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ECONOMIC REGULATION AUTHORITY OF WESTERN AUSTRALIA

WESTERN POWER AA5 EXPENDITURE PROPOSAL REVIEW

ATTACHMENTS

AUGUST 2022

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Document Control

About this Document

Document Name	Review of Western Power AA5 Expenditure Proposal - Attachments
Version #	FINAL REPORT
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Reviewed by:	Oakley Greenwood
Approved by:	CC
Date Final Report Approved:	04 September 2022

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ABBREVIATIONS & ACRONYMS

Abbreviation	Definition
AA	Access Arrangement
AA4	Access Arrangement Four
AA5	Access Arrangement Five
AACE	Association for the Advancement of Cost Engineering
AAI	Access Arrangement Information
ABS	Australian Bureau of Statistics
AC	Alternating Current
ADMD	After Diversity Maximum Demand
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIS	Approved in Service
ALARP	As Low As Is Reasonably Practicable
AMI	Advanced Metering Infrastructure
AMSR	Asset Management System Review by AMCL
AMSS	Asset Management Strategy Standard
API	Application Programming Interface
ARENA	Australian Renewable Energy Agency
AS	Australian Standard
ATO TR	Australian Taxation Office Taxation Ruling
BAU	Business As Usual
BESS	Battery Energy Storage System
BST	Base–Step–Trend
BTM	Behind The Meter
CAPEX	Capital Expenditure
CBD	Central Business District
CEO	Chief Executive Officer

Abbreviation	Definition
CONSAC	Concentric Neutral Solid Aluminium Conductor
COTS	Commercial Off The Shelf
COVID-19	SARS-CoV-2 Virus
CPI	Consumer Price Index
CRM	Customer Relationship Management (Customer Management System)
CTS	Cost To Serve
DC	Direct Current
DER	Distributed Energy Resources
DFA	Delegated Financial Authority
DMO	Default Market Offer
DNSP	Distributed Network Service Provider
DOFs	Dropout Fuse
DRED	Demand Response Enabling Devices
DSLMP	Dedicated Streetlight Metal Poles
DSO	Distribution System Operator
DSTR	Distribution Transformer
DX	Distribution
EDM	Electronic Document Management
ENSMS	Electricity Network Safety Management Systems
ERA	Economic Regulation Authority Western Australia
ERAC	Energy Regulatory Authorities Council
ESOO	Electricity Statement of Opportunities
EV	Electric Vehicle
FFD	Further Final Decision
FTE	Full Time Equivalent
FY	Financial Year
GIA	Generator Interim Access
GTEng	Grid Transformation Engine
HV	High Voltage

Abbreviation	Definition
ICT or ICT Program	Refers to Transmission and Distribution SCADA and Communication and Corporate IT, collectively defined as Information and Communication Technology (ICT) or ICT Program.
IGF	Investment Governance Framework
IP	Intellectual Property
ISO	International Organisation for Standardisation
IT	Information Technology
LED	Light Emitting Diode
LGA	Local Government Area
LiDAR	Light Detection and Ranging
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MFL	Mean failure life
MPFP	Multilateral Partial Factor Productivity
MRL	Mean Replacement Life
MTFP	Multilateral Total Factor Productivity
MVA	Mega Volt Amp
MW	Megawatt
MWh	Megawatt Hour
NEM	National Electricity Market
NFIT	New Facilities Investment Test
NIPM	Network Investment Prioritisation Methodology
NMI	National Meter Identifier
NMP	Network Management Plan
NPC	Net Present Cost
NPV	Net Present Value
NRMT	Network Risk Management Tool
NRO	Non-Recurring Opex
NRUP	Network Renewal Undergrounding Program
NRUPP	Network Renewal Undergrounding Program Pilot

Abbreviation	Definition
NSP	Network Service Provider
NSW	New South Wales
OCSC	Overhead Customer Service Connection
OEM	Original Equipment Manufacturer
OH	Overhead
OPEX	Operating Expenditure
OPPM	Western Power's corporate portfolio management system
PFP	Partial Factor Productivity
PIN	Productivity Index Numbers
POE	Probability of Exceedance
PPI	Partial Performance Indicator
PSA	Proactive Supply Abolishment
PTRM	Post Tax Revenue Model
PTSD	Pole Top Switch Disconnector
PV	Solar Photovoltaics
PV	Present Value
QLD	Queensland
R&D	Research and Development
RAB	Regulated Asset Base
REPEX	Replacement Expenditure
RFI	Request For Information
RIN	Regulatory Information Notices
RMU	Ring Main Units
SA	South Australia
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPN	SA Power Networks
SCADA	Supervisory control and data acquisition
SCCM	Service Connection Condition Monitoring

Abbreviation	Definition
SFAIRP	So Far As Is Reasonably Practical
SPS	Standalone Power System
SSAM	Service Standard Adjustment Mechanism
SSB	Service Standard Benchmark
SST	Service Standard Target
STATCOM	Static Synchronous Compensator
STPIS	Service Target Performance Incentive Scheme
STRM	Short Term Risk Management
SUPP	State Underground Power Program
SVC	Static Var Compensator
SWIS	South West Interconnected System
TC	Tropical Cyclone
TFP	Total Factor Productivity
TNSP	Transmission Network Service Provider
Totex	Total Expenditure
TX	Transmission
UG	Underground
UCSC	Underground Customer Service Connection
VCR	Value of Customer Reliability
VIC	Victoria
VoSL	Value of Statistical Life
VoSL	Value of Statistical Life
VPP	Virtual Power Plant
WA	Western Australia
WACC	Weighted Average Cost of Capital
WOSP	Whole of System Plan
XLPE	Cross-Linked Polyethylene
ZSS	Zone Substation

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Introduction

To provide supporting detail to the findings summarised in the Executive Summary, the following attachments outline the findings of our review of Western Power AA5 Expenditure Proposal and the associated supporting documentation for the period 2022-2027.

A note on information availability

We note that our review was based on the information provided by Western Power with its Access Arrangement Submission, responses to written questions and a series of 'boardroom' style presentations from Western Power management. We have supplemented this information with publicly available data from the Economic Regulatory Authority WA (ERA), Australian Energy Regulator (AER), other Australian electricity networks, industry bodies, governments and our own experience in managing electricity networks and regulatory determinations.

We note that Engevity were not provided with the working, detailed cost estimating, forecasting or risk models that underpin the core calculations of the expenditure proposal. In several cases, the information provided by Western Power was not adequate for us to provide assurance that the proposed expenditure was efficient and could satisfy (or could reasonably be expected to satisfy) the New Facilities Investment Test (NFIT). In these cases, we have relied on comparative analysis against other the practices, expenditure levels and service performance of other Australian networks to assess the reasonableness or otherwise of Western Power's proposed expenditure. Where the comparative analysis has not allowed us to conclude that Western Power's proposal is efficient, we have based our recommendations on our opinion of the most relevant comparator networks.

We recognise that the information asymmetry in the regulatory process is such that Western Power holds much more detailed information on its plans, activities and systems than was made available to our review. Throughout our review, responses to our requests frequently lacked the specific detail that was requested and were often received much later than the original response time.

Engevity understands and appreciates the scale of the resourcing and governance constraints that networks have during the regulatory process, with information to be prepared, reviewed and approved and coordinated across the whole organisation. Despite our concerns with the flow of information during the process, we appreciate Western Power's efforts to present their vision for the South West Interconnected System (SWIS) over the AA5 period during the challenging, but exciting transition of the WA energy system.

Attachment 1: Governance Assessment

1.1 Overview

This attachment reviews Western Power's investment governance system and assesses the application and the effectiveness of the governance system, to provide the context for which major investment decisions and forecasting assumptions are made through the access arrangement period.

1.2 Investment governance system design

Review of Western Power's governance systems, processes and policies forms an important part of the expenditure review to determine the extent to which the governance arrangements can be relied on to determine whether Western Power's access arrangement forward work program and forecasts of capital and OPEX are prudent.

Overall, Engevity found that the Investment Governance Framework (IGF) is aligned with good industry practice and if applied appropriately should be capable of producing prudent and efficient outcomes.

1.2.1 Investment Governance Framework overview

Western Power's governance arrangements are documented in its IGF document, shown below.

The IGF covers:

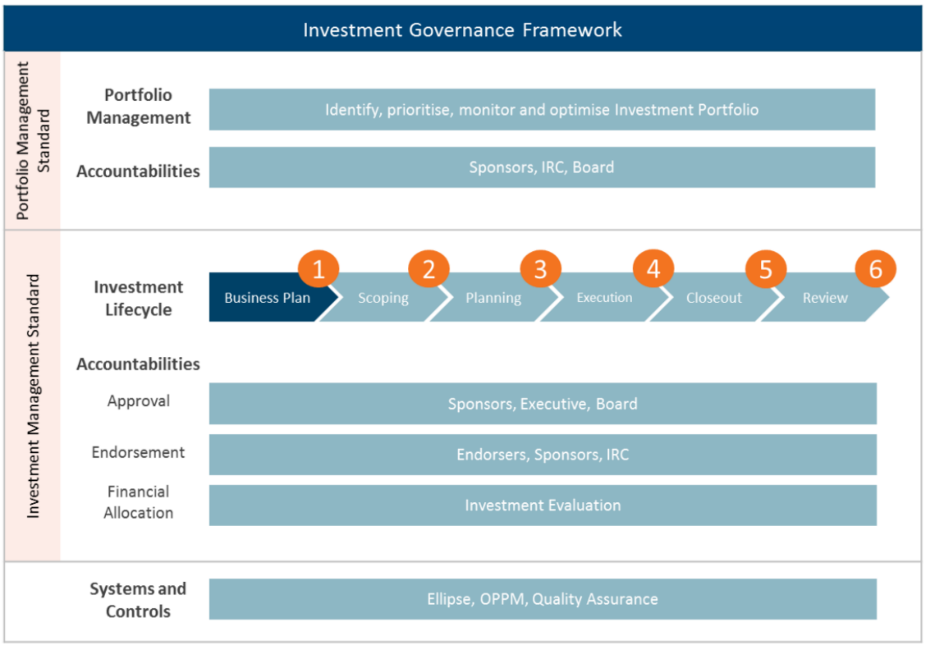
Capital investment (CAPEX)

- All **core capital investments** directly related to the growth or maintenance of the network.
- All **capital investments supporting the core investments** i.e. land, buildings, Information Communication Technology (ICT) hardware or software and fleet.
- **Recovery phase investment** associated with emergency response to a major incident.

OPEX (OPEX)

- **Once off**: non-recurring activity aimed at achieving a specific outcome or benefit such as business improvement or transformation, disposal or decommissioning of assets.
- **Step Change**: Step change in overall cost of an OPEX regulatory category.

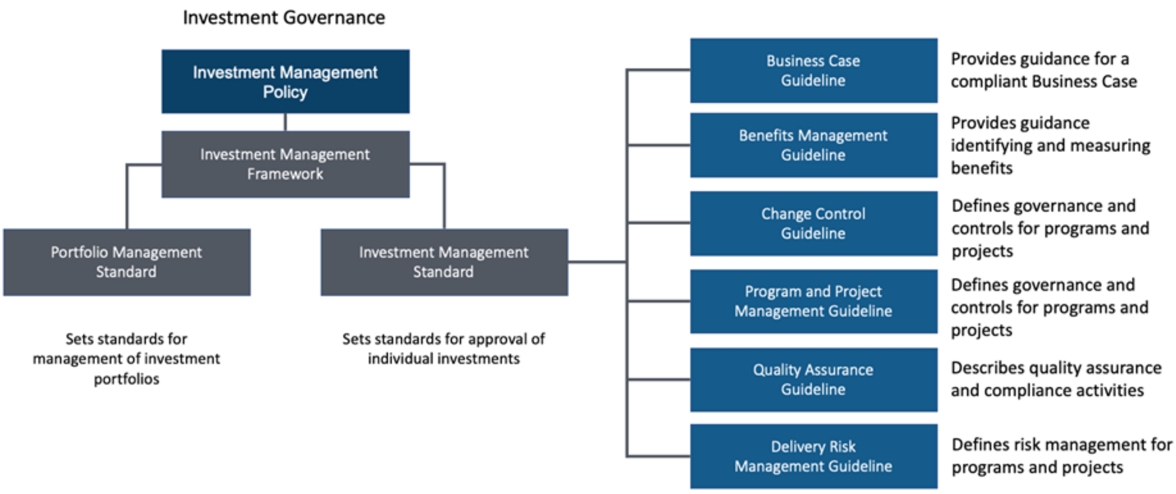
Figure 1–1: Western Power Investment Governance Framework[1]



Inventory purchases, customer funded works, recurrent OPEX (e.g. maintenance activities) and financial investments are outside the of scope for the IGF.

The Investment Governance Framework document is underpinned by the Investment Management Standard and a series of related guidelines. This supporting suite of documents is intended to guide the project deliverables in the governance system and promote consistency and like-for-like comparisons between investment alternatives. The framework of supporting standards and guidelines is illustrated below.

Figure 1–2: Suite of Investment governance documents[2]



1 Source: Attachment 7.1, Figure 4.2

2 Source response to ENG14.03

1.2.2 Investment lifecycle ‘stage gates’

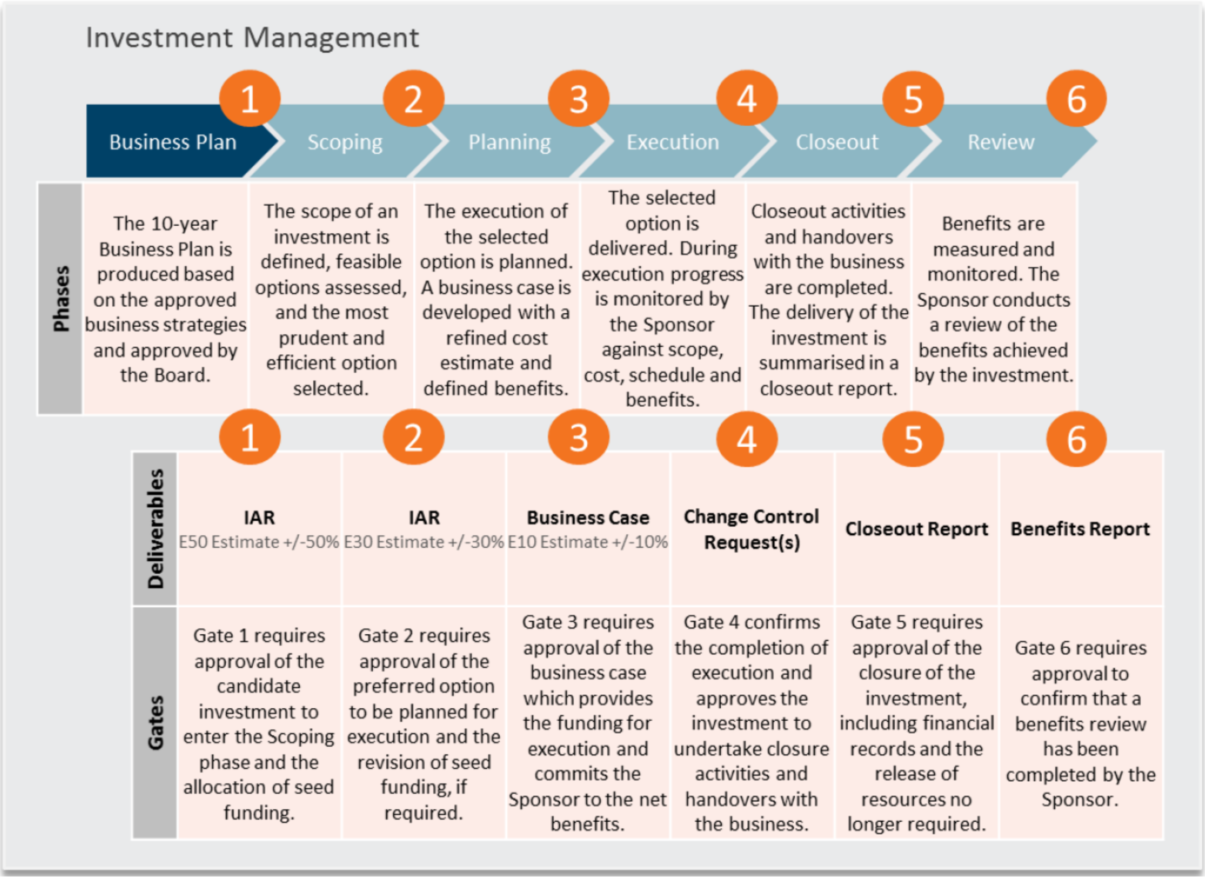
A key feature of the IGF is the stage gates that occur to manage approvals and changes to project parameters (cost, risk, scope, timing) over the investment lifecycle. The general approach is applied across utilities, infrastructure and resources organisations and is consistent with good electricity industry practice.

The main gates within Western Power’s framework for approving the allocation of funds to an investment are:

- **Gate 1 –** Release of ‘seed-funding’ to cover the scoping and planning phases only;
- **Gate 3** – Release of the total funds upon business case;
- **Execution phase** – cost subject to change control as required.[3]

The activities and selected deliverables for each of the stage gates in the investment lifecycle are illustrated in the figure below.

Figure 1–3: Western Power investment management[4]



A key deliverable for each gate is an updated cost estimate for the project, reflecting the refinement of the scope, preferred option, timing and cost from the work that has occurred to date. As would be expected, the claimed accuracy of the estimate improves as the project proceeds through each successive stage gate. Western Power identified that the [5]stated estimate accuracy range at each gate is aligned to Association for the Advancement of Cost Engineering (AACE) recommended

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[3] Wester Power response to RFI ENG14.03

[4] Sources: Attachment 7.1 figure 4.3

[5] Attachment 8.11, Cost Estimation Methodology, Access Arrangement Supplementary

practices for class of estimate[6]. Each estimate class is based on an estimate of a particular maturity level and corresponding range of estimate accuracy. The AACE practices are a well-established industry reference that Western Power has adapted into its IGF to control investment decisions through the project lifecycle.

However, our detailed reviews of Western Power's application of the IGF to the AA4 historical expenditure found that:

a. for a number of significant investments, the project scope was not sufficiently defined at the time of the Access Arrangement to deliver a '50% probability of exceedance' at a portfolio level to ensure that risk is shared appropriately between the business and customers under the regulatory incentive arrangements.

b. the options analysis in Business Case documents dismissed reasonable alternatives on a qualitative basis as unsuitable, without appropriate analysis of cost, timing or benefits[7].

c. some projects included explicit or implicit cost or scope contingencies in estimates that typically equate to 8-10% of overall project costs and effectively change a +/- 10% estimate to a +0% / -10% estimate. (This is also reflected in the +5%/-15% change control thresholds summarised in the table below)

We recognise that this asymmetry in governance and change thresholds is designed to encourage delivery efficiencies to be realised by project managers. However, it also introduces a bias towards overstating project cost that becomes problematic for regulatory forecasts. Without an appropriate correction for this bias in the regulatory CAPEX forecast, the total portfolio cost will also be overstated by a similar proportion.

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

A key attribute of a stage-gate system is to enable "ready" projects to pass through, and those which do not meet the criteria are "recycled" (passed back for further scoping/need definition investigation and refinement) or stopped/" killed" (no longer pursued). Western Power has advised that data regarding project "kill ratios" at project gates are not available, as very few initiatives are 'not approved' because they do not get created unless they have gone through the pre-Gate 1 planning process, and records are not maintained in the system for projects that do not proceed[8].

A relatively direct measure of system effectiveness is the proportion of projects recycled or stopped within the governance process. If an insignificant number of projects are stopped, the inherent assumption is that all projects progressing into the system have a very high likelihood of delivering successful outcomes. Our review of the success rate of Western Power projects in delivering cost outcomes is discussed in Section 1.3 and found a relatively poor predictability of project outcomes (within the claimed estimate accuracy) from the Gate 3 Business Case to the outturn cost.

Western Power has a change management process to manage changes post Gate 3 (release of the total funds) approval. The change control cost and schedule tolerance thresholds are outlined in

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6 Refer attachment 8.11

7 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.

8 Response ENG34.02

Table 1–1 below. Change management approval processes are also required for scope and benefits realisation.

Table 1–1: Cost and schedule change control thresholds[9]

Change in	Threshold
Cost	**Coverage:** All Western Power Investments approved at Gate 3**.** Anticipated change in the 'Current Approved Cost' of an investment where the revision is either: • + 5% of the 'Current Approved Cost', or • - 15% of the 'Current Approved Cost', and • > $50,000 Note: The threshold assessment must compare the proposed Investment Cost to the 'Current Approved Cost' of the Investment. See the Delegated Financial Authority Policy[2] for further context. Exceptions: • For Investments approved at Gate 3 by the Chief Executive Officer and below, Board approval will be required for a Change Control where the total change in Investment Cost (since Gate 3 approval) is +/- $3,000,000 (CAPEX) or +/- $1,000,000 (OPEX). • Note that when the cost of an investment exceeds a specific DFA level, DFA approval via a change control will be required. This requirement overrides the >+5% (& $50k) threshold.
Schedule	**Coverage:** All Western Power Investments approved at Gate 3. Anticipated change in the current approved Schedule that has: • A change > 2 months from the 'Current Approved Gate 4 date' for Investments with a delivery duration < or = 1 year; or • A change > 4 months from the 'Current Approved Gate 4 date' for Investments with a delivery duration with a delivery duration > 1 and < 3 years; or • A change > 6 months from the 'Current Approved Gate 4 date' for Investments with a delivery duration > 3 years; or • Any change from a current approved (post Gate 3) customer schedule (AIS Date) (Customer Investment Portfolio only) Note: Delivery duration is defined as the time from the Gate 3 approval date in OPPM to the approved Gate 4 date in OPPM.

Post construction, Western Power's IGF requires a closeout report (Gate 5) and benefits report (Gate 6) (approximately 1 year after construction complete). The closeout review focuses on the project execution outcomes (scope, cost, schedule) whereas benefits report address demonstration of achievement of NFIT requirements.

In Engevity's opinion, the design of the stage gated approval system and change control management is comparable to processes employed by industry peers and appropriate for the works. The consistent application of the framework, associated processes and input information remains a concern which we discuss in more detail as part of our CAPEX review.

9 Source response to ENG14.03

1.2.3 OPEX governance

The primary focus of our review has been on CAPEX, as it is a larger portion of total spend compared to OPEX, as well as representing a significantly higher change from AA4 to AA5. As noted in Section 1.2.1, once-off OPEX investments (e.g. non-recurring activity aimed at achieving a specific outcome or benefit such as business improvement or transformation, disposal or decommissioning of assets) is covered by the Investment Governance Framework. However recurrent OPEX incurred such as operations and maintenance activities are out of scope. Engevity has not sighted an OPEX governance document, however it is noted that previous reviews of the OPEX system[10] state that they were provided with evidence of detailed processes for budgeting and measurement of operational expenses.

Engevity notes the governance documentation does not cover the governance of OPEX. This matter was identified in the previous reviews and appears to remain unaddressed.

For further analysis on the proposed OPEX allowance, refer to Section 5.0.

1.2.4 Roles and responsibilities

Each investment has a three-step approval process at each gate:

- The **endorser** (generally accountable for the delivery) – confirmation that the deliverables are of a quality that the investment can proceed to the next phase in the investment lifecycle.
- The **sponsor** (accountable owner) –initiates investment definition and proposal and approves mandatory deliverables at each gate following endorsement to ensure the investment is prudent, efficient and meets the objectives of the Investment Portfolio.
- **Finance and Metering Function** – accountable for allocating funding to an individual investment.

Further details regarding roles and responsibilities at each gate is provided in the Investment Management Standard.[11] All approvals are recorded electronically in Western Power's corporate portfolio management system (OPPM)[12]. Where the gate requires spending authority a financial delegate is also involved. Financial delegations are shown in the table below.

Table 1–2: Delegations of authority[13]

	CAPEX (m)	OPEX (m)
Board	> $25	> $10
CEO	≤ $25	≤ $10
Execs	≤ $5	≤ $1
HOFs	≤ $2.5	≤ $0.5
Area Managers	≤ $1	≤ $0.1

10 Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22 (GHD, 26 April 2018)

11 AA5 - ENG34.3 - Governance - Investment Management Standard [redacted]

12 Source response to ENG14.03

13 Source ENG14.03 Investment Governance Framework – Cost & Schedule

Executive oversight is provided through:

- **Western Power's Board of Directors** – approving the Investment Management Policy, Corporate Strategy and Business Plan, and setting investment risk appetite.
- **Investment Review Committee** – executive committee overseeing and monitoring investments, including reviewing performance of Investment Portfolios and endorsing financial allocation to individual Investment proposals meeting the CEO and Board's delegation.

In Engevity's opinion Western Power applies an appropriate level of executive and board oversight for investment decision making

1.3 Investment governance system application and effectiveness

Noting the appropriate design of the IGF described in Section 1.2, this section addresses the system application and outcomes. Specifically:

1. **Is there evidence the IGF has been applied as intended?**
2. **Is there evidence that the IGF works as intended (is it effective)?**

Engevity reviewed the application and effectiveness of the IGF through review of audits done by Western Power and a spot check of supplied project information.

1.3.1 Audit findings

Western Power has supplied an internal audit report[14] on the Investment Governance framework undertaken in 2018. The report provided is an executive summary of another report (not supplied) prepared by an external subject matter expert. The audit found that the design of the IGF was adequate and fit for purpose and was operating effectively. A number of "low rated findings" were raised as opportunities for improvement.

Engevity makes the following observations in relation to the supplied audit materials:

- **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, we would typically expect more frequent management system 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.

Western Power audit reports indicate no major issues with the application of the IGF but are silent on the effectiveness of this framework in meeting cost, schedule and benefits realisation tolerances at key decision milestones. Without clear assessment of IGF performance outcomes, the motivation and direction of continuous improvement efforts are unclear and thus unlikely to be achieved.

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14 AA5-ENG14.04 - Investment Governance Audit Report [redacted]

1.3.2 Project sampling

Engevity conducted a spot check of a sample of projects supplied by Western Power to evaluate compliance with IGF rules and IGF systems effectiveness. We have relied on NFIT Compliance Summary documentation for this sample of projects and cannot confirm the extent to which this sample is representative of the wider portfolio. Portfolio data was requested but has not been supplied.

Key attributes sampled projects

A summary of key attributes of the sampled projects is provided in the table below. We have focussed our review on the investment decision at Gate 3.

Table 1–3: Projects Reviewed

	Gate 3			Actual		Deviation to Gate 3 (no adjustment for scope)		Deviation to Gate 3 Scope Adjusted	
Project	**TOC**	**Start**	**Completion date (AIS)**	**TOC**	**Completion date**	**TOC**	**Completion date (-ve is early)**	**TOC**	**Completion date (-ve is early)**
NMPD Transmission - T0375560 Replace Tx SCADA/Comms: SCAR2	$ 34,030,000.00	Jul-15	Jun-19	$ 33,525,000	14/06/2021	-1%	23.6 months	22%	23.6 months
Tx SCADA & Communications (stage 3)	$ 16,000,000.00	Jul-20	Jun-24	Not completed	Not completed	Not completed	Not completed	Not completed	Not completed
Reactive Voltage Rectification – Stage 1	$ 5,790,000.00	not supplied	Jul-20	$ 3,720,000	22-May-20	-36%	-1.8 months	-36%	-1.8 months
Customer Management System Phase 1	$ 11,960,000.00	Sep-18	Sep-19	$ 10,700,000	1-Dec-21	-11%	26.5 months	?Multiple scope redcutions and no(few?) scope additions. Reconcilsation of	26.5 months
Customer Management System Phase 2	$ 8,010,000.00	May-19	Oct-20	$ 14,200,000	1-Dec-21	77%	14 months	??	14 months
Forrestdale depot	$ 94,780,000.00	Jun-19	Aug-21	$ 79,500,000	31-Aug-22	-16%	12 months	-16%	12 months
HAY Mil substations	$ 13,450,000.00	Nov-19	Dec-21	$ 12,300,000	31-Dec-21	-9%	0 months	-9%	0 months
Grid Transformation Engine	$ 16,350,000.00	Jun-20	Aug-21	$ 16,349,469	Jan-22	0%	5 months		5 months
SPS Round 1 (pilot prgram)	$ 13,400,000.00	Jan-19	Mar-20	$ 14,800,000	Sep-22	10%	29.1 months	23%	29.1 months
SPS Round 2	$ 24,800,000.00		Apr-22	Not completed	Not completed	Not completed	Not completed	Not completed	Not completed
TC Seroja Response	$ 15,450,000.00	Apr-21	Jun-22		no data	Not completed	Not completed	Not completed	Not completed
Cyber Security	$ 4,880,000.00	Feb-22	Nov-22	Not Completed	Not Completed	Not completed	Not completed	Not completed	Not completed
Kalbarri Microgrid	$ 11,570,000.00	Jan-18	Jun-19	$ 15,500,000	30-Nov-21	34%	29.1 months	24%	29.1 months

Engevity has analysed 13 projects, of which we have completion data for nine. Observations from the supplied sample are as follows:

- Actual costs are within 10% of Gate 3 (detailed business case) estimates four times out of nine, if costs are not adjusted for scope changes.
- Many of the projects experienced material and multiple scope changes during execution. If budget costs are **adjusted for scope change, actual cost is within 10% of Gate 3 estimates for two projects out of nine** and not with 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 NFIT 'look-back' reports is higher than many Australian utilities.[15] However, the reconciliation of project costs and asset quantities to regulatory models was difficult, and in some cases not possible with the information provided.

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. These very long delays can distort perspective of project outcomes when looking at spend within an Access Arrangement period and not considering whole of project cost. Whilst we have 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 CAPEX forecast.

Based on the supplied data and Engevity's analysis we have found that Western Power management are taking on more risk in their decision making than is anticipated by the governance systems. Based on the data available we conclude the governance systems are not effective at consistently identifying, valuing, and mitigating risk at the minimum cost.

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[15] We 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.

Attachment 4: Benchmarking Assessment

2.1 Overview

This section reviews Western Power's AA4 actual expenditure and AA5 forecast expenditure to inform our assessment and make recommendations to the ERA to determine whether CAPEX and OPEX is being incurred in a prudent and efficient manner, efficiently minimising costs as required under section 6.40 and section 6.52 of the Access Code.

Our review includes benchmarking expenditure against other Australian service providers, using the AER benchmarking report data. We note that we have not attempted to correct for differences in reporting definitions or local environmental factors between Western Power and the National Electricity Market (NEM) businesses. Therefore, our benchmarking should be interpreted as indicative only, with our detailed investigations providing the substantive recommendations on the efficiency of the proposed AA5 expenditure.

The AER benchmarking report makes use of three types of 'top-down' benchmarking techniques:

- **Productivity Index Numbers (PIN)** that are mathematical indices that estimate the relationships between multiple outputs and inputs, such as Multilateral Total Factor Productivity (MTFP) and Multilateral Partial Factor Productivity (MPFP).
- **Econometric OPEX cost function** models such as Cobb-Douglas Stochastic Frontier Analysis.
- **Partial Performance Indicator (PPI)** techniques that relate one input to one output. Each PPI provides a general indication of comparative performance of Distribution Network Service Providers (DNSPs) in terms of delivering a single output. PPIs are simpler to understand and are often more intuitive for customers, DNSPs and regulators in terms of making comparisons of electricity industry physical and financial outcomes. However, the limitation is that PPIs do not consider interrelationships between multiple outputs or multiple inputs.

This analysis makes use of PPIs in preference to more complex PIN and econometric models to benchmark Western Power's distribution network OPEX, CAPEX and service performance against DNSPs in the NEM. This is because the productivity and economic cost function approaches are more reliant on information in a common data specification that the AER regulated businesses provide each year to the regulator. Western Power reports on a different basis and applying these approaches would bring greater uncertainty in interpreting the outcomes.

As with the AER benchmarking report, the results are presented on data averaged over five-year periods. Engevity acknowledges that PPI benchmarking of DNSP and TNSP relative performance is not conclusive evidence of efficiency or otherwise. We also note that the analysis does not consider Operating Environment Factors (OEF's) that are specific to the Western Power or any other distribution or transmission network. In some cases, the AER's Operating Environment Factors make significant allowance in OPEX for factors that are unique to a certain jurisdiction or network area.

2.2 Distribution Network OPEX Benchmarking

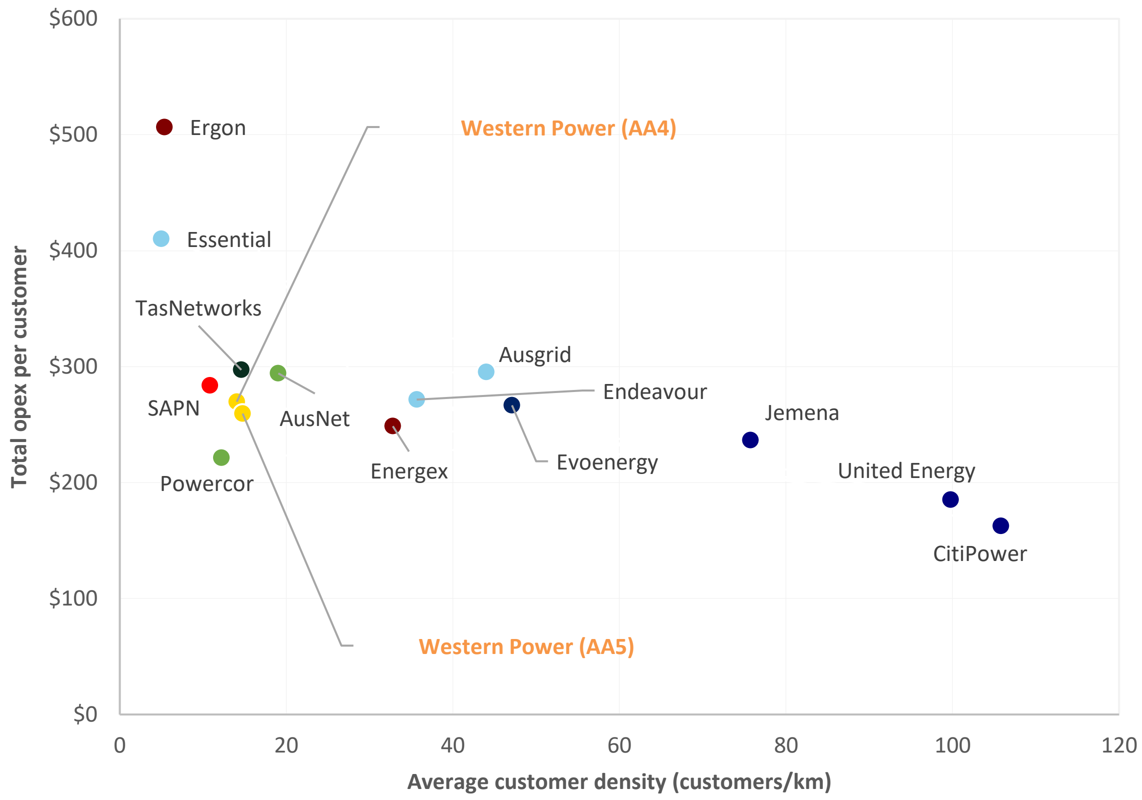
The AER has developed an OPEX benchmarking approach which has been used to establish whether or not a DNSP business is significantly outside a reasonable benchmark level of OPEX when compared to its peers. The approach relies on econometric analysis of historical performance as well as the application of 'Operating Environment Factors' that correct for influences that are unique to a network.

There has been significant critique over the approach as the underlying econometric function is heavily weighted towards customer numbers and highly correlated values such as demand and consumption.

The following graphs show how Western Power compares (excluding OEFs) with other NEM DNSPs in terms of total OPEX PPIs. It should be noted that OPEX benchmarking is applied here to DNSPs only, with TNSPs benchmarked against total cost (OPEX and asset costs) PPIs only, as per the AER's benchmarking approach. DNSPs are also benchmarked against total cost PPIs in this report.

The figure below illustrates DNSP total OPEX per customer as a function of average customer density. Western Power is plotted for AA4 and AA5 averages of total OPEX[16], route line length and customer numbers[17], while NEM DNSPs are plotted for averages over 2016-2020[18]. Western Power results for this PPI over AA4 and AA5 are very similar to each other and follow the general NEM trend (with substantial spread for DNSPs with lower average customer density) of decreasing total OPEX per customer with increasing average customer density. This is expected in terms of DNSPs with higher customer density being able to spread their OPEX across a larger customer base with fewer assets. Western Power DNSP is operating in AA4 and AA5 with slightly less total OPEX per customer than SA Power Networks (SAPN), TasNetworks and AusNet, and more than Powercor. Western Power is, by this PPI, slightly more OPEX efficient in AA4 and AA5 than TasNetworks and less OPEX efficient than Powercor, the two NEM DNSPs with the closest average customer density to Western Power.

Figure 2–1: Benchmark OPEX per customer for Western Power Dx in the AA4 and AA5 periods ($ Real December 2020).



The figure below shows DNSP total OPEX per circuit kilometre as a function of average customer density. Western Power is again plotted for AA4 and AA5 averages of total OPEX, circuit kilometres and customer density, while NEM DNSP's are plotted for averages over 2016-2020. Western Power results for this PPI over AA4 and AA5 are again very similar to each other and follow the general NEM trend (with substantial spread for DNSPs with higher average customer density) of increasing OPEX per circuit kilometre with increasing average customer density. This is expected in terms of DNSPs with higher customer density also having higher costs per circuit kilometre (as assets are located in

16 Western Power AAS – Attachment 11.7 – AA5 Regulatory Revenue Model.xlsm.

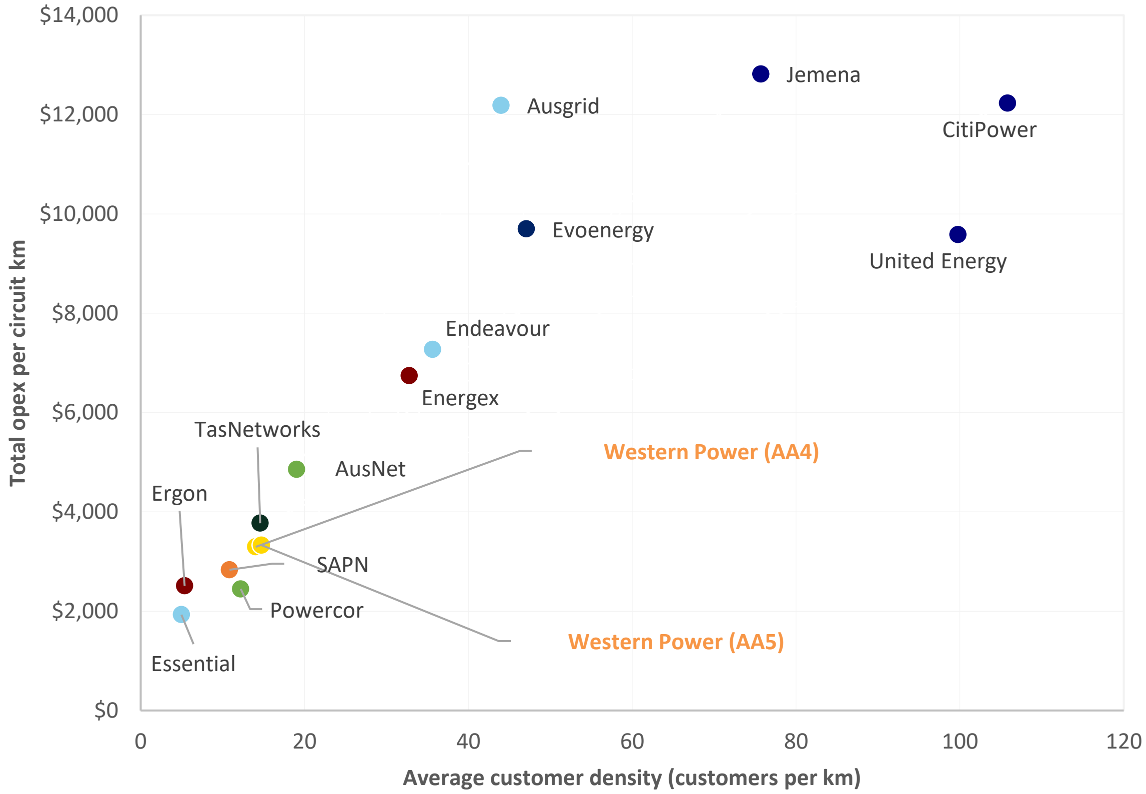
17 Western Power Annual Reliability and Power Quality Reports 2018-2021 and Western Power AAI, 1 February 2022, p. 165

18 AER Annual Benchmarking Report – Electricity distribution network service providers, November 2021, Supporting information: AER - Partial Performance Indicators for distribution.xlsx.

more complex urban environments (requiring traffic control or night works), and are typically higher capacity to serve the higher customer density)

Western Power DNSP is operating in AA4 and AA5 with less total OPEX per circuit kilometre than AusNet, slightly less than TasNetworks, and more than SAPN and Powercor. Given these comparators, the total OPEX reflects the general level of expenditure that is to be expected for an Australian mixed urban-rural network on this PPI. Western Power is, by this PPI, slightly more OPEX efficient in AA4 and AA5 than TasNetworks and less OPEX efficient than Powercor, the most comparable NEM distribution networks in terms of average customer density.

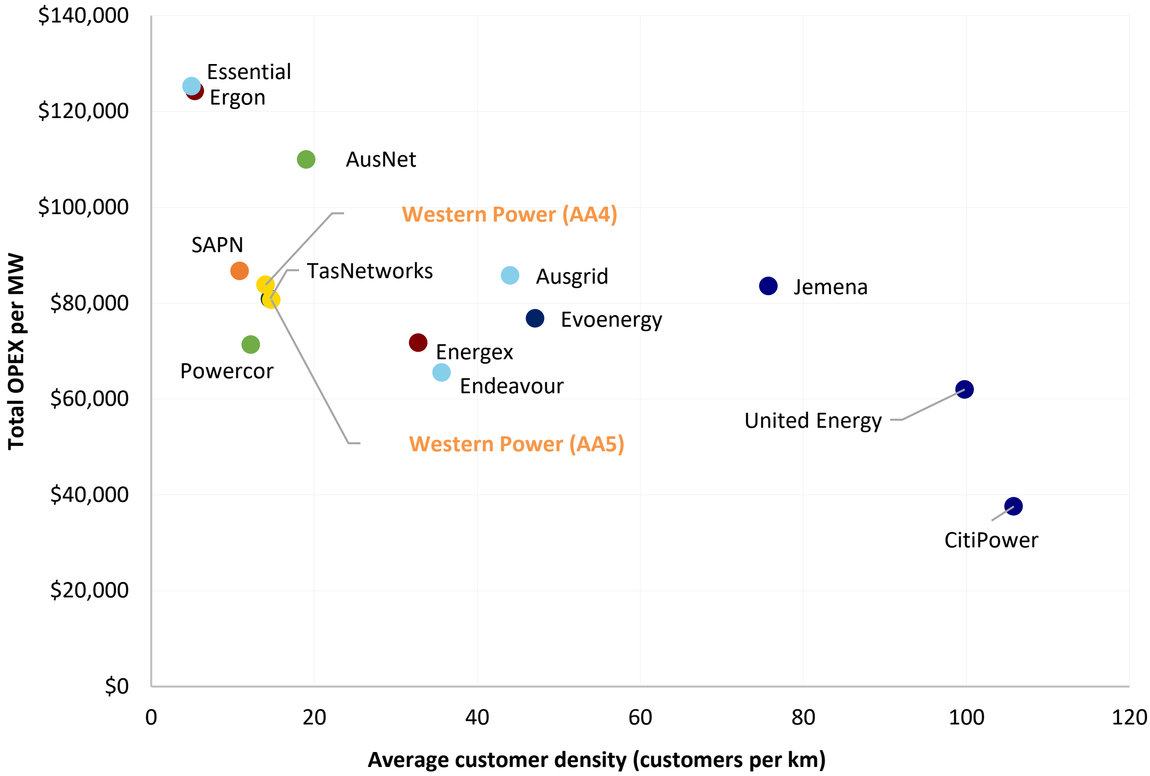
Figure 2–2: Benchmark OPEX per circuit kilometre for Western Power Dx in the AA4 and AA5 ($ Real December 2020).



The figure below shows DNSP total OPEX per MW of maximum demand as a function of average customer density. Western Power is plotted for AA4 and AA5 averages of total OPEX, MW of maximum demand and customer density, while NEM DNSP's are plotted for averages over 2016-2020. Western Power results for this PPI over AA4 and AA5 remain similar to each other and follow the general NEM trend of decreasing total OPEX per MW of maximum demand with increasing average customer density. This reflects that DNSPs with higher customer density predictably service higher maximum demand and are therefore able to access greater scale efficiencies by operating and maintaining fewer, higher capacity assets, and a greater volume of underground assets that are protected from storm events and traffic/machinery/wildlife exposure.

Western Power DNSP is operating in AA4 and AA5 with considerably less total OPEX per MW of maximum demand than AusNet, slightly less than SAPN, about the same as TasNetworks and more than Powercor. Western Power is, by this PPI, as OPEX efficient in AA4 and AA5 as TasNetworks but less OPEX efficient than Powercor, the most comparable NEM distribution networks in terms of average customer density.

Figure 2–3: Benchmark OPEX per MW of maximum demand for Western Power Dx ($ Real December 2020).



There are several key OEFs that are unique to the Western Power network. These include:

- Extensive use of Jarrah species for wood poles (among other issues) resulting in very high unassisted pole failure rates in comparison to NEM DNSPs. These have improved significantly as a result of over $2b recent investment in the WA wood pole program, however they still remain well above the rates observed in the NEM networks.
- The prevalence of sandy soils in metropolitan Perth, reducing excavation costs for underground network infrastructure, making it more competitive with overhead construction than in the eastern states.
- Workforce and contractor hire issues, demand and works deliverability issues due to the particularly strong competitive effects of mining, gas and oil extraction cycles on the availability of WA skilled and unskilled labour.
- The costs of planning for, and responding to, both increasingly intense cyclone/storm events and bushfires on both distribution and transmission networks.

2.3 Distribution and Transmission Network CAPEX Benchmarking

The AER's approach to CAPEX benchmarking involves the use of the return on assets and return of assets (i.e., financing cost and depreciation) to provide a smoothed annual 'capital service cost'. This is affected by a range of factors including:

- differing historical assumptions around initial RAB value (as they were separately calculated under the oversight of several different state regulators);
- differing depreciation life assumptions for similar asset classes;
- different capitalisation and cost allocation practices between businesses - and within a single business over time (meaning that different proportions of costs have been allocated to

unregulated activities, between transmission and distribution and similar activities have been allocated to OPEX and CAPEX on the basis of each company's accounting policies[19]);

- different regulatory WACCs for each business affecting investment decisions; and,
- differing timing for major development needs or actions in the networks (e.g., Victoria's major 500kV transmission investments in the 1980's providing capacity that is still not fully absorbed to date).

Whilst this approach to CAPEX benchmarking provides a reasonable linkage to customer bills, it fails to account for the complexity of assumptions that are embedded in the current RAB values. For this reason, it is also worthwhile to consider the AER's category analysis benchmarks that compare similar categories of expenditure between businesses.

To the extent that the AER's historical position that differing capitalisation and cost allocation practices – between businesses and over time - can be put to one side, the lower-level comparisons at the category level tend to provide more actionable insight in detailed reviews.

The following graphs show how Western Power distribution and transmission CAPEX benchmarks compare to its Australian (NEM) peers in terms of total cost PPIs, defined in accordance with the AER as normalised values of annual user cost of capital plus OPEX, with the former calculated from the WACC, distribution RAB and regulatory depreciation (i.e. the Return *on* Assets + Return *of* Assets building blocks).

Distribution Total Cost Benchmarking

The figure below shows DNSP total cost per customer as a function of average customer density. Western Power is plotted for AA4 and AA5 averages of total cost[20], route line length and customer numbers[21], while NEM DNSP's are plotted for averages over 2016-2020[22]. Western Power results for this PPI over AA4 and AA5 are similar, with AA5 forecast to have slightly lower total cost per customer and slightly higher average customer density than for the AA4 period. Western Power results for this PPI follow the general NEM trend (with substantial spread for DNSPs with lower average customer density) of decreasing total cost per customer with increasing average customer density. This is expected in terms of DNSPs with higher customer density being able to access scale efficiencies by spreading their total cost across a larger customer base served by fewer, higher capacity assets.

Western Power DNSP is operating in AA4 and AA5 with less total cost per customer than TasNetworks, slightly less than SAPN and AusNet, and more than Powercor. Western Power is, by this PPI, more efficient in AA4 and AA5 than TasNetworks and less total cost efficient than Powercor, the two NEM DNSPs with the closest average customer density to Western Power.

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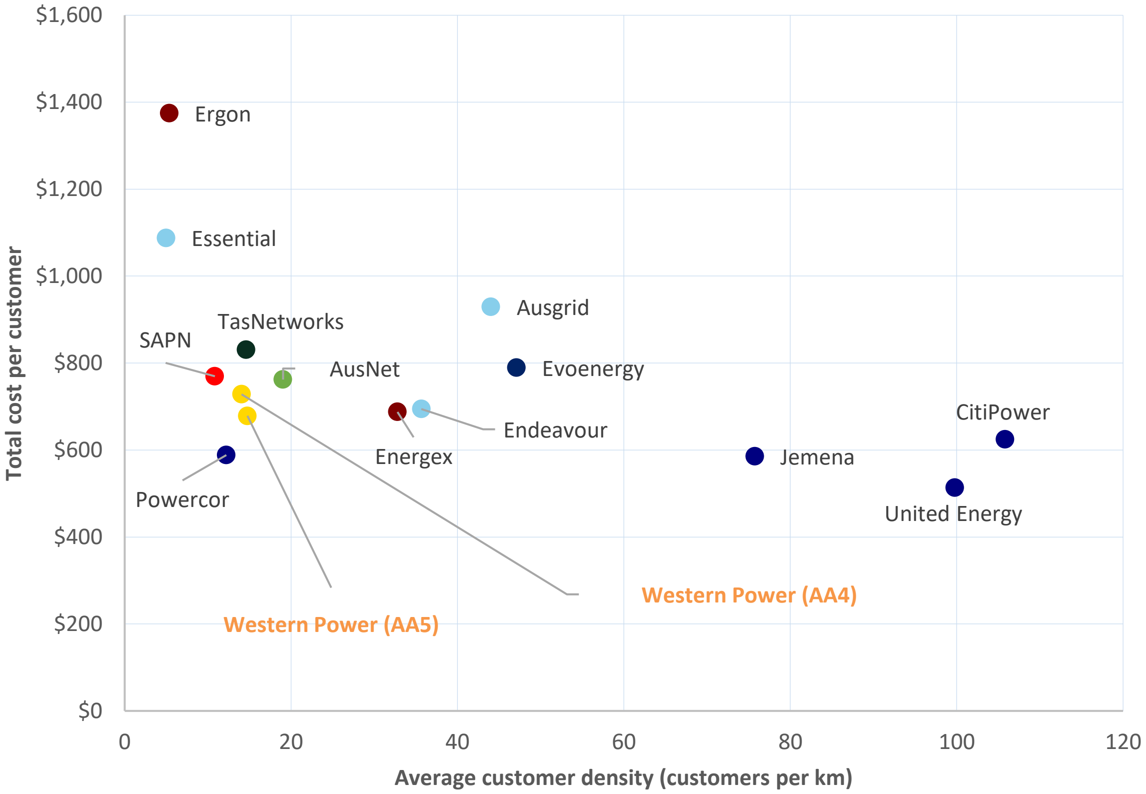
19 For example, some businesses historically expensed cross arm replacements, whist others capitalized them, and others still expensed emergency replacement as repair but capitalized planned replacement. Cross arms are particularly significant in the Victorian business RAB due to a widespread crossarm replacement program in the late 2000's and early 2010's to install steel crossarms for bushfire safety. As a result, their value is disproportionately high in the Vic DNSP RAB values.

