeders and transformers arising from an updated demand forecast that incorporates the impacts of the December 2021 heatwave.

Due to uncertainty regarding EV adoption rates and potential changes to the planning criteria, Western Power proposes the distribution capacity expansion category be subject to the Investment Adjustment Mechanism.

The ERA's independent consultant, Engevity undertook a detailed review of Western Power's proposed increase for distribution growth expenditure.

Engevity identified four key concerns about the efficiency and prudency of Western Power's proposed increase to distribution growth expenditure:

- **Service standards**: There is no explanation of why the additional expenditure is required for Western Power to maintain its service standards. The proposed $115.6 million is to replace or address all MV feeders and DSTRs that Western Power has forecast to be over-utilised in AA5. However, no linkage is drawn between this overutilisation, and how this may result in Western Power not being able to meet its service standards, and to what extent this overutilisation needs to be addressed by capital works to maintain these standards.

  Accepting the risk of managing the network reliability within the minimum service obligations for the feeder type does not appear to have been considered as an option.
- **Operational solutions:** Consideration of whether operational solutions such as demand management as opposed to capacity expansion AUGEX have not been clearly explored. The demand management capabilities as a result of the AMI program, customer DER enablement and Project Symphony learnings could be deployed more rapidly to reduce the need for network augmentation to manage and/or meet service standards, but it is not clear if or how these have been factored into Western Power's distribution growth considerations.
- **REPEX trade-off**: There is limited evidence of reprioritisation across other CAPEX categories. In particular, the works proposed represent a replacement of metro network assets with the purpose of increasing the capacity of the network (consequently categorised as distribution growth). However, there has been no adjustment to account for 'augmentation driven' replacements such as uprated distribution transformers, reconfiguration of feeders, switching improvements or reconductoring existing overhead lines with higher rated conductor (which may also bring forward the undergrounding opportunity and improve the business case for undergrounding works in OH areas).
- **Augmentation scope and costs**: Western Power's augmentation costs per km are at the higher end of expectations – especially when averaged across a program. This is because augmentation for 'organic' load growth (i.e. from existing

> customers) is more frequently addressed through lower capital cost options than constructing new feeders. These include additional or uprated distribution transformers, reconductoring lines with higher rated conductor and establishing new 'normally open' ties between adjacent feeders/zones to improve switching options to rebalance loads between feeders/zones during peak/emergency events.

Engevity recognised Western Power's justification and consideration of additional demand drivers that will affect the distribution network over AA5. However, it was unable to conclude from the modelling provided that the expenditure was required to meet Western Power's reliability and service obligations or that Western Power had adequately considered options to reallocate risk within the total capital expenditure allowance included in the draft decision.

Engevity considers this has resulted in Western Power overstating the forecast number of additional feeders requiring augmentation. Engevity also assessed the forecast unit costs as being very high. In addition, based on the updated information provided by Western Power, Engevity identified that some of the original program included in the initial proposal (and draft decision) is no longer required and recommends a reduction of $30.1 million to the draft decision allowance.

Engevity recommends reducing Western Power's proposed revised distribution growth expenditure by $86.5 million. The reduction is comprised of:

- $30.1 million to the forecast included in the draft decision based on the updated information provided with the revised proposal.
- $56.4 million to the additional expenditure Western Power is seeking in its revised proposal.

Based on the information provided by Western Power and the advice from Engevity, the ERA does not consider Western Power's proposed expenditure is reasonably likely to meet the new facilities investment test. Western Power has not adequately demonstrated that the expenditure is required to meet Western Power's reliability and service obligations. Western Power has not adequately considered other non-network options when determining the number of feeders requiring augmentation. The proposed unit costs do not reflect efficient costs and the new information provided with the proposed increase in expenditure, indicates that some of the original program included in the initial proposal (and draft decision) is no longer required.

Consequently, the ERA has reduced the proposed increase sought by Western Power to $29.1 million ($115.6 million less $86.5 million).

Western Power proposed that distribution growth expenditure should be subject to the Investment Adjustment Mechanism due to uncertainties about electric vehicle take-up rates and potential changes to the distribution planning criteria.