20 Western Power AAS – Attachment 11.7 – AA5 Regulatory Revenue Model.xlsm.

21 Western Power Annual Reliability and Power Quality Reports 2018-2021 and Western Power AAI, 1 February 2022, p. 165

22 AER Annual Benchmarking Report – Electricity distribution network service providers, November 2021, Supporting information: AER - Partial Performance Indicators for distribution.xlsx.

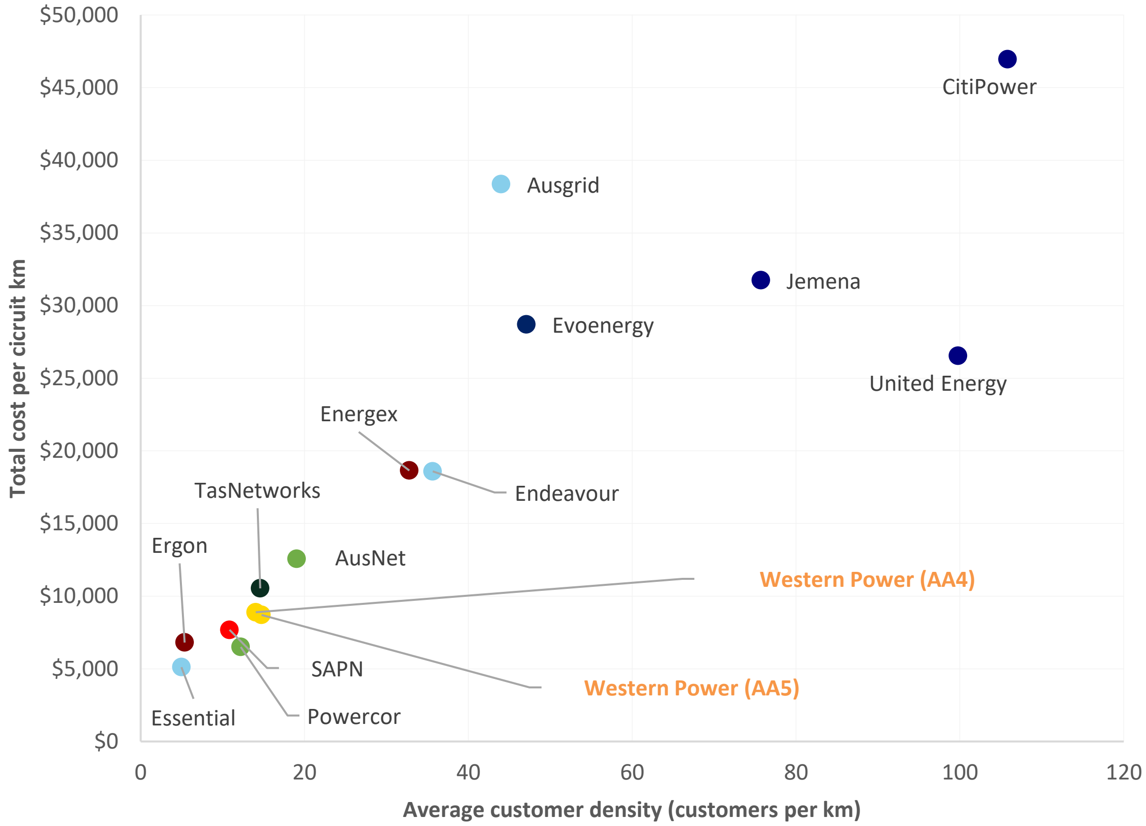
Figure 2–4: Benchmark total cost per customer for Western Power Dx in the AA4 and AA5 periods ($ Real December 2020).



The figure below shows DNSP total cost per circuit kilometre as a function of average customer density. Western Power is plotted for AA4 and AA5 averages of total cost, circuit kilometres and customer density, while NEM DNSP's are plotted for averages over 2016-2020. Western Power results for this PPI over AA4 and AA5 remain similar, with AA5 forecast to have slightly lower total cost per circuit kilometre than for the AA4 period. Western Power results follow the general NEM trend of increasing total cost per circuit kilometre with increasing average customer density. This is expected in terms of DNSPs with higher customer density also having fewer circuit kilometres of assets to spread their costs over.

Western Power DNSP is operating in AA4 and AA5 with less total cost per circuit kilometre than AusNet, slightly less than TasNetworks, and more than SAPN and Powercor. Western Power is, by this PPI, slightly more efficient in AA4 and AA5 than TasNetworks and less efficient than Powercor, the most comparable NEM distribution networks in terms of average customer density.

Figure 2–5: Benchmark total cost per circuit kilometre for Western Power Dx in AA4 and AA5 ($ Real December 2020).



The figure below shows DNSP total cost per MW of maximum demand as a function of average customer density. Western Power is again plotted for AA4 and AA5 averages of total cost, MW of maximum demand and customer density, while NEM DNSP's are plotted for averages over 2016-2020. Western Power results for this PPI over AA4 and AA5 are essentially the same, with AA5 forecast to have slightly lower total cost per MW of maximum demand than for the AA4 period. Western Power results follow the general NEM trend of decreasing total cost per MW of maximum demand with increasing average customer density. As maximum demand generally increases with the size of the customer base, DNSPs with higher customer density also have higher maximum demand, fewer assets per customer, a smaller physical footprint to serve their customers, and consequently lower total cost per MW of maximum demand[23]. As higher density networks are located in more complex urban areas, they are also affected by issues such as traffic control, access constraints, travel times and higher reliability expectations when compared to more rural networks.

Western Power DNSP is operating in AA4 and AA5 with considerably less total cost per MW of maximum demand than AusNet, slightly less than SAPN, about the same as TasNetworks and more than Powercor. Western Power is, by this PPI, similarly efficient in AA4 and AA5 as TasNetworks but less total cost efficient than Powercor, the most comparable NEM distribution networks in terms of average customer density.

[23] Annual Benchmarking Report – Electricity distribution network service providers, AER, November 2021, p. 38

Figure 2–6: Benchmark total cost per MW of maximum demand for Western Power Dx in AA4 and AA5 ($ Real December 2020).

Transmission Total Cost Benchmarking

The figure below illustrates TNSP total cost per end user for Western Power (the transmission side of the business only) and its NEM counterparts. Western Power is plotted for AA4 and AA5 averages of transmission total cost[24] and end user (customer) numbers[25], while NEM TNSP's are plotted for averages over 2016-2020[26]. Western Power results for this PPI over AA4 and AA5 are similar, with AA5 forecast to have slightly higher total cost per end user than for the AA4 period. Western Power results for this PPI are comparable to their NEM TNSP counterparts.

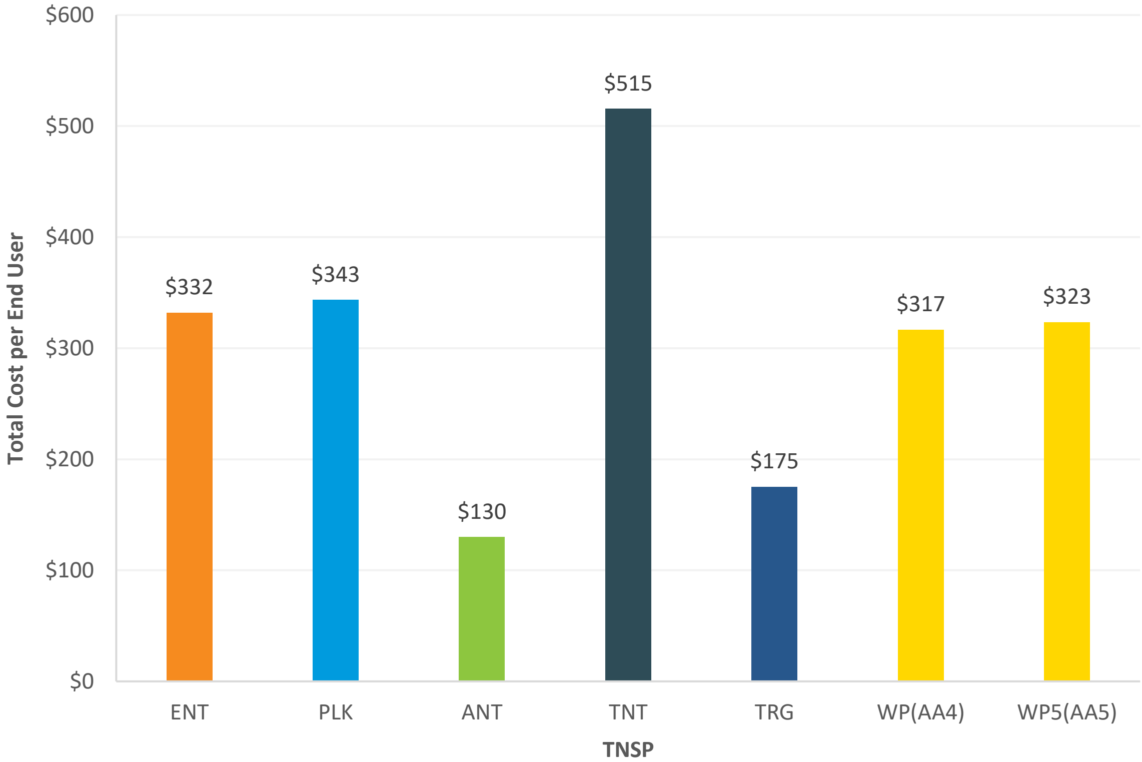
The Western Power transmission network is operating in AA4 and AA5 with about 38 per cent less total cost per end user than TasNetworks transmission network, similar to ElectraNet and Powerlink, about 83 per cent more than Transgrid and about 146 per cent more than AusNet Services. The Western Power transmission network appears, by this PPI, more total cost efficient in AA4 and AA5 than TasNetworks and less total cost efficient than AusNet Services and Transgrid. However, these differences may be largely due to local environmental factors.

24 Western Power AAS – Attachment 11.7 – AA5 Regulatory Revenue Model.xlsm.

25 Western Power Annual Reliability and Power Quality Reports 2018-2021 and Western Power AAI, 1 February 2022, p. 165

26 AER Annual Benchmarking Report – Electricity transmission network service providers, November 2021, Supporting information: AER - Partial Performance Indicators for transmission.xlsx.

Figure 2–7: Benchmark total cost per end user for Western Power Tx in the AA4 and AA5 periods and NEM TNSPs averaged over 2016-2020

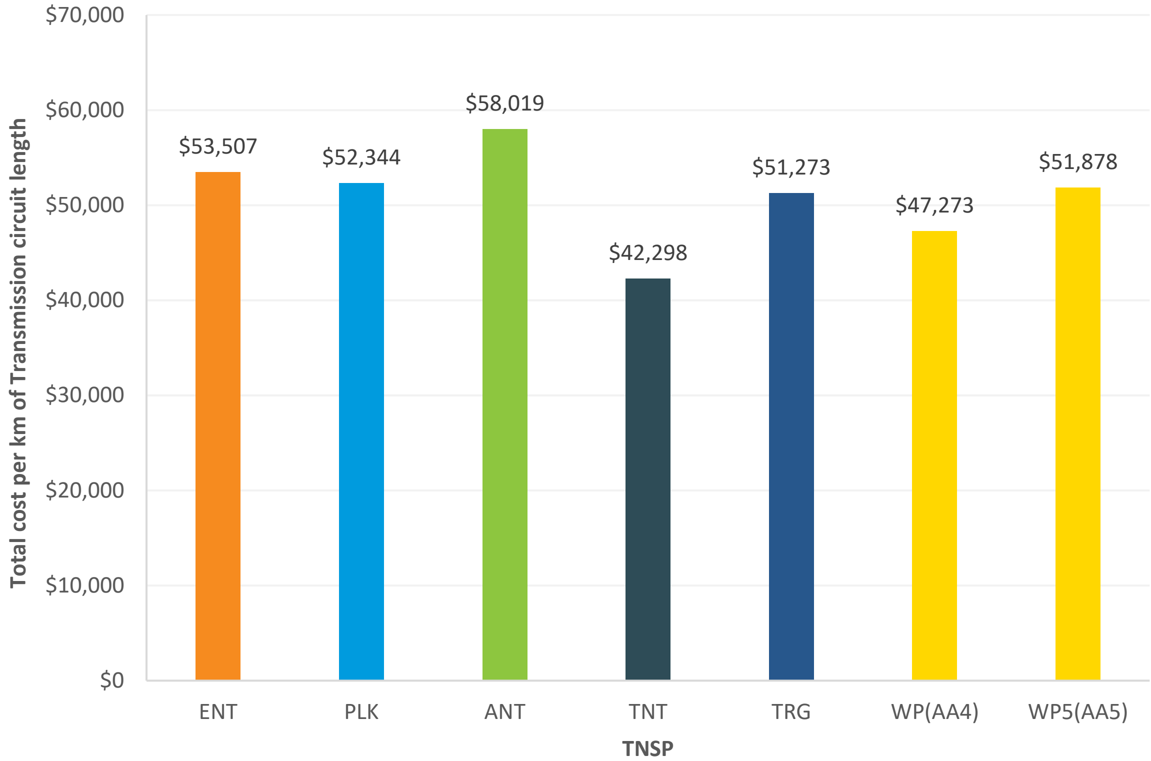


Key: ENT - ElectraNet, PLK - Powerlink, ANT – AusNet Services, TNT - TasNetworks, TRG – Transgrid, WP(AA4) – Western Power (AA4 period), WP(AA5) – Western Power (AA5 period) ($ Real December 2020)

The figure below shows TNSP total cost per circuit kilometre for Western Power (the transmission side of the business only) and its NEM counterparts. Western Power is plotted for AA4 and AA5 averages of transmission total cost and circuit kilometres, while NEM TNSP's are plotted for averages over 2016-2020. Western Power results for this PPI over AA4 and AA5 are again similar, with AA5 forecast to have about 10 per cent higher total cost per circuit kilometre than for the AA4 period. Western Power results for this PPI are again comparable to their NEM TNSP counterparts.

The Western Power transmission network is forecast to be operating in AA5 with about 11 per cent less total cost per circuit kilometre than AusNet Services transmission network, similar to Transgrid, Powerlink and ElectraNet and about 23 per cent more than TasNetworks transmission network. The Western Power transmission network appears, by this PPI, slightly more total cost efficient in AA4 and AA5 than AusNet Services and less total cost efficient than TasNetworks transmission network. However, these differences may again be largely due to local environmental factors.

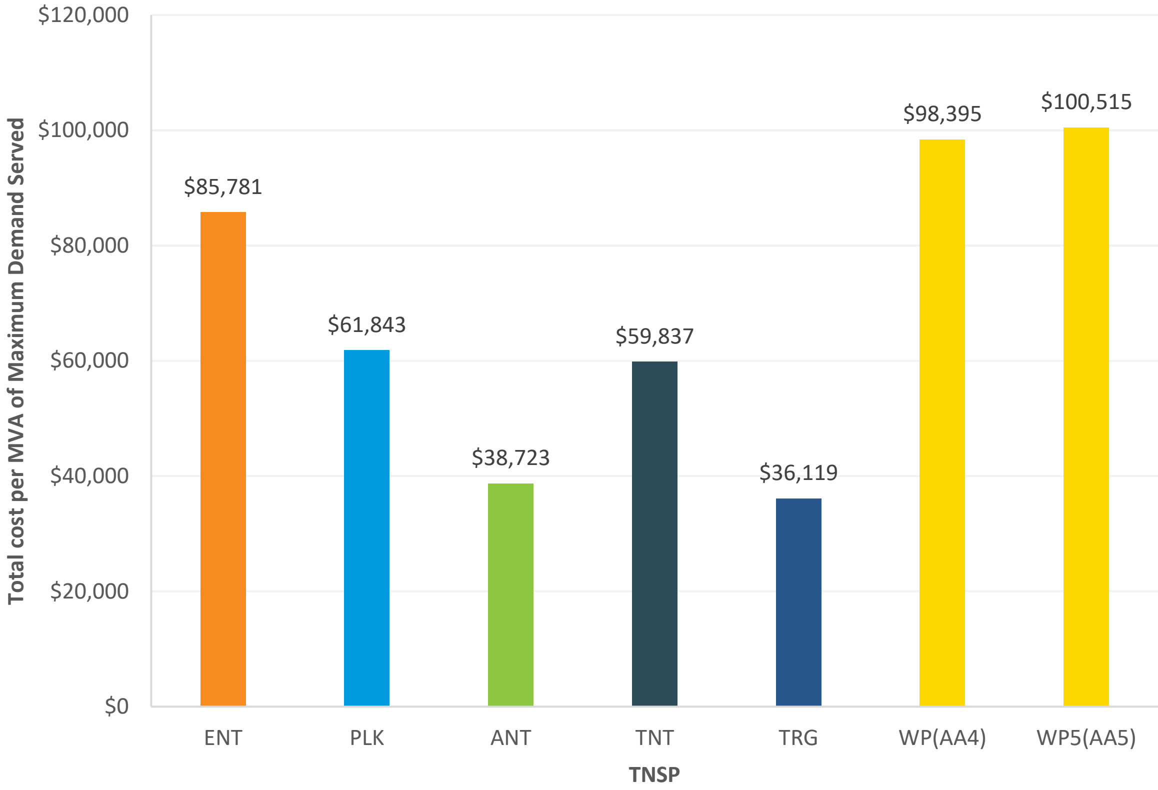
Figure 2–8: Benchmark total cost per circuit kilometre for Western Power Tx in the AA4 and AA5 periods and NEM TNSPs averaged over 2016-2020 ($ Real December 2020)



The figure below shows TNSP total cost per MVA of maximum demand served for Western Power (the transmission side of the business only) and its NEM counterparts. Western Power is plotted for AA4 and AA5 averages of transmission total cost and MVA of maximum demand, while NEM TNSP's are plotted for averages over 2016-2020. Western Power results for this PPI over AA4 and AA5 are very similar, with AA5 forecast to have about 2 per cent higher total cost per MVA of maximum demand served than for the AA4 period. Western Power results for this PPI are higher than for their NEM TNSP counterparts.

The Western Power transmission network is forecast to be operating in AA5 with about 17 per cent more total cost per MVA of maximum demand served than ElectraNet, the NEM TNSP with the nearest total cost performance by this PPI. The Western Power transmission network is forecast to be operating in AA5 with about 178 per cent more total cost per MVA of maximum demand than Transgrid, the NEM TNSP with the lowest total cost per MVA of maximum demand served. The Western Power transmission network appears, by this PPI, less total cost efficient in AA4 and AA5 than any of the NEM TNSPs. It is more than double the total cost per MVA of maximum demand served of Transgrid and AusNet Services. The reasons for the substantially higher total cost per MVA of maximum demand of the Western Power network in comparison to its NEM TNSP peers is not known. It may be partially due to local environmental factors but requires further investigation.

Figure 2–9: Benchmark total cost per MVA of maximum demand served for Western Power Tx in the AA4 and AA5 periods and NEM TNSPs averaged over 2016-2020 ($ Real December 2020)



2.4 Service Performance Benchmarking

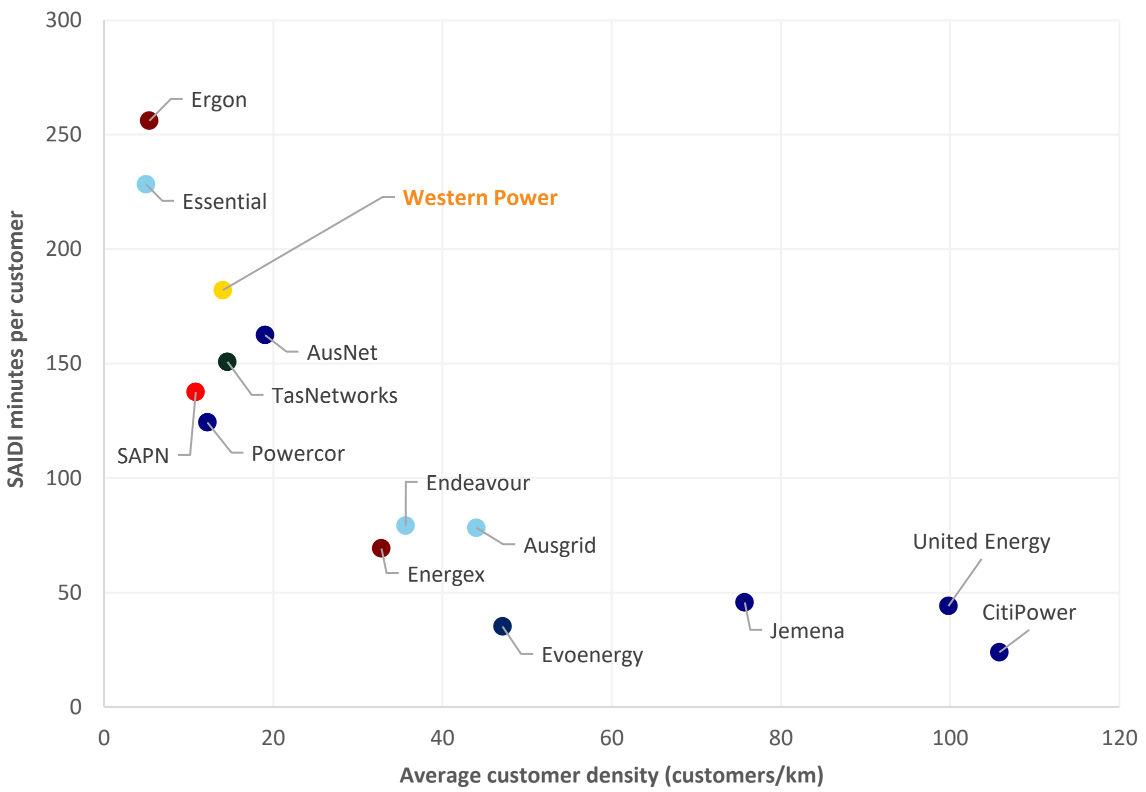
Distribution service performance measures are expressed in terms of the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) to reflect the 'average' consumer's annual interruption duration and frequency. These are often also reported by feeder type (CBD, urban, short rural, long rural) and used to set reliability targets. Adjustments can be made for 'Major Event Days' and weather normalisation to evaluate underlying reliability trends over time. The AER typically uses weather normalised SAIDI exclusive of Major Event Days. Our analysis has not sought to ensure consistent exclusion treatment or weather normalisation for Western Power when making comparisons.

Western Power's distribution overall, plus short rural and long rural feeder, reliability performance SAIDI and SAIFI are compared to other Australian networks below.

The figure below shows DNSP overall SAIDI as a function of average customer density. Western Power results follow the general NEM trend (with moderate spread for DNSPs with lower average customer density) of decreasing SAIDI with increasing average customer density. This is expected in terms of DNSPs with higher customer density being more readily able to avoid unplanned outages on predominantly urban (including a proportion of underground) rather than rural feeders (almost exclusively overhead). Rural feeders are subject to more and longer outages due to increased line lengths with increased exposure to adverse environmental factors, fewer opportunities for network reconfiguration and longer times from depots to reach and locate faults. Less dense networks generally report lower reliability performance. This is because of the greater proportion of long radial feeders, greater exposure of infrastructure to storm damage, bushfire damage, high winds, fauna, vegetation, a greater proportion of assets in less accessible bushland reserves, and lower overall reliability impact from a small number of rural customers resulting in reprioritisation against urban/suburban customers.

Western Power is operating with higher overall SAIDI than both Powercor and TasNetworks, the most comparable NEM distribution networks in terms of average customer density. Western Power overall Network SAIDI, averaged over a five-year period, is ~58 minutes per customer or ~46 per cent higher than for Powercor. Further benchmarking of SAIDI by feeder type provides clarification of the source of this significant difference in distribution service performance later in this chapter.

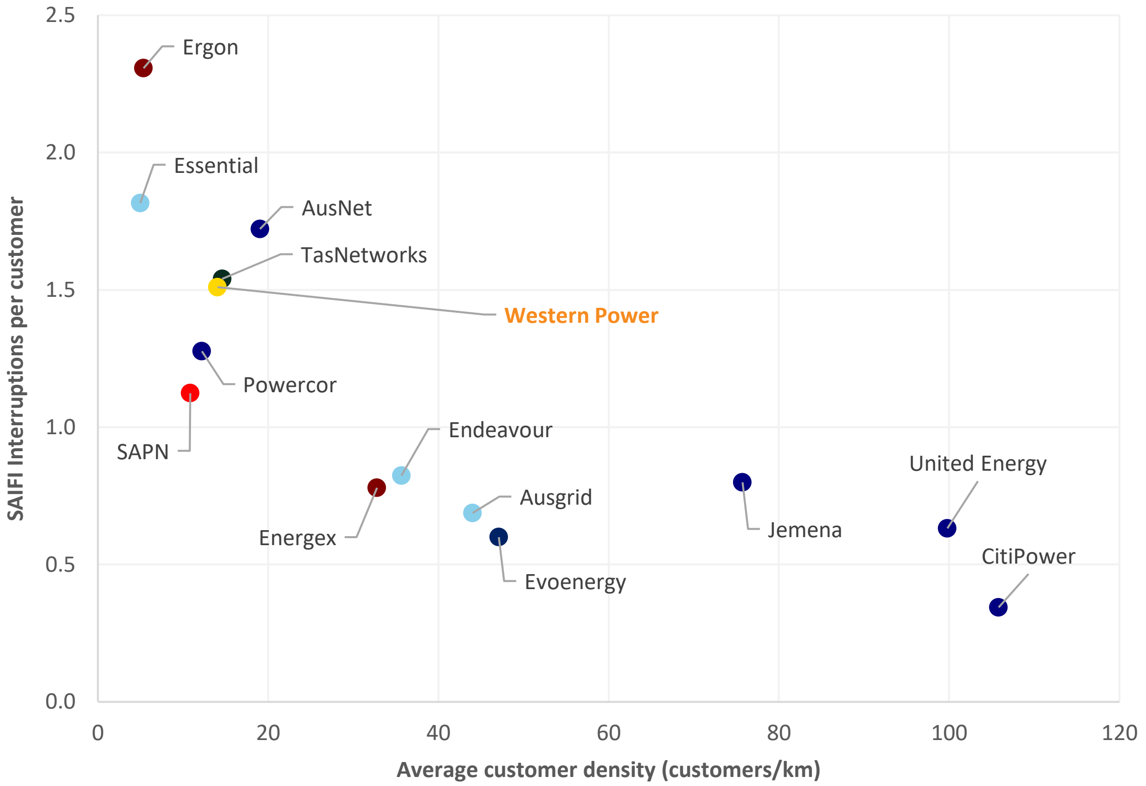
Figure 2–10: Overall SAIDI for Western Power distribution network in comparison to NEM DNSPs



The figure below shows DNSP overall SAIFI as a function of average customer density. Western Power results follow the general NEM of decreasing SAIFI with increasing average customer density. This is again expected in terms of DNSPs with higher customer density being more readily able to avoid unplanned outages on predominantly higher capacity urban feeders where undergrounding is more commonplace and the network is more readily reconfigured to transfer loads, or automatically restore supply via automated reclosers within the MAIFI exclusion thresholds for reliability reporting. Rural feeders are typically radial in configuration meaning that there are few options for alternative supply and network reconfiguration should there be a fault on the feeder. These are usually subject to more and longer outages due to longer line lengths with increased exposure to adverse environmental factors.

Western Power is operating with higher overall SAIFI than Powercor and about the same as TasNetworks, the most comparable NEM distribution networks in terms of average customer density. Western Power overall SAIFI, averaged over a five-year period, is ~0.3 interruptions per customer or ~24 per cent higher than for Powercor. Benchmarking of SAIFI for individual feeder types provides additional clarification of the source of this significant difference in distribution service performance, as is discussed below.

Figure 2–11: Overall SAIFI for Western Power distribution network in comparison to NEM DNSPs



Western Power's distribution SAIDI and SAIFI are compared by feeder type to the other Australian (NEM) networks below.

The three figures below show SAIDI for urban, rural short and rural long feeder types as a function of network average customer density. The charts show the feeder type SAIDI for Western Power[27] against a subset of NEM DNSPs with mixed networks, incorporating rural customers. These are Powercor, AusNet, Essential Energy, Endeavour Energy and Ausgrid[28]. All DNSPs follow the logical trend of higher SAIDI being associated with longer feeder lengths. Some benchmarking comparison results are as follows:

- **Western Power has the second highest rural long SAIDI** in this benchmarking comparison, exceeded only by Endeavour Energy[29].
- **Western Power rural long feeder type SAIDI, averaged over a five-year period, is ~702 minutes per customer** or ~208 per cent higher than that for Powercor, a comparable NEM distribution network in terms of average customer density (it is acknowledged that it would be more accurate to compare SAIDI and SAIFI for different DNSPs based on customer density for each feeder type).
- Western Power has the highest urban feeder type SAIDI in this benchmarking comparison.

27 Data from Western Power Service Standard Performance reports for relevant years.

28 Data from Powercor, AusNet, Essential Energy, Endeavour Energy and Ausgrid Distribution Annual Planning reports and IPART Annual Compliance report – Energy network operator compliance for relevant years.

29 We note that Endeavour only has one rural long feeder that supplies less than 300 customers out of a customer base of around 1 million. Without diversification across a population of similar feeders the results are highly volatile ranging from under 200 minutes to over 1500 minutes per annum. The performance of the feeder is reported but excluded from STPIS and Operating License requirements.

- Western Power urban feeder type SAIDI (excluding Perth CBD), averaged over a five-year period, is ~113 minutes per customer or ~88 per cent higher than that for Powercor.
- Western Power has rural short feeder type SAIDI near the average for all DNSPs in this benchmarking comparison.
- Western Power rural short feeder type SAIDI, averaged over a five-year period, is ~187 minutes per customer or ~84 per cent higher than that for Powercor.

Figure 2–12: Benchmark SAIDI for urban feeder type

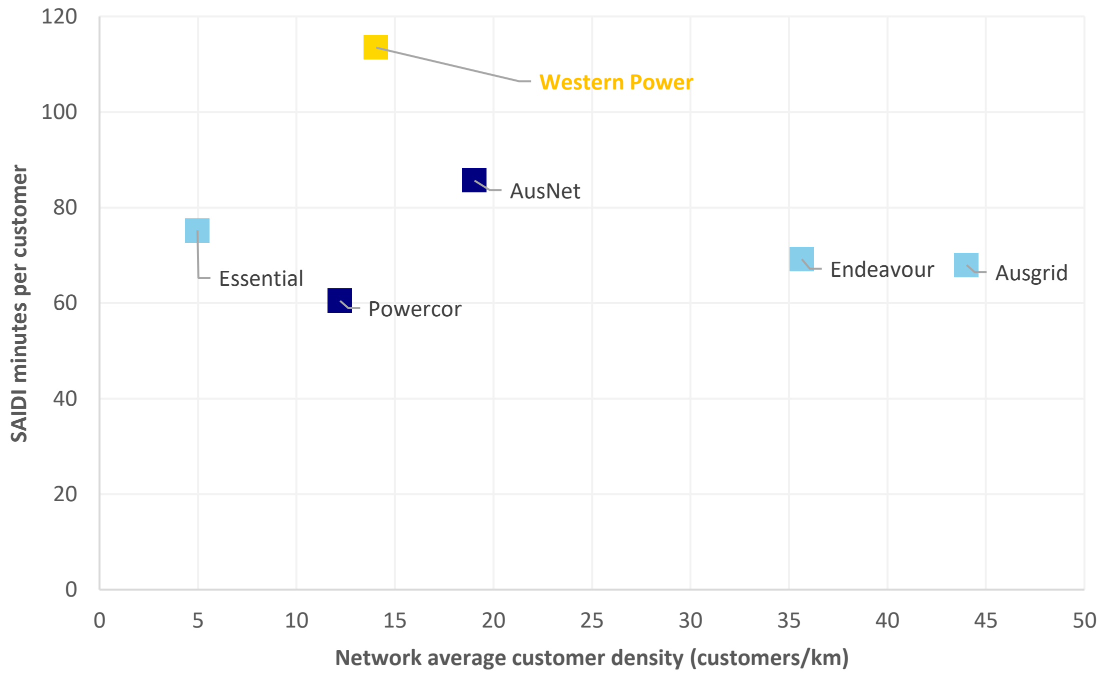


Figure 2–13: Benchmark SAIDI for rural short feeder type

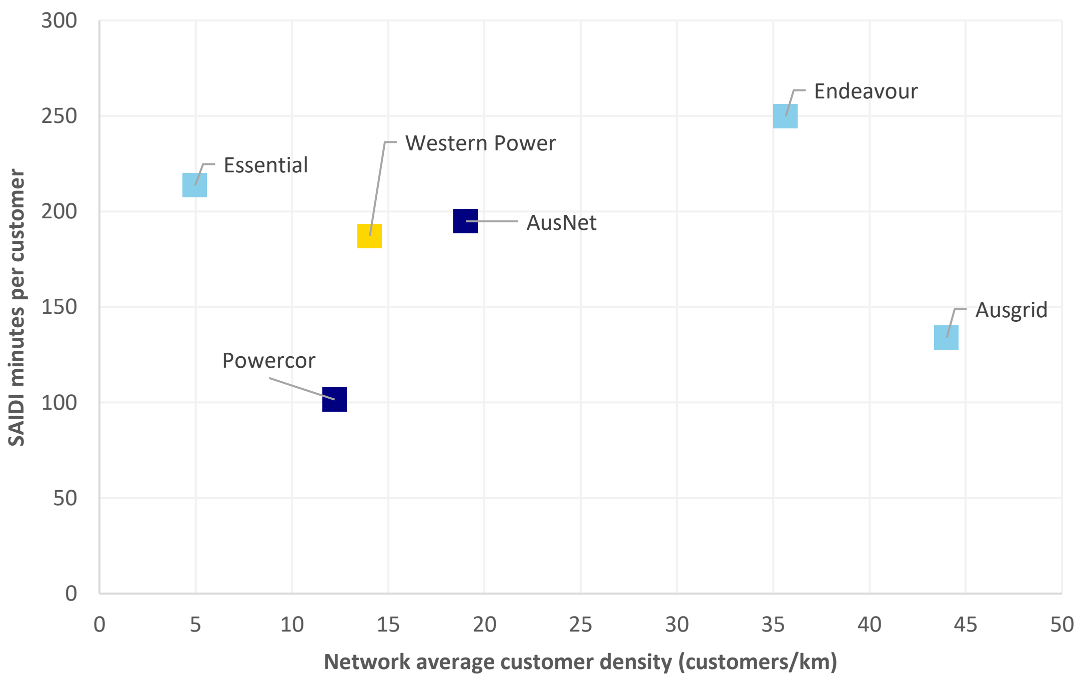
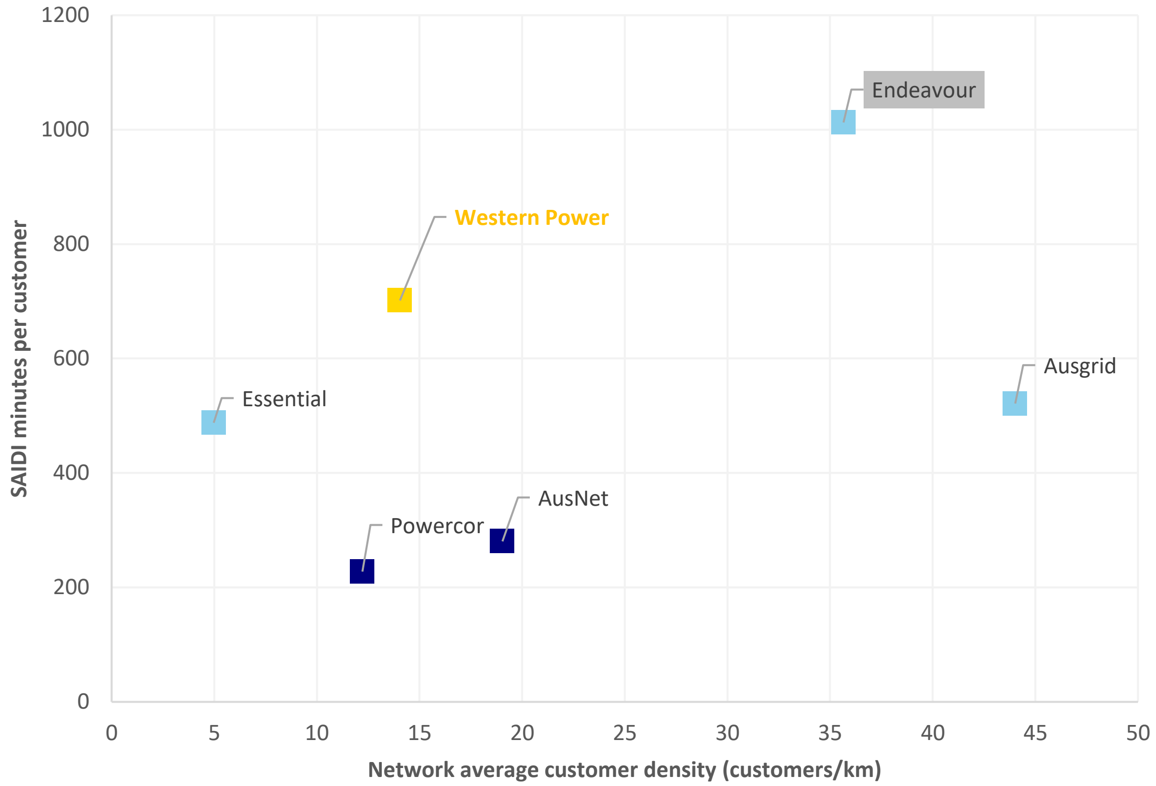


Figure 2–14: Benchmark SAIDI for rural long feeder type[30]



The three figures below show SAIFI for urban, rural short and rural long feeder types as a function of network average customer density. The plot benchmarks feeder type SAIFI for Western Power against the same selection of NEM DNSPs. All DNSPs follow the expected trend of higher SAIFI being associated with longer feeder lengths. Some benchmarking comparison results are as follows:

- **Western Power has the second highest rural long SAIFI** in this benchmarking comparison, exceeded only by Endeavour Energy[31].
- Western Power rural long feeder type SAIFI, averaged over a five-year period, is ~4 interruptions per customer or ~47 per cent higher than that for Powercor.
- Western Power has the highest urban feeder type SAIFI in this benchmarking comparison.
- Western Power urban feeder type SAIFI (excluding Perth CBD), averaged over a five-year period, is ~1.1 interruptions per customer or ~39 per cent higher than that for Powercor.
- Western Power has rural short feeder type SAIFI lower than the average for all DNSPs in this benchmarking comparison.
- Western Power rural short feeder type SAIFI, averaged over a five-year period, is ~1.8 interruptions per customer or ~56 per cent higher than that for Powercor.

[30] It should be noted that Endeavour Energy has only one rural long type feeder, which is not subject to SAIDI and SAIFI standards. This is noted by Endeavour Energy SAIDI, and SAIFI being highlighted in grey.

[31] See footnote on SAIDI performance. Endeavour only has one long rural feeder which is excluded from its reliability targets.

Figure 2–15: Benchmark SAIFI for urban feeder type.

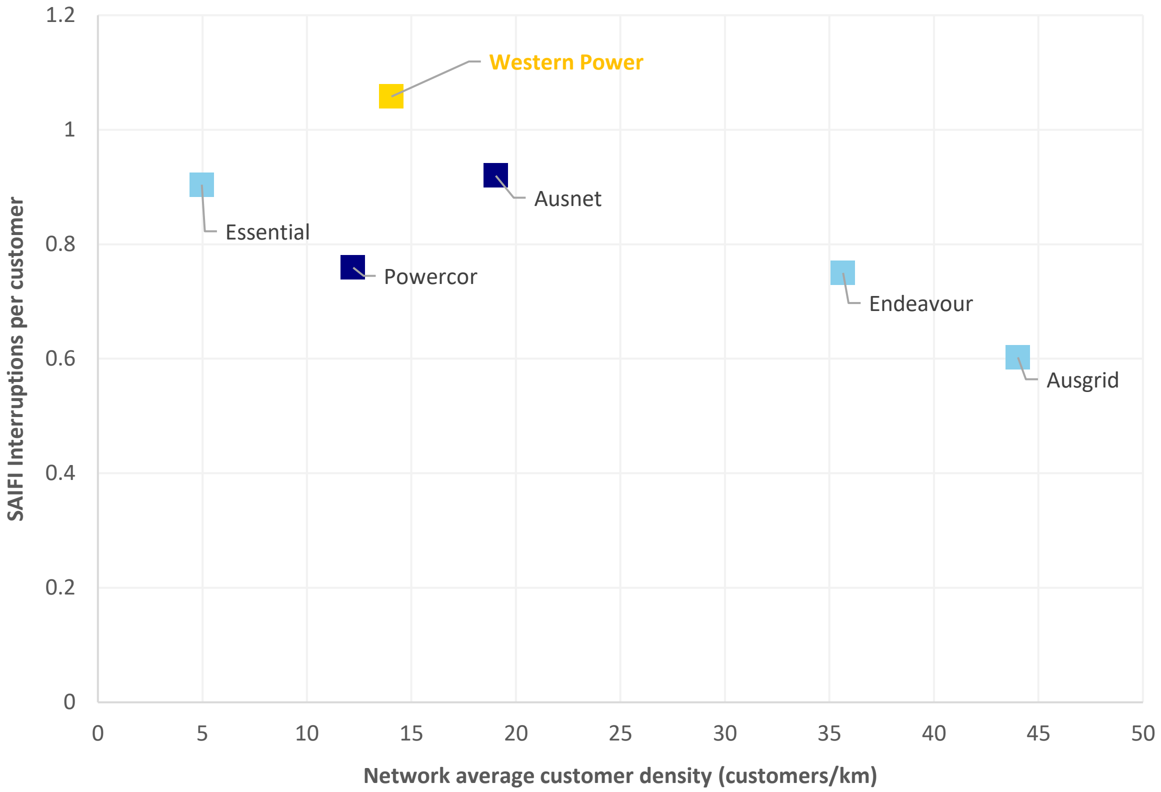


Figure 2–16: Benchmark SAIFI for rural short feeder type.

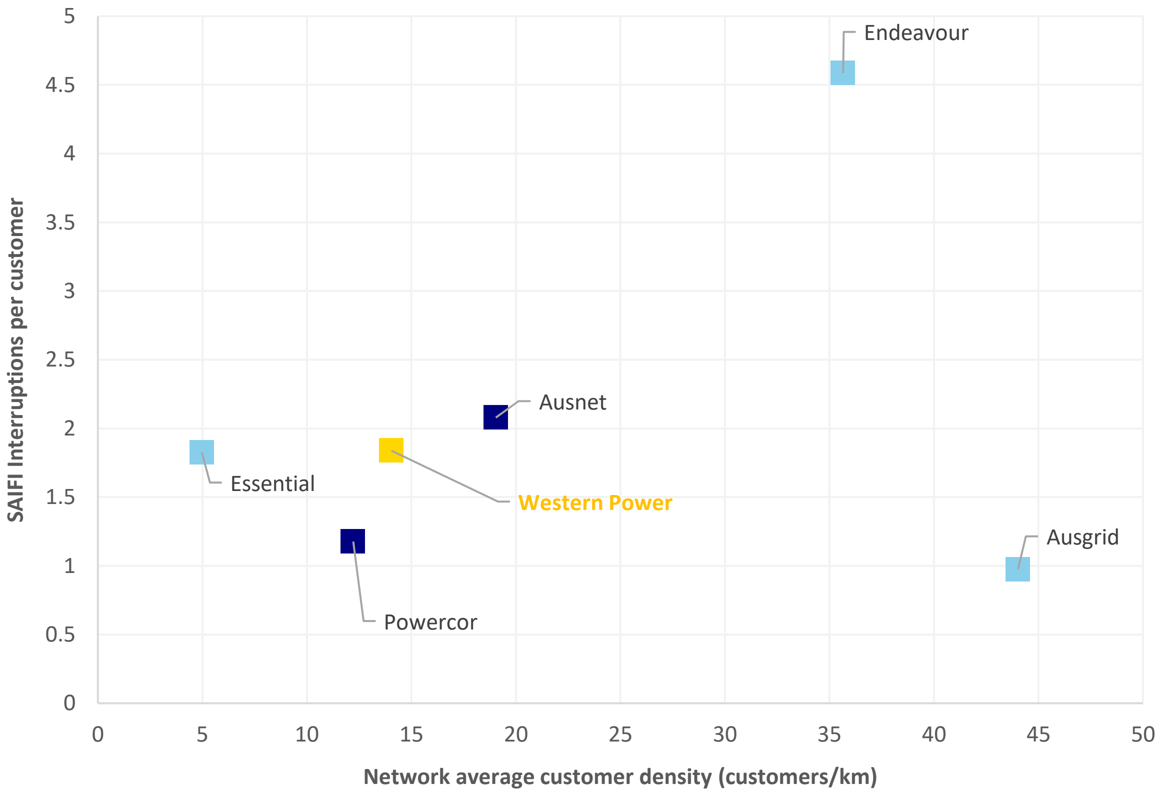
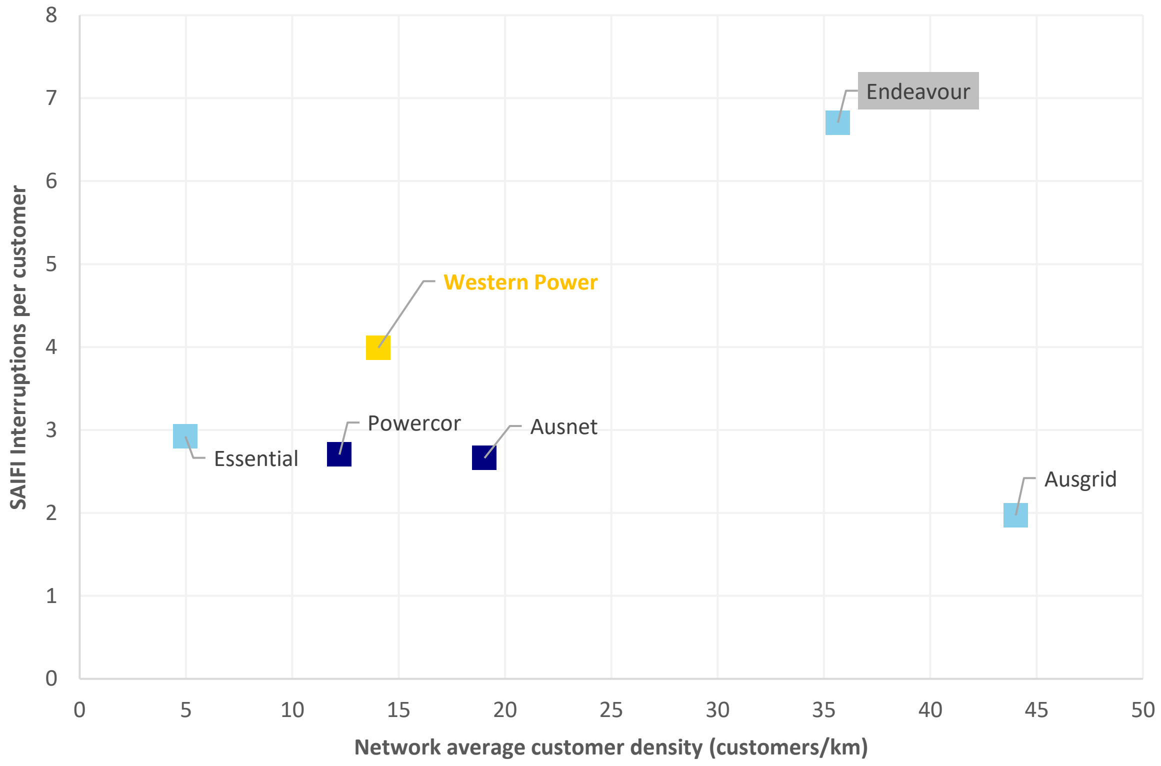


Figure 2–17: Benchmark SAIFI for rural long feeder type.



Transmission service performance is measured differently because it is not uncommon for Transmission networks to report no lost supply in a year due to the inherent redundancy built into the assets. This is because the economic consequences of a transmission interruption might be more widespread than distribution. As a result, Australian TNSPs typically report service performance in terms of the following components:

- **Service** - designed to motivate TNSPs to reduce unplanned circuit outage events, average outage duration and frequency of loss of supply events.
- **Market-impact** – designed to motivate TNSPs to reduce the impact of unplanned and planned outages on wholesale market outcomes.
- **Network-capability** – designed to motivate TNSPs to perform operational and minor CAPEX projects to deliver improvements to the transmission system most important to determining spot prices or supporting periods when users place greatest value on system reliability.

Western Power reports transmission service standard performance in terms of the following components:

- Circuit availability (% hours per year);
- **Loss of Supply Event Frequency** (number of events per year, > 0.1 & ≤ 1.0 System Minutes duration and >1.0 System Minutes duration);
- Average outage duration (minutes per year).

Only the average outage duration, as reported by Western Power, is potentially comparable to the relevant STPIS service performance measure. However, Engevity recognises that there are some significant differences between the definition of average outage duration in the AER STPIS and how Western Power calculate and report average outage duration. Western Power includes all network interruptions regardless of whether a loss of supply occurs, whereas the AER definition specifies where loss of supply has occurred. Also, the impact of each event for Western Power is capped at

14 days, while the STPIS caps the impact of an event at 7 days. Western Power defines average outage duration as the total number of minutes duration of all unplanned interruptions on the transmission network divided by the number of unplanned interruption events (after exclusions)[32].

Western Power's transmission service performance is compared to the other five Australian TNSP's below in terms of average outage duration, which is defined as the total duration of all unplanned interruptions in the transmission network normalised by the number of such events.

The figure below shows the average outage duration for each of the TNSPs. Each column is the average over five years of the yearly average outage duration for each transmission network (2016 to 2020 calendar years for the NEM TNSPs and 2016-17 to 2020-21 financial years for Western Power). The error bars represent plus/minus one standard deviation of the yearly values of the average outage duration for each transmission network.

Western Power transmission network clearly has a substantially higher average outage duration when benchmarked against its NEM TNSP peers. Western Power's transmission network delivers a lower level of service (on this measure) than its NEM TNSP peers.

We note that the Western Power transmission system is predominately operated at lower voltages ranging from 66kV to 220kV and is mainly comprised of overhead wood pole construction rather than the 132kV-500kV steel lattice tower or concrete pole assets that form much of the other TNSPs networks. As a result, the reliability outcomes may still remain appropriate where the electricity system as a whole is delivering acceptable performance, however, it could also signal a vulnerability of the core transmission system to outages that have a widespread impact on the SWIS.

Transmission networks are usually designed to maintain a relatively high level of redundancy and system security due to the much larger impact of a transmission outage than the more localised effect of distribution outages. However, unassisted pole failures averaged 9.6 p.a. over the 5 years from 2016/17 to 2020/21, equating to a transmission wood pole failure rate of 2.4 per 10,000 poles across Western Powers 39,239 population.[33] In comparison, TransGrid ENSMS documents covering 2016/17 to 2020/21 report a five-year average of 1.2 unassisted failures per annum across its 22,964 pole population[34] over the same reporting period[35]. This equates to 0.5 unassisted failures per 10,000 transmission poles – or approximately one fifth of the unassisted failure rate experience by Western Power.

Western Power has an average outage duration more than three times larger than ElectraNet, which is the nearest of the NEM TNSPs in terms of this service performance measure. Western Power also demonstrates the highest spread between years in average outage duration (in 2020-21 the Western Power transmission network average outage duration was 1027 minutes). Noting Western Power's customer insights conclusions that most customers were generally not willing to pay for reliability, and Western Power's target of maintaining reliability at AA4 levels, our review did not attempt to establish the relative cause of the high average value and volatility of yearly average outage duration for the Western Power transmission network in comparison to the NEM transmission networks.

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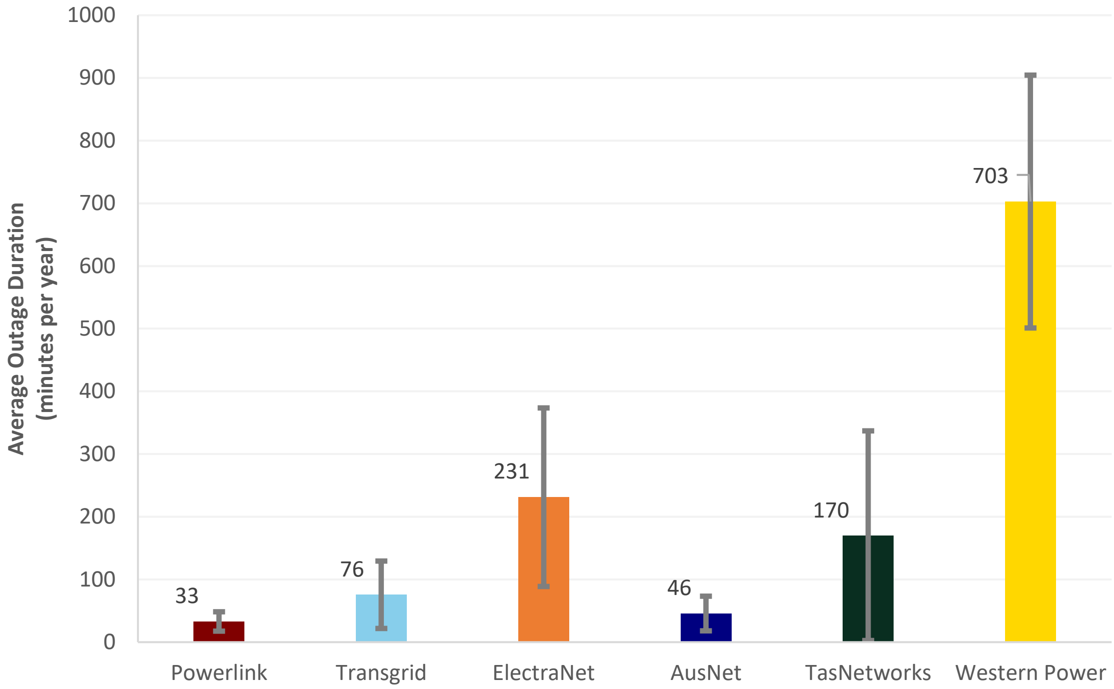
32 Western Power, Service Standard Performance Report for the year ended 30 June 2021, 30 September 2021, p. 18

33 Western Power, *State of the Infrastructure Report 2020/21*, 7 December 2021, p. 9

34 Transgrid, *Annual Safety Performance and Bushfire Preparedness Report 2020/21,* p.6 and prior years.

35 We note that Transgrid wood pole lines are typically 66kV and 132kV assets, most constructed from the 1960's to 1980's.

Figure 2–18: Average outage duration for Western Power Tx network and each of the NEM TNSPs[36].



2.5 Conclusion

Our high-level benchmarking indicates that Western Power performs relatively well on:

- Distribution total OPEX per customer, per kilometre of circuit length and per MW of maximum demand;
- Distribution total cost per customer, per kilometre of circuit length and per MW of maximum demand;
- Transmission total cost per end user and per kilometre of circuit length.

However, Western Power performs significantly more poorly than other networks on the basis of:

- Rural long and urban type feeder SAIDI;
- Rural long and urban type feeder SAIFI;
- Transmission total cost per MVA of maximum demand served;
- Transmission average outage duration.

Whilst we do not recommend any adjustment to Western Power's proposal, Engevity had regard to these benchmarking conclusions, Western Power's overall performance relative to the NEM NSPs, and other more targeted benchmarking analysis using the AER data set for comparative assessment when undertaking the detailed review of its expenditure proposal.

[36] NEM TNSP Economic Benchmarking RIN Data, AER website; Service Standard Performance Report for the year ended 30 June 2021, Western Power, November 2021

Attachment 3:
Demand Forecast Assessment

3.1 Overview

This section reviews Western Power's demand forecast for the period 2020-21 through 2026-27.

Based on our review of the NIEIR report[37] that is attached to Western Power's Access Information, it is our understanding that Western Power:

- **Prepared "forecasts of energy and customer numbers from 2020-21 to 2024-25 in October 2020**… They were subsequently extended out to 2026-27 in April 2021", which suggests that the preparation of these forecasts preceded AEMO's most up-to-date Electricity Statement of Opportunities (ESOO) forecasts for WA, which were released in June 2021.
- Adopted different approaches across alternative customer segments to derive its energy forecasts, *"although autoregressive models are predominately utilised",* which suggests that Western Power's energy forecasts are predominately driven by the historical relationship between energy consumption and its chosen independent variables (which NIEIR lists as being economic activity, electricity prices, and substitution factors).
- **Produces forecasts of solar PV capacity by zone substation, by using a "linear regression model** which was *"fitted for each class above" [residential, small business, medium business, large business]*. The independent variables in the regression model were the number of connections and the fixed and variable electricity tariffs". This indicates to us that Western Power's:
  - **Forecast of PV is not driven by the expected cost of PV systems** (including the effect of Government subsidies) relative to historic costs; or
  - Spatial allocation of PV systems, in effect, simply reflects historical take up.
- Have adopted the following as the main drivers behind their demand forecasts: customer numbers, energy consumption, and PV capacity installed. These drivers are contained within a *"a new methodology . . . that uses Extreme Value Theory".* NIEIR states that *"forecasts and historical peak demand are presented as a probability of exceedance distribution… This means, for example, if ten summer seasons of historical data were available, then half would be expected to be above the POE 50 level of demand and half would be below the POE 50 level of demand. A longer historical series is therefore preferred to ensure that any model is providing a good fit and displaying the desired probability characteristics*".

During the review, Western Power confirmed that *"there have been no material changes made to the demand forecasting approach reviewed by NIEIR"*.[38]

3.1.1 The strengths and weaknesses of Western Power's approach

Based on the information contained in Western Power's Access Arrangement Information documentation, in particular Attachment 7.5 Energy and Customer Number Forecast Report (2020) and Attachment 7.7 Report on Western Power's Forecasting Methodology, as well as its responses to various questions posed to them regarding their demand forecast, we found that there are several areas of Western Power's approach to forecasting energy and demand that require adjustment in order to more accurately inform their proposed capital and OPEX forecasts.

Perhaps the most notable example is the exclusion of any impact of Western Power's own 'solar sponge' Time of Use tariffs, despite the AMI financial analysis benefits calculation relying on an assumed rapid uptake in customers not only moving to, but also responding to ToU price signals from

[37] NIEIR, A review of Western Power's Forecast Methodology for the AA5, June 2021 (Attachment 7.7 to Western Power's Access Arrangement Information).

[38] Response ENG31.01, Friday, 29 April 2022

the start of AA5 at levels that have not been seen in any of the Australian DNSPs to date. This underpins the avoided network investment benefit, which is one of the largest component of the overall AMI benefits calculation.

Our key concerns with Western Power's demand and energy forecasts are summarised below:[39]

Overarching methodology

Western Power's energy forecasts are predominately driven by historical relationships, for example between energy consumption and the independent variables used by Western Power, namely economic activity; electricity prices; and substitution factors.

Whilst it is important to consider historical relationships in the development of any forecast, **medium- and longer-term forecasts in particular should factor in the impact of any <u>structural changes</u>** (i.e., new or changed factors that are not otherwise reflected in the historical relationships) that might affect demand for electricity services over the outlook period.

For example, **new technologies such as EVs and batteries** are likely to influence energy consumption (and demand). Their influence will not be reflected in any historical relationship; therefore, they need to be incorporated via other means (e.g., post-model adjustments, or via simulation). Other factors such as the **expected size of PV systems**, **the consumption behaviour of new (as compared to existing) customers**, or **where tariff changes are being proposed**, also create conditions in which reliance on historical relationships is unlikely to be an accurate means for forecasting future consumption and demand.

Similar observations are made regarding Western Power's demand forecasting methodology: half-hourly simulation modelling (which Western Power has not undertaken) provides the means for analysing the changing patterns of demand across the day as the result of PV generation, as well as incorporating the impact of new technologies, government programs and policies.

Mapping to spatial

Based on the information provided, it appears that the mapping of PV to the zone substation (ZSS) level has been undertaken by way of a *"linear regression model"* which was *"fitted for each class above" [residential, small business, medium business, large business].* The independent variables in the regression model were the number of connections and the fixed and variable electricity tariffs". This indicates to us that (a) forecast PV uptake is not driven by the expected cost of PV systems (or the affect Government subsidies may have on those nett costs); and (b) the spatial allocation of PV systems reflects historical take up, which may not account for levels of saturation[40] within an area (and the impact that this may have on the feasibility and or likelihood of adding more PV in that area).

That said, as Western Power noted in one of their responses**:**

> **"…the system, zone substation and feeder peak demand occurs typically after 5:30 pm at which point the impact of roof top solar is significantly diminished** *and has negligible impact on CAPEX requirements"*.[41]

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[39] Several of our reasons align with NIEIR's recommendations as to how Western Power could potentially improve its forecasting approach.

[40] In its Response ENG31.04, received on Friday, 13 May 2022 11:37 AM, Western Power stated "currently this has not been accounted for in the forecast. This is intended to be incorporated via GTEng 2.0".

[41] Response ENG31.06, Friday, 29 April 2022 5:45 PM.

However, Western Power also note that:

> *"with increased rooftop PV penetration there is limited investment required at system peak however increased rooftop PV is already resulting in additional investment during AA5. A range of voltage management investments have been triggered to better manage the customer LV voltages"*.[42]

This indicates that spatial forecasts are more likely to impact CAPEX arising from minimum demand periods. The AA4 Reactive Voltage Rectification program, alongside the introduction of Time of Use tariffs, greater control of solar inverter exports and the visibility of the low voltage network provided the ~500,000 AMI meters that Western Power expects to have commissioned by the start of AA5 mean that much of the infrastructure and pricing changes to manage minimum demand issues has already been put in place through AA4 investment.

Given the substantial investment in AMI to date, as well as the continuation of the AMI rollout through AA4, Western Power is already heavily committed to time of use tariffs, the value of AMI information to network planning/operations and direct control of customer load/export as the preferred mitigation for minimum demand challenges. We highlight that the AMI business case relies on a very rapid uptake by customers and a very strong, sustained, customer response to time-of-use tariffs to deliver the substantial 'avoided augmentation' benefits that justify much of the investment.

Therefore, promotion of tariff and controllable load/export benefits to customers and much improved use of the existing AMI data set for planning and operational purposes should be pursued as the primary, and least cost, response to minimum demand constraints that emerge through AA5.

No impact of EV or BTM battery take up has been accounted for

Western Power has confirmed that ***"EVs and any assumptions about charging profiles and orchestration have not been included*", nor have behind-the meter (BTM) batteries without orchestration and BTM batteries with orchestration** (i.e., VPPs) been included in its forecasts (energy, peak and minimum demand forecasts).[43]

Given Western Power's forecasts are driving investments in long-lived assets, **it is important that explicit consideration be given to the impact these technologies have on medium to long-term forecasts, even if their impact on the forecasts within the forthcoming regulatory control period is small.** This is because the longer-term forecasts may influence the type, efficient investment horizon and / or size of investments being contemplated in this forthcoming regulatory control period.

For example, all else being equal, **tariff innovation alongside increased battery and EV uptake are likely to offset some of the impact of the higher solar penetration that is driving lower minimum demands**. Without considering these longer-term drivers/forecasts, investment decisions proposed for the next regulatory control period to overcome minimum demand issues may in fact be rendered less beneficial than they would if longer term forecasts that reflect the impact of these countervailing factors had been undertaken and included. Importantly, the is no consideration of whether the minimum demand issue is a temporary problem over the next five to ten years. With solar penetration currently in the order of 35% and State government targets for this to increase to 50% by 2030, there is a natural limit to the volume of additional rooftop solar that can contribute to minimum demand issues (noting that total rooftop solar penetration is ultimately constrained by the number of suitable rooftops, excluding most apartments, a substantial proportion of semi-detached housing, high rise commercial, overshadowed CBD tenancies, a large proportion of long span industrial roofs, detached dwellings in heavily vegetated areas and others.)

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42 Response ENG31.07, Friday, 29 April 2022 5:45 PM.

43 Response ENG31.05, Wednesday, 4 May 2022 11:27 AM.

These above expected relationships raise the question over whether the future that Western Power is planning for accurately reflects the CAPEX, OPEX and tariff reform programs that it has proposed – or whether it more accurately reflects the AA4 needs of Western Power, with the additional transformation program investment included on top.

Solar PV forecasts

On face value, Western Power's:

- Input assumptions do not appear to align with AEMO's latest forecasts (2021 ESOO) of DER up take (e.g., PV)[44];
- Approach does not account for potential changes in the size of future PV systems (as compared to historical); or
- Approach does not appear to contemplate how the spatial take up of PV may change over time (relative to history).

We note that Western Power forecasts that will move from approximately 35% solar penetration now to about 50% by 2030 as a result of the state carbon emissions reduction targets. The average rooftop PV system size has been known to be increasing over time for a decade, Western Power is involved in the connection approvals for each system, and Western Power holds AMI or interval data with 24-hour import/export information for each solar installation on its network. These are trends and forecasting factors that Western Power already holds the most comprehensive dataset available for Western Australian electricity customers.

During AA4, Western Power did not foresee the emergence of minimum demand issues due to rooftop solar until customer complaints about high voltages during the day emerged in 2019. By this time, most NEM networks were actively monitoring minimum demand and introducing tariffs or developing tariff trials to defer the impact and maximise the utilisation of the existing infrastructure.

Whilst we acknowledge the acceleration in PV installations over this time, this information was available to Western Power via the connections process, along with the increasing system size and installation address/NMI. With the increasing solar penetration in WA, it is increasingly less likely that future installation trends will follow historical relationships. This is simply because the customers who installed solar in the past already have solar, so they won't generally be installing new solar in the near future. Given the scale of expected rooftop solar capacity that is installed, and expected to be installed by 2030, Western Power's forecasting approach should be refined to make use of the information that it possesses.

Change in timing of peak demand

Western Power's approach does not appear to contemplate changes in the timing of peak demand.

No differentiation between new versus existing customers

Western Power's approach does not contemplate new customer loads being different to existing customer loads.[45]

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[44] Allow we do acknowledge that Western Power has stated in one of its responses that "Western Power checks its forecasts against AEMO's System forecast. Both forecasts align, but there is a difference in the assumptions made on PV generation". This reconciliation is not clear to us, from reviewing the figures.

[45] Response ENG31.10,, Friday, 29 April 2022 5:45 PM.

Impact of proposed programs or changes in Government policy

Western Power has not included[46] the potential impact of its proposed ToU tariffs (e.g., particularly on minimum demands), the move of some customer off the grid to SAPs systems, or the potential implications of a move to new business models (e.g., VPPs) on its demand and energy forecasts.

Everything else being equal, a solar sponge tariff may help to alleviate minimum demand issues in the medium term, affecting CAPEX, whilst a move to SPS systems would reduce the loads placed on the existing electricity grid.[47] Western Power specifically excludes batteries as a 'low load solution' as an assumption to its 10-year Business Outlook[48] despite several other DNSPs deploying network owned batteries, or community batteries for this purpose.

Western Power's approach does not appear to explicitly take account of changes in Government Policy, for example around curtailment of PV in certain circumstances. That said, in a response to a question on this, Western Power quite reasonably notes that "the impact of curtailment, which was only introduced in February 2022 was not able to be assessed at the time of preparing the demand forecast that informed the AA5 submission. Scenarios may be considered to incorporate the effect of curtailment in future.[49]

Some of these key issues are discussed in more detail in the following sub-sections.

3.1.2 The impact of EVs and BTM batteries do not appear to be reflected in Western Power's forecasts

According to NIEIR's review of Western Power's demand forecasting methodology:[50]

Western Power's medium-term **forecast models do not take into account all new and emerging technologies, such as electric vehicles and batteries. Up to 2024-25 this is not likely to be that significant. It may be more significant post 2024-25.**

Western Power has confirmed this in its responses to questions as part of the review.[51]

In its ESOO, AEMO states:[52]

> *"… in all demand growth scenarios, battery storage is forecast to reduce peak demand, by discharging after sunset (for customers on flat tariffs) or due to high price signals (for customers on time-of-use tariffs)."*

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46 Response ENG31.08, Friday, 29 April 2022 5:45 PM and Response to ENG29.06, Tue 10/05/2022 6:22 PM.

47 Albeit, Western Power's forecast take-up of SAPs systems is low, as a proportion of its overall customer base, hence this is unlikely to be overly material.

48 Western Power, AA5-ENG12.05, 13.05 Board Paper – 22_23 Business outlook 10 Year Plan – Jun 2021, Appendix D, Submission Page 40

49 Response ENG31.09, Tue 10/05/2022 6:04 PM.

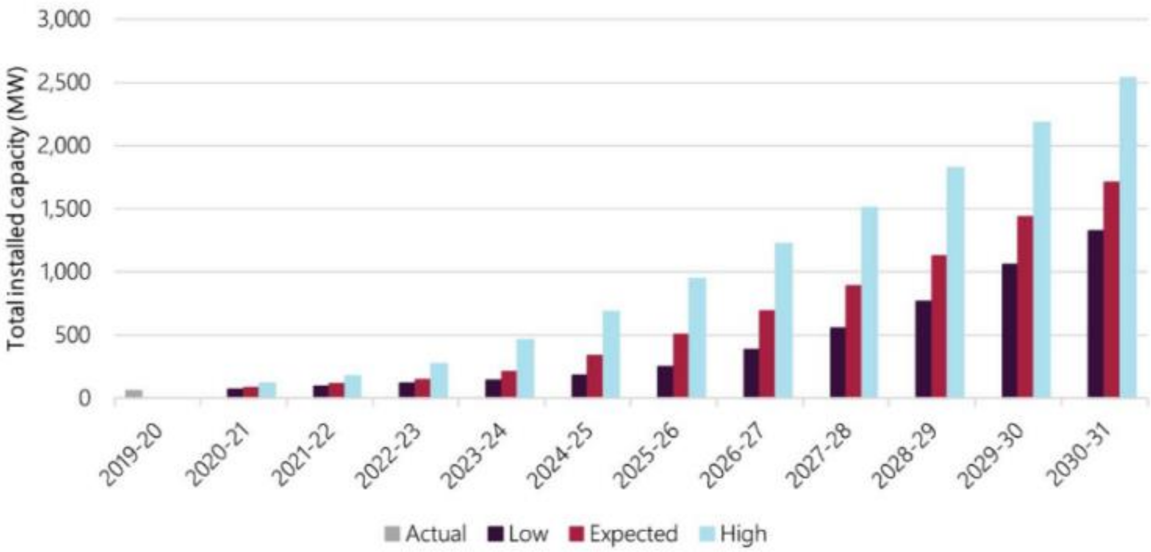
50 NIEIR, A review of Western Power's Forecast Methodology for the AA5, June 2021, page 4 (Attachment 7.7 to Western Power's Access Arrangement Information).

51 Response ENG31.05, Wednesday, 4 May 2022 11:27 AM.

52 AEMO, 2021 Electricity Statement of Opportunities, June 2021, p. 49.

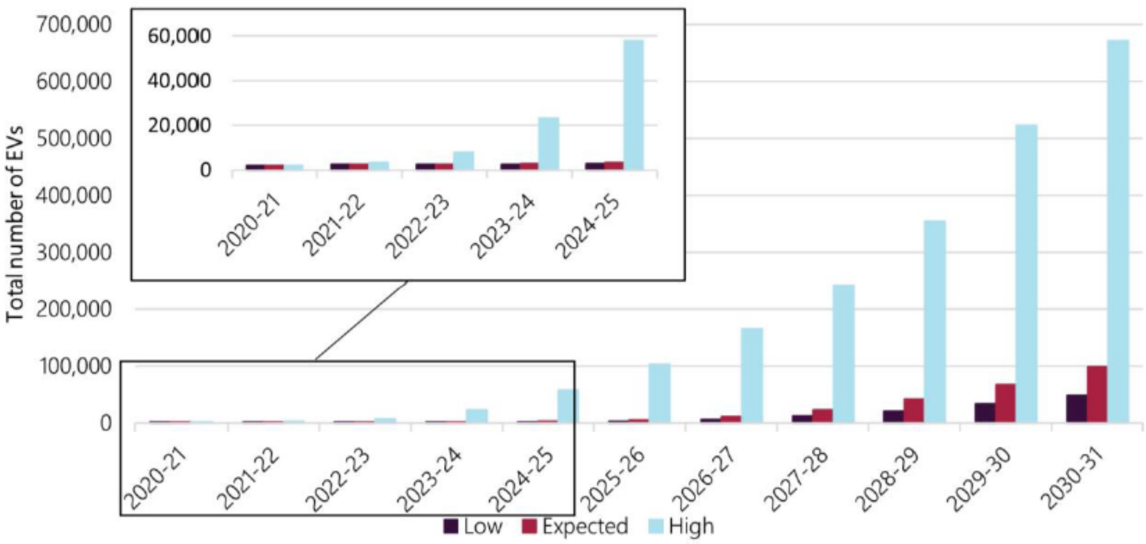
The following two figures summarise AEMO's battery and EV uptake forecasts, from the 2021 ESOO.

Figure 3–1: Actual and forecast installed capacity of BTM battery storage



Source: AEMO, 2021 Electricity Statement of Opportunities, June 2021, page 43

Figure 3–2: Forecast total number of EVs



Source: AEMO, 2021 Electricity Statement of Opportunities, June 2021, page 45

In summary:

- AEMO explicitly suggests that ***"in all demand growth scenarios, battery storage is forecast to reduce peak demand***", which is not unexpected, given the quantum of installed battery capacity forecast and the potential for these devices to provide some level of support (peak, minimum demand) to the network.[53] However, Western Power has confirmed that the impacts of this technology are not included in Western Power's demand or energy forecasts, and in turn its capital program; and

[53] And this level of support may potential be able to be harnessed more in the future, as business models evolve (e.g., if VPPs become more prevalent).

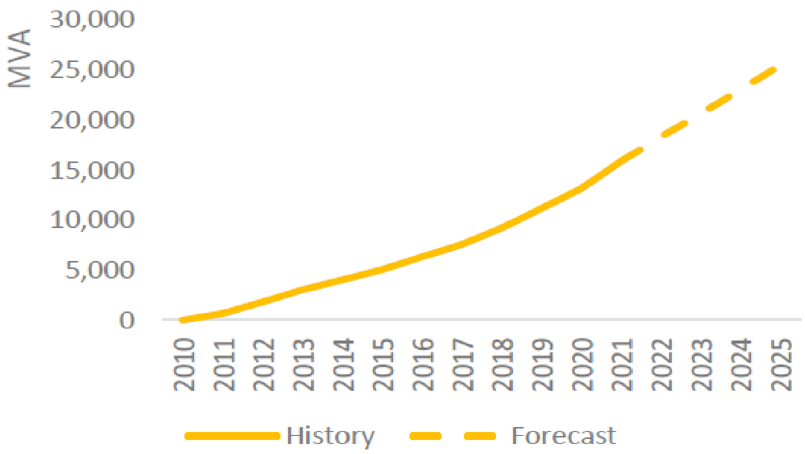
- Given Western Power's forecasts are driving investments in long-lived assets, we are of the opinion that explicit consideration should have been given to the impact of these technologies in their forecasts. In saying this, it is not only their impact on the forecasts within the forthcoming regulatory control period that is relevant, but also, beyond, as longer-term forecasts may influence the type and / or size of investments in this forthcoming regulatory control period.

Solar PV Input Assumptions

Based on NIEIR's review of Western Power's demand forecasting methodology (see Attachment 7.7), it appears clear that Western Power has made an allowance for PV uptake on both energy consumption and peak demand.

However, it is not clear that Western Power's forecast of PV capacity aligns with AEMO's most recent forecast. The following figure is from Western Power's AA submission, and, to our knowledge, is the forecast PV uptake that underpins their demand forecasts.[54]

Figure 3–3: Western Power's forecast PV uptake (MVA)



Source: Attachment 7.5, Energy and Customer Number Forecast Report (2020), 1 February 2022, page 2

54 It should be noted that there appears to be an issue with the units presented (25,000MVA) as this would imply in the order of 4.16m 6kW systems, which is not feasible, and even if this includes distributed-connected systems, this quantum of capacity does not appear feasible.

Western Power has advised that the total figure includes the capacity of larger commercial installations and provided an indicative volume of 2.79m x 6kW systems - which it cited as being more accurate on the basis of assuming equivalence between MW and MVA in the calculations. Engevity notes that this figure still significantly exceeds Western Power's total volume of between 1.2 and 1.3m customers.

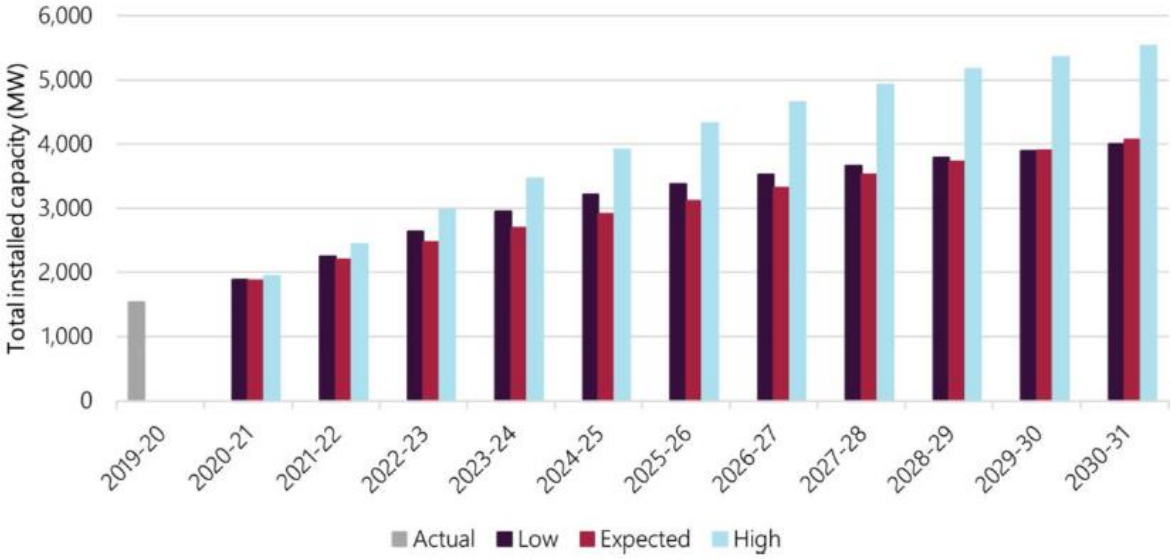
All else being equal, Western Power's proposed correction for MVA to MW conversion implies a power factor of less than 0.7 – which is well below the near unity (1) factors achieved but most modern networks, and significantly below the conservative and historically 'typical' design assumption of 0.8. In the event that these figures accurately represent the power factors achieved on the network it implies that approximately 30% of energy transfer capacity uplift can be achieved via relatively low-cost power factor correction measures alone.

Alternatively, Western Power may be referring to the practice of 'economic oversizing' solar arrays relative to inverter capacity by up to 33% this allows for 6.6kW of solar modules to be connected to a 5kW (5kVA) inverter. In this case, the network would only 'see' the 5kW (5 kVA) inverter – but the yield of the system would be higher as the array can reach the full 5kVA output on more days (rather than simply the peak day).

In this case, without accounting for the additional energy produced by the additional 33% oversized panel capacity (and therefore available to use on the customer site) Western Power may be materially understating the scale of demand decline over AA5 and the value of low-cost customer load shifting opportunities that could reasonably be expected over AA5 from existing and new solar customers. "

The following figure is from AEMO's most recent ESOO.

Figure 3–4: Actual and forecast installed BTM PV capacity



Source: AEMO, 2021 Electricity Statement of Opportunities, June 2021, page 42

Firstly, notwithstanding question marks around the units or basis for Western Power's forecast of installed PV capacity, there appears to be a disconnect between Western Power's forecast and AEMO's most recent forecast, which was published in June 2021.[55]

In addition to the above, as Western Power's approach relies on fitting a linear regression model to historical uptake (at a ZSS level), with the independent variables in the regression model being the number of connections and the fixed and variable electricity tariffs, it is not clear how Western Power's approach accounts for:

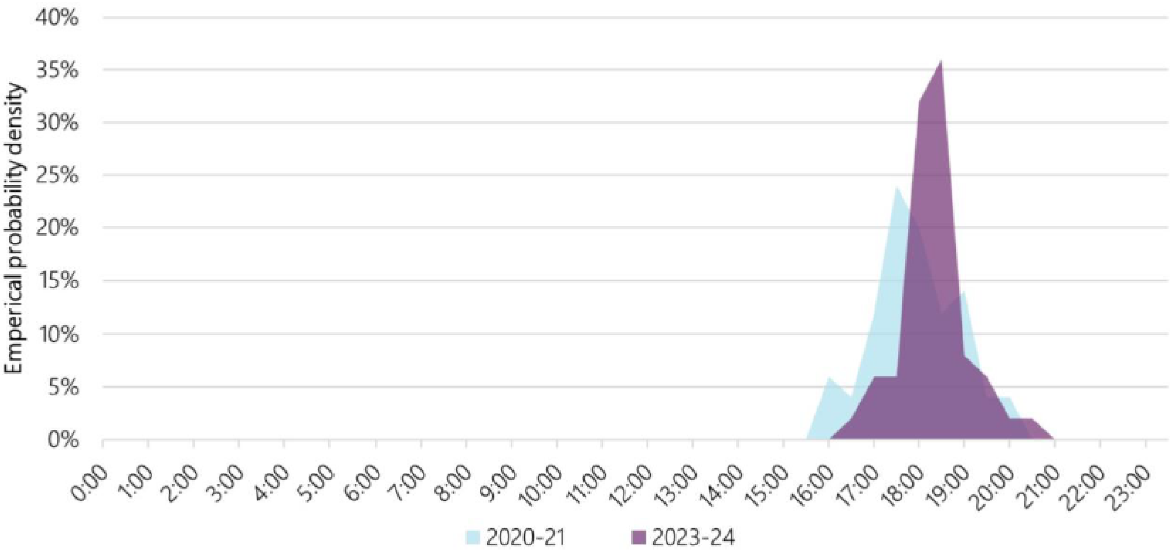
- **The potential for future PV systems to be sized differently to PV systems that have been installed historically**, which may result from, for example, cheaper capital costs (driving customers to increase their size) or changes in Government policies (e.g., curtailment, feed in tariffs, etc);
- **The potential for changes in the locations where PV systems are taken up in the future (relative to history)**, for example, because certain areas might be approaching saturation levels (e.g., rental properties, shading, roof space requirements);[56] or
- **How take up might impact the time of day when peak demands occur on their network**, noting that AEMO is forecasting that (probabilistically) the timing of peak demand will soon occur later in the day (early evening).[57]

55 In its review of WP's forecasts, NIEIR states that "Western Power prepared forecasts of energy and customer numbers from 2020-21 to 2024-25 in October 2020. They were subsequently extended out to 2026-27 in April 2021". This timing suggests that they would not have been able to have regard for the AEMO's most-up-to-date forecasts, which may explain why there is this disconnect, and why NIEIR states that "Western Power checks its forecasts against AEMO's System forecast. Both forecasts align, but there is a difference in the assumptions made on PV generation".

56 In its Response ENG31.04 received on Friday, 13 May 2022 11:37 AM, Western Power stated in relation to the issues of saturation levels that "currently this has not been accounted for in the forecast. This is intended to be incorporated via GTEng 2.0".

57 In saying this, we also acknowledge that in one of its responses, Western Power noted that "the system, zone substation and feeder peak demand occurs typically after 5:30 pm at which point the impact of roof top solar is significantly diminished and has negligible impact on CAPEX requirements".

Figure 3–5: Distribution of forecast time of 10% POE peak demand, expected demand growth scenario



Source: AEMO, 2021 Electricity Statement of Opportunities, June 2021, page 50

Accompanying the above graph, AEMO states:[58]

In the 10% POE expected demand growth scenario, peak demand is forecast to continue to occur during summer and is expected to shift 30 minutes later, from the period between 17:30 and 18:30 to between 18:00 and 19:00 by 2023-24 (see Figure 3-5). This is due to the combined impacts of behind-the-meter PV generation and battery storage operation, and, to a lesser extent, convenience charging of EVs.

Recommendation

In summary, based on the information contained in Western Power's AA submission, namely Attachment 7.5 Energy and Customer Number Forecast Report (2020) and Attachment 7.7 Report on Western Power's Forecasting Methodology, as well as its responses to various questions on their demand forecast, we consider that there are several areas of Western Power's approach to forecasting energy and demand that are not fit-for-purpose and which require adjustment in order to accurately inform their proposed capital and OPEX forecasts.

Whilst recommending a specific adjustment to the demand forecast, or otherwise preparing an independent forecast is beyond the scope of our engagement, we recommend that, as a minimum, Western Power:

- Update their demand and energy forecasts to incorporate the impact of **AEMO's most recent PV forecasts**.
- Update their demand and energy forecasts to incorporate the impact of **AEMO's forecast of behind-the-meter batteries** and as an adjunct to this, the impact of those forecasts on Western Power's ability to harness different proportions of behind-the-meter battery to provide network support services (for both peak demand and minimum demand).
- Update their demand and energy forecasts to incorporate the impact of **AEMO's forecast of EVs** and as an adjunct to this, the impact of those forecasts of EVs adopting different charging patterns.

58 AEMO, 2021 Electricity Statement of Opportunities, June 2021, p. 50.

- **Demonstrate how sensitive its forecasts are to different take-up rates** of (and responses to) its solar sponge tariff, including on EV charging.
- Undertake **a high-level review of the levels of PV penetration that it is forecasting** at a spatial level using their existing modelling approach, and where these exceed levels that are plausible (for example approach or exceed the number of residential buildings in the area), adjust those forecasts down.
- **Review its own rooftop PV connection, operation and location datasets** to identify saturated rooftop solar areas, as well as localities with substantial DER hosting capacity available to improve the accuracy with which the spatial PV uptake can be forecast, as well as the scale of opportunities for network initiated, or community batteries to deliver load support during peak solar export times.

We also recommend that for each of the above adjustments, Western Power identify the impact on its CAPEX (and if material, OPEX) program. Overall, we consider that the energy and demand forecast are more likely to understate than overstate the augmentation component of capital expenditure requirements in most areas.

The primary areas of concern are the undergrounding program and the SPS program, where load growth or SPS/cable sizing are potentially quite heavily exposed to the widespread uptake of electric vehicles over the expected service life of the assets. There is a material risk that a second round of undergrounding investment will be required to accommodate the EV charging demand, or additional SPS units deployed at each customer in rural areas to serve the EV charging load requirements. The imprecision in Western Power's forecast could lead to the programs ultimately doubling the cost to consumers. Western Power should ensure that it has efficiently provisioned for future loads in delivering these programs.

Similarly, whilst the Christmas 2021 power outages were driven by unusually and uncharacteristically high temperatures, sustained over several consecutive days (conditions that go beyond the normal planning assumptions for the network), several distribution transformers tripped from operating above their notional capacity. This could also indicate that historical augmentation investment had not met the underlying demand growth from existing customers installing new, or more energy intensive, appliances such as air conditioners.

Under the sustained heat wave conditions that were experienced, the maximum loading that the network allowed for each residence (i.e. the After Diversity Maximum Demand (or ADMD) becomes challenged as air conditioners increasingly operate in synchronisation to the same outside temperature 'signal'. In turn, any 'diversity' factor in the ADMD planning assumptions is quickly eroded because the dominant load is air conditioning in almost every house, and under these conditions, they are all operating broadly at the same times.

Particularly in areas developed prior to the year 2000, the network would have been sized using more modest ADMD assumptions and much of the housing stock would have been constructed with no, or limited air conditioning and limited thermal insulation requirements. The widespread retrofit of household air conditioning in the 2000's to relatively inefficient housing stock created a pronounced increase in network augmentation requirements across Australian distribution networks. The subsequent addition of additional load such as air-conditioning over the 2010's at the same time as significant addition of rooftop solar makes it difficult to observe the true maximum demand until an extreme load event occurs.

As a result, we consider that it would be prudent for Western Power to review its ADMD planning assumptions in light of the event to ensure that it captures the impact of solar. The existing AMI data enable examination of the diversity relationships under normal and extreme conditions across approximately half of the Western Power customer base.

Given that AMI in rural areas would deliver the most customer benefit in terms of:

- avoided meter reading (due to larger distances);
- reliability performance (due to the long radial lines serving communities); and
- response time (including the large outage duration impact of Western Power's high bushfire risk operating procedures).

Western Power should also consider prioritising these areas in the AMI rollout - with the data also used to optimise the sizing/staging of the very high cost per customer SPS deployments.

Attachment 4:
Asset Management Assessment

4.1 Key points

The asset management framework and systems used by Western Power have been reviewed against ISO 55000 and ERA asset management system requirements. They have previously been found compliant in both cases.

Engevity has reviewed inputs and forecast outcomes of the asset management plans and offer the following observations:

- The forecast retirement of coal generation in the south and increase in utility scale renewables in the north and east are highlighted as challenges for the transmission network. Transmission projects can have quite long lead time (~5 years) so long-term planning is important if the systems are to be ready to meet corporate and state objectives. We have reviewed transmission plans and have found them to be appropriate in the near term (5 years). The long-term plans are less clear. If the very rapid change in circumstances observed in eastern Australia occurs in Western Australia, it is possible that the investment in planning and early-stage delivery of transmission assets to service renewable generation will be a material additional cost to AA5.
- For the distribution network, Western Power's consultant NEIER highlighted opportunities to improve the forecast precision by increased use of location specific drivers. In addition, the policy environment and the proposed energy tariffs are changing in anticipation of changing customer needs. These changes are not included in the forecast model used to develop AA5 asset management plans. Addressing these factors would improve the reliability of the forecast asset management needs.
- **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.

In this section of the report Engevity presents its reviews of asset management plans for regulatory categories of spend that exceed $50m CAPEX, which are not customer growth dependent and are not covered in deep dive in Attachment 8.

Our key observations are noted below:

- AA5 plan for transmission wood poles replacements has forecast rate of unassisted failure is less than current rate and less than asset management targets. This plan should be reviewed to align with corporate risk tolerance.
- Distribution underground cable performance has been decreasing in recent years and is a large contributor to reliability outcomes. The current performance (2020) is worse than asset management targets, as is the forecast future performance. The AA5 investment seeks to replace approx. 0.05% of population per annum, which appears quite low when compared to most other asset classes and suggests there may be some residual risk that could cause

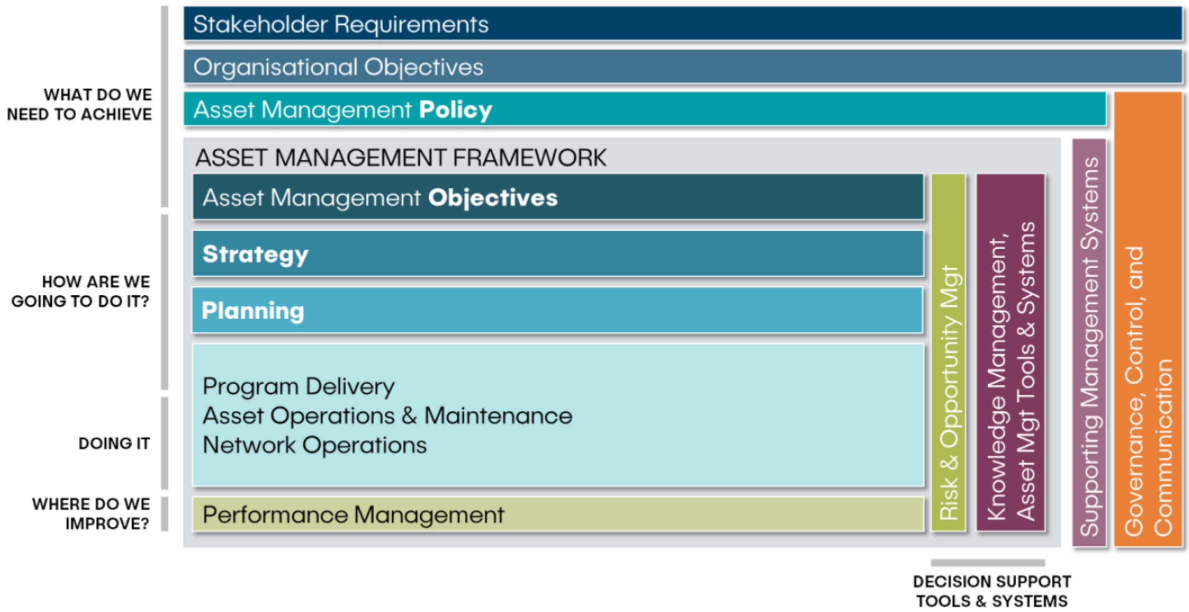
performance shortfalls in the future. This may also reflect the growing industry practice of replacing a relatively short section of cable at the ends to alleviate the majority of reliability performance issues.

- The unassisted failure rate of Dedicated Streetlight Metal Poles has markedly improved over the last five years and is better than asset management targets. The current plan seeks to sustain unassisted failure rate below targets and there is opportunity to reduce the volume of DSLMP treatments without exceeding risks tolerances.
- Other programs >$50m including AMI, NRUP, SPS are reviewed in deep dive section 8 of the report.

4.2 Overview Asset Management Frameworks and Systems

The Asset Management Framework defines the processes and inputs Western Power uses to guide investment in the network.

Figure 4–1: Western power asset management framework



Source: Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, figure 5.1

The asset management framework provides a comprehensive view of the linkages between organisation objectives and the methods used to the achieve those objectives. The framework is informed by a large number of subordinate documents. The primary document describing the asset management function is the Network Management Plan, which is the focus of this chapter.

The network management plan is approximately 400 pages long and makes extensive reference to further subordinate documents. Engevity has not sought to comment on all of the detail in those documents. Rather, this section of the report identifies key areas where Western Power has adopted practices consistent with industry peers and areas where there is further opportunity for improvement. Quantification of the impact of improvement areas will be developed in the OPEX and CAPEX reviews in this report.

4.2.1 Compliant with ISO 55000 Standard

Western Power's Asset Management System achieved ISO 55001:2014, an international standard accreditation in August 2019. This international standard for asset management systems is well regarded in the industry and accreditation to this standard is held by most of Western Power's

Australian industry peers. Other transmission and distribution networks service providers are using methods consistent with ISO55001:2014 but have not yet sought formal certification.

We do note that ISO 55001 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.

Accreditation recognises that a base level of asset management maturity has been achieved by the business, noting that systems will evolve and improve over time as the organisation continues to mature its asset management capabilities. Therefore ISO 55001 accreditation reflects that the elements of a mature asset management system are in place and should be capable of producing repeatable and increasingly efficient asset management outcomes.

Engevity recognise ISO 55001:2014 certification as a significant achievement demonstrating Western Power's asset management system addresses all of the elements of the standard and should be capable of delivering efficient regulatory outcomes.

4.2.2 ERA review of Asset Management System

As a condition of Western Power's transmission and distribution network operating licences the ERA requires Western Power to supply a report by an independent expert as to the effectiveness of the asset management system. ERA audit review and guidelines set out specific effectiveness criteria to be investigated by the auditor and requirements for the audit process.

The 2020 Asset Management System Review Report was completed by Auditor AMCL on 30 November 2020 and covers the period 1 July 2017 to 30 June 2020.

> *"**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."*** [59]

The auditor also identified the following improvement opportunities:

> *"… **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 include consideration of ongoing or escalating operational costs and risk costs associated with time view of investment.***

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

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. *"* [60]

Engevity has considered our findings and those of the asset management system auditor in the context of individual CAPEX reviews. No overarching adjustment is recommended on the basis of our review of Western Power's asset management system.

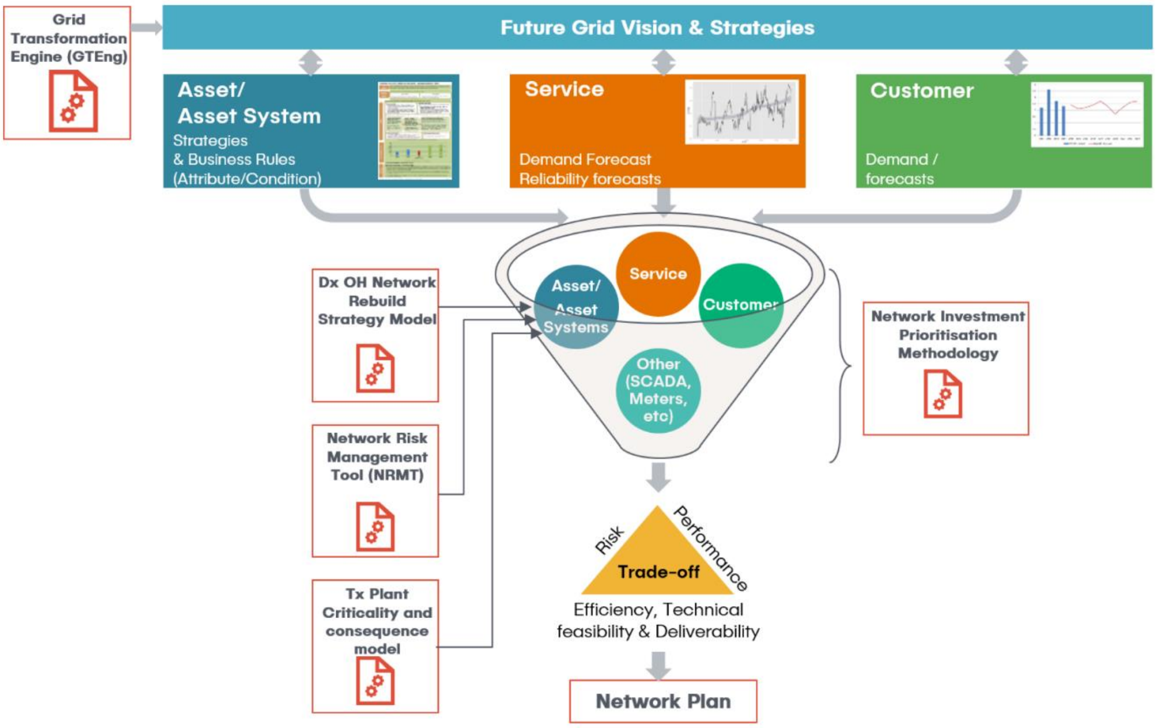
4.3 Investment Planning

Western Power introduces its AA5 proposal by highlighting the fundamental change in the electricity sector that will challenge the network to make efficient decisions in a rapidly changing and uncertain environment. Core to an efficient transition is Western Power's Investment Planning to manage the customer and generator led planning factors that are now outside Western Power's vision and control.

"The electricity system is now in an unprecedented transformation, driven by widespread uptake of customer owned rooftop solar photovoltaic (PV) systems and changes in the utility-scale generation mix towards more renewables, both displacing utility-scale fossil fuelled generators." (AAI para 12)

This section of the report reviews the asset management systems response to the state of the network and changing customer needs. The figure below provides an overview of the inputs and processes that ultimately shape Western Power's investment plan.

Figure 4–2: Western Power network planning process



Source: Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, Figure 5.2

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

The following sections summarise our observations of the key elements of the above figure:

- Inputs - demand forecast and system planning criteria;
- Inputs – Asset data;
- Asset planning methods - Risk based approach;
- Investment prioritisation, investment optimisation;
- System output – Network plans and forecast of unassisted failures.

To maintain a link between our observations and our recommended expenditure levels, we also note example areas from the detailed reviews where we have had regard to these matters.

4.3.1 Inputs - demand forecast and system planning criteria

The key inputs to system planning are the demand forecast and planning criteria. Together, these establish the expected capacity trigger points and timing for augmentation projects.

The system level demand forecast provides the overall trend in the maximum capacity that is required in the system to meet the highest customer demand in a year. While this provides a helpful 'top down' view of the yearly changes in demand, it is the spatial demand forecasts at each of the transmission connection points and distribution substations that ultimately drive augmentation requirements.

It is not uncommon for a flat system demand forecast to mask significant declines in demand in some areas of the network with localised increases in other areas. The underutilised capacity in the negative growth areas cannot practically be relocated to serve the demand growth areas, meaning that there will be a need for new investment in the 'pockets of growth' – even though the system demand is not increasing.

Notwithstanding this, weak demand growth forecasts should act as a flag of caution for networks as the consequences of investing too early can easily result in customers paying for assets that are not used to serve actual demand for several years, or even decades. In higher growth environments, slightly early investment results in any existing capacity being absorbed within a few years such that new capacity would be required shortly after the original expenditure anyway.

Low demand growth rates should also serve to consider the price impact on customers from major investment in a network where customer usage static or declining. As noted in the demand forecast attachment, the core network transformation theme of Western Power's AA5 proposal is at odds with the underlying planning inputs which exclude the impact of the range of technologies that Western Power's investment intends to enable (for example Time of Use Tariffs, AMI, Controllable load and export, Demand Management, Batteries and Electric Vehicles).

We consider that in this environment, an efficient operator would seek to minimise costs by ensuring that planning decisions avoid investment where possible through the use of load transfers, cyclical equipment ratings, probabilistic planning approaches to value the unserved energy arising from a failure, efficient customer load/export management incentives and deployment of mobile generation in summer or permanent network batteries to employ a highly modular technology to simultaneously defer local augmentation and provide flexible load and voltage support at the lower levels of the distribution network during times of high rooftop solar export.