The ERA has not included distribution growth expenditure in the Investment Adjustment Mechanism because, consistent with the price control determined in the framework and approach, it is important that Western Power is exposed to demand risk rather than just passing its costs through to customers. In the case of electric vehicle take-up, Western Power should be seeking ways to enable better utilisation of the existing network and reduce the need to expand the network to meet demand from electric vehicle charging.

Western Power also raised concerns that additional expenditure may be required for potential changes to the distribution planning criteria. One of the Shepherd report recommendations was that the distribution planning criteria should be reviewed in light of the higher than forecast peak demands in some areas of the distribution network during the heatwave conditions in

December 2021. As noted in the Shepherd report, the distribution planning criteria is contained in the Technical Rules. Western Power will need to apply for an amendment to the Technical Rules if it decides to amend its distribution planning criteria. Western Power proposed that such expenditure should be subject to the Investment Adjustment Mechanism. However, the Access Code has provisions for dealing with cost increases or reductions due to amendments to the Technical Rules and consequently there is no need for such expenditure to be subject to the Investment Adjustment Mechanism.

8.3 Distribution reliability

The draft decision required an amendment to ensure the service standard benchmark for rural long SAIDI is no worse than the NQ&R Code requirement of 290 minutes.

Western Power did not set the rural long SAIDI at 290 minutes as required by the draft decision. It has proposed the service standard benchmark should be based on average performance during AA4.

In its revised proposal, Western Power states that it recognises the importance of network performance and customer experience, especially in relation to rural long feeder performance. Western Power agrees with the intent of the ERA to improve the performance of rural long feeders. However, it considers the effect of the draft decision with respect to the rural long feeders would require Western Power to significantly improve network reliability (and its investment in the network) above current levels to meet the NQ&R Code requirements, or face penalties under the service standard adjustment mechanism.

Western Power notes the investment plan in its initial proposal was aimed at maintaining overall reliability levels and managing the technical challenges associated with the integration of DER. However Western Power acknowledges the importance of reliability to the community, the feedback from the ERA in the draft decision and feedback from its own customer engagement process.

Western Power proposes to undertake a bespoke program of investigation and investment into service reliability and performance improvements on the rural long feeders that are exhibiting the worst levels of performance. It proposes a targeted program that focuses on the most under-performing rural long feeders irrespective of other factors such as accessibility and customer densities.

Western Power notes that where savings are made and spare capacity exists within the program budget over the course of the AA5 period, other priority areas will be investigated for additional targeted investment. It notes that these targeted investments will not deliver significant movements on overall SAIDI and SAIFI due to the low number of customers on the feeders it is planning to address.

The proposed expenditure is made up of:

- $8.1 million for a program to replace insulators during 2022/23 in areas currently experiencing poor reliability.
- $183 million for improving six of the worst performing rural long feeders.

The ERA has included the additional expenditure of $8.1 million for the replacement of insulators during 2022/23 in areas currently experiencing poor reliability on the basis that it is required for meeting reliability obligations.

However, the ERA does not consider the proposed expenditure of $183 million is likely to be consistent with the new facilities investment test.

Western Power is proposing to invest $183 million to improve performance on six of the worst performing feeders supplying 6,458 customers in total. The average SAIDI for the feeders selected ranges between 1,514 minutes to 3,656 minutes. The proposed expenditure is based on desktop studies and assumes that over half of the cost is for microgrids and the remainder for network expenditure.

Western Power indicated the likely improvement in performance for these feeders would be between 25 to 50 per cent, which would still leave performance worse than either the NQ&R Code standard of 290 minutes or average rural long performance during AA4 of 772 minutes. The cost of achieving this performance improvement would be approximately $28,000 per customer serviced by these six feeders – but smeared across all SWIS customers.

The ERA acknowledges that improving regional reliability is likely to be costly, and customers are unlikely to be willing to pay the entire cost required. However, 290 minutes is the legislative requirement and Western Power must, so far as is reasonably practicable, meet that requirement.