We recognise that Western Power has adopted some but not all of these measures in preparing its AA5 proposal.

Transmission

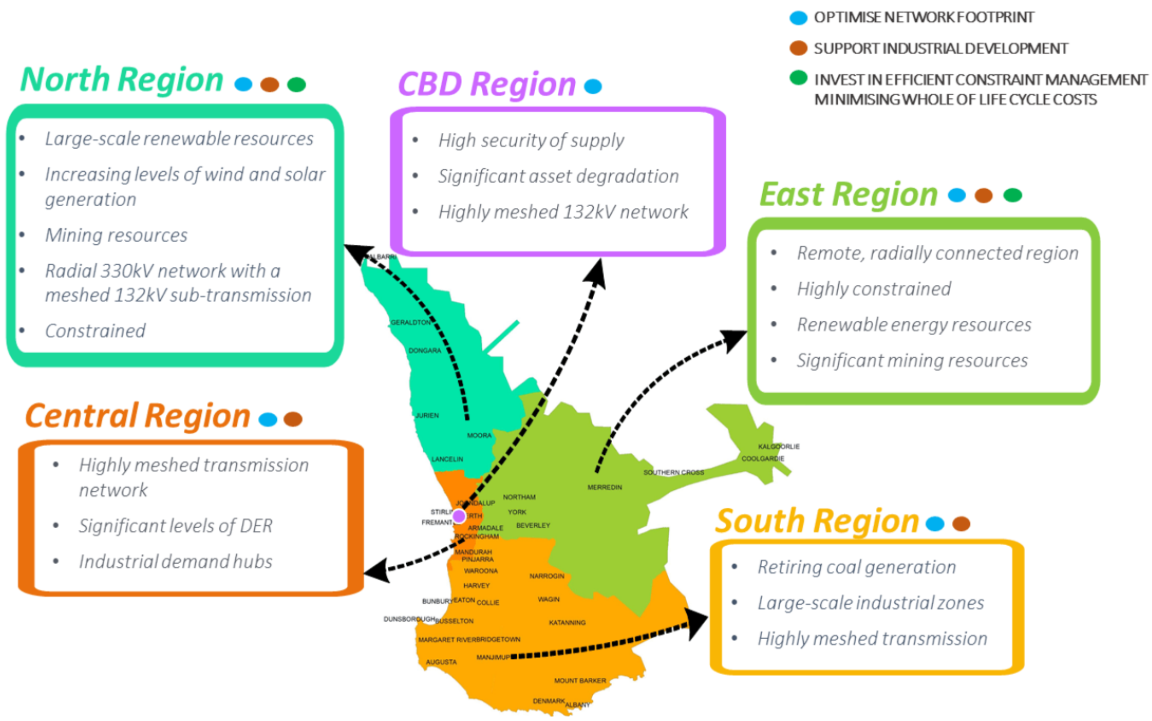
The transmission demand forecast is shown in the figure below. It is apparent that the forecast range outcomes until 2030 are not expected to exceed historical peaks that the network has successfully accommodated. The flat load forecast is consistent with the relatively modest investment proposed by Western Power for transmission system augmentation.

Figure 4–3: Forecast transmission demand

Source: Attachment 8.1, AA5 Forecast CAPEX Report, Access Arrangement Information, Figure 3.5

Within in the overall transmission network Western Power provides a summary of the differing drivers and distribution of generation and demand across the five planning regions in the SWIS. These issues are summarised below.

Figure 4–4: Regional drivers of the transmission network plans



Source: AAI figure 8.4

From the figure above it is noted that large-scale renewable resources are increasing in the North and East Region. Both regions are also identified as having constraints.

> *"A key challenge for the transmission network is the retirement of coal generation, which is shifting the mix of generation from large scale synchronous in the South-East to non-synchronous (i.e. wind and solar) renewable generation in the Central, North and East Country.* ***Augmentations to the transmission system are required to encourage future renewable generation***. *"*
>
> Source: AAI para 829

Transmission projects typically require significant investment, highly specialised resources and extensive analysis. Skills shortages and manufacturing limitations for electrical equipment are expected to accompany the global shift in generation towards renewables, exacerbated by post Covid-19 impacts and the current global geopolitical instability on fossil fuel prices, inflation and interest rates. As such, longer range forecasts of demand and a clear strategy on how this capacity will be delivered alongside the coal plant retirements are needed to ensure the capability and capacity is available to customers when required.

Engevity has reviewed Western Power AA5 plans for the near term and long term. Our review found the near-term investment is relatively well developed with clear plans to address network risk and capacity constraints and to align with section 2.5 of the Technical Rules[61].

The longer-term challenges have been identified but we could not find a well-articulated long-term plan to address those challenges from the documentation provided or our direct engagement with Western Power. Specifically Western Power note that augmentation is required to encourage future renewable generation, but it is unclear whether Western Power has secured the specialised resources that are needed to examine the options to best meet long term network needs and progress the project through the relevant scoping, engagement, approvals and delivery.

Historically, we note the cost, scope, timing and project delivery challenges that arose on Western Power's most recent major 330kV transmission project that was delivered in stages between the Perth and Geraldton areas over the 2010's. The complexity of accommodating a coal fired power station worth of renewable capacity, to be in place just prior to the coal retirement is several orders of magnitude more difficult than constructing a new transmission line to reinforce supply between two load centres that are already serviced by existing transmission lines.

This complexity is further exacerbated by the expected need to negotiate commercial terms and technical requirements with multiple private sector renewables developers as part of the connection process for generation. These generators can reasonably be expected to be reluctant to commit to construction without contracted commitments to the 2029 retirement date from the coal plant owners or agreed compensation arrangements from the state. Similarly, the state is unlikely to allow the retirement of coal plant until sufficient replacement generation is connected to the network to securely meet the energy needs of the SWIS in the transition. These issues will become increasingly critical over AA5 as the transition to renewables is a key part of meeting WA 2030 carbon reduction commitments.

From experience in other network areas, the rapid decline in commercial outcomes for coal generators combined with increasing government urgency to decarbonise energy supply can be expected to drive high urgency on transmission projects. This means that the need for renewables and the retirement of coal capacity is more likely to be brought forward in time rather than pushed back. Without a long-term strategy supported by an implementation plan, there is a risk that

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[61] Technical Rules For The South West Interconnected Network. 1 December 2016, Revision 3

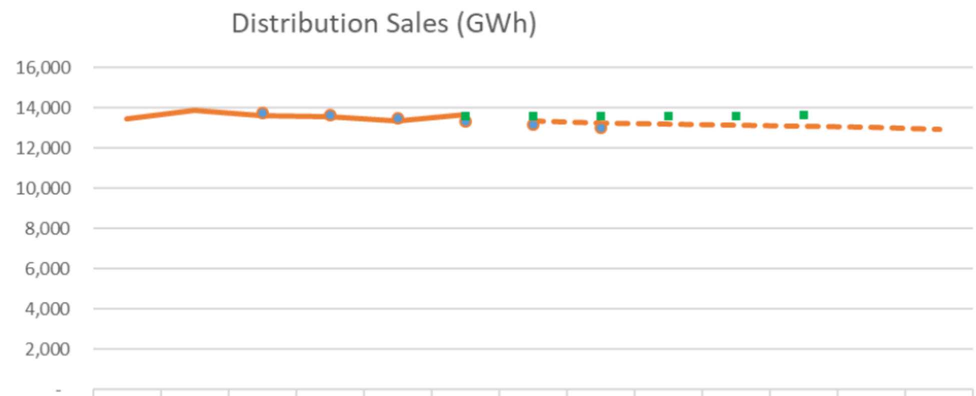
customers in Western Australia could be forced to sustain uneconomic coal generation while the transmission capacity constraints for long term renewable generation is alleviated.

In Engevity's opinion the near-term tasks to sustain the existing transmission network are robust but long-term planning for future energy generation is less well developed. Engevity agrees that although the nature and timing of these long-term investments may not yet be known, early planning and study of the options is reasonably foreseeable and would typically have occurred in the current period to inform planning decisions and contingencies for the AA5 period.

Distribution

Consistent with transmission forecast, total energy delivery via distribution network is flat/declining. The increase in customers of around 19k/year (1.2%/year)[62] is offset by reduced consumption within the overall customer base, particularly for residential customers[63] and small businesses. This reflects more efficient housing, appliances and most significantly, increasing rooftop solar penetration. The result is additional customer connections without a commensurate increase in energy supplied.

Figure 4–5: Distribution Sales forecast (GWh)



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Distribution Sales (a)	13,449	13,885	13,630	13,549	13,361	13,658							
Distribution Sales (2017 f)			13,768	13,643	13,511	13,337	13,194	13,036					
Distribution Sales (2019 f)						13,591	13,609	13,611	13,615	13,617	13,624		
Distribution Sales (f)							13,356	13,280	13,214	13,152	13,086	13,019	12,953

Distribution Sales (a) Distribution Sales (2017 f) Distribution Sales (2019 f) Distribution Sales (f)

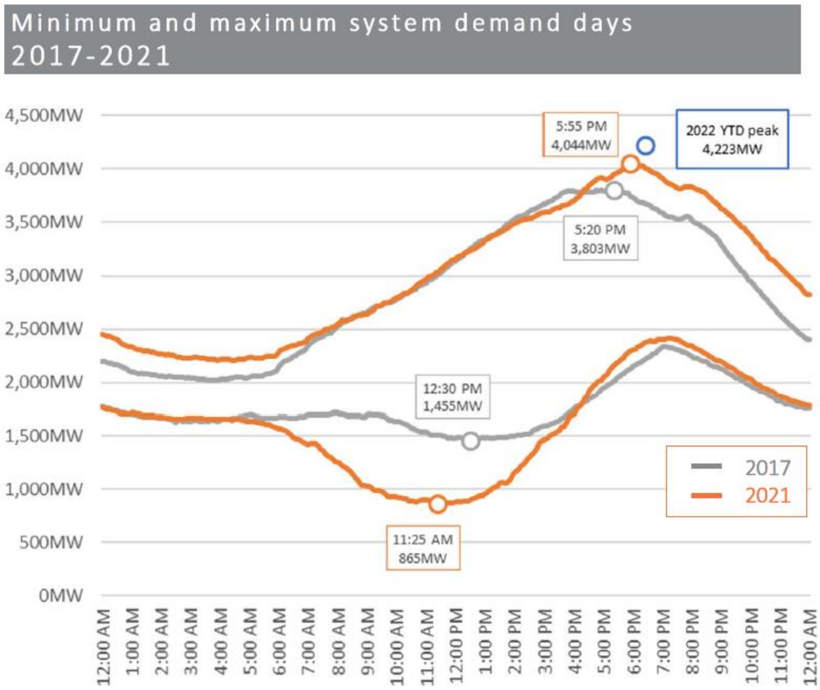
Source: Attachment 7.5, figure 3.2

There are shifts in the system demand over the course of the day where system level peaks are getting higher, and the lows are getting lower. Even more variability is present at the individual substation level where demand extends into the negative at different points of the network (i.e. a net flow of electricity from low voltage customers back up through the distribution network).

62 Western Power, Attachment 7.5, Energy and Customer Number Forecast Report (2020), Access Arrangement Information, 1 February 2022, Figure 3.2

63 Western Power, Attachment 7.5, Energy and Customer Number Forecast Report (2020), Access Arrangement Information, 1 February 2022, Figure 4.6

Figure 4–6: Maximum and minimum systems demand days



Source: Western Power, Our AA5 Proposal Access Arrangement Information, Overview 21 Feb 2022

Distribution design criteria within the Technical Rules require:

1. **All *distribution systems* must be designed to *supply* the maximum reasonably foreseeable *load* anticipated for the area served**. The maximum reasonably foreseeable *load* must be determined by estimating the *peak load* of the area after it has been fully developed, taking into account restrictions on land use and assuming current electricity consumption patterns.
2. ***Distribution systems* must be designed to minimise the cost of providing additional *distribution system* capacity** should electricity consumption patterns change.

Western Power has developed spatial maximum and minimum load forecasts at each zone substation. Engevity understand these forecasts are an input to the Network Management Plan. Zone substation forecast loads at attachments 8.7, 8.8, 8.9 and also in the Network opportunity map[64].

The forecast was prepared in 2020 and provides an outlook to mid-2027.

In October 2020 the first Whole of System Plan developed by the Energy Taskforce was made public. This plan presents four scenarios of how the SWIS could evolve through to 2040. It is unclear from the information provided which, if any, of these scenarios is captured by the AA5 forecasts.

As discussed in the demand forecast attachment, in June 2021 Western Power commissioned National Institute of Economic and Industry Research (NIEIR) to review the forecast methodology. The NIEIR review found that overall, "Western Power's forecasting models appear reasonable, robust and fit for purpose."[65] The NIEIR report went on to propose 13 recommendations/suggestions for improvement in Western Power forecasts.

64 Western Power, Western Power Network Opportunity Map 2021, section 2.3 https://www.westernpower.com.au/media/5840/network-opportunity-map-2021-20211112.pdf

65 Attachment 7.7, National Institute of Economic and Industry Research, A review of Western Power Forecast Methodology for the AA5, June 2021, page XXX

In Engevity's view the following items have potential to influence the basis of Western Power's planning decisions.

Table 4–1: Comments of on forecast methodology

Recommendations/ Suggestion for improvement	Engevity assessment
NEIER Energy Item 2: Integrate zone sub-station specific driver variables via mapping ABS LGAs or ABS Statistical Areas (SA1 – SA4). **Population, dwelling stock, real income, gross product by sector or industry.**	The very rapid shifts in PV penetration and its impact on the network are an important theme throughout AA5. Location specific driver variables for energy, including PV, should be used to build more reliability into the forecast. Western Power holds the most complete data set on WA rooftop solar through the PV connection process and existing AMI/Interval metering data for solar customers.
NEIER Energy Item 6: Applying post-modelling adjustments to energy projections if required. Possible State and Commonwealth energy and environmental programs and new technologies, such as batteries and electric vehicles.	Western Australian government Climate Policy was released in December 2020 and has been followed by a variety of supporting strategies for batteries and electric vehicles. The short-term impact is limited but there is potential significant impact for long lived assets that are expensive to access/ augment, for example underground networks and undersized SPS assets.

Recommendations/ Suggestion for improvement	Engevity assessment
NEIER Energy Item 7: Procure or develop regional specific battery and EV forecasts covering installations, capacity and energy. These models should combine economic and sociodemographic drivers of battery use and EV. Sociodemographic includes age structure, dwelling type, income and geographical location. **NEIER demand Item 4: Include forecasts demand impacts of electric vehicles and battery storage.**	Engevity notes paragraph 9 and 10 of AAI where Western Power comments on the rapid change customer behaviour, government policy, decarbonisation of the electricity system and technological advancement. The model has only limited recognition of these changes. We agree with Western Power that there are unlikely to be large scale, widespread changes in the near term in relation to EV and Battery adoption during AA5 but it is unclear how these factors have or have not been included on longer range forecasts used to develop the investment business cases covering much longer assessment periods. There is potential significant impact scope of proposed long lived assets that are expensive to access/ augment (for example underground networks) or may ultimately prove with hindsight to only address a transient issue (for example the significant AMI, SCADA, ICT and Communications investment to address minimum demand issues and enable load/export control when the growth of private EVs and battery installations provides sufficient flexible load from customer investment to mitigate these issues in the long term – potentially stranding much of the extensive network investment proposed for AA5)

Recommendations/ Suggestion for improvement	Engevity assessment
Engevity observation: The AA5 proposal has various proposed changes to tariffs including a new time of use service 'super off-peak' component from 9am-3pm, with a variable price per kilowatt hour close to zero. **The purpose of this new tariff is to "encourage the use of the network at times of minimum demand. Changing usage patterns will avoid costly reinforcements to the network to meet the requirements of peak and minimum demand days" (AAI para 35)**	We understand the network management plan has been based on the demand forecast reviewed by NIEIR and that does not reflect the super off-peak ('solar sponge') tariff. Engevity note there is some uncertainty on timing and take up of the new tariff and agree with Western Power that the proposed tariff is a useful tool to reducing investments. Without a forecast model that reflects the proposed tariff it is not possible to judge the impact of this tariff on proposed investment in AA5. We note that the aggressive Time of Use tariff response rate assumptions in the financial analysis of the AMI program to calculate the $62m PV deferred augmentation benefit. These assume that 25% of AMI metered customers not only switch to, but significantly respond to the pricing incentives of the tariff in 2021 – rising to 55% of AMI metered customers by 2027. For comparison, the starting figure exceeds the current uptake rate of Time of Use tariffs in Australian distribution networks. We also note that Australian tariff research typically identifies an initial short term consumer response to ToU incentives. This is well documented in studies as the studies are typically conducted over a period of months. Longer term assessments identify that the response declines over a few years when reliant on changes in customer behaviour. However, the benefit is mostly retained for the customer and network when the response is automated by the customer or controlled by the network. This behaviour is not reflected in the AMI benefits calculation or the forecasting process.

The table above outlines a variety of factors that are not considered in the model and should be addressed in network forecasting in a changing environment – even if inclusion only demonstrates that the impact is immaterial. NIEIR found the model does not reflect the regional socioeconomic and land use variables that drive peak and minimum demand at a substation level.

The modelling used to forecast demand does not adequately reflect location specific factors or the proposed super-off-peak ('solar sponge') tariff intended to reduce investment and critical to the AMI business case. In our opinion, the impact of these updates is unlikely to be material in the near term (<5 years) however, the asset management plans prepared for AA5 for long lived assets catering for forecast growth are influenced by needs beyond the current forecast horizon and regulatory period.

4.3.2 Inputs – Asset data

The asset management system uses a data driven approach and is influenced by the availability and integrity of the input data. The availability of reliable data has been an issue for Western Power in the past.

The AA3 review found:

> *Management of data on the existence and condition of assets is a problem for Western Power and this continues to adversely impact the efficiency with which programs and projects are implemented.*[66]

The AA4 review found:

> *The challenge is to improve data accuracy and consistency, and tools and practices which enable Western Power to efficiently analyse and revise strategies to inform their asset management decisions.*

Engevity has not conducted a comprehensive audit of the reliability of underlying data but has observed that potential gaps in data availability remain evident in the Network Management Plan. Examples are provided below.

- Data (e.g. age, type, and quantity) for assets such as cross-arms, stays, and insulators have attribute data is limited and must be estimated.
- Reliable asset age profile for LV OH and ground-mounted switchgear is not available.
- Age for Dx facilities is not available.
- **Data gaps in the system pose a challenge to the maintenance strategy of UG cables**. Approx. 5% of cable are of unknown type. The location of Concentric Neutral Solid Aluminium Conductor (CONSAC)[67] cables is unknown due to data issues[68].
- Assets age of approximately 20 % of the overhead service connections is unknown.
- 31% of capacitor banks and 74% of reactors have an estimated age of between 46-50 years. This is due to the actual age being unknown.

Western Power has self-assessed the current state asset information system data via user survey. This review found that there is a *"systemic problem with the perception of quality of asset information available within Western Power, with an average of just 67% of respondents considering data to be fit for purpose."*[69] The review also found that data gaps or integrity issues could *"lead to delays and poor decisions, mostly conservative."*

Engevity notes that conservative assumptions underpinning the data used in decision making result in costs and risk being inappropriately transferred to customers when Western Power management is best placed to address material data gaps, review conflicting data sources, establish data standards to ensure consistency, make the asset data readily available and put appropriate governance arrangements in place over the businesses data assets. This is a process that several NEM businesses have conducted over the past decade to improve the quality and reliability of their key decision-making data.

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66 Geoff Brown & Associates Ltd, Technical Review Of Western Power's Proposed Access Arrangement For 2012-2017, 2012, Page 1

67 Consac cables (**Co**ncentric **N**eutral **S**olid **A**luminium **C**onductor) was used for underground LV distribution across Australia and internationally. Most Australian networks are experiencing faults due to water ingress at the 'service tee' connection to the customer premises over time. This has led to networks typically replacing the cables in part or in whole.

68 Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022 page 151, 152

69 Ibid, section 11.5

We are concerned that Western Power's proposed investment in ICT, SCADA, AMI and new asset classes such as batteries and SPS will create data management and data governance issues that dwarf their long standing and self-assessed problems with asset data. **Ultimately the benefits arising from the AA5 program are reliant on Western Power's ability to harness the massive volume of AMI data and supporting ICT systems to deliver useful investment insights.**

For example, the LV network operational insights and control mechanisms that Western Power has highlighted as critical to managing increasing DER penetration rely on near-real-time processing of around 1.2m metering data feeds of factors such as demand kVA, consumption kWh, export current kVA, export energy kWh, power factor, power quality factors (V, Hz), neutral integrity, connection status and phase information. Whilst the consumption data is typically held at a 5 minute or 30-minute resolution, the electrical parameters typically need to be provided at a much higher resolution to be useful for the type of control that Western Power envisions.

We note that even some of the smallest of the Victorian DNSPs experience issues in processing datasets that are much smaller than Western Power's. This limits the insights that can be made in both real time operations and longer-term investment decision making. Other Australian networks with lower levels of AMI penetration have applied 'state estimation' approaches to the LV network to approximate network conditions based on a much smaller subset of meters that are installed for network monitoring purposes. These approaches are far more cost effective and have proven to be of suitable accuracy for operational decision making, with much reduced data transmission, processing and warehousing requirements compared to relying on processing the full-scale AMI system data.

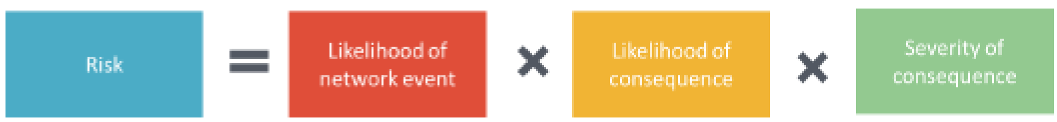
Other organisations use metrics on data quality to increase transparency and focus on improving data integrity and using this metric as a key performance indicator.

Engevity concludes the availability of reliable data for asset management has been a long-standing issue for Western Power and remains unresolved. The current AA5 proposal, along with the preceding proposals have all sought to improve the collection and analysis of reliable data, through implementation of data gathering technologies. It is unclear from the current proposal to what extent the same issue will be present in the next proposal and what measures will be taken to address known data gaps.

4.3.3 Asset planning methods - Risk based approach

Western Power has applied a risk-based approach to replacement planning.

Figure 4–7: Quantitative value of risk calculation



Source: Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, Figure 5.8

A monetised risk score is calculated for all assets as a means of determining their investment priority. With reference the equation above, the likelihood of an event occurring and likelihood of the event causing a type of consequence (safety, environmental, reliability etc) is multiplied by the severity of consequence as measured in dollars.

The risk-based approach is consistent with methods used by other networks and is aligned with the risk-cost assessment methodology in the industry practice application note[70] published by the AER.

Western Power has established network risk categories (Safety, environment, customer (including reliability), legal/compliance, reputation and financial) and risks are assessed in each category for each asset class. These categories are consistent with regulatory requirements and corporate objectives.

Engevity sought to review of details of the asset risk calculations. The transmission network risks are calculated in an excel spreadsheet model that offers high transparency of the data inputs and risk outcomes. The distribution systems risk is model through specialised software.

A walkthrough of this software was provided by Western Power and Western Power gave assurance the models have undergone statistical validation of their utility. We are concerned that the asset failure forecasts from the system are said to take account of the historical data, but almost universally result in a significant upward trend in failures – irrespective of whether the historical trend is upward, downward or flat.

This is a strong indicator that the forecasting algorithms significantly over-weights age as a factor in the calculation. The discontinuity between historical and forecast values is relatively typical of a poorly calibrated age-based forecasting model that is attempting to inflate replacement volumes because the initial conditions still include assets at ages that, according to the age-based risk criteria, should not still exist in service (but field condition information supports continued operation). Our discussion on the likelihood of a network event identifies that this is most likely a result of the use of Mean Replacement Life (MRL) as an anchor for defining the level of (age based) asset risk.

In these cases, removing age as a factor in the calculation and focussing purely on condition indicators provides a measure of how strongly the process is biased toward asset aging as the key determinant of forecast failure rates. We were unable to conduct this test as the system is integrated into Western Power's corporate ICT environment and was not able to be distributed for our review.

Observations from our review of the risk -based approach are provided below.

Conservative estimate of the likelihood of a network event

Western Power uses a variety of asset characteristics, performance history and condition information to forecast the likelihood of a failure event. In the case of the pole replacement model that was demonstrated to us, at least 14 input variables are used. **One important input is the asset age relative to the mean replacement life (MRL).**

MRL reflects the average age at which the assets in a population have historically been replaced. MRL is a highly influential input to Western Power's risk-based approach to asset planning.

> *Likelihood of failure is derived using MRL hazard functions… Exceeding MRL potentially increases the frequency and severity of defects and the likelihood of in-service failure. It does not necessarily translate into an asset failing immediately.*[71]

It is recognised that for many asset classes, exceeding MRL does not automatically trigger asset replacement. The replacement decision will also be influenced by a combination of factors including condition assessment, obsolescence, forecast service needs and/or strategic needs which will help ensure investment optimisation.

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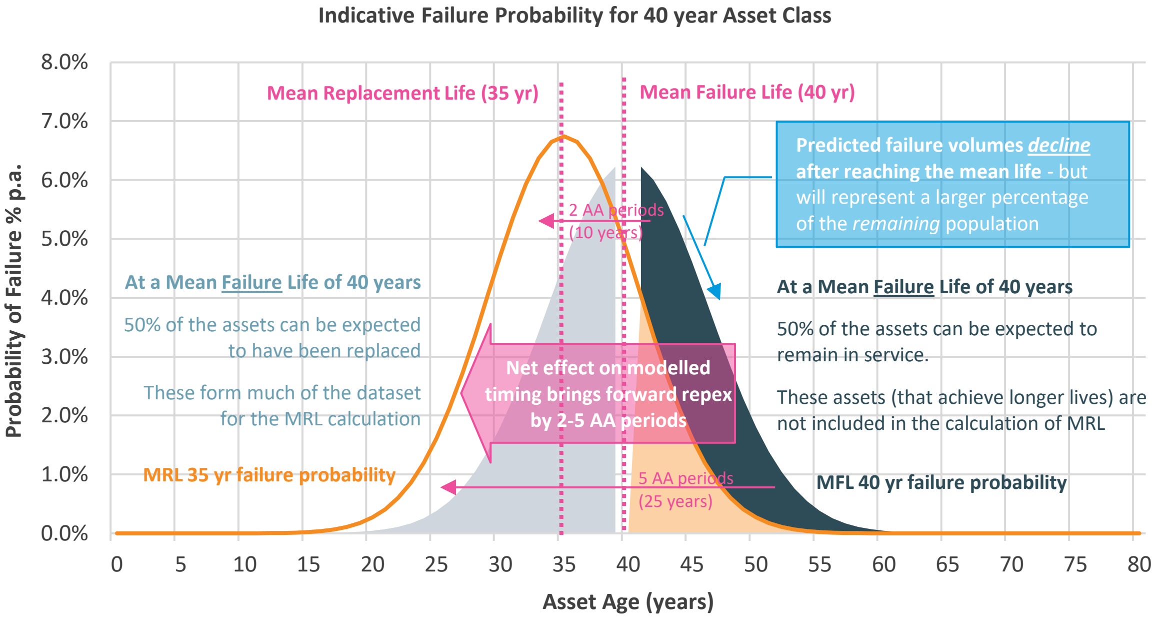
[70] AER, Industry practice application note Asset replacement planning, January 2019 (https://www.aer.gov.au/system/files/D19-2978%20-%20AER%20-Industry%20practice%20application%20note%20Asset%20replacement%20planning%20-%2025%20January%202019.pdf)

[71] Source: NMP page 131

However, a problem arises if optimism or pessimism in the MRL skews the overall state of the remaining asset population in the network. Optimism will cause a network to under-plan delivery volumes potentially causing inability to deliver service standard benchmarks. Pessimism will cause reservation of excessive funds and potentially too many resources to deliver a program which significantly exceeds what is required. Where there is a “use it or lose it” behavioural driver as can occur in corporate environments or regulatory regimes, too much pessimism can enable inefficient use of capital through premature replacements of assets.

Mathematically, the MRL represents an average life at replacement and is therefore influenced by the business’s past replacement decisions and defect/condemnation criteria. As a result, it will understate the actual Mean Failure Life and associated failure distribution that the asset class would exhibit if it were actually allowed to run to failure. Accepting that the MRL will, by definition, be shorter than the theoretical run-to-failure MFL, we can conclude that use of the MRL as a reference point will overstate the age-failure relationship.



Source: Engevity Analysis – indicative asset class

Over time, the continued reliance on the MRL will lead to increasingly conservative risk assumptions because anchoring failure risk to MRL will artificially reduce the volume of older assets in service and favour increasingly early replacement timing. Using the above example of an indicative 40-year MRL asset class we note that:

- Assuming the AER repex model assumption of a normal failure distribution and a standard deviation equal to the square root of the mean, the failure probability distribution is symmetrical around the MRL of 40 years
- Half of the assets can be expected to remain in service beyond the MRL (shown as the darker blue/orange portion of the above graph). These assets are at risk of early ‘age based’ retirement due to the risk relationship in the system between MRL, asset age and risk suggesting, incorrectly that the asset poses a higher probability of failure, even with no change in reported condition.

- The other half of the assets (shown as the grey portion of the graph) are no longer in service, and therefore will contribute to the calculation of an even shorter MRL over time – weighting it more strongly towards the replacement timing for the assets that fail before they reach the MRL and increasing the conservatism in the model when compared to the theoretical run-to-failure MFL (which represents the maximum average service life that could be extracted from the asset class)
- The MRL anchors the risk-based assessment of asset age. As the MRL gets progressively shorter, the older assets that still remain in service are assessed as posing an ever-increasing risk – regardless of the available condition information or the statistical fact that the volume of failures per year will decline. This substantially increases the probability of premature replacement of older assets that remain in good condition.
- The calibration of the model could be improved by attenuating the significance or removing the MRL to failure risk relationship. Otherwise, asset class specific in-service failure statistics vs planned replacement age could provide an indication of the underlying MFL and run-to-failure probability distributions to estimate how conservative the approach of using MRL is for different asset classes.

The AER uses Expected Replacement Lives caparison data when benchmarking the performance of NEM businesses. We have used the AER REPEX model[72] comparison sets to test for systemic trends in Western Power MRL against AER benchmarks. AER benchmark data was sourced from the recent regulatory reviews of Powercor[73], SAPN[74], Essential Energy[75] and Ergon. These networks were included because of the mix of coastal population and sparse distributed inland rural customers.

[72] https://www.aer.gov.au/system/files/AER%20repex%20model%20outline%20for%20electricity%20distribution%20determinations_0.pdf

[73] AER - Final decision - Powercor distribution determination - 2021-26 - Poles repex model - 2014 age profile - April 2021.xlsm (live.com)

[74] AER - Final Decision - SAPN distribution determination 2020-25 - Repex Model - June 2020.xlsm (live.com)

[75] AER - Essential Energy 2019-24 - Draft decision - Repex Model - November 2018.XLSM (live.com)

Table 4–2: Comparison of MRL[76]

	Asset type	Mean Replacement Life NMP Table C.1	AER Comparator Expected Replacement Lives for Other Networks (Min - Max)
Dx Structure	Hardwood Pole Pre-1960	69.2	70.3 56.6 - 74.5
	Hardwood Pole Post-1960	49.2	
	Softwood Pole	50.0	
	Concrete Pole	55.0	55.6 45.9 - 61.3
	Metal Pole	55.0	56.6 45.3 - 77.1
	Auspole	49.2	no data
Dx OH conductor	Dx OH LV Conductor	70.3	91.8 76.6 - 92.6
	Dx OH HV Conductor	70.3	89 61.4 - 105.6
Dx UG Cable	XLPE Cable	30.0	58.1 28.1 - 75.1
	CONSAC Cable	40.0	
	PILC cable	50.0	
Service connections	OCSC	31.9	58.4 49.7 - 70
	USC	30.0	
DSTR	Ground Mounted Delta <100kVA	26.0	61.3 22 - 73.7
	Ground Mounted Sigma <100kVA	37.9	
	Ground Mounted Delta >=100kVA & <300kVA	18.6	52 26.5 - 64.9
	Ground Mounted Sigma >=100kVA & <300kVA	50.0	
	Ground Mounted Delta >=300kVA &<=630kVA	25.9	
	Ground Mounted Sigma >=300kVA & <=630kVA	47.7	
	Ground Mounted Delta >630kVA;	34.3	55.4 45.4 - 62.6
	Ground Mounted Sigma >630kVA	53.1	

Source: Western power Network Management plans Table C.1 and Engevity analysis.

The above table compares Western Power MRL against similar AER Comparator Expected Replacement Lives for other networks.

- No asset types were materially longer than AER comparators;
- 35% of asset types similar to AER comparators;
- 20% of assets less than typical AER comparators but within range;
- 35% of the asset are less than AER range.

Two asset classes are worthy of comment: 1) Service connections; 2) delta transformers. For these assets the replacement life is significantly less than AER comparators and opportunities to increase the MRL at Western Power could deliver operational efficiencies for the business and cost benefits for customers. We have not pursued these issues further as neither type of asset have substantial CAPEX allowances in AA5.

In aggregate we conclude that the MRL of Western Power assets is generally consistent with AER benchmarks with a stronger tendency for Western Power to replace assets earlier, as opposed to later, than the NEM businesses.

[76] Reference AER Comparator Expected Replacement Lives for Other Networks

Likelihood of consequence

The likelihood consequence describes the conversion between the failure event occurring and a consequence of that failure. For the distribution network, Western Power uses historical data to develop likelihood of consequence for its asset populations. This is done with conversion factors relating the number of consequences / number failures.

For transmission, individual assets are considered on a case-by-case basis and a semi quantitative determination is made using expert knowledge. This approach reflects the high materiality of consequence of a failure event and the available network configuration to avoid that consequence.

Engevity was presented with selected example calculations of the likelihood of consequence and is of the opinion the approach used by Western Power is reasonable and largely consistent with practices employed by similar Australian businesses.

Severity of consequence

Western Power has developed severity of consequences for use in its investment decision making as shown below:

Consequence type	Valuation method
Safety	Value of statistical life and disproportionality factors are used to reflect the social acceptability of certain safety outcomes.
Reliability	Value of customer reliability and value of unserved energy
Financial	As for reliability or with financial cost estimates to address consequence of failure (3rd party asset repair, etc). Disproportionality factors are used to reflect the social acceptability of certain safety and environmental outcomes.

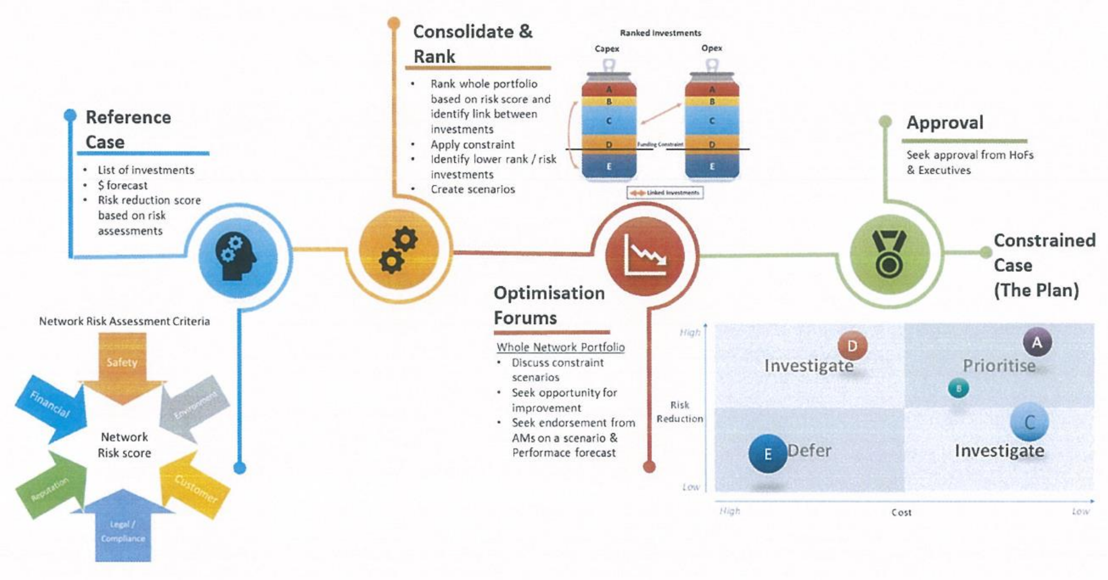
We note that our CAPEX review identified some areas where Western Power either did not apply their severity of consequence framework to value claimed benefits or applied values that don't align with the published reference values. These are discussed in the CAPEX attachment under the AMI program (valuation of safety risk of acceleration, alternative VCR assumption).

Engevity reviewed example calculations of the monetised severity of consequence and is of the opinion the approach used by Western Power is reasonable and largely consistent with the practices of other networks.

4.3.4 Investment prioritisation, investment optimisation and plan development

Following the risk quantification Western Power undertakes a process to prioritise investment to best meet customer needs. This process is defined in the Network Investment Prioritisation methodology (NIPM) guideline. An overview of the sequence of processes is provided below

Figure 4–8: Five phases of NIPM process



Source: Western Power, Network Investment Prioritisation Methodology Guideline, July 2020, Figure 6

Engevity's review of the NIPM finds Western Power's approach is similar to other networks. Subject to process inputs being reliable, the NIPM can reasonably be expected to arrive at an appropriate, optimised plan that reflects corporate objectives and considers financial, operational, network and delivery constraints. The NIPM requires broad engagement of diverse Western Power functional leads, area managers and executive leaders to socialise and gain commitment to the delivery plans. Whilst the process itself appears to be reasonable, our review has identified concerns with the risk evaluation, scale of reprioritisation of the replacement program in AA4 to accommodate a very large SCADA investment and significant variance in reported AA4 project outcomes. This suggests potential issues with the inputs to the process and the alignment of the ex-ante prioritisation with project management and works delivery practices.

Changes in prioritisation over time

The asset management plan presented as part of AA5 reflects the forecast at a moment in time (June 2020) and is expected to change as new information becomes available. It is instructive to review the performance during AA4 to understand the nature and scale of change that has historically occurred through similar techniques as means of judging the reliability of the current forecast.

The table below compares the planned AA4 forecast and actual spend. While the aggregate spend is similar to the plan, deviations at a regulatory category are significant in percentage terms as well as in dollar terms. These reallocations are suggestive of a strong rebalance of the investment priorities over time. For AA4 the balance was shifted in favour of SCADA and communication and IT at the expense of multiple other categories including large reductions to the 'risk driven' categories including the replacement ($53.6m | -7.4%) and regulatory compliance ($64.0m |-16.6%) programs.

Table 4–3: Comparison of AA4 forecast and actual by regulatory category

Reg category	AA4 FFD Forecast	AA4 Actual+ FY22 F1	Deviation	
	$'000s Nominal FY22, including indirect		($'000s)	(%)
Asset Replacement	728,093	674,444	-53,648	-7.4%
Pole Management	704,310	702,510	-1,800	-0.3%
Regulatory Compliance	384,999	321,020	-63,979	-16.6%

Reg category	AA4 FFD Forecast	AA4 Actual+ FY22 F1	Deviation	
	$'000s Nominal FY22, including indirect		($'000s)	(%)
Capacity Expansion	249,813	181,533	-68,279	-27.3%
Business Support	248,713	241,872	-6,841	-2.8%
IT	221,505	293,482	71,977	32.5%
State Underground Power Program	165,602	122,251	-43,351	-26.2%
Metering CAPEX	157,056	163,280	6,224	4.0%
SCADA & Communications	99,773	213,108	113,335	113.6%
Reliability Driven	11,371	23,236	11,865	104.3%
Subtotal	2,971,235	2,936,737	-34,498	-1.2%
Customer Driven (Tx)	126,663	297,731	171,068	135.1%
Gifted Assets	440,822	275,909	-164,912	-37.4%
Customer Driven (Dx)	682,421	587,806	-94,615	-13.9%
Subtotal	1,249,905	1,161,446	71,592	-7.1%
Total	4,221,140	4,098,183	-122,957	-2.9%

Source: Western Power and Engevity Analysis

At a project and asset program level there is more volatility as shown below. For the projects and programs included in AA4 plan, **approximately half of them experienced deviations outside the +/-50% range**.

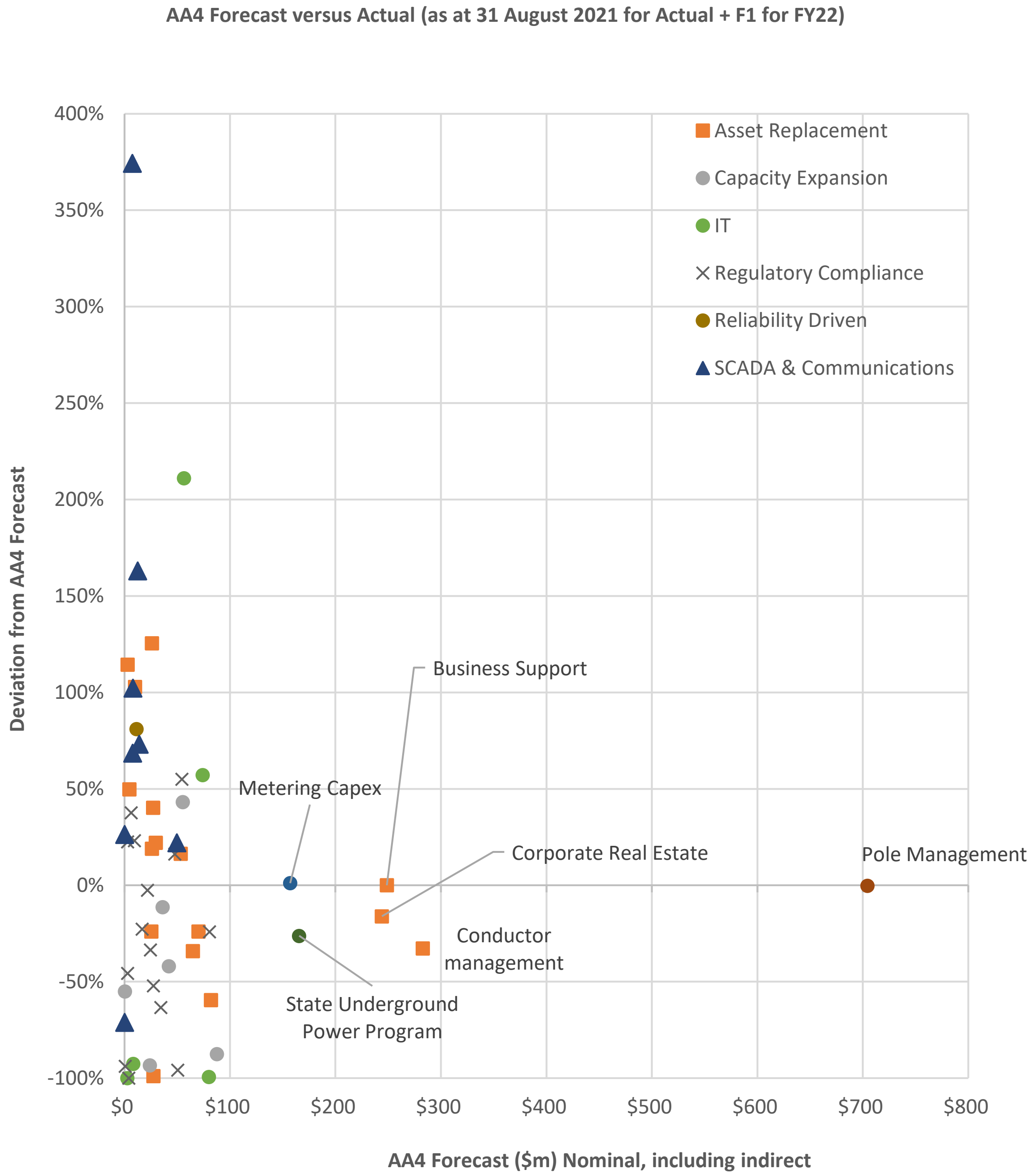
We discuss these scoping, options analysis and estimating issues in the AA4 CAPEX attachment as part of our review of the AA4 HAY-MIL switchboard project in which Western Power:

- qualitatively dismissed a refurbishment option despite acknowledging that it would represent a lower cost solution
- selected the preferred replacement option at an estimated cost in the order of $30m
- found the replacement option cost to be in the order of $60m, substantially exceeding the AA4 estimate
- explored the refurbishment option with the equipment manufacturer, ultimately delivering this option for a cost in the order of $12m

Whilst this project ultimately resulted in lower costs, it highlights that Western Power’s delivery of its capital program is relatively poorly controlled when compared back to Access Arrangement forecasts.

Noting these outcomes, we consider that many of the +/-50% estimates provided in AA4 and in this review are insufficiently developed for the purpose of setting its expenditure allowance as part of the Access Arrangement process. Other businesses progress their preliminary regulatory estimates to a +/- 30% level, supported by costed options assessments, quantified risk and benefit assessments and an evaluation of alternative technical solutions and non-network options.

Figure 4–9: Forecast and actual spend for project and programs in AA4



The figure above shows the deviation for AA4 Plan for projects that have a plan spend. There is an additional $145M of investments for which there was no spend included in the AA4 plan. These are not shown above.

Western Power has provided a variety of reasons for the change including:

- Accounting adjustments and recategorization of spend;
- Change in project scope;
- Change in delivery durations;
- Change in unit costs;
- Differences between modelled and observed asset failure rate;

- Reprioritisation because of:
  - Change in needs – demand, supply;
  - Change in asset strategy – e.g. SPS;
- Estimate omissions – e.g. planning costs for projects to be delivered in subsequent period.

With the benefit of hindsight, it is evident that despite evaluation of asset needs for the AA4 forecast period, internal and external decision-making drivers resulted in significant deviations from plan. Some of the largest deviations were from customer driven assets and gifted assets, both of which are dependent on customer activity from households and businesses, which was affected by uncertainty caused by the global pandemic. Other changes are internally driven. The AA5 portfolio uses the same underlying forecasting approach and is also subject to similar external and internal influences.

Western Power substantially reprioritised the investments in the AA4 forecast portfolio. Based on Engevity's experience, other networks also have large deviations between planned and actual spend at a program level and ERA can reasonably expect material variances over AA5 due to the dynamic WA energy market environment that will frame the period. Notwithstanding the reprioritisation of investment plans, the aggregate spend on OPEX, and CAPEX is not dissimilar to other Australian networks. Safety outcomes are compliant with corporate tolerance. The distribution network reliability performance in some categories falls short of service standard benchmarks and for SAIDI trails network peers. This suggests some potential rebalancing of investment priorities to asset class with greatest contribution to outages may be needed. This issue is discussed further below.

4.3.5 System output – Network plans and forecast of unassisted failures

For each asset type Western Power has quantified:

- Forecast number of unassisted asset failures if allowed to run to fail;
- Forecast number of unassisted asset failures per AA5 plan;
- Western Power maximum target unassisted failure rate;
- The number of assets that are to be reinforced/removed/replaced;
- The number of work orders for repair.

These outputs can be found in section 12 of the Network Management Plan. In this section of the report, we evaluate the consistency between current performance outcomes, trends & risk metrics and the proposed plans for AA5. As previously noted, we have concerns over the influence of age in the algorithms used for failure forecasting.

Transmission asset performance and risk assessment

An overview of asset contribution to transmission load lost and system disturbances is presented below.

Table 4–4: Transmission asset contribution to load loss and systems disturbances

Asset	Load lost (MWh)		System disturbances	
	AA3	AA4	AA3	AA4
Power Transformers	180	304	63	87
Primary plant	178	334	39	88
Protection Systems	28	124	9	13
OH conductors	20	11	18	13
Structures	8	10	4	5
Reactive plant	Not applicable		20	68
Vegetation encroachment	0	98	5	11
Total	386	757	149	272

*Switchboards, outdoor circuit breakers, instrument transformers, disconnectors and earth switches, and surge arresters

Source: Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, data provided at Tables 6.10, 6.16, 6.25, 6.31, 6.58

Another source of performance data to support Western Power assessment of risk is unassisted asset failure data. Changes to Western Power's asset failure data collection in 2017/18 have truncated the historical trends to two-three years. The lack of historical trend data does somewhat impair our ability to correlate trends in asset failures with system performance trends, however the available data confirms assets with the highest systems losses & disturbance are associated with high quantity of failures.

Table 4–5: Transmission unassisted failure

Asset	Unassisted failures (Qty)
Tx Outdoor Circuit Breaker	25%
Tx Power Transformers	20%
Tx Disconnectors and Earth Switches	17%
Tx Protection and Control Schemes	14%
Substation	8%
Tx Indoor Switchboards	5%
Tx Auxiliary DC System	5%
Tx Reactive Plant	2%
Tx Instrument Transformers	2%
Tx Auxiliary AC System	1%
Tx Surge Arresters	0%

Source: Western Power response to Engevity RFI 29.02-2

Finally, the table below shows transmission failures that drive safety outcomes.

Table 4–6: Transmission assets that drive safety outcomes

Asset category	Risk target	Current metric (2020)	Forecast Plan AA5
Ground fires due to:	≤ 7 p.a.	2	3
TX overhead conductors	n/a	2	3 p.a.
TX pole tope fires		0	
Electric shock due to:	≤ 8p.a.		
TX overhead conductors	≤ 8 p.a.	4 p.a.	3 p.a.

Source: Western Power response to Engevity RFI 29.02-2

We can compare the actual performance data above with the current (2020) risk metrics, target and forecast risk metrics prepared in support of the AA5 asset management plans.

Table 4–7: Risk metrics for key asset classes driving transmission performance

Asset category	Risk Metric target limit	Current metric (2020)	Forecast Plan AA5
Power Transformers	≤0.14	0.14 ●	0.12 ●
Primary plant			
Switchboards	≤0.04	0.04 ●	0.03 ●
Circuit Breakers	≤0.016	0.018 ●	0.12 ●
Instrument Transformers	≤0.023	0.023 ●	0.017 ●
Disconnectors and Earth Switches	≤0.009	0.006 ●	0.008 ●
Surge arrestors	Risk model not available		
OH conductors	≤1 p.a.	nil	1 p.a. ●
Protection & control systems	139 failures p. a	136 ●	151 ●
Structures (Wood poles)	≤17 failures p.a.	12 failures p.a. ●	8 failures p.a. ●

Source: Engevity analysis of Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, Tables 1.3, 6.34, 6.39, 6.45

Below we use the actual performance data and forecast risk metrics to make observations on the prudency of transmission plans for AA5. These evaluations are undertaken for regulatory categories with CAPEX greater than $50m and which are not primarily customer driven.

Observations on transmission plans

Power transformers

- Power transformers are major contributor to lost load and systems disturbances. This asset class ranks second in the number of unassisted failures. The current risk assessment is near asset management target.
- Western Power plans to spend $75.5m on asset replacement and renewal to reduce this risk over the course of AA5 with majority of the investment on refurbishment. This is a 40% increase on AA4 actual spend ($53.5M) and includes replacement of 13 power transformers and refurbishments of another 36 of the 332 population. Western Power forecast the residual risk will be within risk management targets.

Engevity considers that Western Power proposal to reduce risk associated with transformer performance is prudent and the pursuit of refurbishment options represents an efficient approach to managing the risks of an ageing transformer fleet.

Primary plant

Primary plant is a major contributor to transmission load losses and systems disturbances. The current (2020) risk level of switchboards, circuit breakers and instrument transformers is at or near target risk level. Tx Disconnectors and Earth Switches are also exhibiting high failure quantities although Western Power assess that these represent lower risk asset types.

Western Power proposes to invest $134.6 million on primary plant replacement and renewal during the AA5 period. This is nearly double the CAPEX incurred in the AA4 period for this expenditure category – and it is evident that the AA5 period greater focus on circuit breakers.

Table 4–8: Primary plans replacements quantities

Asset type	AA4[77] Qty	AA5 Qty
Circuit breakers	68	150
Instrument transformers	263	238
Disconnectors and disconnectors with earth switches	297	196
Surge arresters	90	80

Engevity considers that the increased investment in primary plant to reduce failures quantities and reduce impact on load losses and systems disturbances and lower safety risk is prudent.

Protection and control systems

There has been a strong increase in load loss and systems disturbances between AA3 and AA4 attributed to control and prevention. The current (2020) number of unassisted failures 136 p.a. is marginally below the maximum asset management target of 139 p.a.

Western Power proposes to invest $87.6 million in protection asset replacement and renewal during the AA5 period. This is substantially more than AA4 ($37.9m). Despite this increase the forecast number of unassisted failures to increase 151 failures p.a., exceeding current rate and asset management target 136 failures p.a. Western Power indicates the issue is largely relate to large driven by the quantum of electro-mechanical relays that are operating beyond the MRL and are obsolete and without vendor support. Engevity recognises that modern microprocessor-controlled

77 [redacted]

relays are faster acting and the preferred modern technology for networks. However, most Australian networks still maintain older electromechanical relays in service, despite their age, using various strategies to maximise their service life. These include, salvaging units replaced in augmentation works to mitigate the risk of the remaining population, targeting slower acting relays at more critical network locations and/or accepting the benefits of technology diversity to mitigate common failure modes between relays in redundant protection system configurations.

The plan for AA5 is to replace 375 units of the 11,086 population over AA5. Western Power indicates a performance monitoring program will be used to ensure no material increase in risk. Visual inspections are scheduled for every two months with testing at 5 years.[78]

Engevity considers that increased investment in protection and control systems is prudent, noting that whilst electro mechanical relays are able to be maintained and rebuilt to achieve very long service lives, the skills to support this approach are increasingly rare. These assets usually can't achieve the faster operating times than modern microprocessor-controlled relays are capable of.

Based on the available data it is unclear the extent to which the increase in losses and disturbance will be reversed.

While there is a plan for more than 100% increase in spend for this asset category, Engevity notes that the unassisted failure rate is forecast to continue to increase. Western Power has advised that a performance monitoring program will be used to ensure no material increase in risk.

Transmission poles

Pole failures are relatively small contributor to load and system disturbances. The current unassisted failure rate of 12 poles p.a. is less than asset management target ≤17 failures p.a. but still represents very poor performance when compared to the pole failure rates reported by the NEM transmission networks.

AA5 plan transmission pole unassisted failure rate is to further reduce the failure rates to 8 failures per year. The proposed compliance program CAPEX is $54.2m which includes replacement (qty 2,030) and reinforcement (qty 2,250) of transmission wood poles and replacement of non-wood structures in the transmission network based on condition of the asset.

Engevity considers that there does not appear to be a clear reliability or safety case for the proposed volume of replacement/reinforcements.

Distribution asset performance and risk assessment

The table below shows the contribution to reliability performance for distribution asset classes.

Table 4–9: Contribution to distribution reliability outcomes AA4

Asset Group	SAIDI	SAIFI
DX UG Cable	30.5%	39.5%
Dx OH Conductor	18.0%	17.7%
DX OH HV Switchgear	14.7%	13.9%
Pole Top Fire	12.7%	9.4%
Dx Structure	9.7%	6.8%

[78] Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022 Network Management Plans foot note #196

Asset Group	SAIDI	SAIFI
DX LV Switchgear	5.8%	4.3%
RMU	2.9%	3.3%
DSTR	2.2%	1.8%
DX Surge Arrester	2.2%	2.4%
Dx Meter	0.7%	0.6%
Dx Service Connections	0.5%	0.2%
Public Lighting	0.0%	0.0%
Dx Voltage Regulator	0.0%	0.0%
Customer Equipment	0.0%	0.0%
Grand Total	**100.0%**	**100.0%**

Source: Western Power response to RFI 29.02-2

The contribution of asset performance to safety outcomes is shown below.

Table 4–10: Ground fire

Asset Group	15/16	16/17	17/18	18/19	19/20	Total
Dx Pole Top Fire	17	45	23	90	101	40.2%
Wood Poles	5	5	10	3	13	5.2%
Cross-Arms	4	4	6	2	4	2.9%
Insulators	3	2	1	2	-	1.2%
Stay Systems	-	1	1	1	-	0.4%
Non-Wood Poles	1	-	-	-	-	0.1%
Dx OH Conductor	26	33	43	43	23	24.5%
Dx Clashing	6	3	5	1	9	3.5%
Dx UG Cables	4	3	8	5	7	3.9%
Dx Overhead Service Connection	-	2	1	3	-	0.9%
Dx Underground Service Connection	-	-	1	-	-	0.1%
	66	**98**	**99**	**150**	**157**	**83.1%**
Pole Top Switch Disconnectors	15	10	15	14	10	9.3%
Drop-Out Fuses	6	2	4	2	1	2.2%
Recloser	2	1	-	1	1	0.7%

Asset Group	15/16	16/17	17/18	18/19	19/20	Total
HV Disconnectors	-	-	1	2	1	0.6%
Sectionaliser	-	-	-	-	-	0.0%
Load Break Switches	-	-	-	-	-	0.0%
LV Disconnector	5	3	1	-	2	1.6%
LV Distribution Frame	-	-	-	-	-	0.0%
Dx Transformers	5	1	2	2	-	1.5%
Dx Surge Arrester	1	-	1	1	-	0.4%
Dx Ring Main Units	-	-	-	-	1	0.1%
Regulating Transformers	-	-	1	-	-	0.1%
Capacitor	-	-	-	-	-	0.0%
Reactor	-	-	-	-	-	0.0%
	34	**17**	**25**	**22**	**16**	**16.6%**
DSLMP (Streetlights ALL Target)	1	-	-	-	1	0.3%
	1	**-**	**-**	**-**	**1**	**0.3%**

The table below shows electric shocks are primarily associated with faults in service connections followed by overhead conductors.

Table 4–11: Electric shock

Asset Group	15/16	16/17	17/18	18/19	19/20	Total
Dx OCSC	99	83	57	67	92	51.6%
Dx UCSC	23	19	32	46	41	20.9%
Dx OH Conductor	25	20	10	15	22	11.9%
Dx Clashing	-	-	-	-	-	0.0%
Dx UG Cables	7	8	8	10	20	6.9%
Wood Poles	1	1	7	2	-	1.4%
Dx Pole Top Fire	1	2	-	1	-	0.5%
Cross-Arms	1	-	1	1	-	0.4%
Stay Systems	1	-	-	-	-	0.1%
Insulators	-	1	-	-	-	0.1%
Non-Wood Poles	-	-	-	-	-	0.0%
	158	**134**	**115**	**142**	**175**	**93.8%**

Asset Group	15/16	16/17	17/18	18/19	19/20	Total
Dx Transformers	9	-	6	4	3	2.8%
LV Disconnector	1	2	-	1	-	0.5%
LV Distribution Frame	-	-	-	-	-	0.0%
PTSD	-	2	1	-	-	0.4%
DOFs	-	-	1	-	-	0.1%
Sectionaliser	-	-	-	-	-	0.0%
Load Break Switches	-	-	-	-	-	0.0%
HV Disconnectors	-	-	-	-	-	0.0%
Recloser	-	-	-	-	-	0.0%
Dx Ring Main Units	-	-	-	-	-	0.0%
Dx Surge Arrester	-	-	-	-	-	0.0%
Regulating Transformers	-	-	-	-	-	0.0%
Capacitor	-	-	-	-	-	0.0%
Reactor	-	-	-	-	-	0.0%
	10	**4**	**8**	**5**	**3**	**3.9%**
DSLMP (Streetlights ALL Target)	4	1	4	6	3	2.3%
	4	**1**	**4**	**6**	**3**	**2.3%**
	172	**139**	**127**	**153**	**181**	**100.0%**

The target actual and forecast unassisted failure rate gives insight into Western Power's plan to sustain reliability and safety outcomes.

Table 4–12: Unassisted failure rate

Asset category	Unassisted failure target limit (qty p.a.)	Current metric (2020)	Forecast Plan AA5
Cable mgmt. (UG)	≤399	399	555
OH conductors	≤246	193	311
HV switchgear			
Pole Top disconnectors	≤105	68	82
Reclosers	≤43	24	24
Drop Out Fuses	≤313	314	365
Structures (Wood poles)	≤328	185	266

Asset category	Unassisted failure target limit (qty p.a.)	Current metric (2020)	Forecast Plan AA5
Cross-arms	≤349	157	138
Stay systems	≤221	275	233
Insulators (Incl pole top fires)	≤512	539	429
RMU – type with defects	n/a	19	42
RMU – others	≤7	5	4
Transformer Mgmt	≤261	233	314
Dedicated Streetlight Metal Pole	≤15	9	8

Source: Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, Table 1.5

Through review of actual performance outcomes trends, current and forecast unassisted failure rates we can evaluate the prudency of Western Power proposed investment in AA5. We have evaluated prudency for regulatory categories with CAPEX greater than $50m and which are not primarily customer driven. Our observations are noted below.

At this point, we note the near universal short-term increases in forecast failure rates across the various asset categories. Engevity reiterates its concerns with the failure forecasting algorithms that Western Power relies on to establish the need and scope of its compliance programs. Engevity considers that there are a number of parameters in the model that do not lead to efficient forecasts of replacement expenditure in the AA5 period. We discuss this further in the replacement program review in the AA5 CAPEX attachment, as well as explaining the inherently flawed reliance on Mean Replacement Life (MRL) as an anchor for asset risk calculations.

Observations on distribution plans

Dx Pole management (asset renewable and replacement)

AA5 forecast wood pole unassisted failure rate is 266, approximately 19% fewer failures than asset management target (328) although higher than current rate (185). (NMP table 12.8)
Western Power will invest $423.1 million in wood pole replacement and reinforcement in the AA5 period. These cost figures exclude treatments in the SPS and NRUP programs where >19,000 poles will be removed from the network and effectively form part of the risk reduction.

Engevity consider the forecast failure rate indicates that there is scope to defer expenditure in this asset class to allow failure rate to increase, whilst remaining within the asset management target.

Dx pole management (Compliance)

The program covers replacement of cross arms, insulators and stays that support the overhead infrastructure.

Failure of these assets may lead to range of adverse safety impacts including ground fire (via pole top fire), electric shock, physical injury and property damage, as well as service disruption.
Recent performance data have highlighted that the occurrence of pole top fires causing groundfires has been rapidly increasing in frequency from 17 events to 101 events in the 5 years leading up to 2019/20. The same issue is the fourth largest cause reliability problems.

AA5 compliance plans has CAPEX, $104.4 million, which is 23 % higher than AA3. We note that during the AA5 period there have been changes to work methods that were implemented by Western Power that have increased the unit cost of works relative to the start of AA4. This includes changes to insulator washing and siliconing work to manage pole top fires. The change has led to the work no longer being performed under live line conditions following a safety incident resulting from a flashover during live line insulator washing (pressure washing from an elevated work platform using a high voltage rated live line 'washing stick' and a non-conductive hose. A review of the incident was undertaken with the findings summarised in the Director of Energy Safety order 01-2021 as follows:

"Based on the evidence obtained thus far from the investigation, I have formed the opinion that there was a deficiency in the type of live line washing stick being used at the time of the incident. Moreover, I have formed the opinion the testing of the live line washing stick did not meet the minimum requirements."[79]

The order required an improvement in equipment compliance checks, testing requirements, test labelling of equipment and pre-service inspection by line workers. Importantly, with these provisions in place, the order did not require live line insulator washing to be discontinued for safety reasons.

Engevity notes that the increased capital investment to manage pole top fires is also accompanied by a significant step change in OPEX on insulator washing – focussing on a much smaller scope (high risk assets) than was historically addressed through live washing practices.

Engevity considers the program to reduce pole top fires through the compliance plan CAPEX to be prudent but notes that the increased cost (for a reduced scope) in the associated maintenance program is not supported by the safety requirements and risks outlined in the Energy Safety Order No. 01-2021 for live line insulator washing.

Switchgear management

The asset group includes HV overhead switchgear (Reclosers, Sectionalisers, Pole Top Disconnectors, Drop Out Fuses, Load Break Switches), LV switchgear and Ring Main Units (RMUs). Combined these assets are the primary contributor of SAIDI and SAIFI outcomes. Unassisted failure data has been provided for the period 2017/18 through to 2019/20 and there is no clear time trend in the performance data. Western Power indicates a manufacturing defect in a specific class of RMU poses both a workforce safety risk as well as a reliability risk.

AA5 switchgear asset replacement and renewal CAPEX ($122.9 million) is five times larger than AA4 ($19.3M). There is limited detail available on the supporting costs and Engevity understand that the majority of the cost increase is associated with replacement of RMUs.

RMUs are ground mounted HV switchgear that enable switching, isolation, and protection of the underground distribution network. Western Power plans to replace 2,025 ring main units over a 10-year period (qty 1,000 in AA5). Western Power state these units have a manufacturing defect which makes them prone to gas leaks and can lead to catastrophic failures.

Engevity believe an increase in expenditure in switchgear management is prudent however we don't have sufficient data to validate the cost and feasibility of the proposed 5-fold increase in expenditure relative to AA4.

Overhead conductors

Overhead conductors contribute approximately 18% to SAIDI and SAIFI outcomes. Conductor failures and clashing contributed to ~28% of all ground fires caused by the Dx network. The overall trend in

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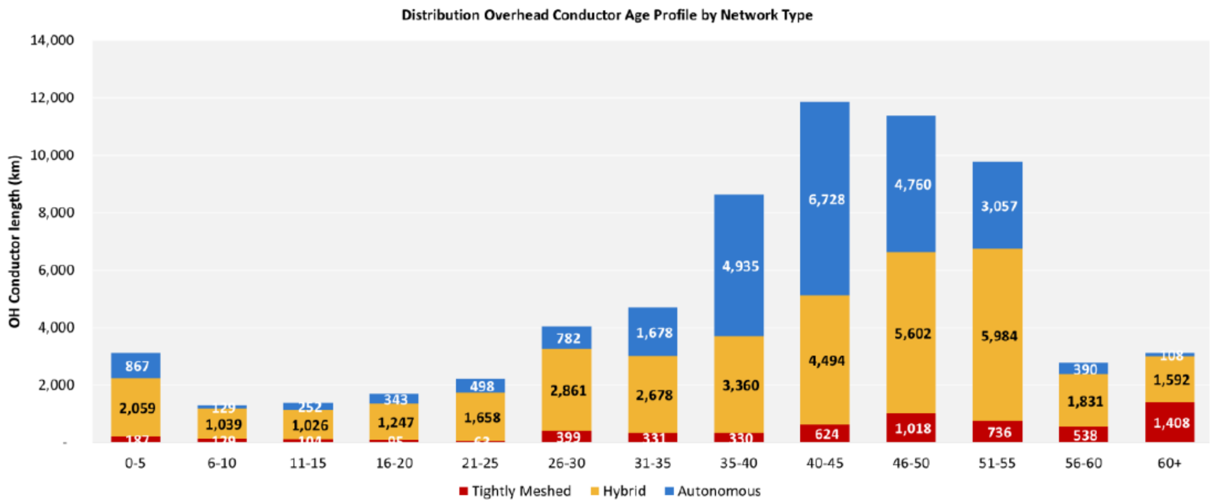
[79] Director of Energy Safety, *Order No 01-2021*, p.1.

failure rate has been stable in AA4 with a decreasing trend in the extreme and high fire risk zones.[80] The OH conductor asset population is 65,917km. The asset age profile is skewed to older assets, meaning the volume of assets likely to need treatment will increase sharply in the next 10 years.

Figure 4–10: Distribution overhead age profile



Source: Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, Figure 7.6

As part of the asset replacement and renewal CAPEX plan ($181.4m) Western Power plans to replace 1,074km, address the risk of 454km and remove 876km of OH conductor. This represents a modest decrease in the AA4 expenditure ($190.5m)[81]. In addition, a further 5,539km is proposed for removal in relation to transformational rebuilds in the autonomous network, mostly due to the SPS program.[82] In aggregate, asset removal is a key part of the treatment strategy.

Abolition of overhead conductors as part of the SPS program appears is an important part of the OH conductor asset management plan. Engevity have made a recommendation to reduce the scale of SPS roll out as well as to hold replacement expenditure (excl. SPS, AMI, Undergrounding) at AA4 levels as a result of our concern over the systemic bias toward overstating risk and failure forecasts in Western Power's project evaluations.

If this adjustment is made, Western Power's overhead conductor program would need to be adjusted to both take account of the scaled back SPS program and reprioritise replacement and compliance expenditure to best manage risk within the total allowance.

Underground cables

Underground cables AA5 forecast unassisted failure rate is 555 per year, 40% higher than asset management target (399) and 40% higher than the current rate (2020).

The unassisted failure rate more than trebled in the period 2015/16 to 2019/20 from 112 failures p.a. to 399 p.a.[83] Western Power indicated "an increasing asset failure rate within this category has also contributed negatively to reliability performance compared to the SSB."[84] Although underground circuits are less than half the circuit length of overhead cable, underground cable contributes nearly

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[80] Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, Table 7.12, p. 146

[81] Western Power, AAS Attachment 5.2 CAPEX variance report, Conductor mgmt.

[82] Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022, Table 12.6, p. 295

[83] Western Power, Attachment 8.2 Network Management Plan, Access Arrangement Supplementary, 1 Feb 2022 Table 7.18

[84] Western Power, Access Arrangement Information, p.197, para 880

twice as much to SAIDI, SAIFI than overhead. This is consistent with the inherent challenges of locating and repairing faults in unground assets and their location in densely populated areas.

The increasing rate of failure is a concern. The UG cable asset class is relatively young with 70% of UG length under 20 years (at 2020). The majority of the underground cable is XLPE and has stated MRL of 30 years. Underground cables have been known to have asset type failures (widespread manufacturing & installation issues) on other networks.

The current plan treatment is to, “Proactively replace targeted cables that have been identified to potentially fail prior to the fault occurring (using the strategy’s criticality framework, which incorporates the targeted cable testing program’s condition results). (NMP table 7.19). The success of the proposed approach to condition monitoring will in part depend on the availability of asset baseline data to assess performance changes. It is noted that previous approach to underground cable has been to replace on failure. Under this approach condition data gathering may not have been a priority. In addition, the asset management plan suggests the current data on cable type in each location is incomplete. In the longer term, Western Power proposal establishing historical performance trends will be helpful to a targeted replacement program.

For AA5 Western Power plans to “Replace ~10-20km p.a. of Dx UG cables under reactive and proactive programs” (NMP p 15). For reference, this is approximately 0.05% pa of the population of 28,274 km.

In Engevity’s opinion, based on the large contribution to reliability outcomes, there are grounds for rebalancing asset replacement effort in favour of distribution underground cable replacement. We remain concerned at the scale of the forecast failure increase and note that it may relate more to the forecasting approach rather than actual deterioration of the asset class. On this basis we note that Western Power is able to actively reallocate investment priorities within the overall CAPEX allowance to manage the most critical failure risks over AA5.

Transformer replacement and renewal

Distribution transformer asset performance data indicates the current rate of failure has only minor impact on reliability and safety outcomes. The current number of unassisted failures 233 p.a. has been fairly stable over the last 3 years and is similar to asset management target 261 p.a.

Western Power uses condition data and risk-based framework to develop the AA5 asset replacement and renewal plan (CAPEX $75.5m). AA5 forecast spend is substantially higher than AA4 actual ($42.8M) which was underspent by 34% due to lower actual failure rate than predicted. The AA5 plan will cause 2,586 transformers to be replaced out of a population of 70,523 and is forecast to result in number of failures increasing to 314 p.a., which is greater than target.

Engevity observes that the increase in forecast failures despite a near doubling of CAPEX also points to the bias to over forecasting failure rates and therefore capital program requirements. This follows a 34% underspend of the forecast for AA4 ‘due to a lower actual failure rate than predicted’, which also indicates that the historical model was quite inaccurate but has still been reused for the AA5 forecast. We have adjusted the replacement program to account for these factors which can be found in the AA5 CAPEX attachment.

Engevity supports Western Power’s plan to allow the distribution transformer asset failure rate to gradually increase is prudent until it approaches the tolerable limits. We note that many distribution networks allow distribution transformers to run to failure where it is safe to do so, and reliability impacts are acceptable. As part of its investment in distribution transformers, the asset performance and risk assessment models should be updated.

Streetlight Management

The drivers of the streetlight programs include structural failure of Dedicated Streetlight Metal Poles (DSLMP) either through corrosion, cracked weld or vehicle collision; and environmental compliance with type of luminaire to be used including shifting from mercury vapour to light emitting diode (LED).

Unassisted failure of DSLMP is on a clear improvement trend from 49 failures in in 2015/16 to 9 failures in 2019/20.

Western Power plans to invest $50.4m direct capex on streetlight replacement and reinforcement in the AA5 period. The proposed expenditure of AA5 is similar to AA4 ($49.9m). [85]

The proposed investment includes:

- planned and reactive replacement (Qty 4,500) and reinforcement (Qty 2,000) of metal streetlight poles that have failed or been identified for treatment via inspection;
- reactive luminaire replacement at end of life / failure (qty 30,000);
- streetlight cable replacement (usually reactive) (to serve 23,440 luminaires).

It is noted that the majority of the proposed asset replacements, other than DSLMP, are reactive rather than planned. The DSLMP asset is a combination of planned and reactive. The forecast number of unassisted DSLMP failures in AA5 is 9 p.a., compared to target 15p.a.

Engevity considers that the volume of asset renewal and replacements for Western Power's streetlight DSLMP renewal for AA5 could be reduced to better align forecast failure performance to Western Power's asset management targets for the asset.

Asset categories reviewed elsewhere

The remainder of the CAPEX, including the major investment programs are reviewed in detail in the forecast CAPEX attachment.

[85] Engevity notes that some reclassification of portions of streetlighting expenditure have occurred in recent periods. These result in a significant change in the total investment in streetlighting against historical levels. The Western Power AAI Submission document summarise the like-for-like public lighting expenditure.

Attachment 7: OPEX Assessment

5.1 Overview

This section presents our review of Western Power's (Western Power) proposed OPEX allowance. OPEX has a direct correlation to revenue, and it is typically passed through to customers in the year that it is incurred. For this reason, OPEX, alongside the cost of capital, have the greatest immediate effect on prices over a regulatory period.

5.2 Key observations

The quantum of Western Power's total OPEX appears consistent with other networks servicing broadly comparable geographies and customer characteristics, normalising for scale and customer density differences. This observation relies on a Partial Factor Productivity (PFP) comparison that can only be made at a macro level (and taken to be informative rather than conclusive), as the Western Power data is prepared outside the AER's data collection framework and associated reporting requirements and definitions.

As a result, there will inevitably be subtle but material differences in data specifications that mean that the Western Power's relative position is either over or understated. This includes any consideration of Operating Environment Factors (OEFs) that the AER applies as a post-modelling adjustment to its econometric analysis in order to account for geographical, jurisdictional and environmental cost drivers that are unique to individual networks.

Notwithstanding the above, our comparative assessments suggest corporate costs are currently relatively high and would move Western Power further away over AA5.

5.2.1 OPEX forecasting approach

Western Power has utilised the Base–Step–Trend (BST) methodology to estimate OPEX for AA5. The BST for AA5 provides a target OPEX view for the business to work towards that is derived from the 'revealed' historical cost of operating the business – in this case the actual expenditure in the 2020-21 year[86] (the Base), adjusted over the AA5 forecast period for upward and downward changes from OPEX programs that are expected to start or stop over the period (the Step Changes), and the changes in network scale and input costs over the outlook period (the Trend).

This approach is almost universally applied for OPEX forecasting across Australian network businesses and interacts heavily with the incentive arrangements for OPEX outperformance – such as the AER's Efficiency Benefit Sharing Scheme, and the ERA's Gain Share Mechanism.

Under 'steady state' operating conditions, where OPEX requirements are likely to be relatively consistent from one period to another, the BST approach is an effective and efficient means of forecasting OPEX requirements.

However, the assumption that Western Power's actual past expenditure should be a good indicator of the efficient expenditure the network will require in the future – due to the typically recurrent nature of OPEX from period-to-period – may not be the most suitable forecasting approach given the transformational change proposed for AA5.

To confirm whether the BST approach remains appropriate to forecast Western Power's efficient OPEX over AA5, detailed analysis would be required of its SPS, AMI, undergrounding and ICT programs to understand how these would interact with historical maintenance and operation

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86 The reported 'base' expenditure in the 2020/21 year has not been reported consistently across the Western Power submission documents or the supporting models. Engevity has relied on the audited regulatory accounts for the Covered Transmission & Distribution business to verify the base year estimates within a small margin ($1-2m). Engevity has subsequently adopted the $406.5 million value which was provided in Western Power's OPEX model as the starting point. This figure and the associated forecast aligns with the AA5 total OPEX forecast of $2,182.7 million that is included in Western Power's AA5 proposal.

activities. This would inform consideration of whether Base Year OPEX provides a robust basis for forecasting future efficient costs.

Without undertaking this analysis, it is also more difficult to assess Western Power's proposed step changes. Western Power may have an incentive to identify new costs not reflected in Base OPEX, or costs increasing at a greater rate than the rate of change, that are required to support its business transformation program. But Western Power may not have a corresponding incentive to identify those related costs that are decreasing or will not continue. Information asymmetries make it difficult for us to identify those future diminishing costs. There is a risk that including proposed step changes would upwardly bias the total OPEX forecast.

Engevity did not undertake a detailed assessment of OPEX items captured within Western Power's Base OPEX due to limited access to supporting detail.

5.2.2 Impact of the SPS transformation

Western Power is proposing to substantially accelerate its SPS deployment in the rural areas of its network, ostensibly to minimise the long-term cost to customers relating to maintaining and ultimately replacing the rural network with a more reliable and resilient electricity supply solution, whilst minimising exposure to bushfire, vegetation, wildlife and severe weather events. **Engevity is conceptually supportive of the SPS strategy but has concerns with the scale, implied unit costs, timing and deliverability of the program**, which we discuss in the SPS program review section of the forecast CAPEX attachment.

The SPS program will result in the removal of redundant network poles and wires to improve poor network reliability and performance on long rural feeders. The significant change will impact OPEX in several ways. For the transition period – which could unfold over two or more regulatory cycles the OPEX impact will be a net increase as the remaining overhead lines will still operate in parallel to the SPS deployments until the line assets can be decommissioned (i.e. after all load that was served by the line is transferred to SPS supply) and the associated OH line maintenance, inspection and emergency response activities ceased – along with any recurrent reliability compensation payments. **This anticipated transitional cost increase is not evident in the OPEX submission, reflecting an implied assumption that Western Power transitions its existing cost structure very quickly to the final state in AA5**.

5.2.3 Operation of Regulatory Incentives

Given the change in network configuration of this scale, we do not consider that Western Power's OPEX over the use of the AA4 necessarily base year represents a strong basis for setting the OPEX requirements going forward into AA5. **However, the Base-Step-Trend approach accommodates this imprecision by relying on the regulatory incentives to correct for under- and over-spends of the allowance over time.** This will occur provided that the approach is applied consistently over several AA periods. This may mean that Western Power significantly exceeds its OPEX allowance in AA5 – to the extent it cannot drive further efficiencies in the business. This would result in a higher 'revealed' cost in the Base Year for the AA6 OPEX forecast. In other words, although Western Power could instead realise operating efficiencies to offset an overspend, it may also incur a negative incentive position over AA5. Continued application of the BST approach would set the annual 'Base' OPEX requirement at a higher level for AA6. In turn this would incentivise Western Power to remove any transitional costs for its OPEX cost structure over AA6 to achieve a positive incentive position – in turn revealing the 'efficient' base OPEX that is required for AA7 (and so on).

Our reviews found that Western Power is expected to experience deliverability issues with the proposed capital program and is at risk of potentially incurring OPEX above the allowance through the transition costs arising from the reconfiguration of the network service model in the SWIS. **Putting these concerns to one side, the incentive arrangements for OPEX are ultimately self-correcting in the long term (i.e. over several access arrangement periods). This mitigates much of**

the risk to Western Power of overspending the allowance. Engevity's recommendations for the CAPEX program include significant reductions in the scope of the AMI, SPS, ICT/SCADA/Comms, Undergrounding programs and broader reductions to the remainder of the replacement CAPEX programs in AA5. We consider that this will aid Western Power's management of the OPEX associated with administering the planning, delivery, integration and operation of a substantial volume of network assets and corporate systems over the AA5 period. Instead, **it is likely that the full scope of these programs will most likely be delivered over the AA5 and AA6 regulatory periods, levelling resourcing and reducing upward pressure on labour costs for both OPEX and CAPEX program resources in the current 'tight' labour market and increasingly inflationary economic environment.**

5.2.4 Potential to Capitalise Non-Recurring OPEX Items

The change in approach to network service provision triggers the inclusion of a non-recurring OPEX allowance of $61.0 million for decommissioning and removal of network as SPS roll out occurs and a similar $7.4 million allowance in OPEX for the East Perth 66kV line removal[87]. **Engevity highlights that if there is any delay to SPS roll out or a decision is made to maintain lines in service for longer as customers get comfortable with the benefit-risk trade off from SPS relative to network supply, this OPEX allowance will not be utilised within AA5**.

5.2.5 Growth factors

The proposed Transmission and Distribution network growth factor methodology results in a greater line length at the period end than at the period commencement, which is at odds with Western Power's plans to decommission a significant portion of OH line as a result of the SPS program.

Distribution

Western Power use a network growth escalator which is based on a weighted combination of growth in customer numbers, circuit line-length and ratcheted peak demand, to escalate its indirect costs. This appears to be adapted from the AER's approach to standardise OPEX cost functions across the NEM businesses.

The indirect costs that are escalated by this cost function include items such as superannuation, regulatory fees and energy safety levy which do not exhibit a direct causal relationship with network growth. **Therefore, we recommend removing the network growth escalation from indirect costs but retaining escalation adjustments for labour costs and productivity changes.**

Engevity also notes that the final distribution network growth multiplier is overstated as it estimates a higher line length at the end of the period than at the beginning, despite the removal of lines under the SPS program over the period. Ideally the AA5 line length would align with the SPS business case (i.e. expressed net of other distribution line growth) to more accurately reflect the AA5 program.

To address this issue, **Engevity recommends the removal of the line-growth element in calculating the distribution network growth escalator**. This represents a relatively minor adjustment the overall OPEX growth function output as the line-length factor is weighted at 15% and the decommissioned lines represent a small portion of Western Power's overall distribution line length.

Transmission

Transmission connection points were previously used as part of the Transmission network growth estimation process. Historically there has been effectively zero growth in Transmission connections in recent years. Western Power is now suggesting that overall customer numbers be used to estimate network growth. Engevity is concerned that network diversity and a longer planning horizon will mean that Transmission capacity has a longer time constant than distribution and this proposal

87 Western Power, AA5 Proposal, Table 7.14, page 168.

could trigger a one-off transmission growth step that is not justified. **Engevity recommends that the current growth factors be maintained for Transmission. We have implemented this change in our alternative forecast of efficient costs.**

5.2.6 Interaction with CAPEX Recommendations

Engevity has recommended significant changes to the AA5 CAPEX, that would have an impact on the OPEX forecast. As a 'top-down' forecasting approach, the Base-Step-Trend methodology does not provide the granular detail needed to adjust OPEX categories/programs individually for each AA5 year. Engevity recommends a productivity factor of 2 per cent per annum in part to compensate for greater productivity from the proposed investments in SPS, as well as to recognise business efficiency improvements that are realised within the short depreciation life of ICT system investments. **This adjustment has been incorporated into our calculation of recommended OPEX and applied across the total of Western Power's transmission and distribution OPEX.**

For AMI, the additional meter reading cost reduction from the AMI financial analysis has been added back to the OPEX forecast to reflect the removal of the AMI acceleration scope from the CAPEX program.

5.3 Western Power's proposed OPEX

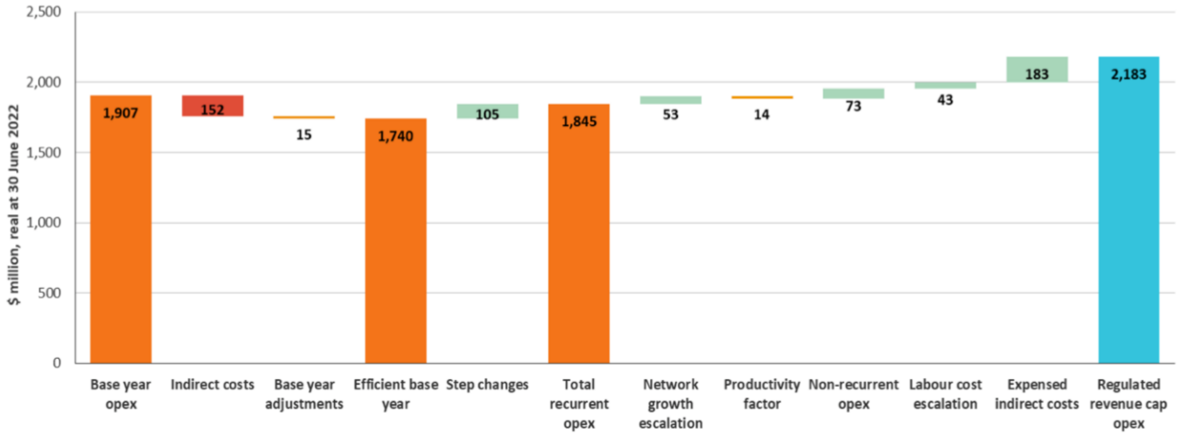
The below table shows Western Power's proposed OPEX categorised using the primary BST cost elements resulting in a total revenue cap OPEX of $2,182.7 million.

Table 5–1: AA5 proposed Tx, Dx & Corporate Total OPEX (real $ million 30 June 2022)

OPEX	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Recurrent Network Base	348.1	348.1	348.1	348.1	348.1	**1,740.5**
Recurrent Step changes	21.9	21.1	20.9	20.7	20.3	**104.9**
Total recurrent network costs	**370.0**	**369.2**	**369.0**	**368.8**	**368.4**	**1,845.4**
Network growth escalation	5.1	7.1	10.7	13.8	16.2	**52.9**
Efficiency dividend/ Productivity factor	-0.9	-1.9	-2.8	-3.8	-4.8	**-14.3**
Non-recurrent costs	10.9	18.1	13.4	13.2	16.9	**72.5**
Expensed Indirect costs	34.7	35.8	35.5	37.5	39.9	**183.4**
Labour cost escalation	4.3	6.5	8.5	10.6	12.9	**42.7**
Total revenue cap OPEX	**423.9**	**434.9**	**434.3**	**440.1**	**449.5**	**2,182.7**

Source: Western Power, AA5 Proposal, Table 7.2, page 142.

Figure 5–1: Build-up of AA5 total OPEX forecasts, $ million real at 30 June 2022



Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.4, page 141.

5.4 Engevity Recommended OPEX

The table below shows the recommended OPEX following the adjustments described above. There are no recommended adjustments related to the base year efficient costs, nor to the recurrent step changes proposed. Overall, we recommend a total reduction to the OPEX allowance of $134.4 million.

Table 5–2: Recommended AA5 Tx, Dx & Corporate Total OPEX (real $ million 30 June 2022)

OPEX	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Recurrent Network Base	348.1	348.1	348.1	348.1	348.1	**1740.5**
Recurrent Step changes	21.9	21.1	20.9	20.7	20.3	**104.9**
Adjustment to Remove Insulator Washing	*-5.3*	*-5.3*	*-5.3*	*-5.3*	*-5.3*	*-26.5*
Total recurrent network costs	**364.7**	**363.9**	**363.7**	**363.5**	**363.1**	**1,818.9**
Network growth escalation	3.2	4.6	6.7	8.4	10.1	**33.0**
Adjustment to Productivity factor	*-7.5*	*-14.8*	*-22.1*	*-29.3*	*-36.4*	***-110.1***
Non-recurrent costs	10.9	18.1	13.4	13.2	16.9	**72.5**
Expensed Indirect costs	33.1	33.0	31.3	31.8	32.6	**161.8**
Labour cost escalation	4.2	6.2	7.9	9.7	11.6	**39.6**
Add back BaU AMI meter reading costs	0.4	0.8	1.2	1.6	2.0	**5.9**
Total revenue cap OPEX	**409.0**	**411.8**	**402.1**	**398.9**	**399.9**	**2,021.6**

Source: Engevity analysis based on Western Power's OPEX model.

The following table summarises the adjustments Engevity recommend to the Western Power proposed OPEX and are based on the adjustment to the BST approach to the escalation analysis using the Western Power OPEX model.

Table 5–3: Engevity Recommendations OPEX (real $ million 30 June 2022)

OPEX	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Western Power Proposed	423.9	434.9	434.3	440.1	449.5	**2,182.7**
Engevity Adjustments	*-14.9*	*-23.1*	*-32.2*	*-41.2*	*-49.6*	***-161.1***
Recommended	**409.0**	**411.8**	**402.1**	**398.9**	**399.9**	**2,021.6**

Source: Western Power, [redacted] Engevity analysis.

Further assessment of the proposed OPEX allowance is included in the remainder of this attachment.

5.5 Historical Performance

Western Power completed the AA4 period with a reported total OPEX[88] of $2,025.1 million[89] ($real 2022) or 3.5% more than regulatory allowance[90]. Western Power is requesting an increase in the total for AA5 of $2,182.7 million ($real 2022) which represents a 7.8% increase over AA4.

We note that the AA4 total OPEX represented a 19% reduction on the OPEX spend in the AA3 period[91] which has enabled Western Power to efficiently reduce its operating costs whilst generally complying with the regulatory, reliability, safety and customer requirements that are imposed on it.

Western Power argues that AA5 period OPEX will be a slight reduction on AA4 while carrying out a higher functional load for the business. Engevity considers that the figures indicate that overall AA5 estimate is slightly higher in real terms, however the comparison of Western Power's overall OPEX values is complicated by the inconsistent presentation of values throughout the Western Power's submission and its supporting information.

The AA5 proposal employs the Base-Step-Trend approach which builds on an efficient 'Base' year (in this case 2020/21). Engevity has some concerns relating to the continuing effects of efficiency programs and the cost base applicable at the end of AA4. In addition, detailed budgets for OPEX, net of new initiatives were not provided for review – with Western Power considering it unnecessary under a Base-Step-Trend methodology. Whilst we understand the basis for Western Power's position the absence of a suitably granular OPEX report for the base year has limited our ability to resolve OPEX issues at a more granular level.

In addition, Western Power has a number of targeted programmes driven by specific circumstances, which were funded as part of the AA4 OPEX allowance. Such programmes are intended to be 'mainstreamed' as part of the AA5 period. We expect that these changes in approach would generally deliver operating efficiencies to Western Power such that there is no need to materially increase expenditure.

88 Including estimated costs for the current 2021/22 year and beyond.

89 Western Power, AA5 Proposal, paragraph 338, page 64.

90 Western Power, AA5 Proposal, Table 5.1, page 63.

91 Western Power, AA5 Proposal, paragraph 338, page 64.

During AA4 the following variations from the planned expenditure were noted by Western Power. Importantly, this included the following changes to distribution maintenance practices that resulted in both increases and decreases in the scope and cost of network maintenance:

- an **increase to SCADA and Communication maintenance costs** due to the measures supporting cyber security efforts, revised SCADA functionality and increased deployment of AMI;
- **increase to distribution preventative condition-based maintenance costs** driven mainly by an increase in vegetation management, overhead line maintenance and overhead switchgear maintenance. These increases were a result of a combination of factors including increase in hazard tree management, defect find rates, and costs for overhead maintenance activities;
- **increase to corrective emergency maintenance costs** due to responses to natural events such as bushfires and cyclones;
- **decrease to distribution preventative routine maintenance costs** mainly due to reduced insulator silicone-ing activities (as a mitigation measure for pole top fires) during a review of work practices;
- **decrease to distribution corrective deferred maintenance costs** due to process improvements that enabled transfer of OPEX to CAPEX and lower priority faults to be deferred;
- **decrease to holistic inspections costs** due to a reduction in scope as a result of the implementation of LiDAR; and
- **increase to transmission preventative routine maintenance costs.**

In addition, over the AA4 period, the risk of network instability was steadily increasing because of the impact of broader changes in the WA energy landscape resulting in both a) a rapid increase in rooftop solar uptake as well as b) the connection of largescale renewables. The increase has put additional pressure on OPEX as more complex switching, contingency planning and execution are required. For example, the following pressures on OPEX are noted:

- **Increased distribution SCADA system expenditure to respond to a large number of obsolete assets** which exhibited higher failure rates, which is also reflected in the increased CAPEX delivered during the AA4 period, and additional SCADA maintenance due to the implementation of mobile radio and AMI technologies;
- **increased metering OPEX net of meter reading costs** as a result of an increase in the AMI installation rate over the AA4 period;
- **higher than expected extended outage payments** and call centre costs as a result of an unprecedented increase in significant natural events such as bushfires, storms and cyclones during this period;
- increased network operations costs as a result of:
  - **implementation of the Generator Interim Access** (GIA) which allowed large scale renewable generation to connect to the network before constrained access implementation[92];

[92] Note that constrained access is now being implemented as part of the regulatory reform program (see Chapter 3 of WP's AA5 proposal for further details on constrained access).

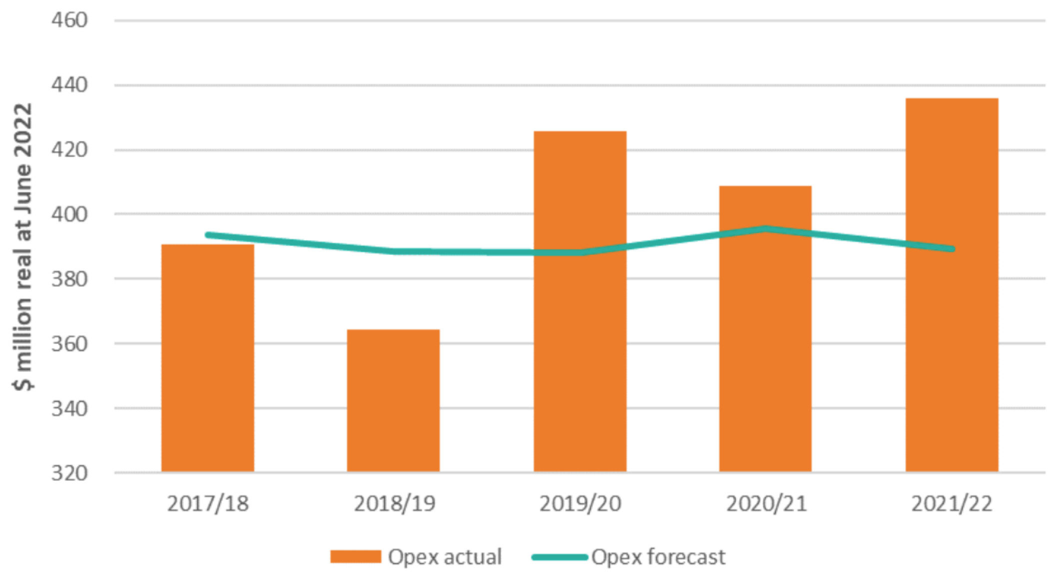
— **significant reviews of the system restart plan** in the new low network demand context. This work was done in conjunction with AEMO and Energy Policy WA to ensure there are up to date plans and procedures to restart or power up the network in the event of a system black scenario;

— **an increase in Western Power's costs to respond to industry transformation,** specifically the support of the regulatory reform program; and

— **an uplift in the cyber security capability** aligned to the further implementation of SCADA systems and changes to regulatory obligations during the AA4 period.

The figure below shows Western Powers Projected and Actual OPEX for AA4.

Figure 5–2: Comparison of AA4 forecast and actual OPEX, real $ million 30 June 2022.



Source: Western Power, AA5 Proposal, Figure 5.2, page 64.

The factors listed above continue to place pressure on OPEX, alongside the necessary duplication of some activities as the business transitions to the new systems, technologies and processes that are being implemented as part of the system transition. The upward pressure is partially offset by operating efficiencies that Western Power has achieved over AA4 however there is still an upward trend in reported expenditure towards the end of the AA4 period. These changes are largely reflected in the AA5 forecast, albeit using the base year of 2020/21 - which does not include the additional costs being incurred in 2021/22.

The overall AA4 result follows from a significant trend of reducing OPEX during AA3 and the first two years of AA4 by building operational efficiency through contemporary asset management practices. The AA4 period has also limited CAPEX to a projected $4,098.2 million ($ real 2022).[93] As such, the resource allocations were in line with historical trends.

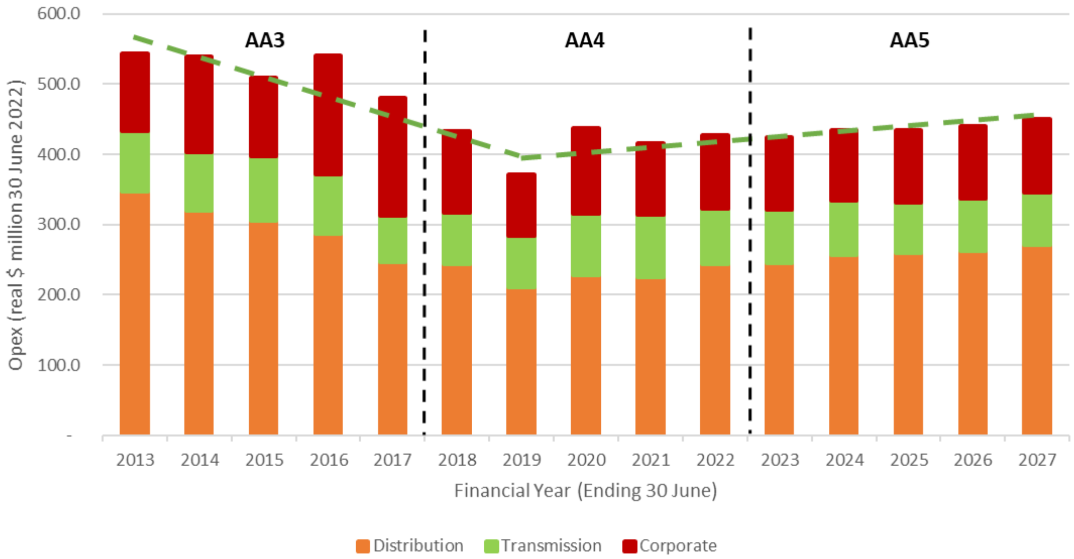
Western Power's proposed CAPEX of $5,375.6 million ($ real 2022)[94] in AA5 (recovering $4,341.1 million from tariffs and $1,034.5 million from contributions), is proposed to increase by 31.2 per cent for Transmission & Distribution combined, adding significant resource pressure on the business.

93 Western Power, AA5 Proposal, Table 5.1, page 63.

94 Western Power, AA5 Proposal, Table 8.1, page 179.

The historical OPEX trend is shown to reduce from an annual spend of some $543.0 million ($ real 2022) at the beginning of AA3 to an annual forecast total of $426.7 million ($ real 2022) in 2021/22. The below graph highlights the comparison between the actual OPEX in AA3 and AA4, and the proposed OPEX for AA5. Historically, OPEX was trending down at a relatively consistent rate until 2018/19. However, it has since been trending upwards – eroding the greater efficiencies Western Power achieved during AA3 and the early part of AA4. Western Power's assertion that OPEX has been trending down over AA3 through to AA5 does not align with this upward trend from the second year of the AA4 period. Given the strong efficiency gains that Western Power achieved over AA3, it is important that future productivity growth targets place appropriate incentives on Western Power to ensure that past OPEX efficiencies are retained through the network transition over AA5 and beyond.

Figure 5–3: AA3 & AA4 historical & AA5 forecast OPEX, including indirect costs & escalation.



Source: Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.2 {real $ million 30 June 2022).

5.6 Regulatory Framework

Western Power operates under an Access Code which allows Western Power discretion over the approach for forecasting OPEX. Accordingly, Western Power has proposed the Base-Step-Trend methodology for its AA5 OPEX forecast.

OPEX is expenditure that is generally incurred each year for the following:

- Operating & maintaining the physical network and digital assets that comprise and support Western Powers network and delivery of services to customers;
- Responding to faults and emergencies;
- Performing customer related functions; and
- Performing corporate support services.

From an accounting perspective, OPEX is expenses that are incurred, and the benefits 'consumed', within a single accounting period. This is in contrast to CAPEX, where the investment is made to deliver benefits to customers for the life of the asset. A portion of the original value is expensed each year through depreciation to spread the initial expense across the asset's useful life.

The incentive arrangements for OPEX are intended to ensure that Western Power's OPEX reflects the annual cost of efficiently minimised service provision costs. Accordingly, Western Power has emphasised that efficiencies achieved during the AA4 period are embedded into the AA5 forecasts as well as expected further productivity improvements. We note that relying on these assumptions does not provide assurance that the full benefits that were promised in business case documentation for AA4 investments were fully realised by the 2020/21 base year.

The BST methodology involves selection of the most efficient year of the proceeding period and, following adjustment for non-recurrent costs and any inefficiencies, is taken as an efficient 'revealed cost' base from which to forecast future OPEX. This efficient OPEX is then adjusted annually to allow for:

- Expenditure that is not recurrent in nature in the efficient base-year cost;
- OPEX associated with one off issues and step changes in the forecast period; and
- Changes to output and cost input trends over the forecast period.