Western Power has not presented an overall plan to improve reliability on rural long feeders over time. Although Western Power proposes improvements to six feeders during AA5, 73 feeders (86,000 customers) out of the 84 rural long feeders (100,000 customers) have an average SAIDI greater than 290 minutes and 43 feeders (35,000 customers) have an average SAIDI greater than the overall average rural long performance of 772 minutes.

Using as a guide the costs presented by Western Power for the six worst performing feeders the likely costs for applying this strategy across the rural long network would be prohibitive and unlikely to meet the 290 minutes reliability standard for all rural long customers.

If Western Power does not meet the rural long service standard benchmark set in the final decision it will be subject to a financial penalty at the next access arrangement review. For example, if it performs at the level it is proposing for the AA5 benchmark it will incur an annual penalty of around $22 million. This will be offset by any positive amounts it achieves on other service standard measures and there is an overall cap of about $18 million on the total net penalty (or reward).

The ERA considers that Western Power needs to develop a plan to address rural long reliability to meet is legislative obligations and has included a capital allowance of $88 million (equal to the estimated penalty noted above) in forecast expenditure for AA5 to enable them to progress this in a way that best meets the affected communities' needs.

The allowance must be used to develop and implement an overall plan and undertake work to address regional reliability, including identifying and trialling solutions that improve reliability in pilot areas. The ERA expects that Western Power will consult with rural customers to identify specific rural long areas suitable for pilot projects and will then work with the relevant local community to develop the lowest cost option to seek to improve reliability for that community.

The ERA will require regular reports from Western Power on progress and will include updates in the annual service standard performance report. The allowance will be subject to the Investment Adjustment Mechanism, so if Western Power does not invest the money as intended the allowance will be returned to all customers at the next review.

Providing Western Power invests the allowance effectively to develop and implement an overall plan to address regional reliability, including implementing solutions that improve reliability in pilot areas, the service standard adjustment penalty relating to the difference between 290 minutes and the service standard benchmark proposed by Western Power (733.5 minutes) will not be imposed.

The ERA recognises that the level of expenditure included in this final decision will not be sufficient to achieve an average performance of 290 minutes for rural long customers. However, it expects the work facilitated by the allowance will enable quantification of the cost and practicalities of bringing rural long reliability in line with the NQ&R Code requirements. This will better inform meaningful engagement with customers and policy makers to develop standards that are acceptable and at a reasonable cost.

8.4 SCADA and IT

Western Power considers the forecast expenditure for SCADA and IT included in the draft decision is not sufficient to address its needs including cyber security requirements and has proposed an increase of $99.8 million for:

- $30 million to address SCADA and telecoms cyber security risks.
- $16 million to manage cyber security risks at the Master Station.
- $31 million to manage corporate ICT cyber security risks.
- $15 million to communicate with standalone power system assets.
- $8 million to meet customer communication expectations in line with recommendations of the Shepherd report.

Engevity provided the following advice on the proposed increase to expenditure:

- The revised proposal has not included sufficient evidence regarding quantification of risks or net benefits to network users, sufficiently detailed business cases or options analysis, or provided sufficient evidence of efficiency and prudency of investments.
- This is particularly pertinent given the scale of the investment for the program and the comparative scale-up to both network peers and prior regulatory periods. The expenditure included in the draft decision provides an expenditure allowance that is already at the extreme upper end of expectations for Australian distributors and transmission service providers.
- Information provided in the revised proposal has only referenced the incremental expenditure above the draft decision allowance with limited detail provided on the impact to the remaining composition, distribution and financial outcomes or timing flexibility for the remaining SCADA and Communications program components.
- This approach implicitly assumes that all components of the program pose identical risk, benefit, interdependency profiles and timing requirements, creating a lack of transparency and clarity over program direction for AA5 that would be required to be reasonably certain the expenditure is consistent with the new facilities investment test.

In relation to the expenditure sought for communications with standalone power system assets, Engevity noted that Western Power had not provided any additional information regarding the program, either at a detailed or high level. Engevity advises:

> We previously raised concerns about the high unit costs of Western Power’s SPS program and understood that the program, as it stood – or otherwise the metering

> component of the AMI program included the necessary control and communication equipment to implement Western Power's SPS solution at scale.
>
> The omission of details for the SPS program in the Revised Proposal raises questions regarding the robustness of Western Power's business cases for two of the largest network transformation programs in AA5. Further explanation of why this essential component of expenditure was excluded, detailed justification or a demonstration of why the expenditure could not be addressed by the budgets for these programs has not been provided.