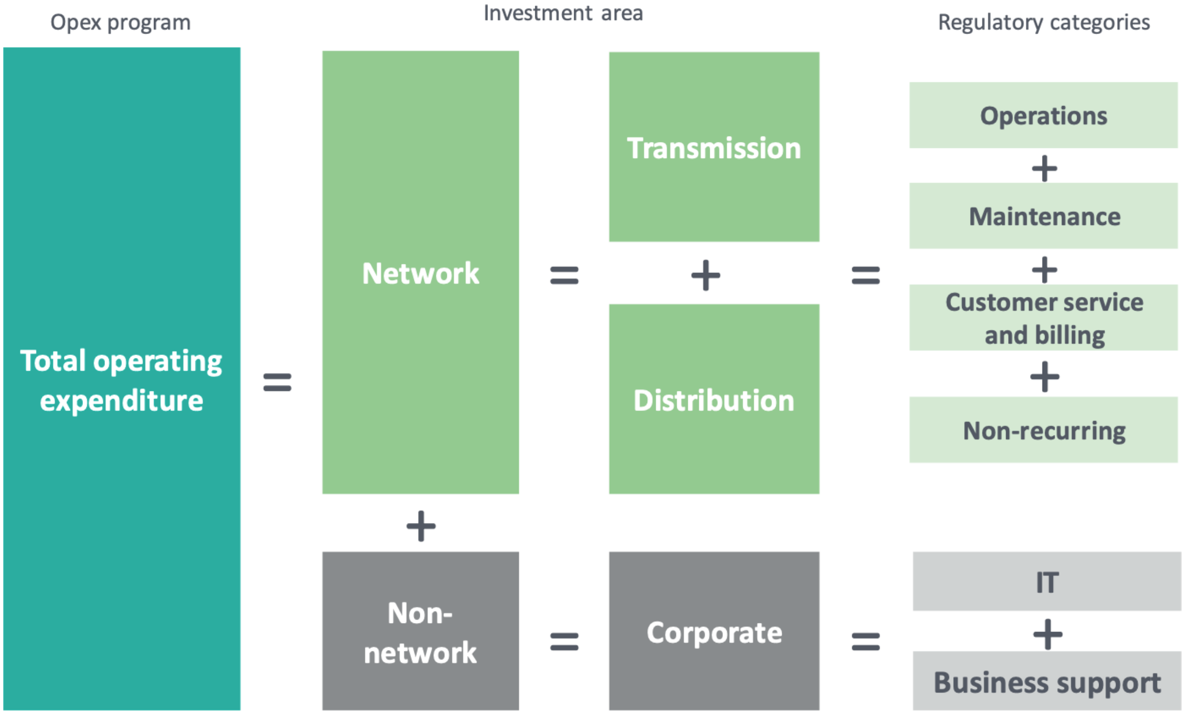
Western Power's regulated OPEX is split into the categories shown in the figure below which show a illustrative build-up of total OPEX.

Western Power is required to meet the Access Code objective to promote efficient investment in and efficient operation and use of services provided by electricity networks in Western Australia for the long-term interests of consumers in relation to:

- Price, quality, safety, reliability and security of electricity;
- The safety, reliability and security of covered Networks; and
- The environmental consequences of energy supply and consumption, including reducing greenhouse gas emissions, considering land use and biodiversity impacts and encouraging energy efficiency and demand management.

In this regard it is important to establish the efficient base year and adjust not only for the known additions but to consider the net effect of Western Power's new strategies such as SPS & AMI roll-out on overall OPEX. There is considerable flow on effect to OPEX from Western Power's CAPEX proposals, especially the strategic programs and the supporting expenditure required to support contemporary digital network operation.

Figure 5–4: Regulatory OPEX categories.



Source: Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.1, page 136.

Western Power has nominated 2020/21 as the base year for expenditure that best reflects current operational norms. Engevity highlights that the projected activity in AA5 is unusual for Western Power as a transmission and distribution network business. This means that the expenditure in AA4 is unlikely to represent a strong basis for the cost of operating the network in AA5 due to the scale of technology, investment, operational and service delivery changes that are expected to occur – as well as the management of transition issues as Western Power reconfigures the SWIS electricity supply model. As such we would typically recommend against the use of BST in these circumstances, however the forecasting method is at Western Power's discretion.

This base year is then adjusted for step changes in recurrent and inefficient OPEX in order to produce a base spend from which to forecast total annual expenditure. The scale escalation is expressed as a function of network and customer growth to calculate a network growth factor, which is net of any projected productivity improvements.

Importantly, adjustments are applied for non-recurrent OPEX, allowing for the effect of material new programs is to be embedded in the forecast. The forecast increase to the base annual OPEX for labour cost escalation has then been applied, and the calculated network growth factor added.

Justification for the relative weighting of the growth function parameters for Western Power (these are the statistical regression coefficients for each variable in the AER's OPEX benchmarking function[95]) are not evident in the data provided but appears to mirror the approach taken by the AER for the NEM businesses.

Engevity, while accepting of the approach proposed by Western Power is well attuned to the effects of strategic programs and the overall required funding envelope. Our attention is also focused on the adequacy of labour escalation factors due to the influence of the changing skills mix in AA5 and the price escalation impacts arising from recent geopolitical events.

5.7 Base Year and Western Power's Benchmarking Performance.

Engevity understands that the 2020/21 year is the lowest cost OPEX year in AA4, however we highlight certain discrepancies in relation to the base year reference numbers.

The quantum of these differences and their overall effect on Western Power's base-year estimate to be $348.2 million ($ real 2022)[96].

While it is likely that Western Power would expect the nominated base year would be deemed efficient as a result of applying approved costs onto the previously efficient base year in the AA4 period, Engevity has tested this proposition against regulatory accounts and Western Power's own figures included elsewhere in the AA5 submission document package.

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95 The AER's OPEX function is derived from the NEM businesses historical OPEX performance from 2006 and informed by publicly available international data from New Zealand and Canadian (Ontario). It is primarily based on the parameters of Customer Numbers, Historical Maximum Demand, Energy Throughput, Circuit Length and Percentage of Underground. Engevity notes that the very strong correlation between Customer Numbers, Demand and Energy, (with typical R^2 values of 0.9 or higher), the cost function is heavily weighted to customer numbers (as the number of customers ultimately drives the demand and energy parameters – and all three parameters are correlated to the point that they are statistically indistinguishable from one and other). In previous regulatory processes for the NSW distributors, these parameters were calculated as accounting for approximately 80% of the explanatory power of the benchmarking function. There is also a further correlation between customer numbers and line length (by feeder type) that is not considered in the AER's approach – but is broadly reflected in customer density and asset intensity measures.

As a result, challenges arise with the application of the network growth factor to Western Power's proposed reduction in circuit length over AA5 from the SPS program. The low explanatory power attributed to circuit length means that there is a very limited impact on the OPEX growth calculation from the application of the AER's function. This leads to the situation where the cost function implies that Western Power will have a higher line length at the end of AA5 than the start – despite the proposed decommissioning of a significant volume of assets through the SPS program. Whilst we recognise the logical inconsistency, the actual impact on the OPEX calculation by correcting for the actual length was found to be immaterial due to the low explanatory power that is attributable to circuit length in the AER's OPEX function.

96 See also Western Power, AA5 Attachment 7.8 – Operating Expenditure Model, 'BST calcs' sheet, Cell J35.

We have also made a comparison to other Australian networks using high-level benchmarks to establish the relative OPEX efficiency of Western Power. Western Power contends that AA4 efficiencies are carried over into the AA5 period however we have not been provided with evidence that proposed benefits for AA4 were fully realised in the nominated base year or whether benefits that were to be realised in the AA5 period from AA4 investment are fully reflected in the forecast.

Noting our concerns over the systemic overstatement of risks, failure volumes and costs in Western Power's Access Arrangement forecasting that is discussed in our CAPEX review, we emphasise the importance of reconciling promised and delivered benefits across regulatory periods. This should be captured in post implementation reviews, benefits realisation assessments and other retrospective analysis of project performance/success that are undertaken as part of Western Power's routine investment governance and assurance activities.

How Do We Make Comparative Assessments?

Our review has drawn on the Australian Energy Regulator's (AER) Regulatory Information Notice (RIN) data and included the equivalent data for Western Power against the benchmark comparators shown below. The analysis shows that Western Power's benchmarks as a reasonably efficient operator against a group of 'target peer' distribution businesses operating in the National Electricity Market (NEM).

We note that these measures do not directly consider service performance outcomes which is one area where Western Power lags the Eastern States, particularly given the poor state of its wood pole network in the 2000's and continuing legacy of managing the very large, reinforced pole population that remain in service. Western Power's unassisted pole failure rates remain at levels that are multiples of the NEM distributors and the very high rural SAIDI is an outlier against the other Australian networks.

An Accelerated Network Transformation – Can it be delivered?

Engevity is concerned that Western Power is embarking on a significant network transformation agenda without a reasonable assessment of the deliverability of the proposed program that considers the WA market capability and capacity in areas such as SPS, AMI, SCADA, Communications, ICT and undergrounding, where the volume of work that is proposed for several of these categories is much higher than has previously been delivered by the workforce of the necessary specialist personnel available in Western Australia. Furthermore, the labour market and broader economic conditions are such that attempting to deliver additional work in these areas will place upward pressure on already inflationary indicators on labour markets and the general economy.

It is likely that the proposed AA5 OPEX will be under pressure as Western Power moves to progress the transformation of the SWIS, and with it, several areas of its business operations. Engevity remains unconvinced that adequate allowance had been made for the new programs, their interaction, overall level of change and rapid realignment of the nature of the asset base and network operations during the period. Sustained management of the network and associated business transformation activities will be required to manage the downside risk to the OPEX spend.

Our Observations and Issues

We highlight the following examples of OPEX spend requiring consideration during our review:

- **Expensing the network removal**, the use of the current unit rate of $19.5 thousand / km as the average throughout the program does not reflect the scale economies that will be realised during the network roll out and annual maintenance activities.
- **The adequacy of SCADA OPEX allowances** for the costs of operating and licencing the new system, including costs of decommissioning the old system.

- **SPS maintenance**, while the business case lays out OPEX costs these are based on a small number of installations in AA4, the majority of which had not been delivered at the time of preparing Western Power's AA5 forecast. It may be that significant scale factors apply as either efficiencies or inefficiencies or that actual installation numbers are subsequently constrained to align with the OPEX estimates. There is also a concern that OPEX savings may not be fully built into forward estimates given their relative absence from the 2020/21 base year. The limited existing experience with SPS assets within Western Power and the industry more broadly, also suggests there is a potential OPEX increase depending on the transition period, speed of roll out and organisational change achieved.
- **Undergrounding** – the undergrounding programme is extensive and is dependent on local government support, which is not guaranteed. Should the rates of undergrounding fall short of those nominated, OPEX requirements would notionally increase – however, we are not able to verify or reconcile the OPEX benefits from the undergrounding program against the base year costs at a level of granularity that is meaningful.
- **AMI** will be similar with OPEX increasing from $104 million in AA4 to $112 million in AA5 net of reduced meter reading costs.[97] Engevity has not sighted evidence that this OPEX is fully inclusive of all system operational costs for full AMI roll out support.
- **Telecommunications OPEX** may not be adequate to support the required communications functionality for full AMI deployment nor a fully functioning DNMS system given the scale of the SCADA/ICT/Communications CAPEX proposed by Western Power.
- **Increases in LiDAR frequency** should deliver reduced maintenance and patrol cost, but this is not evident in the step changes or cost trends applied by Western Power.
- **Network growth calculations** appear to be based on the AER's peer performance measures from its econometric OPEX benchmarking. These growth functions have some logical inconsistencies when applied to Western Power's AA5 proposal (such as implying a higher line length at the end of the period than the start - despite Western Power proposing to remove significant overhead line under the SPS program).
- **The AER benchmarking data** for 2020 shows transmission average productivity at around 1.7per cent and average distribution productivity at around 1.2%. The OPEX index for 2020 in the AER data supports the view that a that substantially higher rate of productivity should be applied than Western Power's proposed 0.25 per cent. p.a.

Table 5–4: Productivity Growth AER Data Averages 2006 to 2020.

Period	TFP Index	PFP Index OPEX
Growth Rate 2006-2020	-0.6%	0.3%
Growth Rate 2006-2012	-2.1%	-3.5%
Growth Rate 2012-2020	0.4%	3.1%
Growth Rate 2020	1.2%	5.1%

Source: Economic Insights, Economic Benchmarking Results for AER's 2021 DNSP Annual Benchmarking Report, extract from Table 2.1, page 11.

- From the AER productivity data summarised in the table above, Engevity highlights that Western Power's proposed 0.25 per cent p.a. OPEX productivity factor is far lower than the

97 Refer to 'DX_Inputs' sheet of Regulatory Model, Actual AA4/Forecast AA5 Real FY22

AER’s measured productivity growth rate over the past 10 years (which has continued to improve, with 5.1 per cent p.a. reported for 2020 and 3.1 per cent p.a. for 2012-2020).

- Noting that the industry productivity growth has been improving at a rate of over 3.0 per cent p.a. since 2012, we consider that Western Power’s proposed rate is well below industry expectations. We also recognise the material OPEX reduction that Western Power achieved over AA3 continue to provide benefits as total OPEX has remained relatively consistent. However, **Western Power’s significant investment in ICT, SCADA and AMI in AA4 should be delivering significant benefits, we cannot verify that the productivity benefits associated with these programs are actually embedded in the AA5 OPEX** forecast (noting that the impact of the full benefits from the investment cases had not been fully realised in the 2020/21 base year).
- The base-step-trend approach does not provide transparency over these costs, and we have not been able to obtain information at a sufficient level of detail from Western Power to verify that the productivity gains from AA4 investment are reflected in the proposed AA5 OPEX forecast. **Engevity considers that a more aggressive productivity target of 2.0 per cent p.a. over AA5 would address both the issue of the low productivity factor proposed by Western Power, as well as ensuring that a material allowance for efficiencies for AA4 investment is embedded in the forecast**.
- **Western Power also intends to expense Indirect cost against OPEX of $183.4 million (real $ 2022)**. While the Western Power OPEX model provides a link back to the cost categories in the base year, no commentary that identifies the specific programs that underpin this expense has been sighted.

Western Power claims that its OPEX forecasts are overseen with a robust expenditure governance framework. However, Engevity has not sighted OPEX governance documents that demonstrate the implementation of the governance frameworks. Similar observations have been made in other external reviews of Western Power’s governance over its OPEX program (for example AMCL’s recent review of the asset management system for the ERA). However, we recognise that the practice used by the businesses is that OPEX budgets are updated annually based on the investment planning cycle (shown in the Network Management Plan) and business outlook. This is then approved as part of the budget cycle. Significant increases in OPEX are subject to a governance process which would continue to control OPEX levels over AA5.

We also note that OPEX components related to the transmission and distribution networks reflect maintenance, repair and operational expenses which should be relatively stable from year to year. This is not necessarily the case for the SPS and other strategic initiatives as implementation is in an early phase and largely absent from the 2020/21 base year.

5.7.1 Benchmark comparisons

Benchmarking of electricity distribution business operational and economic performance is difficult because of the different environments in which each business operates. A large range of issues impact on the CAPEX and OPEX required to provide reliable electricity distribution services, including:

- **Geographic differences** including vegetation types, proximity to ocean environments, mountain versus desert terrain, soil types;
- **Climatic conditions** including average rainfall, prevailing winds, flood prone areas, temperature, humidity, diurnal and seasonal variations in temperature;
- **Customer differences** including load profiles, energy requirements, the number of customer connections, the density of connections, the development history of the network;

- **Jurisdictional regulatory** differences including voltage standards, customer performance targets and codes, safety standards, the responsible regulator, industry funded contributions, planning standards, differences in government policy; and
- **Operational requirements and restrictions** including depot location, fleet availability, staff numbers and skill mix, equipment supply availability, access to emergency resources from other networks for recovery from major storm or bushfire events etc.

To allow a reasonable comparison to be made between businesses, several partial factor productivity measures have been used to normalise some of these metrics against some key 'scale' measures of the businesses. This treatment enables a meaningful assessment of comparative performance to be made, noting that accounting and performance data definitional issues mean that comparisons can never be taken to be entirely accurate.

The normalised measures that we have used are as follows:

- Customer density measured as customers per circuit km or route km;
- CAPEX, OPEX or Totex per circuit km or route km;
- CAPEX, OPEX or Totex per customer;
- Reliability metrics such as SAIDI, SAIFI, MAIDI and similar; and
- Full-time Equivalent (FTE) staff numbers per circuit km or route km; and,
- FTE per customer number or customer density.

We recognise that Western Power's operating environment does differ from the NEM networks, however there are certain networks that share similar physical, socio-economic, natural threats and operating environments. We have identified Powercor (Vic), SA Power Networks (SAPN – SA)) and AusNet Services (AusNet - Vic), to form a 'target peer group' on the basis that they are all mixed urban-rural networks of comparable scale that serve both coastal and inland areas. Engevity's expectation is that Western Power's outcomes should be broadly similar to these businesses when considered over the range of PPIs. The following figures (and those in the Appendices) explore some of these normalised metrics to understand where Western Power compares to its eastern state peers.

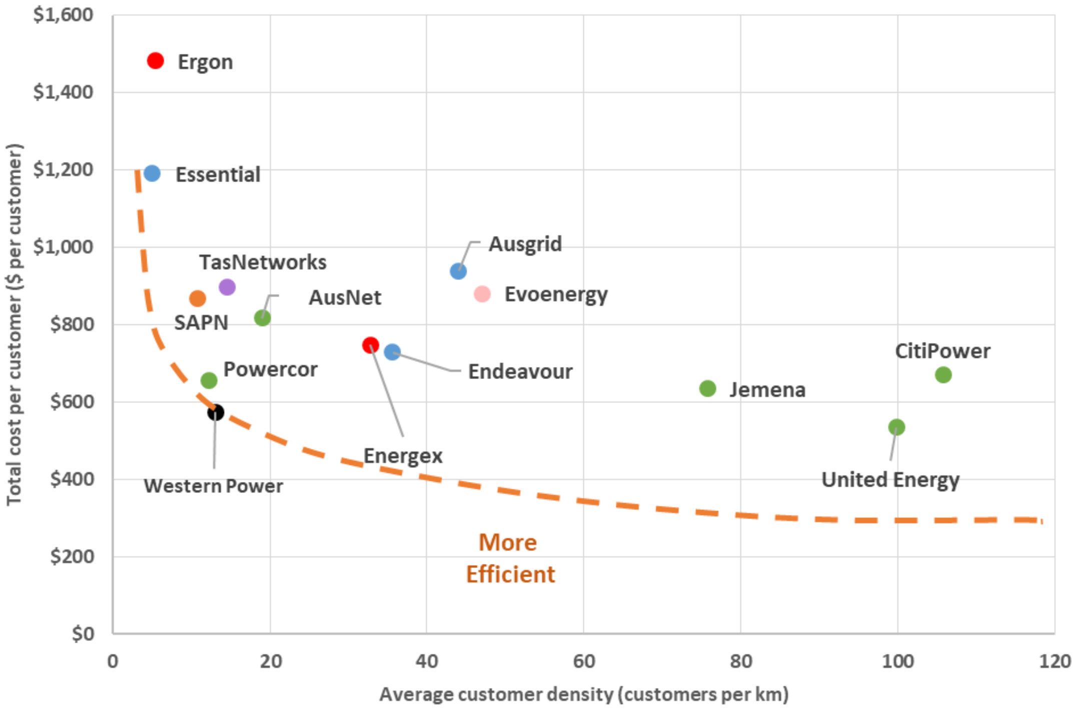
The figure below shows the relative performance of Western Power compared to the other Australian distribution businesses. Here the total expenditures per customer are compared to the 5-year average customer density per circuit km of distribution network. The different circumstances and influences on the NEM DNSPs provide variation in outcomes and a spread of performance.

A conceptual 'efficient frontier' has been generated where more efficient businesses have a lower total cost either per customer or per circuit km[98], although at low customer density other network factors affect the cost per customer or per circuit km observed. Nonetheless Western Power appears to benchmark close to the 'target peer group' as one of the more efficient networks in the analysis.

The figure indicates that on a Totex basis Western Power demonstrates cost efficiency close to or better than the 'target peers'.

[98] Not that an SFA analysis has not been possible to generate this efficient frontier. Unless indicated otherwise the efficient frontiers in these figures are manually generated.

Figure 5–5: Total CAPEX plus OPEX cost per customer versus 5-year average customer density (real $ 2022)



Source: AER RIN Data 2013 to 2021, adjusted for ABS CPI data and RBA forecast CPI, Western Power's AA5 application.

One area where there is a concern with OPEX efficiency relates to two particular cost categories shown in Western Power's Regulatory Financial Statements:

- Corporate (or Business support); and
- Other OPEX (or Non-recurring expenditure).

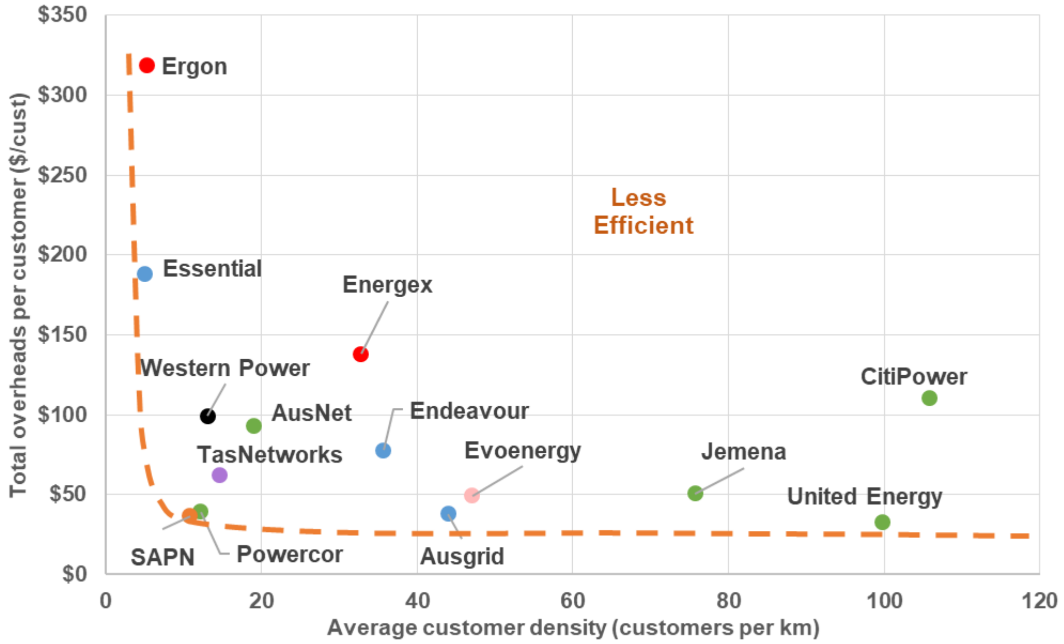
Engevity highlights that these cost categories are the Western Power overhead expenditure categories that capture costs not related to operations and maintenance of the transmission and distribution networks, including the customer service and billing functions of Western Power's business.

The AER's RIN reporting information on overheads categorises these as:

- Corporate overheads; and
- Network overheads.

While there may be definitional differences between the AER's RIN reporting information and Western Power's treatment of overheads, a broad comparison of these costs for the whole business provides a measure of relative efficiency between Western Power and the 'target peer group'. Figure 5–6 below shows that Western Power's overhead costs compare reasonably with AusNet but are about twice per customer compared to SAPN and Powercor.

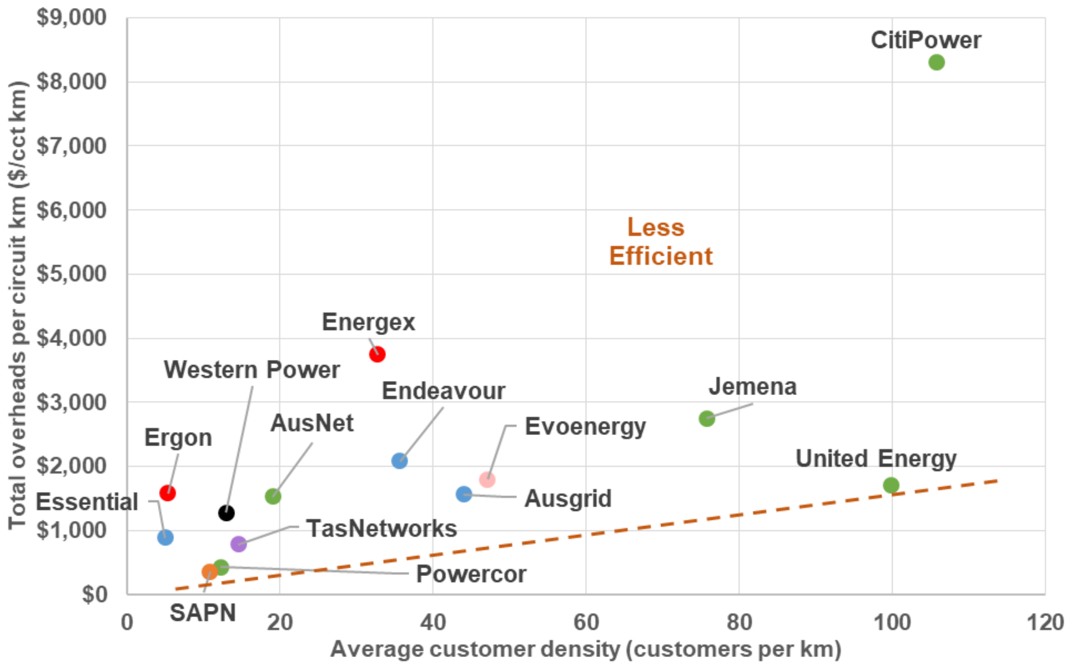
Figure 5–6: Corporate cost per customer versus 5-year average customer density (real $ 2022)



Source: AER RIN Data 2013 to 2021, adjusted for ABS CPI data and RBA forecast CPI, Western Power's AA5 application.

The following figure shows that Western Power's overhead costs per circuit km are lower than AusNet's but again about twice those for SAPN and Powercor.

Figure 5–7: Corporate cost per circuit km versus 5-year average customer density (real $ 2022)



Source: AER RIN Data 2013 to 2021, adjusted for ABS CPI data and RBA forecast CPI, Western Power's AA5 application.

Western Power has not provided a breakdown of the business support or non-recurring expenditure costs and therefore it is difficult to assess whether the efficiency differences seen on a PFP basis have a legitimate activity need which drives the observed unit cost outcomes.

As a general comment, Western Power's overheads seem to be related to preparing for and early implementation of the transition to SPS deployment, higher AMI penetration and SCADA costs (which are identified in its OPEX model). The corporate overheads may be higher than would have otherwise been expected due to these transitional arrangements. With the available information, it is difficult to further unpack the costs and benefits related to its new SPS, AMI and Undergrounding strategies to OPEX.

5.8 Forecast OPEX

The AA5 proposal for OPEX is based on the base-step-trend approach. The forecast OPEX for AA is shown in the table below.

Table 5–5: AA5 forecast OPEX including indirect costs and escalations, real $ million 30 June 2022

OPEX category	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Transmission	74.8	77.7	72.9	73.6	74.4	**373.5**
Distribution	245.7	255.8	258.8	262.9	270.7	**1,293.9**
Corporate	103.4	101.3	102.6	103.6	104.5	**515.4**
Total OPEX	**423.9**	**434.9**	**434.3**	**440.1**	**449.5**	**2,182.7**

Source: Access Arrangement Information for the AA5 Period (1 February 2022),

Western Power is forecasting a total OPEX spend for the AA5 period of $2,182.7 million (real $ June 2022) which represents a $157.6 million increase on the AA4 period expenditure ($2,025.1 million real $ June 2022[99]).

There are a number of assumptions which underpin the OPEX forecast including the proposed new functions, network growth and systemic cost increases.

OPEX is naturally two segments, system OPEX which includes distribution, transmission & corporate costs and new incremental OPEX associated with expanded AMI, Undergrounding, SPS, SCADA developments & supporting IT. The OPEX associated with the latter functionality will have savings which will incrementally reduce the overall OPEX when comparisons are made with AA4 and AA3 periods. An example of this saving relates to the removal of existing rural lines where savings associated with reduced pole inspection, line maintenance and emergency response should logically result in a decrease in OPEX going forward.

In addition, savings will be made from major structural adjustments such as depot rationalisation, removal of on-call functions and the like in SPS areas, once the roll-out has achieved a scale which warrants rationalisation. However, this will initially be offset by the proposal to expense the decommissioning of lines with a total cost of some $61.0 million for distribution decommissioning, $7.4 million for 66kV removal associate with the East Perth substation, and $4.1 million for the regulatory reform program. These are a total of $72.5 million non-recurring costs.[100].

5.9 OPEX Base Year

Western Power has proposed the base year of 2020/21, the year it believes is representative of the normal expenditure for major functions of Distribution, Transmission & Corporate. The real OPEX direct expenditure for the 2020/21 year was $372.2 million (nominal $ June 2021) including Business

99 Western Power, AA5 Proposal, Table 5.1, paragraphs 334 & 338, pages 63 & 64.

100 Source: page 168, Section 7.7, non-recurrent OPEX, 2 components.

Support allocation but excluding indirect expenditure, and before base year efficiency adjustments and escalation to real $ 30 June 2022[101].

In order to establish the correct expenditure reflective of an efficient base year Western Power has made the following adjustments;

- **Removal of non-recurrent expenditure** on design costs not otherwise accounted for in projects;
- **actuarial adjustment costs**, correction of unintentional payments;
- regulatory reform costs; and
- indirect costs.

For this process Western Power proposed a direct cost value of $348.1 million as the starting point for the BST. The base value of $348.1 million is built up as shown in the table below.

Table 5–6: Base recurrent (revenue cap) OPEX for 2020/21 (real $ 30 June 2022)

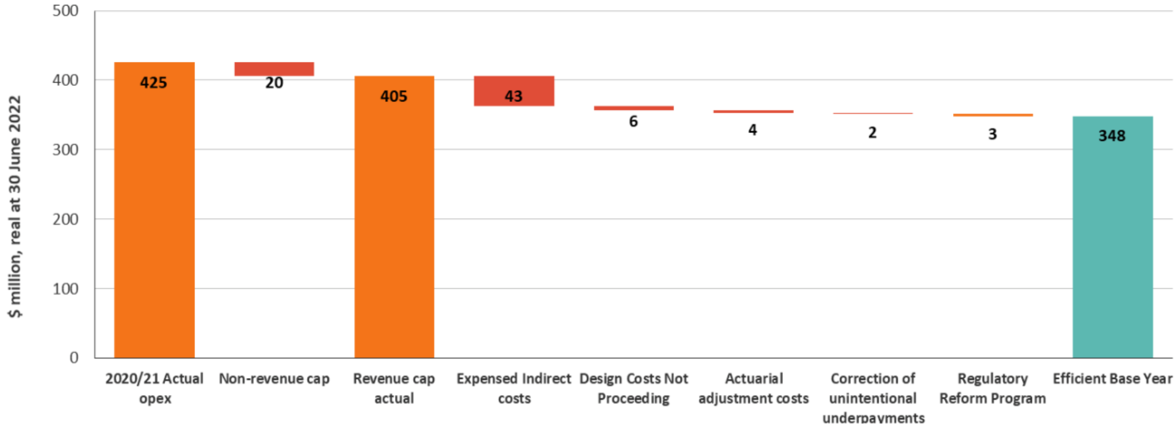
Cost Category	Transmission ($m)	Distribution ($m)	Total ($m)
Preventative Maintenance	35.1	65.5	100.6
Corrective maintenance	10.3	66.2	76.5
Operations	13.4	19.0	32.4
Customer service & billing	0.0	37.1	37.1
Other	1.9	6.3	8.2
Corporate costs	22.2	71.2	93.4
Total	**82.9**	**265.2**	**348.1**

Source: Western Power, Access Arrangement Information for the AA5 Period, 1 February 2022, page 144, Engevity analysis & allocation of Corporate costs in proportion to other direct transmission and distribution cost ratio.

A waterfall chart representation of the derivation of the efficient base year from the nominal actual 2020/21 OPEX is shown in the following figure.

[101] See Western Power, AA5 Attachment 7.8 – Operating Expenditure Model, 'BST calcs' sheet, Cell G35.

Figure 5–8: Determination of efficient base year, $ million real at 30 June 2022



Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.5, page 144.

This efficient base year is seen in the table above from which step-changes and escalations are required to be added to develop the BST forecast. Table 5–7 expands on this information by providing the base-step-trend on the cost category breakdown in the base year, to develop the forecasts of OPEX by cost category over AA5. Western Power's OPEX model calculates the base-step-trend forecast in this manner.

Table 5–7: AA5 forecast OPEX including expensed indirect costs and escalations

TXN						
Financial Year (Ending 30 June)	2023	2024	2025	2026	2027	Total
SCADA & Communications	10,754	10,738	10,863	10,991	11,110	54,457
Non-revenue cap services	0	0	0	0	0	0
Network Operations	4,444	4,444	4,496	4,520	4,545	22,449
Operations Total	15,199	15,182	15,359	15,512	15,655	76,905
Preventive Condition	14,338	14,316	14,483	14,654	14,812	72,601
Preventive Routine	28,364	28,320	28,650	28,988	29,301	143,622
Corrective Deferred	10,690	10,673	10,798	10,925	11,043	54,130
Corrective Emergency	1,312	1,310	1,326	1,341	1,356	6,645
Maintenance Total	54,704	54,619	55,256	55,909	56,512	277,000
Business Support	29,623	28,807	29,141	29,299	29,458	146,328
Corporate Total	29,623	28,807	29,141	29,299	29,458	146,328
Non-recurring Opex	4,880	7,925	2,309	2,216	2,240	19,570
Other Total	4,880	7,925	2,309	2,216	2,240	19,570
Total	104,406	106,532	102,065	102,935	103,864	519,802

[$ million real at 30 June 2022]

DXN						
Financial Year (Ending 30 June)	2,023	2,024	2,025	2,026	2,027	Total
Reliability Operations	1,750	1,766	1,787	1,820	1,847	8,970
SCADA & Communications	11,304	11,401	11,540	11,750	11,929	57,925
Non-revenue cap services	0	0	0	0	0	0
Network Operations	11,774	11,895	12,039	12,181	12,300	60,188
Operations Total	24,828	25,062	25,366	25,751	26,077	127,083
Preventive Condition	42,007	42,972	44,117	45,546	46,993	221,636
Preventive Routine	42,471	42,839	43,360	44,150	44,821	217,641
Corrective Deferred	10,954	11,049	11,183	11,387	11,560	56,134
Corrective Emergency	73,198	73,832	74,730	76,092	77,249	375,102
Maintenance Total	168,630	170,692	173,390	177,176	180,624	870,513
Call Centre	5,592	5,650	5,718	5,785	5,842	28,587
Metering	3,245	3,273	3,313	3,374	3,425	16,630
GSL Payments	3,591	3,628	3,672	3,715	3,752	18,357
Distribution Quotations	5,078	5,122	5,184	5,279	5,359	26,022
Metering Corporate	20,712	19,646	19,110	18,535	17,688	95,692
Customer Service Total	38,219	37,319	36,997	36,687	36,066	185,288
Business Support	73,816	72,541	73,418	74,284	75,014	369,073
Corporate Total	73,816	72,541	73,418	74,284	75,014	369,073
Non-recurring Opex	14,028	22,732	23,018	23,285	27,905	110,967
Other Total	14,028	22,732	23,018	23,285	27,905	110,967
Total	319,521	328,346	332,190	337,183	345,685	1,662,925
					Total	2,182,727

Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.4, page 146.

5.9.1 Misalignment of Base Year

The total expenditure in 2020/21 of $425 million (nominal $ 2020/21) in the above waterfall chart represents OPEX including non-recurrent (or non-revenue cap) OPEX. The 'revenue cap actual' at $405 million (nominal $ 2020/21) in this figure does not precisely match the numbers in the regulatory accounts which is slightly higher, at $411 million (nominal $ 2020/21). On the basis of Western Power's submission data in its OPEX model, the revenue cap actual is $399.1 million (nominal $ 2020/21) which is escalated[102] to $406.5 million (nominal $ 2021/22) and this is the value Engevity has used to verify the efficient base year of $348.1 million.

While the base year is 2020/21 from which the BST is escalated, there will be no impact on the starting point for the forecasts should Western Power overspend in 2021/22 and therefore no impact on the forecast AA5 OPEX.

Consistent with the ERA's Final Decision on the framework and approach, Western Power has set its SSTs at the average annual level of performance achieved in the AA4 period, with adjustments where appropriate to the relevant measure and where individual penalty caps applied during the AA4 period.

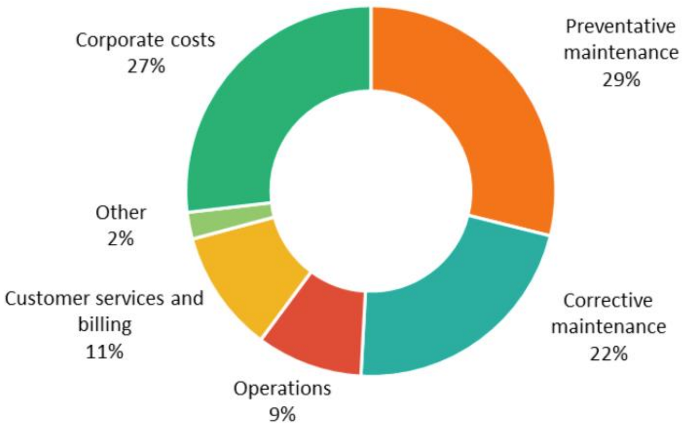
5.9.2 Recurrent OPEX Categories

The majority of OPEX in the 2020/21 base year (60%) is spent on recurring functions in support of the Western Power network.

102 The approved regulatory escalation rate is 1.840% to move 2020/21 to 2021/22 dollars.

The figure below shows the principal breakdown to the recurrent expenditure by category. Noting that Corporate Costs are projected to be 27 per cent of total.

Figure 5–9: Forecast base year recurrent OPEX by category



Source: Western Power, Access Arrangement Information for the AA5 Period, 1 February 2022, page 145.

Preventative maintenance expenditure relates to the routine activities required to maintain Distribution and Transmission assets in a state to perform their full functionality and may involve inspection, monitoring or invasive techniques to ensure asset functionality and integrity. A major benefit of this activity will accrue to Western Power's asset management system thereby tracking asset performance and continuing status as a predictor of remaining life. Analysis of such data is a major input to life cycle decisions such as asset retirement and/or replacement.

Corrective Maintenance is required to rectify any reasonable defect which will affect asset functionality, safety or performance. Corrective maintenance levels may indicate that individual assets or a class of assets require replacement or refurbishment. Such indicators may be utilised to propose CAPEX for a change of strategy where the opportunity is taken to provide the required functionality in an entirely different way e.g., SPS strategy which will have flow on effects to pole& line maintenance as well as the organisation of Western Power's regional resources.

Corporate Costs are costs in support of the activities of running the Western Power business. Further discussion of these costs is provided below.

Following the recurrent OPEX methodology described, Western Power has submitted the base year spend of $390.9 million including expensed indirect costs as previously noted. This is based on the Synergies Economics report which shows an inflation rate for 2020/21 of 1.75%[103] – consistent with WA Treasury statistics at the time the proposal was prepared. A slightly higher rate of 1.84 per cent was applied in the regulatory model, however recent inflation measures indicate a significantly higher value would apply in practice. Given the current economic and geopolitical uncertainties, we expect that inflation assumptions will be revisited as part of Western Power's revised proposal.

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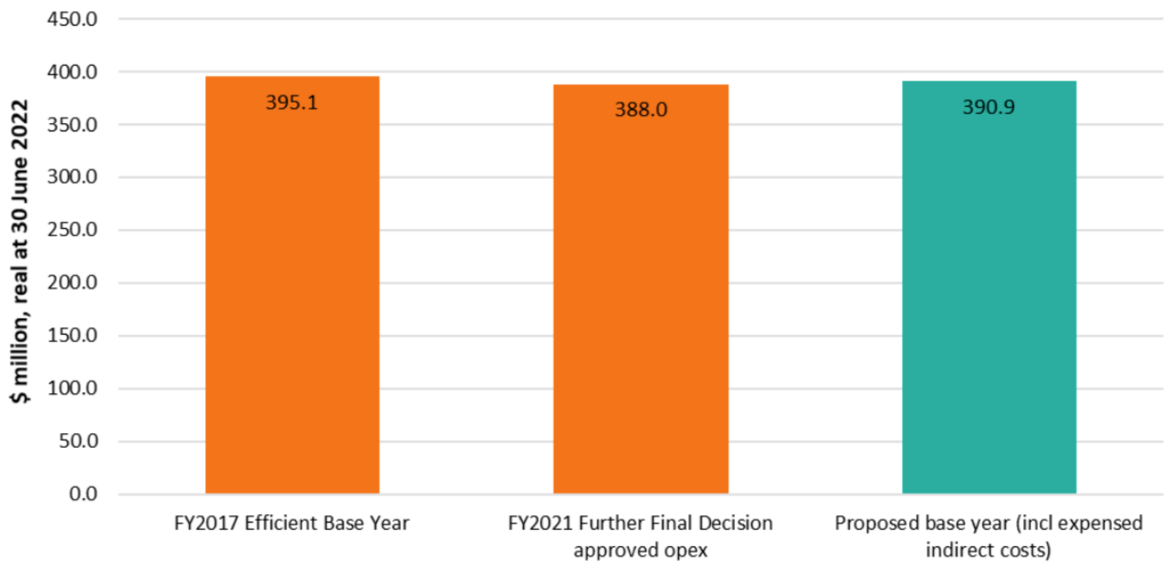
[103] Source: WP Proposal, page 146. Attachment 7.3…

Figure 5–10: Efficient base year compared to AA4 OPEX, including expensed indirect costs, $ million real at 30 June 2022



Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.7, page 146.

5.9.3 Step changes during AA5

Having established the roll forward base year, the effect of OPEX step changes over the outlook period is taken into account. Western Power is proposing 11 new step changes which will affect proposed expenditure in the roll forward base year, they are summarised in the following table.

Table 5–8: Proposed OPEX Step Changes, $ million real at 30 June 2022

Step Change	Description	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Repair streetlight faults	Additional volume of streetlights to repair, and additional cost due to increase in labour and LED material costs	4.5	4.5	4.5	4.5	4.5	22.7
DSO capability	Develop the necessary internal capability within Western Power to Operate its DSO function as stipulated in the DER roadmap, including processes to ensure compliance of new DER devices connecting to the network meet technical standards	4.4	4.4	4.4	4.4	4.4	21.8
Meter reading	Less manual meter reading as a result of the acceleration of the AMI deployment	-0.8	-2.1	-2.8	-3.6	-4.5	-13.9
Silicone treatment program	Changing the approach to our silicone treatment program to maintain the safety and reliability of the Western Power Network and our workforce	5.3	5.3	5.3	5.3	5.3	26.4
Digital substation	Support for installation of devices and additional resources to analyse and prosses the data associated with new digital substation program	1.0	1.0	1.0	1.0	1.0	5.0
SCADA and Tele-communications	Cyber security, SPS and AMI implementation	3.9	3.9	3.9	3.9	3.9	19.5
SPS maintenance	Inspections and emergency response aligned with increase in SPS volumes	0.2	0.7	1.3	1.8	2.4	6.4
Governance and safety assurance	Increased Safety, Environment, Quality & Training (**SEQT**) training program & increased focus on compliance & governance	0.8	0.8	0.8	0.8	0.8	3.8
Light Detection and Ranging (**LIDAR**) program	New strategy to survey one-quarter of the network each year rather than the full network each 3-4 years. Shifted from non-recurrent to recurrent expenditure	1.2	1.2	1.2	1.2	1.2	6.1
Distribution power quality monitoring	New system to be developed to improve data accessibility for the low voltage network's power quality meters	0.4	0.4	0.4	0.4	0.4	2.2
HV injection unit and emergency response generator	New strategy to deploy additional emergency response generators as part of fault response	1.0	1.0	1.0	1.0	1.0	5.0
Total value of step changes		**21.9**	**21.1**	**20.9**	**20.7**	**20.3**	**104.9**

Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.4, page 146.

In total the proposed step changes to OPEX for the AA5 period amount to $104.9 million.

The proposed step changes are described below:

- **Streetlight repairs ($4.5m p.a):** Additional volumes of streetlights to be serviced. Western Power has not provided evidence to demonstrate the proposed cost is efficient.
- **DSO capability ($4.4m p.a.):** Western Power has not provided evidence to demonstrate the proposed cost is efficient.
- **Meter Reading ($4.5m p.a. by 2026/27):** While it is clear savings can be achieved by remote readings rather than manual reads, Western Power has not provided evidence to verify the forecast saving.
- **Silicone Treatment Program ($5.3m p.a.):** This program was justified in AA4 and has increased in cost due to the decision to conduct the procedure while de energised which will incur substantially higher switching and planning costs in addition to lowering the daily unit rate of completions. We note that the move away from live line work is not required under the Energy Safety Order 01 – 2021 which instead recommends improved equipment testing, compliance and work practices for live line insulator washing. This is largely consistent with the Victorian Electricity Supply Industry guidelines[104] and recent awareness publications involving washing equipment condition[105]. On this basis, we do not consider that the step change is efficient.
- **Digital Substation ($1m p.a.):** The concept of such substations is well known in other utilities. Details relating to Western Power's planned implementation are not clear beyond equipment condition monitoring. Condition monitoring may prevent failures and assist in overall system performance. There may be savings in the reactive and planned maintenance categories. However, these targeted savings are not noted by Western Power[106].
- **SCADA & Telecommunications ($3.9m p.a.):** Both programs of expenditure are coupled with major CAPEX spends proposed in the AA5 period. Additionally, they build on previously approved programs from AA4. Western Power has not provided evidence to demonstrate that the proposed cost is efficient.
- **SPS Maintenance ($2.4m p.a. by 2026/27):** Cost estimations here are seen to ramp up reflecting the ambition to install approximately 1,800 SPS units in the AA5 period. Total estimated expenditure is projected to be in excess of $6.4M with built-in additional expenditure planned for the next period. While the strategy is self-evident in terms of reliability improvement it provides Western Power with several OPEX savings in the areas of pole maintenance, replacement, line patrols, fire mitigation, emergency response and line hardware maintenance. It is not clear if the estimates are net of these benefits.
- **Governance & Safety Assurance ($0.8m p.a.):** Engevity has examined these programs and it appears that much of the proposed AA5 activity is consistent with broad industry practice.
- **LiDAR program ($1.2m p.a.):** LiDAR is a sophisticated inspection methodology used by the majority of DNSP's and TNSP's as a cost-effective way to inspect geographically spread assets. The proposal here is for additional costs to increase the frequency of inspections. This should

104 Victorian Electricity Supply Industry, *VESI Fieldworker Handbook,* updated 2008, pp. 15-16

105 Victorian Electricity Supply Industry, *VESI HV Live Work Committee & VESI Work Practices Committee – Awareness Bulletin Live Work Equipment*,

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

result in improvements in reliability and cost savings associated with corrective maintenance, but these do not appear to have been included in the proposal.

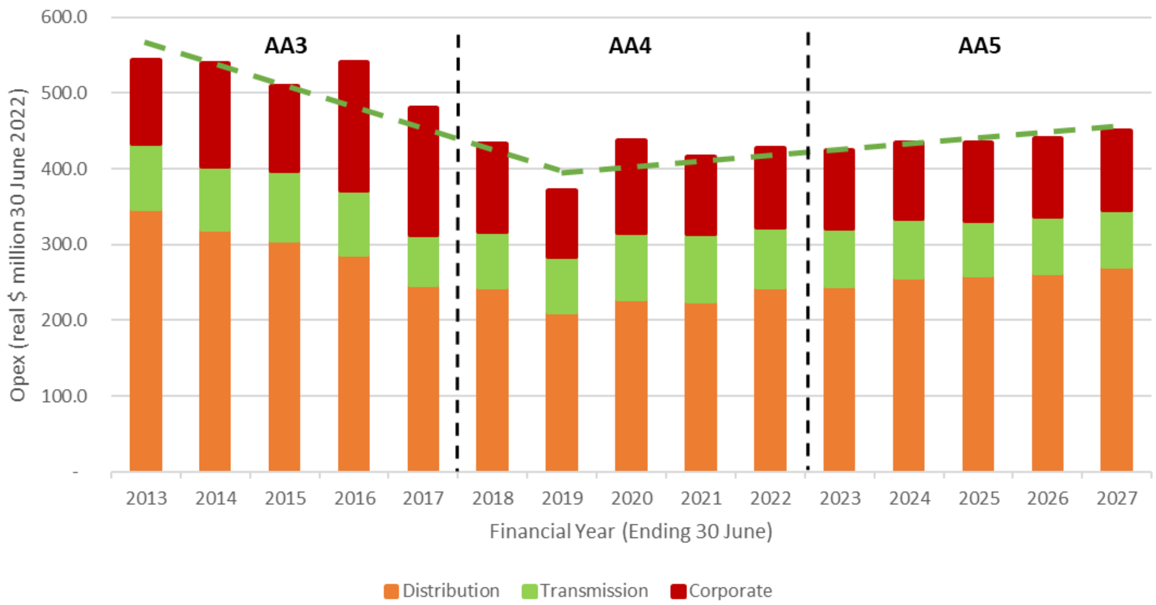
- **Power Quality ($0.4m p.a.):** Large local demand variations attributable to local generation will expose Western Power connections to unacceptable voltage variations and increasingly power quality issues. Investments in Power Quality monitoring are prudent and necessary. At a system level Western Power is investing heavily in control and monitoring equipment (e.g., AMI) as well as SCADA in order to manage these issues. While the overall strategy seems necessary it is not clear how the information will be focused, and the measured effects managed in real time. Nor is it clear how the OPEX associated with the initiative will be offset if at all by actions taken as a result of the information gained.
- **High Voltage Emergency Generator ($1m p.a.):** In recent periods many DNSP's have utilised High Voltage generators to provide local network support in the event of outages or as a temporary augmentation to local load carrying capacity. It is assumed that this is the Western Power strategy. Such equipment is available from the market on a hire basis, and it appears that Western Power intends to pursue this strategy along with an ownership strategy. Long term supply contracts with service providers may be more efficient.

In summary, Western Power has not provided sufficient information to demonstrate that the proposed step changes are efficient expenditure and that any offsetting savings have been incorporated in the proposal.

5.10 Trending Base Year

The overall trend of final projected OPEX proposed by Western Power is illustrated below.

Figure 5–11: AA3 & AA4 historical and AA5 forecast OPEX, inc. indirect costs and escalations



$ million real at 30 June 2022

Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.2, page 137.

Western Power has proposed the following changes to account for Network Growth and Productivity benefits.

5.10.1 Network Growth

Distribution Network Growth: Western Power provided a KPMG report on the AER's historical approach to calculating the network growth factors for the NEM businesses. This approach has since been updated by the AER, which addressed the factors identified in the KPMG report and adopted by Western Power. We note the logical inconsistency between the calculated escalation rate for network scale (reflecting an increase in circuit kilometres over AA5 in the network growth formula) against the reduction in actual circuit km over AA5 that is proposed by the end of the AA5 period (due to line decommissioning following the SPS program).

Transmission Network Growth: The escalation factor in the BST is based on customer numbers, circuit length and ratcheted maximum demand. Western Power is proposing a compound annual growth rate of 0.3 per cent. The weighting on customer numbers is 24.1 per cent which drives the largest contributing factor to 1.5 per cent[107] Western Power is proposing a change to the AA4 period methodology in dealing with customer numbers. Western Power has proposed to substitute the overall end-user customer numbers rather than the approach in AA4 which utilised the number of Transmission connections (a much lower and effectively stable number).

This appears reasonable, however it may introduce a modest upward movement in the escalation of forecast OPEX as overall customer numbers grow at a lower rate often reflecting economic conditions, while transmission connection points often move in a lag effect as transmission capacity is taken up and the network is re arranged to give the required capacity. It is recommended that consistent practice be adopted with other TNSP's in the NEM. **For this report, Engevity has returned this growth element back to the number of transmission connections in the OPEX model for this Draft Report.**

5.10.2 Corporate & Indirect OPEX growth

Western Power proposes that the growth factors discussed above apply to the corporate and indirect costs as well. We highlight that accepting this proposal would effectively exclude corporate costs from productivity improvements by including them in the cost and scale escalation rather than treating them as a cost category that is largely independent of network scale.

Western Power notes that the treatment is consistent with the AER's application of the methodology.[108] If accepted by the ERA this to the NEM businesses. In total Western Power's proposal would lead to a total network growth escalation of $52.9 million.

In practice, this should be at least partially offset by the specific productivity factor that is applied to capture the expected rate or productivity improvement over the AA5 period. In this regard, Western Power has proposed a productivity improvement factor that is well below reported industry productivity trends.

5.10.3 Productivity Improvements

Western Power's proposal includes a productivity growth factor of 0.25 per cent – which it says reflects expected industry-wide improvements in finding more efficient ways and is consistent with the AER's methodology for forecasting productivity growth.[109] This translates to a reduction of $14.3 million to Western Power's base OPEX for the AA5 period.

Western Power engaged Synergies to forecast OPEX productivity estimates for its AA5 proposal. Synergies used a Multilateral Total Factor Productivity model to generate productivity estimates

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107 Source: Table 7.8, pp. 164; 167

108 WP proposal, p. 167.

109 WP proposal, p. 163.

using data from the AER's 2019-20 Benchmarking Regulatory Information Notices.[110] Synergies selected what it considered to be the five most comparable networks – namely, SA Power Networks (SAPN), Powercor, AusNet Services, Essential Energy and Ergon Energy. Synergies stated these distributors have similar network characteristics to Western Power, including rural network segments.[111] Synergies noted the most recent productivity growth factor applied by the AER was 0.5 per cent per annum.

Synergies suggests a range for the productivity growth factor of 0 to 0.5 per cent per annum based on its productivity analysis for the five NEM distributors, combined with its scan of regulatory precedent.[112] Consistent with Synergies' recommendation, Western Power applied the mid-point of the identified range, which results in a 0.25 per cent per annum productivity adjustment over the AA5 period.[113] Synergies stated the AER's current assumption of 0.5 per cent productivity growth is at best an upper bound for the recent productivity trajectories of the five NEM comparators it considered are of most relevance to Western Power.[114]

Engevity's assessment

Engevity considers, on balance, Western Power should be able to target an efficiency improvement across the AA5 period of 2 per cent per annum. This assessment is based on more recent benchmarking data and a holistic assessment of Western Power's OPEX forecast. This translates to a reduction of $110 million to Western Power's base OPEX for the AA5 period.

We have used the most recent data available from the AER's 2021 benchmarking reports to generate the productivity estimates (see Table 5–9 below). This data may not have been available to Synergies at the time of its assessment.

The average productivity of the five distributors selected by Synergies is now between roughly zero and 2.6 per cent per annum over a five and 10 year period, respectively.

There is significant variability in this data from year-to-year, which suggests longer time periods provide a more robust basis to forecast future productivity growth. Engevity notes productivity changes for NEM transmission networks are less stable and do not show a strong trend over time relative to distribution OPEX productivity. So, we have not sought to rely on the transmission data. These NEM productivity trends are shown in the tables below.

110 WP proposal, pp. 167–168.

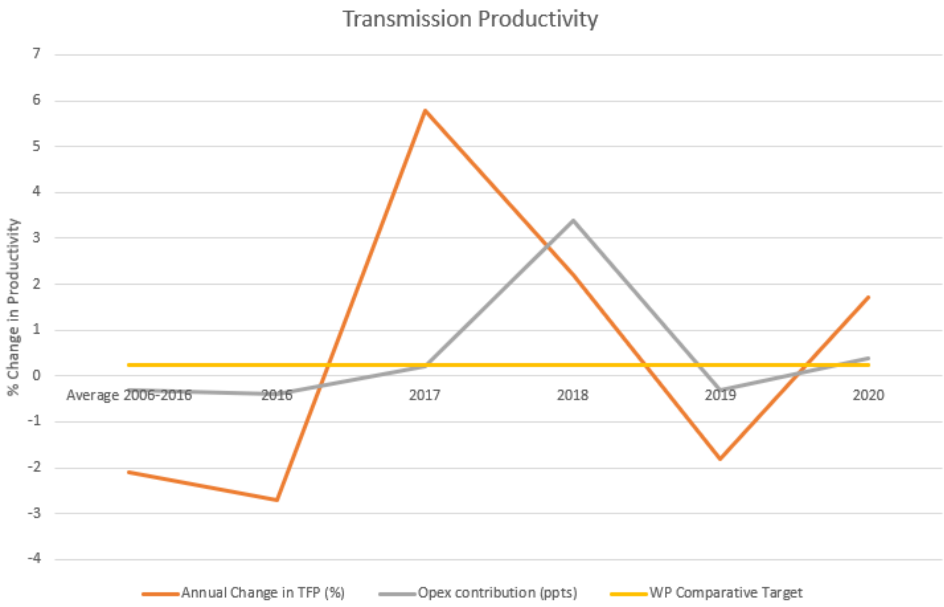
111 WP proposal, attachment 7.3, p. 39.

112 WP proposal, attachment 7.3, p. 40.

113 WP proposal, p. 168.

114 WP proposal, attachment 7.3, p. 40.

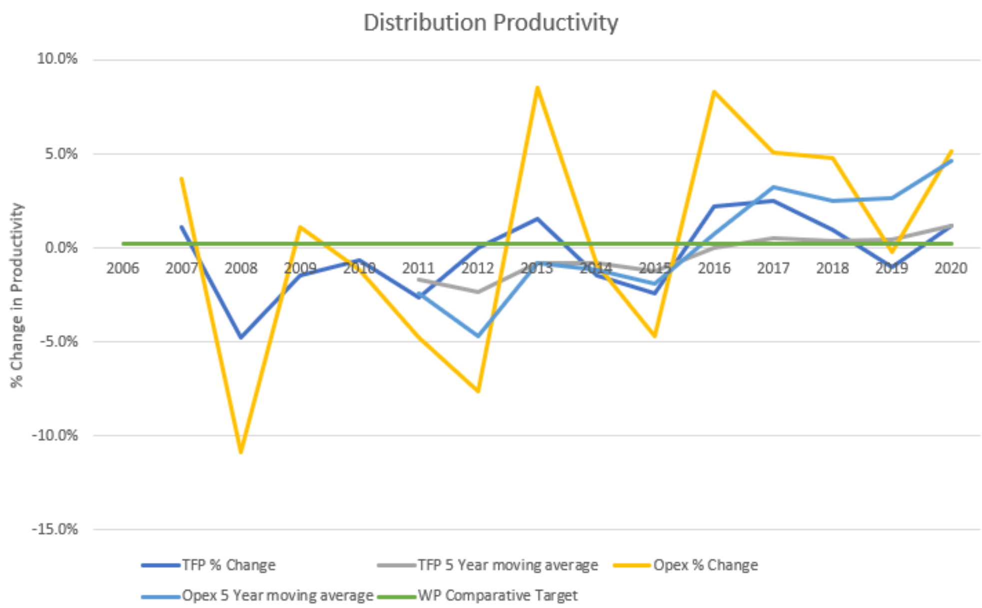
Figure 5–12: NEM actual Transmission efficiency progression over time



Source: AER 2021 Transmission Benchmarking Report and supporting data files; Engevity Analysis.

The year-to-year variability in the above transmission productivity data may reflect the lumpier nature of, and longer planning and delivery time frames for, transmission network CAPEX projects. This would impact OPEX and productivity as the higher cost projects add capacity in larger increments and attract a greater proportion of overheads during high investment periods. This is often followed by a more modest augmentation program as the new capacity is taken up by customer demand.

Figure 5–13: NEM actual Distribution efficiency progression over time



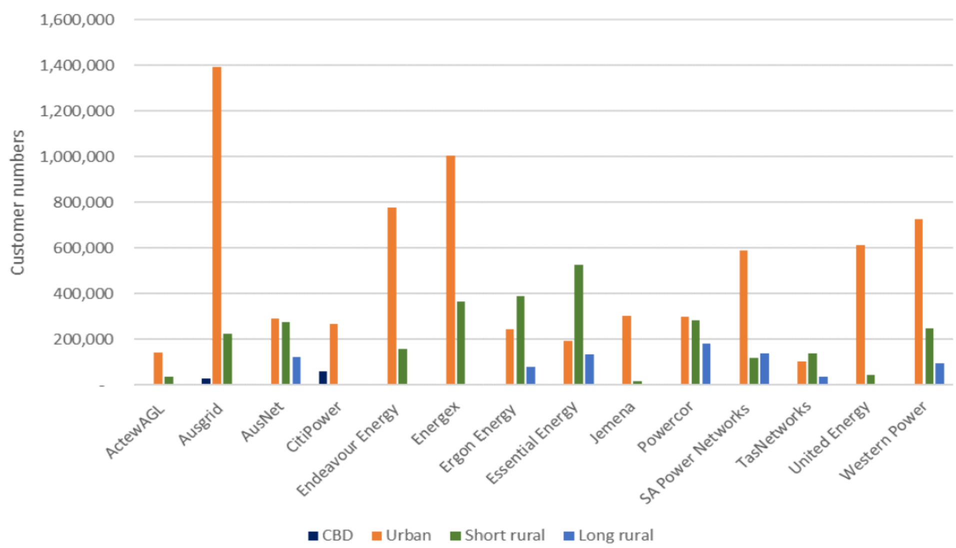
Source: AER 2021 Benchmarking Report and supporting data files; Engevity Analysis.

Synergies and Western Power depart from the AER's methodology to forecasting productivity growth. The AER considers the productivity growth factor should only capture the productivity growth that would be achieved by a distributor on the 'efficiency frontier', so it bases its estimate on the highest ranked distributors in the NEM. This helps to control for the scope for other distributors' performance to include an element of 'catch-up productivity'.[115]

Of the five networks selected by Synergies, only Powercor and SAPN are at the efficiency frontier. The average productivity of these two distributors is now between roughly zero and 4 per cent per annum over a five- and 10-year period, respectively. Synergies considered the other frontier networks – Citipower and United Energy – were not comparable given they are Melbourne-based urban distributors with no rural network segments. But Synergies (and Western Power) did not base their forecast on just the Powercor and SAPN data, nor did they reconcile their departure from the AER's methodology by including the non-frontier distributors. Synergies only stated: "we consider it more appropriate for Western Power's productivity growth factor to be informed by data from those networks that bear the closest resemblance to it (noting that even these comparators are imperfect)."[116]

Engevity accepts it is difficulty to make like-with-like comparisons between Western Power and the NEM distributors. The figure below summarises the NEM distribution network characteristics related to customer connections by feeder type and location, and also includes Western Power. It is noted Western Power's spread of customers seems highly comparable to Endeavour Energy's profile, except it does not have a long-rural category. Synergies did not include Endeavour Energy in its analysis. Endeavour Energy has achieved an average productivity growth of 7 per cent per annum from 2016 to 2020, and 2 per cent per annum over 2006–20 (Table 5–9).

Figure 5–14: NEM DNSP customer connection distribution by feeder type



Source: AER 2021 DNSP RIN data (various); Engevity Analysis

Finally, it is noted there may be scope for Western Power to achieve greater OPEX efficiencies than what it has included in its base OPEX forecast. Western Power's forecast does not identify 'CAPEX–OPEX trade-offs' that are expected from its proposed SPS and AMI capex programs. For example, the reduction in long-rural distribution feeders from the SPS program will lower inspection and repair costs, and smart meters do not require remote reads. These efficiencies are expected to be

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

116 WP proposal, attachment 7.3, p. 39.

significant – taking into account our recommendation to scale these programs back for AA5. We were unable to undertake a detailed assessment of whether these activities are captured within base OPEX to explicitly make this adjustment. This information was not made available to us despite several requests.

Based on the above factors, Engevity considers, on balance, Western Power should be able to target an efficiency improvement across the AA5 period of 2 per cent per annum. This outcome is more consistent with Western Power's stated approach to estimating the productivity growth factor – using the most recent benchmarking data available and distinguishing between movements in the efficiency frontier versus 'catch up'.

Table 5–9: NEM DNSP's actual OPEX efficiency outcomes over time, figures are in per cent

Year	EVO	AGD	CIT	END	ENX	ERG	ESS	JEN	PCR	SAP	AND	TND	UED	AVG
2007	-1	19	-9	**-6**	-3	29	-10	-2	14	5	-15	-2	7	**1**
2008	-2	-30	9	**-18**	-3	-8	-15	29	4	-2	2	0	2	**-2**
2009	-2	10	-17	**13**	1	1	3	-7	-12	-7	-16	-13	2	**-6**
2010	-10	-7	-7	**7**	2	5	0	-13	8	-4	12	-15	-3	**-2**
2011	-13	5	12	**-3**	-7	-15	-1	3	-1	-18	-3	13	-19	**-4**
2012	1	-8	-22	**-4**	-4	1	-20	-11	-16	1	-3	-10	-3	**-8**
2013	-7	28	5	**11**	-7	29	12	3	-7	-7	-10	27	13	**5**
2014	-11	-11	-3	**-8**	9	3	15	2	8	-5	-5	-7	-3	**-1**
2015	8	-14	6	**-3**	-3	-16	-1	0	-2	1	-3	24	8	**1**
2016	85	11	0	**-5**	15	-2	26	-5	19	18	-13	-7	-11	**8**
2017	-12	13	6	**14**	2	17	-2	-3	-3	-14	22	-23	10	**0**
2018	-12	19	15	**11**	-1	-4	-2	10	-6	5	3	8	25	**5**
2019	4	6	-10	**6**	7	-4	-13	-4	5	-4	-2	13	1	**0**
2020	7	10	4	**11**	5	-3	3	17	8	15	-2	-2	-3	**5**
Average 2006-2020	3	4	-1	**2**	1	2	0	1	1	-1	-2	0	2	**0**
Average 2016-2020	14	12	3	**7**	6	1	2	3	4	4	2	-2	4	**3**
Average 2006-2016	-4	-1	-3	**-1**	-2	3	-2	1	-1	-4	-4	2	0	**-2**

Source: AER 2021 Distribution Annual Benchmarking Report and Supporting Data Files

5.10.4 Non-Recurrent OPEX

Western Power has removed $14.6 million of non-recurrent OPEX from the 2020/21 actuals to establish the efficient base cost. However, going forward in AA5 it is proposing $72.5 million on non-recurrent spend, most of which is associated with line removal. There are three components, the removal of redundant lines from the SPS programme, the removal of the 66kV lines associated with rationalisation as part of the East Perth substation project, and the $4.1 million for the regulatory reform program.

The largest proportion of the spend is associated with removal of overhead lines following installation of SPS. It is not clear where the ongoing benefits of line removal which will clearly offset some of these costs are counted or if these estimates are net of those costs. Similarly, it is expected that there will be some cost savings accruing from the 66kV line removal. Of the $72.5m some $68.1 million is in line decommissioning[117].

Depending on how the SPS programme is viewed, this may not be non-recurrent expenditure but may need to be treated as a separate project which spans several regulatory periods. There is a question as to the programme cost efficiency, which will clearly change with scale economies. Western Power has not set out how these costs and benefits will be incurred/realised or provided information on its cost estimate for de-commissioning and OPEX savings over time.

The 66kV component is a separate matter and associated with the East Perth substation, this cost is required to facilitate the transfer of land to Development Western Australia. As such, the cost could be netted off against any payment for the land, and likely is better treated as a CAPEX.

5.10.5 Real Labour, productivity and growth escalation rates

Western Power has adopted Synergies Economic Consulting Pty Ltd (Synergies) recommendations on forecast labour and productivity rates which feed into the escalation factors used in the BST calculation within Western Power's OPEX model. The following Table 5–10 shows the Synergy recommendations. Engevity has also adopted the labour escalation rates in our recommendations but substituted an alternative productivity factor.

Table 5–10: Synergies Recommendations on Escalations

OPEX Category	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Labour cost	0.88%	0.77%	0.77%	0.77%	0.77%	0.77%
Productivity	-0.25%	-0.25%	-0.25%	-0.25%	-0.25%	-0.25%

Source: Synergies Economic Consulting, Forecast cost escalators for Western Power's 2022-27 regulatory period, 4 October 2021. Real Labour escalation from Table 9, page 32 (positive = cost increase), Productivity from Table 12, page 40 (negative = productivity improvement or cost reduction).

Synergies has also recommended Western Power use the following percentages of labour as a proportion of network costs[118]:

- Transmission labour comprises 70.4 per cent of the Transmission OPEX; and
- Distribution labour comprises 59.2 per cent of the Distribution OPEX.

Engevity has reviewed the Synergies approach and accepts these weightings as reasonable for the purpose of our review.

[117] WP proposal, Section 7.7, page 168.

[118] Synergies, Forecast cost escalators for Western Power's 2022-27 regulatory period, 4 October 2021, page 5.

The remaining costs relate to the change in prices for materials, which Synergies has recommended be included at a 0 per cent p.a. real escalation rate for AA5 in its October 2021 report, subject to an updated analysis following the ERA's Draft Decision. Engevity considers that this approach is reasonable – recognising recent inflationary pressures caused by COVID-19, increased consumer demand, supply chain interruptions and rising geopolitical tensions.

The following table shows the growth numbers and weightings which underpin Western Power's growth rates and growth factors applied in its BST calculation.

Table 5–11: Western Power forecast growth numbers and weightings for its BST growth factors

OPEX	Weighting	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Tx Customer numbers (#)	24.1%	1,204,283	1,222,380	1,241,008	1,259,635	1,278,350	1,297,342
Tx Circuit length (km)	49.3%	7,579	7,624	7,522	7,599	7,583	7,566
Tx Ratcheted Maximum Demand (MW)	26.6%	3,989	3,989	3,989	3,989	3,989	3,989
Dx Customer numbers (#)	55.7%	1,204,243	1,222,340	1,240,968	1,259,595	1,278,310	1,297,302
Dx Circuit length (km)	15.5%	96,371	96,114	95,921	96,951	97,859	97,530
Dx Ratcheted Maximum Demand (MW)	28.8%	3,504	3,504	3,504	3,504	3,504	3,504

Source: Western Power [redacted]

Western Power's OPEX model calculates the annual growth rates and the cumulative growth rates over the AA5 period as is shown in the following table

Table 5–12: Western Power forecast annual and cumulative growth rates for its BST growth factors

OPEX	Weighting	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Tx Annual Growth Rate	100.0%	-0.22%	0.66%	-0.29%	0.87%	0.25%	0.25%
Tx Cumulative Growth Rate	n/a	-0.22%	0.43%	0.14%	1.01%	1.27%	1.52%
Dx Annual Growth Rate	100.0%	0.87%	0.80%	0.82%	1.00%	0.97%	0.78%
Dx Cumulative Growth Rate	n/a	0.87%	1.67%	2.50%	3.53%	4.54%	5.35%

Source: Western Power [redacted]

In its OPEX model Western Power calculates the escalation from the base year and applies these to its disaggregated OPEX cost categories with an overall compound annual growth rate (CAGR) of 0.30% per annum for Transmission costs and 1.05% per annum for Distribution costs[119].

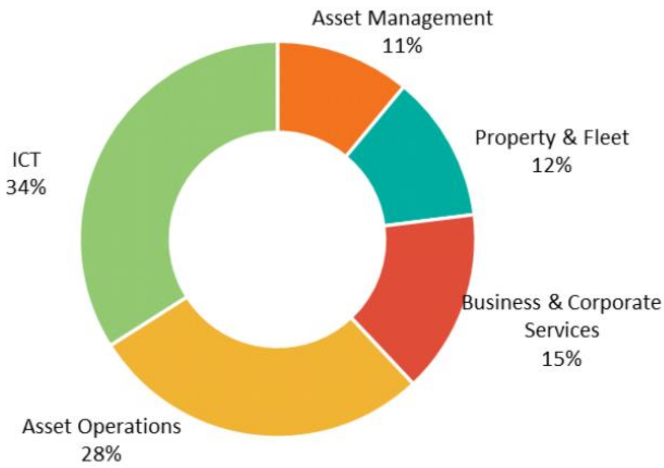
5.10.6 Indirect Costs

This category of OPEX is comparatively large, $183.4 million[120] and contains several areas where inefficiencies may occur. These costs resemble expenses which would normally be considered as business overheads. The detail of this category raises questions that would benefit from further investigation if appropriate detail of the costs was available. Overall Western Power is utilising the BST approach to estimate this category and have not provided the necessary detail.

The overall level of indirect costs is lower than the AA4 period projecting $842.6 million in total compared to $910 million for the AA4 period. The reasons for this are not clear.

Major indirect cost categories include, Asset operations, IT, Asset management, Property and Fleet as well as Business and Corporate services. The breakdown is illustrated in the figure below.

Figure 5–15: Breakdown of indirect costs



Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.9, page 172.

The total of $842.6 million indirect costs is split into $659.2 million which is capitalised into CAPEX projects, and $183 million which is expensed and treated as OPEX (see table below). Western Power uses the split of between 74.3% and 74.5% of indirect costs allocated to distribution based on the direct cost ratio resulting each year from the direct efficient base year plus step changes seen against transmission and distribution services respectively. See Section 7.9 of the Western Power proposal.

Table 5–13: AA5 CAPEX & OPEX indirect costs, $ million real at 30 June 2022

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 total
Capitalised indirect costs	132.5	131.9	133.0	131.7	130.1	659.2
Indirect costs expensed to revenue-cap services	34.7	35.8	35.5	37.5	39.9	183.4
Total indirect costs	**167.2**	**167.8**	**168.5**	**169.2**	**169.9**	**842.6**

Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Table 7.18, page 173.

[119] WP proposal, Tables 7.8 and 7.10, pages 164 and 166 respectively.

[120] Source: Section 7.9, page 171.

Build-up of the Efficient Base Year Indirect Costs

Western Power has provided the following cost build -up from the efficient base year and applied the already established adjustment factors and escalation reflecting network growth, labour escalation and productivity change to establish the Indirect Cost profile shown in Table 5–14.

Table 5–14: Build-up of AA5 total CAPEX & OPEX indirect cost forecasts, $ million real at 30 June 2022

Expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5
Efficient base year	**151.8**	**151.8**	**151.8**	**151.8**	**151.8**	**758.9**
Step changes	13.6	13.6	13.6	13.6	13.6	68.2
Total recurrent indirect costs	**165.4**	**165.4**	**165.4**	**165.4**	**165.4**	**827.1**
Network growth escalation	0.5	0.7	1.0	1.4	1.7	5.2
Productivity factor	-0.4	-0.8	-1.2	-1.7	-2.1	-6.2
Non-recurrent opex	0.0	0.0	0.0	0.0	0.0	0.0
Labour cost escalation	1.7	2.5	3.3	4.1	4.9	16.5
Total regulated revenue cap indirect costs	**167.2**	**167.8**	**168.5**	**169.2**	**169.9**	**842.6**

Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Table 7.17, page 173.

Engevity cannot identify a direct causal relationship that would justify the Indirect Costs being escalated by the network growth factor in particular. These overhead costs do not have a causal relationship to the network length, capacity or number of end-use customers. In practice, the forecast spend for these costs would be expected to decrease on a per unit cost basis.

It is noted that part of our recommendation to adopt a higher productivity growth factor (section 5.10.3) is to allow for a larger CAPEX volume and other organisational efficiencies. These benefits will accrue from investment in new and enhanced systems which may not be embedded in the proposed efficient base year. Without a correction for these efficiencies over the AA5 forecast years, Western Power's actual productivity improvement rate in AA5 may be materially understated. This would continue into the AA6 period where the investment in AA5 assets and systems will drive a significant 'background' level of productivity growth from the atypical network and business transformation investments that are expected to be delivered between now and 2030.

As shown in Table 5–14, Western Power has included the following step changes in the Indirect Cost build up:

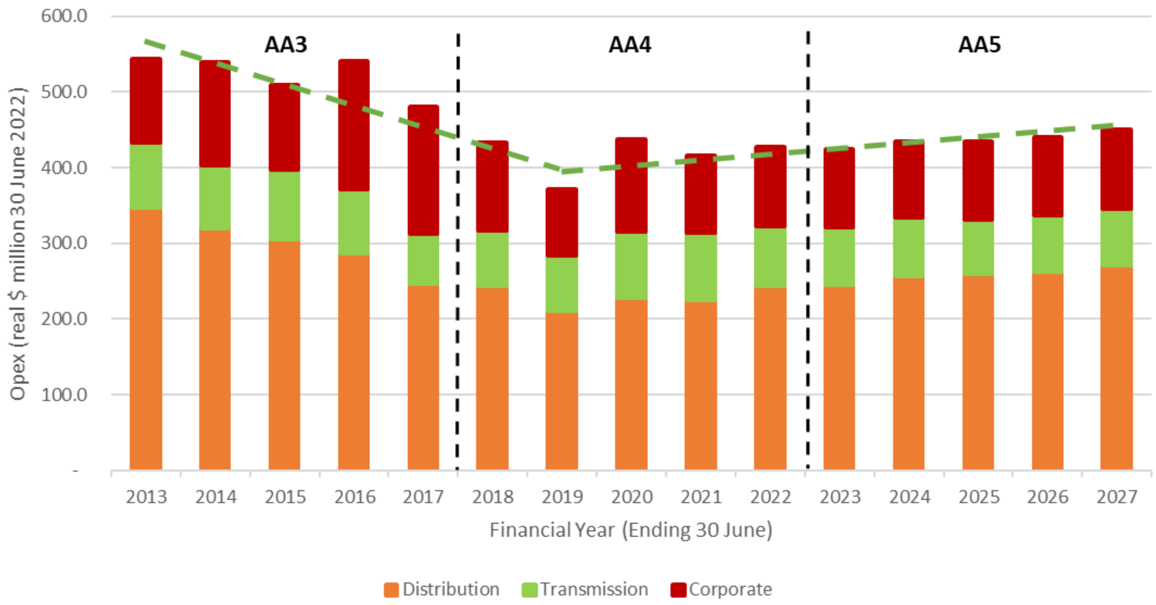
- Increased support services to support the Capital Program of $6.3 million;
- Cyber Security program $3.5M;
- increased IT contract support costs of $3.8 million.

Network growth of $5.2 million is included, and real productivity improvement of $6.2 million has been deducted, consistent with the methodology applied to direct costs. Labour costs are forecast to escalate in line with Western Power's estimates for direct costs by a total of $16.5 million.

5.10.7 Summary of overall OPEX

The overall trend of final projected OPEX proposed by Western Power is illustrated below.

Figure 5–16: AA3 & AA4 historical and AA5 forecast OPEX, inc. indirect costs and escalations



$ million real at 30 June 2022

Source: Western Power, Access Arrangement Information for the AA5 Period (1 February 2022), Figure 7.2, page 137.

5.11 OPEX Interactions with CAPEX

This section summarises the OPEX interactions with CAPEX, in particular how Western Power's proposed capital program will impact future operating costs.

5.11.1 Capital Investments to deliver operating efficiency benefits

Several CAPEX projects are justified on the basis of delivering operational savings in future years. It is important to ensure that these efficiencies are recognised in forecasts to make sure that the required OPEX level reflects the benefit and timing of these efficiencies being realised by customers.

We have specifically considered:

1. **How future field operations OPEX will be affected by the very large SCADA project proposed by Western Power** as it delivers more automation and control to lower levels of the network;
1. **how the operational benefits in the last mile of AMI** will be utilised in order to reduce costs;
2. **what benefits will accrue from large scale deployment of SPS** and what fundamental change to existing cost profiles that will make to operationally affected areas; and
3. **what benefits in OPEX will accrue from undergrounding**.

Apart from the projected productivity improvement of 0.25 per cent each year during AA5 and a forecast reduction in meter reading costs due to the acceleration of the AMI program, Western Power has not explicitly shown any savings from the completion of various CAPEX programs commenced in AA4 (e.g. Depots) or new programs related to the transformation strategy it is proposing to undertake in AA5.

For example, we are not seeing the ongoing OPEX savings which accrue from the AA4 and AA5 transformation programs such as:

- Overhead line maintenance, patrols and repairs associated with undergrounding; and

- The OPEX benefits from the distribution line decommissioning phase of the SPS program, or the undergrounding program related to the avoided line maintenance, patrols and repairs associated with removal of overhead assets.

5.11.2 Specific OPEX-CAPEX Issues

Interaction of Distribution Network with SPS

Western Power has advised that the AA5 period will include a substantial scale up of SPS deployment for customers currently served by long rural feeders. The intended numbers are 1,800 during AA5 rising to a ceiling of 4,000 over a 10-year period by 2030/31. As at December 2022 a trial of 6 customers was completed and a roll out to 52 customers was completed. Additional units were deployed as a more timely response to natural disaster damage than rebuilding the overhead network. 'Round 2' of the program is forecast to be delivered in AA5 following a step up in the last year of the AA4 period.

The initial unit costs for the SPS assets appear to be very high as Western Power develops the supply chain to deliver SPS assets at scale in Western Australia. As a result, we expect that further scale benefits will be obtained over the life of the program from both the 'cost-curve effect (the equipment reduces in cost over time), a prudent ramp up in scale to manage the capability of a fledgling market of service providers, as well as the 'learning curve' effect (where Western Power, customers and contractors will become significantly more efficient as they complete more installations).

Western Power has supplied contract values for Round 2 and 3 of $59 million but is targeting a 30% cost reduction over the AA5 period, initially 15% from contractor costs and 15% from the benefits of decommissioning. However, as with other programs, it is not clear how the targets have been derived or whether or not it is appropriate to treat them as efficiencies that will be realised in AA5. We do highlight that the business case analysis is conducted on a 50-year net present cost (NPC) basis, which risks overstating the scale of technology cost reductions over time.

Western Power is targeting the removal of 40% of the Distribution Network (assumed to be based on line length) which equates to approximately 17% of the network risk assessed by Western Power. Connections with under 500kWh annual consumption are targeted for supply abolishment. Western Power is also providing opt-in incentive payments between $1k and $100K for customers to disconnect and be self-sufficient.

Interaction of Distribution Network with AMI

Western Power is experiencing the effects of significant growth in renewable generation installation on the local Distribution network. Already some 3GW of capacity is installed between the AA3 and AA4 periods. It is estimated that AA5 will see an additional 3GW installed. Western Power is experiencing record low system demand at times of peak solar generation and significant growth in Maximum Demand in late afternoons resulting primarily from Air Conditioning load which is not offset by solar generation.

In an attempt to exercise some control on the factors driving demand Western Power has proposed an AMI rollout for all customers on the network. This AMI program commenced in 2019[121] during the AA4 period. It is envisaged to complete the roll out in AA5 through to 92% of the customer base and the required CAPEX has been included in the regulatory proposal to achieve the roll out.

We note that Western Power currently deploys meters at the customers cost as part of the new renewable generation connection process. Noting the existing solar penetration of around 35% and the government targets to reach 50% by 2030, it is difficult to understand why Western Power would

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[121] WP proposal, para 232, page 34.

not continue with this practice to minimise the total metering costs recovered through the common network charges. This approach is widespread in the NEM with the customer required to fund the necessary metering upgrade prior to installing generation equipment. Such a model if continued in Western Power's franchise would provide the necessary means to manage local distribution assets and quantities such as voltage, power factor and the like as well as to disconnect installations on the basis of system need. Whilst the NEM distributors have struggled to achieve the AMI penetration rates that Western Power currently reports, a hybrid approach to maximise customer funded AMI installation could reduce the cost of the AMI rollout by avoiding network funded meter installations for the 15% of customers who are expected to install DER resources over the period to 2030.

Engevity notes that the additional 15% in solar penetration represents a volume of around three quarters of the customers targeted by the proposed acceleration of the AMI program in AA5 – which affects approximately 20% of Western Power's customer base. Where new solar/battery/EV charging installations are required to fund their meter installation as part of the connection process, the majority of the network capex for the AA6 portion of the AMI rollout could be avoided. Where solar penetration is improved

Western Power has opted for a model which funds the installation at every connected premise. Obviously, this will accrue additional roll out costs but also save meter reading costs while requiring investment in data gathering and management systems. The detail of what is proposed here is not clear but with such a rich data environment being established some investment in systems will be necessary. This system investment will require a level of OPEX spend in addition to meter reading cost savings. The necessary licence and operational costs will all accrue to OPEX.

Western Power is investing in an upgraded SCADA system as part of the AA5 strategy, while it is not clear that plans exist to integrate the AMI data and control capability with the updated SCADA installation it is highly recommended that such integration be considered. It is also recommended that Western Power consider strategies for implementation to achieve effective control and indication at the Distribution level as a result of the AMI deployment.

IT Projects – Customer Management System

Our CAPEX recommendation not to proceed with the acceleration component of the AMI roll out in AA5 means that part of the proposed step change reduction in meter reading costs outlined in the project financial analysis for the acceleration component have been added back into OPEX. We note that this is less than the step change included in Western Power's proposed OPEX calculation that also included the avoided meter reading benefits from the base AMI rollout meters.

IT Projects – Customer Management System Example

The efficiency benefits from IT systems are often difficult to accurately quantify. Notwithstanding, these projects are proposed and justified on the basis of improving productivity in some way.

We note that material benefits are cited as achieved in Western Power's AA4 NFIT report for the Customer Management System (and the significant additional scope for investment in associated systems), but we are unable to verify that they were incorporated in the base year. In practice there are four outcomes:

- **the benefits have already been realised** and are reflected in the base year OPEX cost;
- **the benefits will be realised in the final year of AA4** and should be adjusted for in the proposed OPEX;
- **the benefits will be realised in AA5** and OPEX should be adjusted for in the proposed OPEX);
- **the benefits have not or are not going to be realised** in which case the capital expenditure does not meet the NFIT.

5.11.3 Recommendations

Using Western Power's BST OPEX model, Engevity has implemented its recommended changes to the escalation assumptions used. Table 5–15 provides the recommended adjustments to the proposed OPEX for AA5.

Table 5–15: Engevity Recommendations OPEX (real $ million 30 June 2022)

OPEX	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Western Power Proposed	423.9	434.9	434.3	440.1	449.5	**2,182.7**
Engevity Adjustments	*-14.9*	*-23.1*	*-32.2*	*-41.2*	*-49.6*	*-161.1*
Recommended	**409.0**	**411.8**	**402.1**	**398.9**	**399.9**	**2,021.6**

Source: Western Power, [redacted]

In summary we recommend:

- Remove the circuit length as an input to the Distribution network growth factor, as the SPS rollout should see a reduction in the circuit length over AA5.
- Return the Transmission customer number driver to the number of Transmission connections instead of the proposed end-user customer number, as the latter has limited impact on a well-designed Transmission network.
- A productivity improvement of 2 per cent per annum over AA5, rather than the proposed 0.25 per cent per annum; and
- Change the Corporate and Indirect cost growth factor to exclude the network growth element as there is no causal relationship with these overhead costs.

The table below provides further detail of the BST build-up adjustments recommended by Engevity using Western Power's OPEX model adjusted as described above. The reductions in the total OPEX allowance and the cumulative reductions are provided.

Table 5–16: Engevity Detail of BST Recommendations OPEX (real $ million 30 June 2022)

Adjustment for Discussion	2022/23	2023/24	2024/25	2025/26	2026/27	Total	Cum. Adjust
Western Power Proposal	423.9	434.9	434.3	440.1	449.5	**2,182.7**	0.0
Remove Dx Cct Km Escalation	423.8	434.8	433.7	439.0	448.6	**2,179.9**	-2.8
Tx Growth to Connections	423.0	433.7	432.1	437.0	446.2	**2,172.1**	-10.6
Remove Indirect Cost Growth Escalation	421.6	431.6	429.0	433.1	441.4	**2,156.7**	-26.0
Change Productivity to 2% pa	413.9	416.4	406.2	402.7	403.3	**2,042.4**	-140.3

Adjustment for Discussion	2022/23	2023/24	2024/25	2025/26	2026/27	Total	Cum. Adjust
Remove Silicone Treatment Program step change	5.34	5.34	5.34	5.34	5.34	**2,015.7**	-167.0
Add back BaU AMI meter reading costs	**0.4**	**0.8**	**1.2**	**1.6**	**2.0**	**2,021.6**	-161.1

Source: Western Power, [redacted]

Challenges in assessing Western Power's OPEX proposal for AA5

Given the proposed transformation of Western Power to adapt its network to the rapidly changing energy landscape, the standard Base–Step–Trend methodology may no longer be an appropriate basis for forecasting recurrent OPEX – at least between AA4 and AA5. The proposed network transformation project, including the transition to deployment of SPSs, increased undergrounding and AMI, may represent a 'break' in the time series. In other words, OPEX items that have been largely recurrent in the past may no longer be part of Western Power's business-as-usual activities (as discussed in section 5.2.1 above).

We were unable to test this assumption in Western Power's proposal. Despite our requests, Western Power would not or could not provide the cost detail underlying its planned OPEX – especially OPEX relating to Western Power's strategy to deploy SPSs, increased undergrounding and AMI. Although Western Power may claim its OPEX model accounts for these impacts, we did not have visibility of the OPEX line reductions netting off, for example, lower overhead system inspection and maintenance costs from increased undergrounding.

We were therefore limited in our ability to consider how these programs interact with Western Power's base OPEX. For example, Western Power's plans to accelerate its SPS deployment in rural areas will result in the removal of redundant network poles and wires, which would significantly increase OPEX as it transitions to a new cost structure. Detail on these anticipated transitional costs is not provided in Western Power's proposal or subsequent information request responses.

Despite the reductions to the OPEX forecast recommended above (engaging in the detail of Western Power's proposal), we consider Western Power will be under significant pressure to deliver its OPEX program within the allowance as it undertakes its business transformation project. There is a risk that Western Power's OPEX allowance is not adequate to manage several new initiatives, the interaction of those initiatives with normal operations, and the overall level of change. Western Power will need to exercise a level of governance and operational discipline that improves on its AA4 performance. Our recommendations to reduce delivery pressure across several of the network transformation programs should mitigate some of these risks by significantly reducing the overall scale of activity that Western Power is required to manage over AA5. But a holistic assessment beyond the detail of Western Power's OPEX proposal may be required to balance its overall revenue allowance.

In the same context, it is noted that there is a risk Western Power's proposed non-recurrent OPEX to decommission distribution overhead lines ($61.0 million) and remove the 66 kV transmission line ($7.4 million) will not be able to be fully completed in AA5. These are ambitious targets. Western Power is not bound by a regulatory obligation to meet these commitments and has discretion to defer these programs to AA6 (as distinct from making efficiency gains). If so, forecast efficient expenditure for AA5 will be overstated. Customers are not in a position to manage this risk, so the ERA may consider mechanisms to commit Western Power to deliver these outcomes or better share risk.

Attachment 6:
Asset Lives Assessment

6.1 Overview

This section summarises our review of the asset lives used by Western Power. Asset lives feed into the regulatory depreciation calculation, which in turn affects the rate at which the asset value is recovered from customers.

Our review outlines Western Power's proposed lives against the historical lives that have been used and evaluates the reasonableness, or otherwise, of Western Power's Proposal with reference to those adopted by other Australian network businesses.

6.2 Western Power Proposed Lives

Western Powers proposed lives are shown below for both distribution and transmission

6.2.1 Distribution

Western Power has proposed to amend the asset lives for underground cables, switchgear and equity raising costs for expenditure for expenditure incurred during AA5. The previous lives will be retained for expenditure incurred prior to AA5. In addition, new asset classes have been introduced for stand-alone power systems and storage...

Table 6–1: Standard Lives AA Change

	Standard life (AA1/AA2)	Standard life (AA3)	Standard life (AA4)	Standard life (AA5+)
Wooden Pole Lines	41.00	41.00	41.00	41.00
Underground Cables	60.00	60.00	60.00	50.00
Transformers	35.00	35.00	35.00	35.00
Switchgear	35.00	35.00	35.00	30.00
Street lighting	20.00	20.00	20.00	20.00
Meters and Services	25.00	15.00	15.00	15.00
IT	10.16	6.00	6.00	6.00
SCADA & Comms	10.16	10.16	10.16	10.16
Other Dix Non-Network	10.16	10.16	27.00	27.00
Dx Land & Easements	-	-	-	-
Equity Raising Costs		43.00	43.00	39.00
SPS			15.00	15.00
Storage			10.00	10.00

Source: Western Power Regulatory Model DX Inputs Sheet

6.2.2 Transmission

Western Power has proposed to amend the asset lives for transmission reactors, circuit breakers and equity raising costs for expenditure for expenditure incurred during AA5. The previous lives will be retained for expenditure incurred prior to AA5. In addition, a new asset class has been introduced for transmission secondary systems.

Table 6–2: Standard Life AA Comparison

	Standard life (AA1/AA2)	Standard life (AA3)	Standard life (AA4)	Standard life (AA5+)
Transmission steel towers	60.00	60.00	60.00	60.00
Transmission wood poles	45.00	45.00	45.00	45.00
Transmission metering	40.00	40.00	40.00	40.00
Transmission transformers	50.00	50.00	50.00	50.00
Transmission reactors	50.00	50.00	50.00	40.00
Transmission capacitors	40.00	40.00	40.00	40.00
Transmission circuit breakers	50.00	50.00	50.00	40.00
SCADA and communications	34.15	11.00	11.00	11.00
IT	16.85	6.00	6.00	6.00
Other non-network assets	16.85	16.85	27.00	27.00
Land & Easements	-	-	-	-
Equity raising costs	-	49.00	49.00	46.00
Transmission secondary systems	-	-	-	30.00

Source: Western Power Regulatory Model TX Inputs Sheet

6.3 Benchmark Lives from Other Businesses

Engevity has considered the asset lives used by the NEM businesses as the basis for our comparison, sourced from the relevant Regulatory Information Notice templates, which group lives by more general common asset classes.

6.3.1 Distribution

We consider that the asset lives carried forward from AA4 are typically aligned to the shorter end of typical Australian industry experience. In relation to the proposed changes for AA5 arising from:

- **Underground Cables reducing from 60 years to 50 years**.
- Whilst the ATO TR 2021/3 does include underground assets at 50 years, it also includes overhead and underground service cables at 40 years and 50 years respectively[122] (which Western Power groups into its 15 year 'meters and services' category).
- The NEM businesses report lives in the range of 48 years and 60 years.
- **Switchgear reducing from 35 years to 30 years**. We note that *the ATO tax ruling holds distribution substations, including switchgear at 40 years.*
- **Equity Raising Costs reduce from 43 years to 39 years** which appears to be intended to align the recovery of equity raising costs over the notional life of the network asset that the

[122] Australian Taxation Office, *Taxation Ruling TER 2021/3*, p. 173

proceeds from the equity raising are invested into. Engevity has not commented on this change.

- **Meters and Services were reduced from 25 years to 15 years for AA3** and carried forward at 15 years through AA4 and now to AA5. These assets are frequently managed as separate asset categories at longer lives for both meters (typically 15-20 years for AMI) and services (typically 20-40 years).
- **SPS Assets to be retained at 15 years**.
- **Storage Assets to be added at 10 years** which we understand to represent network owned storage such as community batteries, batteries used for load/voltage management and other network battery applications.

For regulatory purposes, assets are typically grouped into higher level categories than are used for asset management decision making. This simplifies depreciation schedules through value weighting network components (such as distribution lines) rather than fine level evaluation of asset classes. The approach is also similar to Western Power using Wood Pole Lines as an asset class rather than separate Poles, Cross Arms and Conductor classes.

While this is usually appropriate for revenue and regulatory purposes the management of over-life assets in these cases should be carefully monitored by the regulator as there is a material risk of the business choosing to replace whole asset segments rather than genuinely considering the value of refurbishment and component level replacement options (such as targeted pole replacements, conductor span replacements, and cross arm replacements using a mix of maintenance program and capital program interventions).

This is because some portion of the combined asset will retain some remaining service life. For example, the SPS assets are broadly comprised of:

1. A **solar array** with **25-year** manufacturer performance guarantees and a 20-year tax depreciation life in TR 2021/3[123].
2. **Solar inverters** which can typically be purchased with a **10-year** manufacturer warranty but may remain in service longer provided it is supplied by a reputable manufacturer these are included in the ATO definition for solar PV systems noted above.
3. Potentially a **diesel generator** which frequently remain serviceable for **15-40 years** depending on manufacturing quality, operating profile and maintenance regimes. The ATO assigns a life of 20 years[124] for diesel reciprocating engines.
4. **Battery Energy Storage Systems** which are typically warranted for 10 years operation at one full cycle per day to deliver 80% of the rated storage capacity at the end of the warranty period.

   In practice it would be unusual for customers to fully cycle their storage capacity every day. In practice this results in an approximately linear degradation rate that could reasonably expect to extend life to **15-20 years for most daily, part-cycling applications. Even at this point in time, the BESS will notionally still provide 80% of its rated capacity** and may be suitable to stay in service longer at reduced capacity if it remains electrically safe to do so. Options exist to add additional storage capacity or otherwise adopt alternative storage technologies in the future as they become economically preferable.

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123 Australian Taxation Office, *Taxation Ruling TER 2021/3*, p. 175: *"Photovoltaic electricity generating system assets (incorporating photovoltaic panels, mounting frames and inverters)"*

124 Australian Taxation Office, *Taxation Ruling TER 2021/3*, p. 174

5. **A container, ancillary wiring, switchgear** and equipment **which typically lasts the life of the equipment** in domestic/small commercial applications, and may remain suitable for continued service beyond, subject to technical suitability, condition and compliance with future wiring and safety requirements.

These component asset lives generally align with Western Powers asset management documentation and broader industry experience. For an asset class such as SPS we consider that is appropriate to adopt a 'value weighted' life where the higher value components (BESS, Structure, Solar Array) have a stronger influence on the life than the Inverter (noting that Inverter electronics, alongside water ingress into rooftop isolators are typically the most common age-related failures in quality small scale solar installations).

Alternatively, where there is a desire to manage costs more clearly (such as to support measurement of BESS unit costs, against broader market data over time) we recommend splitting SPS assets into its constituent components to reflect that each component can be replaced independently at different points in time. This would achieve the same depreciation charge as a accurately weighted 'composite SPS asset' however, the expected change in technology costs, preferred storage technology and emergence of competitive external market offers for similar systems means that the costs for the BESS and Solar are expected to materially change the relevant weightings over the AA5 period and beyond.

6.3.2 Transmission

We consider that the asset lives carried forward from AA4 are typically aligned to the longer end of typical Australian industry experience, with potential changes for AA5 arising from:

- **Equity Raising Costs reduce from 43 years to 39 years** which appears to be intended to align the recovery of equity raising costs over the notional life of the network asset that the proceeds from the equity raising are invested into. Engevity has not commented on this change.

6.4 Engevity Assessment

Engevity has reviewed the proposed changes in lives, as well as the asset classes that are expected to see substantial new investment over AA5 and beyond. We have based our recommendation on:

- Western Power historical lives;
- Comparisons to the lives applied to the NEM businesses;
- Our experience with modern network and SPS equipment.

We recognise that these recommendations retain or extend the asset lives for several categories, however, other than underground cables class - which is retained at the AA4 value, our recommendations have been aligned with the lower end of Australian NSPs reported lives.

Engevity considers Western Power's proposed Asset lives for Wood Pole Lines, Transformers, streetlighting, IT, SCADA and Comms, Other Distribution Non-Network categories are reasonable.

A brief explanation of our recommended changes to Western Power's proposed lives for expenditure during AA5 is provided below:

- **Underground cables**. Reducing the asset life by ten years would place the life for asset class below the NEM average and at on the lower end of the range (excluding United Energy at 35.6 years across most distribution network asset classes) **Engevity recommends that the asset life assumption for underground cables is retained at 60 years.**
- **Switchgear** is frequently included in the 'substation' category for other networks, with an average reported asset life of 43.5 years (ranging from 35-51 years). Western Power's existing

assumptions are already at the lower limit of industry expectations. **Engevity** recommends that the existing asset life assumption for switchgear is retained at 35 years.

- **Meters and Services** are included at a life of 15 years – which reflects the typical life used by Australian DNSP's for AMI meters. However, longer lives are applied to non-AMI meters (typically 25 years) and services (average 46 years, ranging from 35-55 years) Whilst these are relatively low value assets, they are needed for every LV connection at a scale that means a 15-year replacement cycle is not efficient and does not minimise cost. Given the neutral integrity monitoring included as part of Western Power's AMI rollout, any routine early replacement of services for risk management will become increasingly challenged. **Engevity recommends that a separate 'LV services' and 'legacy meters''** categories are created given the vastly different difference in asset lives. A value weighted calculation of the standard life could also achieve the same purpose within the existing regulatory categorisation. Noting:

  a. the higher value and longer life of underground service connections.

  b. the large volume of recent investment in the overhead service replacement under the 'twisties' program, with the Network Management Plan noting that the majority of overhead service connections have been replaced in the past 10 years.

  c. the significant undergrounding program planned for AA5 resulting in an increased volume of higher cost underground service connections. The policy of new service connections being exclusively underground will also increase the proportion of underground service connections.

  d. Western Power's 2017 published pole to pillar charges in the order of $3,400-$4,900 per property when compared to AMI installation costs an order of magnitude lower at $300 to $500 per connection.

  e. the historical and ongoing investment in AMI assets, with the intent to replace most of the remaining legacy meter population over AA5.

  The appropriate meter and services asset class life will be heavily aligned to the life given to the underground services assets. To establish an appropriate single asset life for the meters and services asset class we have taken the lower end of the range used by the NEM businesses of 35 years for services, a 15-year life for AMI meters and a 7-year remaining life for the legacy meters that are forecast to be replaced before the end of the AA6 period. **This results in a recommended value weighted asset life for the meters and services category of 32 years.**

- **SPS** assets are proposed to be depreciated over a 15-year asset life. Which appears to be too heavily weighted towards the shorter life inverter assets given typical lives noted by Western Power in their Network Management Plan of 10 years for an inverter, 20 years for a solar array/battery and 30 years for a generator/relocatable structure. Our discussion above highlights that these are well aligned with typical manufacturer expectations. **Engevity recommends that the SPS category is split into constituent categories to reflect the wide variation in asset lives and expected changes in technology costs (and therefore value weights) of an 'overall' SPS asset life over future periods. As a result, we consider that an asset life of 20 years is appropriate for the SPS asset class as this reflects the expected life of the solar array and battery components that form the majority of the SPS asset costs.**

Overall, we note that the distribution asset lives proposed by Western Power typically fall at the shorter end of industry expectations, whilst transmission asset lives are generally aligned or longer than the lives used by the NEM TNSPs.

6.5 Findings

The findings of our review of asset lives are summarised in the following sections.

6.5.1 Distribution

The following table summarises our recommended changes to Western Power's proposed lives and provides the range of lives used by the other Australian network businesses for regulatory depreciation purposes. Green denotes where Western Power is aligned, or higher than the NEM average and light orange denotes where Western Power is below the average of other Australian networks.