In relation to the additional expenditure for enhancing customer communications in line with the Shepherd report recommendation, Engevity note the importance of improving customer communication and engagement and the increasing importance to the health and safety of customers as extreme weather events and associated outages are likely to increase.

However, Engevity advises:

> [Engevity] accept that this investment was not able to be included in the initial proposal due to the timing of the Shepherd Report's release. However, we note there is minimal detail in this investment proposal and significant uncertainty surrounding the program prudency or deliverability. While we acknowledge Western Power has provided program cost estimates, there is no evidence of options analysis to determine cost efficiencies.
>
> A significant part of the customer communication CAPEX has been allocated for the upgrading of Western Power's website and similar customer-facing portals. While these activities can improve the customer experience, there is not a clear or supported connection between the expenditure and its necessity to adequately deliver business services. Inclusion of the Shepherd Report recommendations must be in alignment with criteria of the NFIT, the case for which has not been adequately made.
>
> Further, Western Power has made a significant investment in excess of $20 million in its Customer Management System over AA4 to enable capabilities such as customer self-service, improved customer communications and greater availability of information on outages to customers via online channels. The Revised Proposal does not outline how it intends to build on its existing capability or why recent improvements and planned further development are inadequate for business service delivery.
>
> We consider that Western Power is already well placed to address much of the Shepherd Report requirements using the capabilities of existing and further planned development of its Customer Management Systems.

Based on the information provided by Western Power and the advice from Engevity, the ERA does not consider the proposed expenditure is reasonably likely to meet the new facilities investment test. The revised proposal has not provided sufficient evidence of efficiency and prudency of investments. The expenditure included in the final decision for SCADA and IT provides an expenditure allowance that is already at the extreme upper end of expectations for Australian distributors and transmission service providers.

8.5 Decommissioning

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 capital expenditure model and target revenue model and is satisfied the amendment has been made consistent with the draft decision. As indicated in the draft decision, the decommissioning costs will be included in the standalone power system expenditure for the Investment Adjustment Mechanism.

8.6 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 solution.

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 the forecast 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.

8.7 Metering

The draft decision noted that Western Power proposed to accelerate its advanced metering program so that most customers will have an advanced meter by the end of AA5. Under its business-as-usual approach (i.e. installing advanced meters in new properties, meter replacements and meter exchanges initiated by customers) most properties would have an advanced meter by the end of AA6 (2032). The proposed acceleration will bring that date forward by five years to 2027.

Western Power's business case for the accelerated advanced metering program indicated the incremental capital expenditure for acceleration was $115. 6 million and that the difference in net present cost when comparing full deployment by 2027 (based on the accelerated program) and 2032 (based on business as usual) was $21 million. The business case described benefits that would arise from acceleration but did not include quantification of such benefits.

Given the relatively small difference in net present cost terms and time-period, the ERA's draft decision included the accelerated metering costs. However, it was subject to Western Power quantifying and demonstrating the benefit of the acceleration in its response to the draft decision, removing any contingency allowance and demonstrating that it would be able to deliver the program in AA5.

In its revised proposal, Western Power has identified that the expenditure required has reduced by $27.5 million to remove the cost of dual element metering.[50]

Western Power has also provided additional information on the benefits of accelerating the program, confirmation that the forecast expenditure was based on meter unit cost and does not include a contingency allowance and the plans it has to ensure the program can be delivered.

Western Power notes it has identified two additional benefits applicable to advanced meters – manually read interval meters and self-read benefits – that had not been included in its original business case. It states that the case for advanced meter acceleration was not based solely on incremental quantifiable benefits:

50 A dual element meter can separately measure two things. For example total solar energy generated by a PV at the property and energy imported from the network.

> Rather, the reason for the acceleration is that AMI is a necessary enabling technology "to support actions under the Western Australian Government's DER Roadmap, such as DER aggregation and improved tariffs and network tariff structures that reward efficient use of the power system"

In relation to deliverability, Western Power advises it has taken on additional high volume service providers and internal crews to meet the increased installation rate compared to AA4.

Western Power considers it has sufficient labour in place to perform the meter installation but notes that the greater risk is likely to be meter supply. It states it is addressing this by obtaining an additional meter provider.

Taking account of the additional information that has been provided, the ERA maintains its draft decision to include Western Power's proposed metering costs (adjusted for the removal of dual element metering costs) in forecast capital expenditure for AA5.

8.8 Summary of final decision forecast capital expenditure

The ERA has calculated revised values for AA5 forecast capital expenditure in accordance with the ERA's determination under the final decision on whether the forecast of new facilities investment may, under section 6.50 of the Access Code, be taken into account in the determination of total costs and target revenue.

As discussed in the operating expenditure attachment, the ERA has revised Western Power's proposed indirect costs. In addition, the ERA's amendments to direct capital expenditure and operating expenditure affect the allocation of indirect costs and labour escalation across different categories of expenditure.

The ERA has also applied the revised labour escalation factor set out in Attachment 6 (forecast operating expenditure) to capital expenditure.

The revised values determined for the final decision are shown in **Error! Reference source not found.** below.

Table 16: Final decision capital expenditure for AA5 (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total	Western Power revised proposal
Transmission direct capital expenditure							
Asset replacement and renewal	45.0	44.2	39.7	39.1	40.0	207.9	207.9
Growth	91.6	85.5	71.4	93.6	33.0	375.1	375.1
Compliance	36.1	36.8	39.7	26.9	21.5	161.0	161.0
Total	**172.7**	**166.5**	**150.8**	**159.6**	**94.4**	**744.0**	**744.0**

	2022/23	2023/24	2024/25	2025/26	2026/27	Total	Western Power revised proposal
Distribution direct capital expenditure							
Asset replacement and renewal	332.6	354.7	366.6	364.1	372.0	1,790.0	1,790.0
Growth	163.4	156.7	158.2	164.2	160.0	802.4	889.0
Improvement in service	0.23					0.23	0.23
Compliance	51.2	64.5	65.5	65.2	65.8	311.3	405.3
Total	**547.4**	**575.8**	**590.3**	**593.6**	**596.8**	**2,903.9**	**3,084.5**
SCADA and Telecommunications							
Transmission	27.9	28.5	33.5	33.1	34.9	157.9	201.7
Distribution	22.5	22.2	25.5	30.0	31.1	131.3	148.3
Total	**50.4**	**50.7**	**59.0**	**63.1**	**66.0**	**289.2**	**350.0**
Corporate							
Transmission	23.9	25.8	30.4	18.0	13.9	112.0	100.7
Distribution	41.4	47.3	61.1	37.0	37.0	223.9	246.0
Total	**65.3**	**73.1**	**91.6**	**55.0**	**50.9**	**335.9**	**346.7**
Total gross direct capital expenditure	**835.8**	**866.1**	**891.7**	**871.2**	**808.2**	**4,273.0**	**4,525.2**
Contributions (direct costs)							
Transmission growth	(57.5)	(31.2)	(31.2)	(31.2)	11.7	163.0	163.0
Distribution asset replacement	(27.1)	(35.3)	(45.3)	(54.2)	(56.2)	(218.2)	(218.2)
Distribution growth	(107.0)	(107.0)	(107.0)	(107.0)	(100.0)	(528.1)	(528.1)
Total	**(191.7)**	**(173.6)**	**(183.6)**	**(192.5)**	**(167.8)**	**(909.2)**	**(909.2)**
Total net direct capital expenditure	**644.1**	**692.5**	**708.1**	**678.6**	**640.4**	**3,363.8**	**3,616.0**

	2022/23	2023/24	2024/25	2025/26	2026/27	Total	Western Power revised proposal
Indirect costs							
Transmission	35.8	33.5	31.6	31.0	21.9	153.8	159.1
Distribution	93.2	94.1	95.2	93.0	97.9	473.3	499.5
Total	**129.0**	**127.6**	**126.8**	**123.9**	**119.7**	**627.1**	**658.6**
Labour escalation							
Transmission	0.4	0.8	1.1	1.5	1.2	5.0	14.5
Distribution	0.9	1.9	3.0	3.9	5.0	14.7	41.8
Total	**1.3**	**2.7**	**4.1**	**5.4**	**6.2**	**19.7**	**56.3**
Indirect costs allocated to contributions							
Transmission	(9.3)	(4.8)	(4.6)	(4.6)	(1.8)	(25.2)	(25.0)
Distribution	(15.6)	(16.1)	(17.0)	(18.4)	(18.4)	(85.6)	(84.7)
Total	**(24.9)**	**(20.9)**	**(21.7)**	**(23.0)**	**(20.2)**	**(110.8)**	**(109.7)**
Labour escalation allocated to contributions							
Transmission	(0.1)	(0.1)	(0.2)	(0.2)	(0.1)	(0.7)	(2.1)
Distribution	(0.2)	(0.4)	(0.7)	(0.9)	(1.1)	(3.3)	(8.8)
Total	**(0.3)**	**(0.5)**	**(0.8)**	**(1.2)**	**(1.2)**	**(4.0)**	**(10.9)**
Total AA5 capital expenditure							
Gross capital expenditure	966.1	996.4	1,022.6	1,000.5	934.2	4,919.8	5,240.1
Contributions	(216.9)	(195.1)	(206.1)	(216.7)	(189.3)	(1,024.0)	(1,029.8)
Net capital expenditure	749.2	801.4	816.5	783.8	744.9	3,895.8	4,210.3

Source: ERA analysis

Required amendment 1

Forecast capital expenditure must be amended to be consistent with the ERA's final decision.

Appendix 1 Code extract of sections relevant to AA5 capital expenditure

6.51 For the purposes of section 6.4(a)(i) and subject to section 6.49, the forward-looking and efficient costs of providing *covered services* may include costs in relation to *forecast new facilities investment* for the *access arrangement period* which at the time of inclusion is reasonably expected to satisfy the test in section 6.51A when the *forecast new facilities investment* is forecast to be made.

6.51A *New facilities* investment may be added to the *capital base* if:

(a) it satisfies the *new facilities investment test*; or

(b) the *Authority* otherwise approves it being added to the *capital base* if:

(i) it has been, or is expected to be, the subject of a *contribution*; and

(ii) it meets the requirements of section 6.52(a); and

(iii) the *access arrangement* contains a mechanism designed to ensure that there is not double recovery of costs as a result of the addition.

New facilities investment test

6.52 New facilities investment satisfies the *new facilities investment* test if:

(a) the *new facilities investment* does not exceed the amount that would be invested by a service provider *efficiently minimising costs*, having regard, without limitation, to:

(i) whether the *new facility* exhibits economies of scale or scope and the increments in which capacity can be added; and

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

(iii) if it is not a *priority project*, alternative options to the new facility (including the capital costs and non-capital costs that would be incurred in respect of that alternative option);

and

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

(i) either:

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

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

or

(ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or

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

(iv) the new facility is in respect of a *priority project*.

The provisions in relation to a modified test do not apply as Western Power has not requested a modified test to be approved.

A "priority project" is a project specified as a priority project in a "whole of system plan". A whole of system plan is the document published by the Minister from time to time as the Whole of System Plan for the efficient development of the SWIS over a 20-year period.

6.54 In making a determination under section 6.52 the Authority must have regard to:

(a) if the new facilities investment is in respect of a *priority project*, for the purposes of considering the amount invested or recovered under section 6.52(a), the unit costs of the service provider's actual new facilities investment only; and

(b) whether the new facilities investment was required by a written law or a statutory instrument.

6.55 Section 6.54 does not limit the matters to which regard must or may be had in making a determination under section 6.52.

6.55A If the Authority makes a determination under section 6.52, it must provide reasons for its determination in its draft decision and final decision, and such reasons must provide detail on how the Authority applied the guidelines referred to in section 6.56 in making its determination.