Table 6–3: Engevity Recommended Asset Lives AA5 – Distribution

	Western Power AA4 life	Western Power AA5 Proposed life	NEM Avg (range)	Engevity Recommended
Wooden Pole Lines	41.00	41.00	48.6 (35-58)	**41.00**
Underground Cables	60.00	50.00	53.3 (35.6-60)	**60.00**
Transformers	35.00	35.00	47.4 (35.6-58)	**35.00**
Switchgear	35.00	30.00	43.5 (35-51)	**35.00**
Street lighting	20.00	20.00	20.00	**20.00**
Meters and Services	15.00	15.00	15.00 25.00 46.05 (35-55)	**32 (or split)** **15 AMI Meters** **7 Legacy Meters** **35 Services**
IT	6.00	6.00	5.5 (5-10)	**6**
SCADA & Comms	10.16	10.16	10.2 (7-15)	**10.16**
Other Dx Non-Network	27.00	27.00	9.9 (5-17.4)[1]	**27.00**
Dx Land & Easements	-	-	-	**-**
Equity Raising Costs	43.00	39.00	Not considered	**39.00**
SPS	n/a	15.00	-	**20 (or split)**
– SPS Solar PV				*20*
– SPS Inverter				*10*
– SPS Relocatable Structures				*30*
– SPS Generator				*30*
– Storage (SPS and Network)	*n/a*	*10.00*		*20*[2]

Source: Engevity analysis - Western Power Regulatory Model and AER Final Decision PTRM models

1. Buildings and property are generally excluded from this category for the NEM businesses resulting in a lower weighted average life when compared to Western Power.
2. Storage assets are typically warranted for 10 years operation at one full cycle per day – or otherwise given a 'cycle life' by the manufacturer of around 3,500 – 4,000 cycles to degrade to 80% of the initial storage capacity. SPS installations are unlikely to fully cycle their storage every day, especially in mid-season and winter months where heating and cooling demands are much lower relative to the daytime solar production.

The 20-year life aligns with a BESS operation that cycles less than one full cycle per day as well as Western Power's Network Management Plan assumptions for battery storage. At end of life, it may be economically preferable to add additional storage to the system to restore capacity and keep using the remaining 80% capacity in the existing cells. (however ongoing technology advances are likely to mean that the current lithium-ion battery chemistry has been surpasses as the most appropriate battery technology for these applications)

6.5.2 Transmission

Engevity has reviewed the transmission asset lives proposed by Western Power and considers that they are reasonable when they are assessed against the lives used for regulatory depreciation in other Australian transmission networks. We observe that Western Power typically applies lives at the longer end of industry norms to its transmission assets. This is the opposite outcome to our assessment of distribution standard lives. The longer lives of 50 years that have been used in AA4 and prior for circuit breakers and reactors are at the upper end of expectations for service life but are not unreasonable as older primary transmission assets are able to provide very long service lives through rebuilds, refurbishment and replacement of the wearing parts such as contacts, insulation and seals. The reduction in lives for these assets is consistent with the general trend by transmission equipment manufacturers to move away from rebuildable/serviceable equipment to minimise maintenance requirements and reliability impacts – especially given the complexity caused by the need to take critical plant out of service to perform most maintenance tasks. Similar approaches have been implemented in most industries as reflected in the reduced servicing requirements (and reduced serviceability through sealed-for-life assemblies) for modern cars, aircraft and industrial equipment. This means that Western Power's revised asset lives simply reflect that modern equipment is not expected to remain in service as long as older technologies because contemporary manufacturers have struck a different balance between maintenance costs, reliability impacts, refurbishment options and capital cost when compared to older manufacturers.

We recommend that the transmission asset lives proposed by Western Power for regulatory depreciation are accepted.

Table 6–4: Western Power Proposed AA5 asset life - Transmission

	Western Power AA4 life	Western Power AA5 Proposed life	NEM Avg (range)	Engevity Recommended
Transmission cables	55.00	55.00	47 (40-60)	55.00
Transmission steel towers	60.00	60.00	56 (50-60)	60.00
Transmission wood poles	45.00	45.00	49 (45-55)	45.00
Transmission metering	40.00	40.00	-	40.00
Transmission transformers	50.00	50.00	44 (40-50)	50.00
Transmission reactors	50.00	40.00	42 (40-45)	40.00
Transmission capacitors	40.00	40.00	42 (40-45	40.00
Transmission circuit breakers	50.00	40.00	44 (40-45)	40.00
SCADA and communications	11.00	11.00	17 (10-37)	11.00
IT	6.00	6.00	5 (4-7)	6.00
Other non-network assets[1]	27.00	27.00	15 (7-40)	27.00
Land & Easements		-	-	-
Equity raising costs	49.00	46.00	-	46.00
Transmission secondary systems [2]	n/a	30	19 (15-37)	30.00

Source: Engevity analysis - Western Power Regulatory Model and AER Final Decision PTRM models

3. Buildings and property are generally excluded from this category for the NEM businesses resulting in a lower weighted average life when compared to Western Power.
4. Several networks simply use a ‘primary plant’ or ‘transmission substation’ asset life for regulatory depreciation purposes to capture the major electrical assets at substations (e.g. transformers, circuit breakers, reactors, capacitor banks and other switchyard equipment). Where this occurs, most of the TNSPs break out transformers, buildings and secondary system from the more general substation asset class.

Attachment 7:
Historical CAPEX Assessment

Overview

Engevity notes that Western Power has provided a large amount of information for its AA4 projects, however, in most cases supporting detail including cost breakdowns, business case analysis, change process, evidence of governance, executive oversight and approvals were not provided.

The original and subsequent supporting documentation packages provided did not provide a complete suite of contracts, cost estimates or details on change requests and in some cases the information was provided at different resolutions, and we noted changes in project scope over time which made it difficult to follow the impact of changes on our review. As a result, the assessment and our review remained difficult to assess in detail.

In some cases where we have not been able to follow the full progress of the project, we have made assessments of efficiency against industry pricing, typical network management expectations and normal Australian construction contract management practices to assess whether any absent or unclear information would affect our assessment. Where data provided was either incomplete or insufficient detail, we have applied conservative assumptions in our analysis.

AA4 CAPEX Review Summary

At the request of ERA, Engevity has conducted a review of a sample of the projects conducted in AA4 and the below table is a summary of our findings.

Table 7–1: AA4 NFIT Assessment [$m nominal]

Project/Program	AA4 Actual Cost $m	Variance to AA4[125] $m	Recommended Adjustments
Kalbarri Microgrid	15.77	+4.37	Nil
Hay MIL Switchboard	12.3	-17.7	Nil
Grid Transformation Engine	14.5	+14.5[126]	Nil
Reactive Voltage Rectification	25.1	+25.1[127]	Nil
SPS	51.2	+51.2[128]	Nil
Wood Pole Management	679.3	-8.4	Nil
IT, SCADA & Communications	506.6	+185.3	Nil
AMI	158.77[129]	+55.5	Nil
Customer Management System	24.9	-	-24.9
Forrestdale Depot	79.5	-26.4	Nil
Total Expenditure Assessed	**1,567.94**	**+283.47**	**-24.9**

Engevity's assessment of each of the projects and programs in the table above is set out below.

[125] Negative variances indicate a material underspend of the AA4 Further Final Decision (FFD) forecast for the project. Positive variances indicate a material overspend of the FFD forecast. Figures from NFIT compliance summaries. Note that the overall CAPEX allowance is set at a total level, Western Power can reprioritise expenditure throughout the AA period within the overall capital expenditure allowance. This provides the flexibility to adapt the capital expenditure portfolio to meet changing or unforeseen needs.

[126] Attachment 5.6 AA4 – NFIT Compliance Summary – Grid Transformation Engine, Table 2.2, p.4. Variance to AA4 FFD stated as -$14.5M. Regulatory approval (AA4 FFD) is listed as 'n/a'.

[127] Attachment 5.7 AA4 – NFIT Compliance Summary – Reactive voltage rectification, Table 2.2, p.4. Variance to AA4 FFD stated as -$25.1M. Noted that regulatory approval (AA4 FFD) listed as 'Nil'.

[128] Attachment 5.8 AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Table 2.2, p.4. Variance to AA4 FFD stated as 'n/a' and regulatory approval (AA4 FFD) as 'n/a'. Western Power notes "SPS projects were not identified as part of the AA4 submission, rather separate business cases were raised for SPS units as the opportunity was identified" on p. 9.

[129] Western Power Attachment 5.2 - AA4 CAPEX Variance Report, [redacted]

7.1 Kalbarri Microgrid – AA4 Assessment

7.1.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **Kalbarri Microgrid Project**. We found that **the expenditure complied with the NFIT requirements**. As a result, we have not recommended adjustment to this project.

The expenditure and scope of the Kalbarri Microgrid project is summarised in the table below.

Table 7–2: AA4 Expenditure and scale – NFIT Compliance – Kalbarri Microgrid [$m nominal][130]

	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1 actual	Yr2 Actual	Yr3 actual	Yr4 actual	Yr5 forecast	Total
Western Power Actual AA4 CAPEX	-	-	-	-	-	**15.77**
Expenditure that does not meet NFIT	-	-	-	-	-	**-**
Engevity Recommended	-	-	-	-	-	**15.77**

130 Sources: AAS – Attachment 5.3 – AA4 NFIT Compliance Summary – Kalbarri Microgrid, 1 February 2022, p. 17

Assessment Overview

Table 7–3: Assessment Overview

Project/Program	AA4 Kalbarri Microgrid - NFIT Compliance
Actual Cost $m	$15.77m
Variance to approved $m	$4.37m ($0.08m on final approved budget following change control request)
Need	The project was classified as necessary for maintaining reliability under the NFIT 6.52(b). The feeder was clearly underperforming compared to SAIDI and SAIFI SSBs, with Kalbarri township in particular experiencing outages that increasingly exceeded SAIDI and SAIFI SSBs over the AA3 period.[131]
Scope Definition	The Kalbarri community strongly supported the need for a timely reliability solution.[132] The solution was well justified through probabilistic analysis as being able to address the reliability issues on the feeder and for Kalbarri township.[133] [134]
Timing	Engevity is satisfied that the solution was needed at the time of delivery and accepts that delays caused by events outside of Western Power control were reasonable.
Risk Management	Contractor position and the contingency that occurred resulted in around $3m in extra costs, or 20% of final project value. Western Power stated in its NFIT package that it believed its partner [redacted] intentionally inflated cost proposals, was biased towards certain service providers, and that Western Power was left without any bargaining power.[135] Western Power may need to look closer as to how it can manage these risks in the future, particularly for larger projects such as its AA5 SPS program.
Cost Efficiency	At the time of project approval in the ERA's final decision on Western Power's AA4 determination, the selected solution was found to have the lowest NPC of viable solutions. This costing and finding was supported by GHD in its review of Western Power's proposed AA4 expenditure.[136] Increase of $4.1m in project costs on costs determined at planning stage has likely increased the NPC of this option above the original second-best solution, installing a diesel generator, particularly as these additional costs are all experienced early in the project lifecycle.[137] However, we believe the investment still meets the NFIT as the majority of this cost increase was outside Western Power's control and relates to the collapse of a contract partner occurring after solution option was selected and progressed.

131 Kalbarri Microgrid – Hotspot reliability study, Western Power, 2016, p. 33

132 Kalbarri Microgrid – Hotspot reliability study, Western Power, 2016, pp. 77-79

133 [redacted]

134 Kalbarri Microgrid Feasibility Study, Western Power, 2017, p. 21

135 Kalbarri Microgrid – Change Control Request #1, p. 3

136 Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, GHD, 2018, p. 133

137 [redacted]

Project/Program	AA4 Kalbarri Microgrid - NFIT Compliance
Scope Efficiency	The final scope of the project substantially evolved from the original proposal, resulting in additional costs and delays. Technology requirements were not accurately scoped/planned for initially, including: Actual BESS costs were 244% greater than initially expected given the different application of the BESS from previous projects Failure to integrate windfarm resulted in a small diesel generator being required in addition to the BESS, at additional cost Additional works were necessary due to the physical impacts on the network of TC Seroja
Strategic Alignment	The solution aligns with Western Power's Distribution Network Reliability Performance Strategy and Western Power's broader network vision for a modular grid.[138] [139] The solution leverages new technology essential for the transition to high penetrations of renewables, supporting environmental objectives[140] and producing learnings that can be leveraged for further grid transformation projects.
Options Analysis	Western Power undertook appropriate NPC analysis on three reasonable options for solutions to reliability issues on the Kalbarri feeder, after discounting a fourth 'do nothing' option as a non-solution[141]. GHD supported the costings and findings of the initial options analysis at project scoping stage which identified the BESS microgrid solution as the recommended option. [142] Engevity notes that the scope, costs and technical model of the BESS option significantly evolved as the project progressed.
Delivery Model	Western Power experienced significant issues in delivery of the project resulting in additional costs and delays due mostly to issues with contracted parties. COVID-19 and TC Seroja were factors outside of Western Power control that also contributed to delays.

Findings

Overall, we consider that the Kalbarri Microgrid Project for the AA4 satisfies the NFIT requirements.

7.1.2 AA4 NFIT Assessment

Overview

The Kalbarri Microgrid consists of a 2MWh BESS located on the GTN 603 Kalbarri feeder. This is the sole, radial feeder from Geraldton to Kalbarri, serving around 2000 customers.[143]

The core rationale behind the implementation of the microgrid was to solve the issues with the reliability of the feeder. Western Power identified the 603 feeders as a reliability 'hotspot',

[138] Distribution Network Reliability Strategy, Western Power, 2017, p. 14

[139] Attachment 8.3 - Grid Strategy, Western Power, 2022, p. x

[140] Climate Change Commitment, Western Power, 2021, p. 1

[141] Attachment 5.3 - AA4 - NFIT Compliance Summary - Kalbarri Microgrid, Feb 2022, Western Power, pp. 17-18

[142] Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, GHD, 2018, p. 133

[143] Attachment 5.3 - AA4 - NFIT Compliance Summary - Kalbarri Microgrid, Feb 2022, Western Power, pp. 4-5

consistently performing below the SSB for long rural feeders and experiencing a large number of outages that resulted in material community concern. [144]

The final approved budget for the Kalbarri Microgrid project was $15.7m. This is a 37.7 per cent increase from the initial approved budget of $11.4m in the ERA's AA4 final decision for Western Power. The increases in project budget followed a more detailed planning process and two change control processes were due to a number of factors within and outside of Western Power control, including:

- Underestimation of complexity and cost of BESS technology;
- Substantial increases in contract costs due collapse of original contract partner and subsequent lack of Western Power market power to procure a competitively priced alternative;
- Scope creep and delays due in part to events such as COVID-19 and TC Seroja but also oversights in the original technical solution, resulting in additional work and assets being required.

The project was expected to be delivered by 30 November 2021 at a cost of $15.8m, $0.1m overbudget.[145] [146]

Western Power achieved material improvements in its rural long and rural short SAIDI and SAIFI measures in AA4 compared to AA3, including a marked uptick between July 2021 and February 2022. Western Power attributes this performance increase to the installation of microgrids, including Kalbarri.[147]

Findings

Engevity reviewed the documentation provided by Western Power for the **$15.8m Kalbarri Microgrid** project and found that the project:

- was completed at a cost $0.1m above the final approved budget.
- **was needed** to maintain reliability under NFIT 6.5.2(b), evidenced by the ongoing SAIDI and SAIFI performance issues over AA3 for the affected feeder. [148]
- **was scoped efficiently** in collaboration with the Kalbarri community, who supported the microgrid solution[149] as the preferred and more timely solution to address reliability issues. [150] [151]
- **was appropriately timed** as the solution was needed at the time of delivery, with no reasonable case for deferring the work within the AA4 period or beyond. The project

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144 Attachment 5.3 - AA4 - NFIT Compliance Summary - Kalbarri Microgrid, Feb 2022, Western Power, pp. 3-4

145 Attachment 5.3 - AA4 - NFIT Compliance Summary - Kalbarri Microgrid, Feb 2022, Western Power, p. 11

146 Attachment 5.3 - AA4 - NFIT Compliance Summary - Kalbarri Microgrid, Feb 2022, Western Power, p. 125

147 Access Arrangement Information, 1 Feb 2022, Western Power, pp. 81-84

148 Kalbarri Microgrid – Hotspot reliability study, Western Power, 2016, p. 33

149 Kalbarri Microgrid – Hotspot reliability study, Western Power, 2016, pp. 77-79

150 [redacted]

151 Kalbarri Microgrid Feasibility Study, Western Power, 2017, p. 21

experienced delays that were caused by events (subcontractor insolvency) that were outside of Western Power's control.[152]

- **was subject to risk management controls that were not unreasonable.** The subcontractor insolvency required a [redacted] contingency to be released to complete the project with the [redacted][153]

Engevity raises a concern over these comments due to the increased scale of contracted work proposed for AA5, and Western Power's potential lack of sophistication and experience in managing contracts and contractors when delivering projects in more remote areas of the network (with fewer alternative suppliers). Additional risk management provisions such as schedules of rates for variations, reasonable Principal rights to approve/disapprove subcontractors, agreed mobilisation/demobilisation costs and extensions of time for the contractor if Western Power exercises these rights should be implemented by Western Power.

- **was delivered using efficient costs** with the project representing the lowest Net Present Cost (NPC) when reviewed for the ERA's final decision for the AA4 determination, this was supported by GHD in its review of Western Power's proposed AA4 expenditure.[154]

The total $4.3m increase in the project costs over the planning stage estimate would mean that the NPC of the cost of the delivered microgrid option would probably exceed the diesel generator alternative. However, Engevity considers that most of the increase was associated with factors relating to TC Seroja damage and the subcontractor insolvency rather than the technical solution itself (as Western Power would remain similarly exposed to contractor insolvency risk on a diesel generation project). Therefore, we consider that these factors should not influence our view of the project's cost efficiency.

- **addressed the scope efficiently** by managing scope changes, service outcomes and project costs within the original estimate. In the general market, battery costs have been and continue to remain highly variable, depending on the application, size, vendor, timing, duration and chemistry.

We recognise that battery costs for the project were over 200 per cent higher than the initial estimate, as it was based on Western Power experience in other applications, but the cost impact was absorbed through other scope revisions (such as the adoption of a small diesel generator in place of a connection to a nearby windfarm during project development and delivery).

- aligns with Western Power's Distribution Network Reliability Performance Strategy and Western Power's broader network vision for a modular grid. [155] [156] The solution leverages new technology essential for the transition to high penetrations of renewables, supporting

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152 Whilst some parties may direct critique at Western Power's delay in enforcing contractual positions with the head contractor, Engevity notes that most construction disputes are best resolved physically, financially and legally in a collaborative environment with fairly open communication. This mitigates the much larger risk of indefinite construction delays, head contractor abandonment of the incomplete project or delays to progress or payments due to the legal process.

153 [redacted]

154 Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, GHD, 2018, p. 133

155 Distribution Network Reliability Strategy, Western Power, 2017, p. 14

156 Attachment 8.3 - Grid Strategy, Western Power, 2022

environmental objectives[157] and producing learnings that can be leveraged for further grid transformation projects.

- **was based on documented NPC analysis of three reasonable options** for solutions to reliability issues on the Kalbarri feeder, after discounting a fourth 'do nothing' option as a non-solution. [158] During their AA4 review GHD supported the costings and findings of the initial options analysis at project scoping stage which identified the BESS microgrid solution as the recommended option. [159]
- **had an appropriate delivery model** for an unusual project such as this, leveraging the market to provide skills delivering assets that fall outside Western Power's core capability. Western Power contracted with a reputable and creditworthy head contractor in [redacted]

The subcontractor insolvency, COVID-19 and TC Seroja all contributed to delivery challenges in costs and time. Whilst we have previously highlighted that there are some improvements to be made in Western Powers Contract and Contract Management practices for contracted works in more remote areas, the contractual issue following the subcontractor insolvency was resolved reasonably, without extensive legal costs, large construction delays or overly excessive costs from the negotiated commercial resolution.

Overall, Engevity considers that the project satisfies the requirements of the NFIT.

Further details on the Kalbarri microgrid program are provided below.

Further supporting details

The Kalbarri microgrid project was proposed on the basis of being necessary to maintain reliability of supply and therefore has a positive NPC. The Kalbarri feeder was clearly underperforming compared to SAIDI and SAIFI SSBs, with Kalbarri township in particular experiencing outages that increasingly exceeded SAIDI and SAIFI SSBs over the AA3 period. The Kalbarri community also strongly supported the need for a timely reliability solution.[160]

The microgrid solution was well justified through probabilistic analysis as being able to address the reliability issues on the feeder and for Kalbarri township and included reliability benefits calculated at $4.77m.[161] [162]

At planning stage, the project had a total approved cost of $11.4m. This approved cost was increased by $4.3m to $15.69m following two change control requests.[163] The key reasons for this cost increase were:

- Final award cost of the Kalbarri BESS was 244% greater than initial estimate, at $6.6m compared to an initial $2.7m.[164] Western Power leveraged learnings from a smaller 1MWh

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157 Climate Change Commitment, Western Power, 2021, p. 1, Environmental objectives have also been included into the recently revised Access Code Objectives

158 Kalbarri Microgrid Business Case, Western Power, 2017, pp. 17-18, In practice, Engevity considers that the 'do nothing' option should be costed on an order-or-magnitude basis to demonstrate that it is not viable, rather than excluding it on a largely subjective and binary basis. In this case Engevity highlights that it is difficult to improve reliability at the end of long overhead feeders at low cost without a) duplicating the line or connecting a second line to provide redundancy, b) placing the line underground to protect it from storm /wind/fire/vegetation/fauna impacts, c) adding generation and/or storage at the end of the line, with the capability to disconnect and reconnect to the grid when necessary to form an islanded microgrid. The distances involved mean that the cost of the network reinforcement solutions are almost certainly prohibitive.

159 Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, GHD, 2018, p. 133

160 Kalbarri Microgrid – Hotspot reliability study, Western Power, 2016, pp. 77-79

161 [redacted]

162 Kalbarri Microgrid Feasibility Study, Western Power, 2017, p. 21

163 Attachment 5.3 - AA4 - NFIT Compliance Summary - Kalbarri Microgrid, Feb 2022, Western Power, p. 3

164 Attachment 5.3 - AA4 - NFIT Compliance Summary - Kalbarri Microgrid, Feb 2022, Western Power, p. 7

BESS in Perenjori which may not have been an application representative of the Kalbarri microgrid requirement.[165]

- Western Power also experienced additional costs due to collapse of joint venture partner [redacted] and subsequent mitigation activities, as explained further below.

Contractor position and the contingency that occurred resulted in approximately $3m in extra costs, or 20% of final project value. Approximately $2m of this additional cost occurred as a result of increased contract value with [redacted] following the collapse of its joint venture partner: [redacted]

Western Power originally executed a Supply, Deliver and Install contract with [redacted]

Western Power's NPC analysis set out in its business case explored four options for addressing the reliability issues on the Kalbarri feeder, set out in the table below:[166]

Table 7–4: Kalbarri Microgrid Options Considered ($m)

#	Option Title	Nominal Capital Cost	Net Present Cost over 15 Years
1	Do Nothing	Not financially assessed as it does not address reliability issue.	
2	Backup Diesel Power Station Microgrid	$11.62	$6.94
3	BESS Microgrid	$11.40	$5.45
4	New Feeder to Kalbarri	$26.09	$14.34

At the time of project approval in the ERA's final decision on Western Power's AA4 determination, the BESS microgrid solution was found to have the lowest NPC of viable solutions. This costing and finding were supported by GHD in its review of Western Power's proposed AA4 expenditure.[167]

Key assumptions used in this NPC analysis included:[168]

- The microgrid had an asset life 15 years;
- Western Power removed reliability outlier years to more fairly assess need and benefits;
- Assumes BESS will cover 95% of interruptions for SSAM benefits and VCR calculations;
- Assumed R&D tax benefit $1.22m PV, which represents greater than 10% of project costs.

165 Attachment 5.3 - AA4 - NFIT Compliance Summary - Kalbarri Microgrid, Feb 2022, Western Power, p. 7

166 [redacted]

167 Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, GHD, 2018, p. 133

168 [redacted]

Engevity supports these assumptions as reasonable and justified.

Increase of $4.3m in project costs on costs determined at planning stage has likely increased the NPC of this option above the original second-best solution, installing a diesel generator, particularly as these additional costs are all experienced early in the project lifecycle.[169] However, we believe the investment still meets the NFIT as the majority of this cost increase was outside Western Power's control and relates to the collapse of a contract partner occurring after solution option was selected and progressed.

In summary, Engevity recommends Western Power reflects on the following lessons learnt from the Kalbarri microgrid project:

- Technology requirements for the microgrid were not accurately scoped and planned for initially. In particular, BESS costs can be substantially variable depending on application and failure to integrate the local windfarm resulted in diesel generator being required anyway (although smaller than scoped for the diesel microgrid) at additional cost.
- [redacted] and that Western Power was left without any bargaining power.[170] Western Power may need to look closer as to how it can manage these risks in the future, particularly for larger projects such as its AA5 SPS program.

169 [redacted]

170 [redacted]

7.2 HAY MIL Switchboard - AA4 NFIT Assessment

7.2.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **HAY MIL Switchboard project delivered in AA4**. We found that **the expenditure complied with the NFIT requirements**. As a result, we have not recommended adjustment to this project.

Table 7–5: AA4 expenditure and scale – NFIT Compliance – HAY MIL Switchboard [$m nominal][171]

	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1 Actual	Yr2 Actual	Yr3 Actual	Yr4 Actual	Yr5 Actual	Total
Western Power Actual AA4 CAPEX	0	1.9	7.6	2.8	0	**12.3**
Expenditure that does not meet NFIT	-	-	-	-	-	**-**
Engevity Recommended	0	1.9	7.6	2.8	0	**12.3**

171 [redacted]

Assessment Overview

Table 7–6: Assessment Overview

Project/Program	AA4 HAY MIL Switchboard
Actual Cost $m	The actual cost of $12.3m is appropriate in terms of need for refurbishment/replacement of key CBD transmission switchboards subject to elevated risk of catastrophic failure. The least-cost of the options that meet all safety and reliability requirements has been selected. Engevity remains concerned that the lack of costing for a 'refurbish all' option makes it challenging to guarantee the most cost-efficient solution has been selected.
Variance to approved $m	Total of $17.7m (59%) less than AA4 FFD. The large variance is due to the revised business case having a recommended option of hybrid refurbishment/ replacement instead of full replacement, which was found on closer examination to be excessively expensive. Engevity considers that the specialist nature of the work means that consultation with [redacted] should have occurred before the AA4 submission to inform its option analysis, feasibility decisions and pricing.
Need	There was a clearly identified need for replacement/refurbishment of the ageing 11 kV switchboards at the Perth CBD Hay Street and Milligan Street substations. Engineering reports outlined risks of explosive failure of the old switchboards, with replacement/refurbishment recommended within the AA4 period.
Scope Definition	Engevity considers the scope is commensurate with the need and is in line with the NFIT.
Timing	Engevity considers the timing of the project is appropriate on the basis that it occurred in accordance with the condition assessment recommendations.
Risk Management	Engevity considers the risks and reasons for urgent action have been clearly identified and the investment is appropriate. However, the absence of any risk quantification makes it difficult to establish that the most efficient and prudent solution was objectively chosen. Noting the value of the project and criticality of the sites, we would expect the risk management and options assessment process to include a quantification in terms of reducing Expected Unserved Energy (MWh) valued at the Value of Customer Reliability. The qualitative assessment of options for effective mitigation of safety and reliability risk in the NFIT compliance summary and attached business case is noted.
Cost Efficiency	The delivery of the project, to ensure the safety and reliability of two of the most important substations in the Perth CBD that are critical to supply reliability, is prudent expenditure. However, Engevity is concerned that the lack of costing for a refurbish option at the outset due to its qualitative dismissal as infeasible is problematic. Other Australian NSP's have moved to quantitative approaches to justify capital investment in dollar terms to ensure that the benefits of investment outweigh the risks. Engevity considers the project was delivered in a cost-efficient way, as the out turn cost was well below the cost forecast in the AA4 submission, representing a more efficient solution than the original scope.

Project/Program	AA4 HAY MIL Switchboard
Scope Efficiency	The scope of the works in the hybrid solution is well defined. Engevity considers the project scope is appropriate for dealing with the safety and reliability risk identified need. However, Engevity is concerned that the lack of costing for a refurbish all option makes it impossible to guarantee the most scope-efficient solution has been found. Engevity considers the project scope is appropriate for the defined outcomes.
Strategic Alignment	The project is consistent with the principles of the Western Power revised CBD Strategy and the Transmission Plant Circuit Breaker and Switchboard Asset Strategy. The project follows Western Power's corporate strategy and procurement policies, including the Investment Governance Framework. Engevity considers the project is aligned with the strategic intent of the transmission replacement program.
Options Analysis	Western Power reviewed available options after the AA4 submission, which recommended 'like-for-like' replacement. They appear to have considered financial, legal, reputational, safety, reliability, technical, quality and environmental risks in considering the subsequent business case options – but only at a relatively high level using their risk matrix. The recommended hybrid replacement/refurbishment Option 4 appears to Engevity to be a reasonable balance of major risk alleviation at substantially lower cost than the 'replace all' Option 2. However, the 'refurbish all' Option 3 is not costed – and had been dismissed at the outset despite the assertion that it would be significantly lower cost. In addition, the Option 4 'hybrid' approach appears to be a relatively conventional refurbishment scope – where most components are refurbished, with replacement of components with poor serviceability, and the most critical components. Engevity considers that the specialist nature of the work means that consultation with [redacted] should have occurred before the AA4 submission to inform its option analysis, feasibility decisions and pricing.
Delivery Model	All materials and equipment for this project were sourced in accordance with Western Power's corporate procurement policies. [redacted] engagement under a procurement of materials contract and installation/refurbishment service contract was subject to a Waiver of Competition/Exemption approval. The project appears to be appropriately staged across the AA4 period and demonstrates the benefits of engaging with equipment manufacturers early in the scoping process to better understand the options and likely costs for maintaining older equipment in service. Again though, [redacted] should have been consulted before the AA4 submission.

Findings

Engevity has reviewed Western Power's proposed expenditure relating to the **HAY MIL Switchboard** project and found that:

a. **The proposed expenditure is efficient** with the objective of minimising costs on the basis that there is a detailed option analysis with the support of external specialists. The least-cost of the options that meet all safety and reliability requirements has been selected. Engevity remains concerned that the lack of costing for a refurbish all option makes it challenging to guarantee the most cost-efficient solution has been selected.

b. **The program captures the available and realisable economies of scale and scope** with procurement of customised parts and spares for the hybrid installation/refurbishment solution by Long Lead Commitment from [redacted] as the OEM. The delivery model allows advantages of economies of scale when the manufacturer sets up the factory for fabrication.

c. The proposed investment **is consistent with reasonable expectations** of the level of future network services required by customers because the Hay Street (HAY) and Milligan Street (MIL) substations are two of the most important in the Perth CBD and critical to supply reliability. The proposed investment substantially lowers safety and reliability risks, including for catastrophic switchboard failure.

d. **A reasonable range of alternative options has been considered** for the proposed investment, with the most appropriate solution chosen. This is evidenced by Western Power's use of external expert consultants [redacted] in formulating and revising the options. There is consideration of safety, reliability and other risks in each of options. Engevity considers that the 'refurbish all' option should have been costed. Engevity also considers that issues associated with the availability of appropriate replacement components to appropriate safety and technical standards for the 'replace all' option should have been resolved before the AA4 submission.

Recommended Adjustment

Overall, we consider that the Hay MIL Switchboard Project for the AA4 satisfies the NFIT requirements.

7.2.2 AA4 NFIT Assessment

Expenditure Overview

The Hay and Milligan Street Substation Switchboard Refurbishment (HAY MIL Switchboard) project forms a part of Western Power's transmission asset replacement program. The justification for the project came from engineering reports commissioned by Western Power in 2017 that outlined imminent risks associated with switchboards in the HAY and MIL substations, with the presence of explosive failure modes[172]. Replacement of the switchboards was recommended within five years.

Western Power state that the HAY MIL Switchboard investment comprised of refurbishment/ replacement of six switchboards:

- MIL: 2 X GEC and 1 X Yorkshire;
- HAY: 2 X GEC and 1 X Yorkshire.

The HAY MIL Switchboard project was originally forecast to cost $29.9m in AA4 as a full replacement of the switchboards was planned to be completed by March 2021. The ERA's AA4 final decision

[172] AAS – Attachment 5.4 – AA4 NFIT Compliance Summary – HAY MIL Switchboard, pp. 4-5

allocated $30m to the project. The business case revised the cost of full replacement to $62.1m, based on functionally equivalent rather than like-for-like replacement (not possible due to changes in safety and technical standards over the last 50 years). The project's most recent estimate to complete is $12.3m, which is a $17.7m (-59 per cent) cost reduction and was expected to be completed on 31 December 2021. The recommended option of hybrid refurbishment/replacement in the revised business case project was costed at $13.5m. The project was delivered to revised budget and completion time.

Historical Context

Western Power first considered the need for the HAY MIL Switchboard project in 2017 as part of the AA4 transmission asset replacement program. This was based on engineering reports commissioned by Western Power that outlined imminent risks of explosive failure of the old switchboards (some were about 45 years old and approaching end of service life) at the HAY and MIL substations. The project was originally conceived as a replacement of six 11 kV switchboards at the HAY and MIL substations (2 X GEC and 1 X Yorkshire at each substation). The GEC switchboards are pitch-filled and the Yorkshire switchboards contain SF6 gas-filled circuit breakers. Due to age and type, there were numerous safety and reliability issues associated with these switchboards, including explosive failure with arc flash. The age of the switchboards meant a lack of availability of spare parts or replacements. The HAY MIL Switchboard replacement/refurbishment project finally adopted an option for replacement/refurbishment of all six switchboards, three each at the HAY and MIL substations.

In 2015, [redacted] identified the risk of arc flash on the GEC switchboards of the type at the Hay Street and Milligan Street substations as high[173]. In 2018, Western Power, supported by [redacted] investigated refurbishment for the Hay Street and Milligan Street switchboards. This study looked at options other than full replacement, in order to lower CAPEX while addressing the condition-driven risks identified in these switchboards[174]. In 2019, [redacted] also provided a condition assessment for Milligan Street GEC switchboards. In 2019, business case [redacted] for MIL and HAY 11 kV switchboard refurbishment recommended a refurbishment/replacement hybrid option as the revised preferred solution[175].

Need

There was a clearly identified need for replacement/refurbishment of the ageing 11 kV switchboards at the Hay Street and Milligan Street substations. Engineering reports commissioned by Western Power outlined risks of explosive failure of the old switchboards (some were about 45 years old and approaching end of service life). Replacement was recommended within five years i.e. in the AA4 period.

Engevity considers the need has been justified in line with the NFIT.

Scope Definition

The solution was to refurbish/replace components of the six 11 kV switchboards at the HAY and MIL substations:

- MIL: 2 X GEC and 1 X Yorkshire;
- HAY: 2 X GEC and 1 X Yorkshire.

173 Switchboard Condition Assessment and Risk Management Plan, [redacted] for Western Power, 27 May 2015

174 Hay Street and Milligan Street Switchboard Refurbishment Option, Western Power, 10 December 2018

175 [redacted]

Western Power has considered alternative options to achieve the same outcome and on the basis of cost, safety and reliability opted for refurbishment/replacement.

The project has followed Western Power's corporate and procurement policies, including the Investment Governance Framework ([redacted]).

Engevity considers the scope is commensurate with the need and is in line with the NFIT.

Timing

Engevity considers the timing of the project is appropriate on the basis that it occurred in accordance with the condition assessment recommendations.

Risk Management

Engevity considers the risks associated with the existing 11 kV switchboards, including the reasons for urgent action, have been clearly identified by Western Power and the investment in the HAY MIL Switchboard project is appropriate. However, Engevity considers that the absence of any risk quantification makes it difficult to establish from Western Power's documentation that the most efficient and prudent solution was objectively chosen. Noting the value of the project and criticality of the sites to the Perth CBD supply, from our experience with other Australian NSP's we would expect the risk management and options assessment process to include a quantification of risk in terms of reducing Expected Unserved Energy (MWh) valued at the Value of Customer Reliability[176] The qualitative assessment of options for effective mitigation of safety and reliability risk in the NFIT compliance summary and attached business case is noted. However, Engevity believes a quantitative approach to justify capital investment is required to ensure the benefits outweigh the risks.

Cost Efficiency

The delivery of the HAY MIL Switchboard project, to ensure the safety and reliability of two of the most important substations in the Perth CBD that are critical to supply reliability, is prudent expenditure.

The HAY MIL Switchboard project was delivered using Western Power's stage gates. The business case ([redacted]) considered multiple options and the recommended option was based on revised refurbishment/replacements costs estimated after extensive investigations by Western Power, [redacted] The large variance from the AA4 approved expenditure represents decreased expenditure associated with the revised refurbishment/replacement recommended option. The investment substantially lowered safety and reliability risks, including for catastrophic switchboard failure.

The hybrid replacement/refurbishment recommended option is more cost-efficient than the revised replace all option, while the 'do-nothing' option is inconsistent from the safety and reliability point of view. However, Engevity is concerned that the lack of costing for a refurbish option at the outset due to its qualitative dismissal as infeasible is problematic, given that a refurbishment option was found at approximately one third of the cost of Western Power's proposed solution in its AA4 submission and approximately one sixth the actual cost identified to implement their preferred AA4 solution following further scoping. To avoid the potential for incorrect qualitative decisions on risks and benefits, other Australian TNSP's and DNSP's have moved to quantitative approaches to justify capital investment in dollar terms to ensure that the benefits of investment outweigh the risks.

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176 AER now sets the VCR for the NEM networks. Whilst the residential average VCR across the NEM is currently \$25k/MWh but higher values of \$68k/MWh are published for the small to medium commercial (<10MVA) and project specific values for CBD projects have been proposed at \$170k/MWh for the Sydney CBD and \$90k/MWh for Inner Sydney in TransGrid's *Powering Sydney's Future, RIT-T Project Assessment Draft Report*, p.7

These variances bring into question the validity of the options assessment process and the qualitive risk assessment processes that Western Power has frequently relied on to justify the majority of its projects for both AA4 and AA5. Our review of Western Power's project cost variance found very high variability in outturn cost vs AA4 regulatory estimate in the positive and negative direction. We also note that there was no clear trend by expenditure type or asset type. As a result, these trends appear to be random, which suggests a largely uncontrolled project cost management process.

Notwithstanding these comments, Engevity considers the HAY MIL Switchboard project was delivered in a cost-efficient way, on the basis that the out turn cost was well below the cost forecast for the project in the AA4 submission, and much lower than the actual pricing of Western Powers original solution. Therefore, the project implemented in AA4 represents a more efficient solution to the network need than the original scope included in the AA4 proposal.

Scope Efficiency

The scope and design have focused on safety and reliability outcomes for key CBD transmission switchboards subject to elevated risk of catastrophic failure. The project has followed Western Power's corporate and procurement policies, including the Investment Governance Framework [redacted]

The scope of the works in the hybrid replacement/refurbishment solution is well defined. Engevity considers the project scope is appropriate for dealing with the safety and reliability risk identified need. However, Engevity is concerned that the lack of costing for a refurbish all option makes it impossible to guarantee the most scope-efficient solution has been found.

Engevity considers the project scope is appropriate for the defined outcomes.

Strategic Alignment

The project is consistent with the principles of the Western Power revised CBD Strategy ([redacted]) and the Transmission Plant Circuit Breaker and Switchboard Asset Strategy ([redacted]).

The project follows Western Power's corporate strategy and procurement policies, including the Investment Governance Framework [redacted]

Engevity considers the project is aligned with the strategic intent of the transmission replacement program.

Options Analysis

Western Power reviewed available options after the AA4 submission, which recommended a 'like-for-like' replacement of the switchboards. Western Power appear to have considered financial, legal, reputational, safety, reliability, technical, quality and environmental risks in considering the subsequent business case options – but only at a relatively high level using their risk matrix. Assessment of options was also against a qualitative criterion of a prudent investment, addressing deliverability issues and alignment with the Western Power Asset Management Strategy.

Western Power considered 4 options in the business case as part of this investment[177]:

- Option 1 – 'Do-nothing' and reactively replace on failure due to fault, age or an external influence. This option does not assess safety and reliability risk or any of the other evaluation criteria. It is not consistent with the actions of a prudent operator and does not align with the Asset Management Strategy. Estimated CAPEX $0m ($0m Net Present Cost (NPC)).

177 Western Power, *AAS – Attachment 5.4 – AA4 NFIT Compliance Summary – HAY MIL Switchboard – 1 February 2022,* pp. 8-9

- Option 2 – 'Replace all' six switchboards. Only possible with functionally equivalent replacement due to changes in safety and technical standards over the last 50 years. Requires extensive siteworks and interim temporary switchboard. The cost more than doubled in comparison to that in the AA4 submission. Estimated CAPEX $62.1m ($41.4m NPC).
- Option 3 – 'Refurbish all' six switchboards. This would involve major service of each component of each switchboard, maintaining the type/mechanisms of each board. **A cost estimate was not developed for this option.**
- Western Power states that **'this option would be significantly cheaper than the recommended option'**. However, no costing was undertaken because Western Power states that 'the option does not fully satisfy any of the remaining evaluation criteria'.
- Option 4 – Hybrid replacement/refurbishment combination. This is the recommended option that was completed. A refurbishment of components where practicable and retrofitting/replacing components that are root cause of major risks (particularly circuit breakers). Less than a quarter of the cost of Option 2, much shorter outage times and maintains full functionality of the boards during the project (no interim solution needed). Defers full replacement cost for an estimated 20 years. Supported by [redacted] and Western Power investigations as the most viable option. Estimated CAPEX $13.5m ($13.2m NPC).

The recommended hybrid replacement/refurbishment Option 4 appears to Engevity to be a reasonable balance of major risk alleviation at substantially lower cost than the 'replace all' Option 2. However, the 'refurbish all' Option 3 is not costed – and had been dismissed at the outset despite the assertion that it would be significantly lower cost.

In addition, the Option 4 'hybrid' approach appears to be a relatively conventional refurbishment scope – where most components are refurbished, with replacement of components with poor serviceability, and the most critical components. Engevity considers that the specialist nature of the work means that consultation with [redacted] should have occurred before the AA4 submission to inform its option analysis, feasibility decisions and pricing for a $30m-$65m investment.

Whilst it has been favourable to customer in this instance, Engevity remains concerned that this issue is likely to affect the scoping and options assessment of Western Power's AA5 program.

Delivery Model (including staging)

All materials and equipment for this project were sourced in accordance with Western Power's corporate procurement policies. [redacted] engagement under a procurement of materials contract and installation/refurbishment service contract was subject to a Waiver of Competition/Exemption approval.

Western Power states that its records and drawings of the 1974 switchboards are 'virtually non-existent' and it was necessary to engage a contractor with relevant expertise, historical experience and factory set-up. Engevity considers that the Waiver of Competition/Exemption approval is appropriate because [redacted] is the Original Equipment Manufacturer (OEM). Engevity further notes the procurement contract includes a Long Lead Commitment for [redacted] to supply customised parts and spares as part of the risk mitigation strategy associated with refurbishment of aged assets. This provides economies of scale for manufacturer factory set-up related to parts and spares fabrication.

The project appears to be appropriately staged across the AA4 period and demonstrates the need for and benefits of engaging with equipment manufacturers early in the scoping process to better understand the options and likely costs for maintaining older equipment in service.

7.3 Grid Transformation Engine – AA4 NFIT Assessment

7.3.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **Grid Transformation Engine project delivered in AA4**. We found that **the expenditure complied with the NFIT requirements**. As a result, we have not made recommendations for ERA to make any adjustments in this expenditure category.

The expenditure and scope of the Grid Transformation Engine project is summarised in the table below.

Table 7–7: AA4 Expenditure and scale – NFIT Compliance – Grid Transformation Engine [$m nominal][178]

GTEng	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1 Actual	Yr2 Actual	Yr3 Actual	Yr4 Actual	Yr5 Forecast	Total
Western Power Actual AA4 CAPEX	-	-	-	-	-	**14.5**
Expenditure that does not meet NFIT	-	-	-	-	-	-
Engevity Recommended	-	-	-	-	-	**14.5**

Assessment Overview

Table 7–8: Assessment Overview

Project/Program	Grid Transformation Engine
Actual Cost $m	Over the AA4 period, the total project expenditure was $14.5m which included GTEng Proof of Concept ($4.5m) and GTEng Enterprise $10m.
Variance to approved $m	The total expenditure of $14.5m (nominal) aligns with the original forecast in the Western Power business case. No specific allowance was included in the AA4 allowance for GTEng
Need	The development in technology clearly meets a present need in Western Power's network area. We understand Western Power's energy scenarios proved a useful input for EPWA system planning activities such as the Whole of System Plan. Engevity understands that Western Power's Future Grid model (GTEng) is used to undertake whole-of-system NPC analysis to define an optimised modular grid program.[179]
Scope Definition	Engevity has concerns with the underlying assumption used in GTEng particularly in respect to the forecasting approach which appears to not include robust sensitivities or options analysis, cost input assumptions have

178 [redacted]

179 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, pp.7-10

Project/Program	Grid Transformation Engine
	not been validated to actual costs, and no quantitative analysis of the emissions impact (see limb 3 of the Access Code). Engevity understands that GTEng is decision-making tool that is used by Western Power as part of the modular grid strategy and uses end-of-life asset management considerations as inputs and outputs investment pathways for SPS and Microgrids.[180] Engevity recognises that this approach is reasonable in theory, however, has been unable to interrogate or verify the assumptions, inputs or outputs. Given the early stages of GTEng use and deployment, Engevity remains concerned that it may not currently capture all key factors relating to making prudent and efficient investments and that many assumptions are likely to evolve with experience, both of which can substantially modify model results.
Timing	Western Power clearly has a need for improved modelling and scenario testing capability.
Risk Management	GTEng is a purpose-built modelling tool that clearly compliments Western Power's existing network planning and risk management platforms.
Cost Efficiency	The operational efficiency benefits associated with the business case for GTEng have not been clearly stated by Western Power. Also, we have concern that the level of evidence provided in the scaled-up Enterprise investment in GTEng has not had a third-party review or evidence provided that the benefits are being realised. The actual expenditure aligns with the forecast which may be as a result of self-performing the delivery.
Scope Efficiency	Also, Engevity has not observed any third-party validation of the outcomes in the Enterprise version of GTEng as was completed for the Proof-of-Concept version of the platform. The GTEng scope appears to have omitted a robust scenario-based planning functionality and is driven by relatively static inputs which need to be monitored closely given the scale of expenditure that is reliant or influenced by the GTEng.[181] The exclusion of EV's in the customer demand forecast and treatment of the residual service life of assets beyond the Mean Replacement Life is also a concern. Despite this concern, Engevity considers that the expenditure for the development of GTEng has been staged in line with good industry practice. Further development and validation of the system as part of ongoing improvements could address the issues noted above.
Strategic Alignment	The Western Power corporate plan identifies the need for a modelling toolset to support the organisation consider the range of possible scenarios as the sector continues to decarbonise and become more decentral. Engevity understands that GTEng is now not only being used for short term investment decision but also long-term strategic planning.

180 Attachment 8.2 – Network Management Plan, Western Power, p. 134

181 We understand that the Whole of System Plan considers energy forecast scenarios and informs the GTEng modelling.

Project/Program	Grid Transformation Engine
Options Analysis	Although the cheapest option was not selected, Western Power appears to have balanced cost, risks and functionality of the alterative cases considered. The option selected also appears to have retained the IP from both earlier learnings through the proof-of-concept version and for future use cases which is an advantage. Engevity is however concerned that the selection of Option 2(b) may not overcome internal key person risks identified and limit the internal ability to scale the platform.
Delivery Model	The expenditure has been staged in line with prudent industry practice.

Findings

Engevity has reviewed Western Power's proposed expenditure relating to **GTEng AA4 Project** and found that:

a. **The proposed expenditure is efficient** with the objective of minimising costs on the basis that the project has demonstrated a clearly identified need and supports Western Power to undertake required transition planning to a modular decentralised grid and the tool appears to be integrated in AEMO's Whole of System Plan essential for medium to long term system planning.

b. The program captures the available and realisable economies of scale and scope through clear and logical staging of the works.

c. The investment **is consistent with reasonable expectations** of the level of future network services required by customers because it facilitates the assessment of the cost, timing and technology tradeoffs across Western Powers service area.

d. **A reasonable range of alternative options has been considered** for the proposed investment, with the most appropriate solution chosen. This is shown by evidence in the GTEng NFIT compliance summary which considered multiple delivery and scope alternatives.

Recommended Adjustment

Overall, we consider that the Grid Transformation Engine Project for the AA4 satisfies the NFIT requirements.

7.3.2 AA4 NFIT Assessment

Expenditure Overview

Western Power's Grid Transformation Engine (GTEng) was developed in response to the change in technology, customer behaviour and the financial risk of future distribution network asset stranding which is compounded by assets reaching end of life. It has supported a more sophisticated planning capability through leading scenario modelling used in both short- and long-term network planning.

Over the AA4 period, the total project expenditure was $14.5m which included GTEng Proof of Concept ($4.5m) and GTEng Enterprise $10m. The total expenditure of $14.5m nominal aligns with the original forecast.

Historical Context

After developing a proof of concept, Western Power scaled the platform to an enterprise solution to improve traceability, automation, reduce dependency on various SME's within the business.

Need

Western Australia is unique in position to many of its peers in the National Electricity Market when it comes to navigating the decentralisation and decarbonisation of the grid. This is because the regulatory and legislative environment in WA allows much greater flexibility for Western Power to incorporate the alternatives into the network RAB (in contrast to the NEM networks, who face various ring fencing, regulatory, customer consent and historical factors that make it more difficult). The development of Standalone Power Systems (SPS) and embedded networks or microgrid technology now creates an opportunity for consideration beyond traditional network replacement works.

Furthermore, the financial risk of over investing in ageing regional network could have a detrimental impact on Western Power customers, if alternative technical solutions are not thoroughly considered and optimised across the network. The development of GTEng has been peer reviewed and validated by specialist consultants and has been largely scoped and delivered by in house resources with the support of some external specialists.

The GTEng platform has been used on strategic projects such as SPS, Network undergrounding, Whole of System Plan and the Community PowerBank project and appears to possibly improve on more traditional network planning techniques. Engevity remains concerned however, that the enterprise version of GTEng has not been independently verified and some of the input assumptions appear not linked current market pricing and do not consider likely outcomes, such as EV uptake. Given that it is also embedded into the annual and 10-year planning process it is important that the modelling is regularly reviewed and independently verified.

The ongoing development in GTEng platform clearly is a priority for Western Power's and is considered by Engevity as a likely important element to further mature as Western Power transitions to more renewables and implements its modular grid strategy.

Scope Definition

The development of the initial PoC GTEng platform is a prudent staging of the investment. This was used to explore and test modelled optimisation of various concepts. Whereas the scaled-up Enterprise GTEng supported the sustainability of the solution and appears to have embedded it into future planning across the Western Power organisation.

GTEng is supporting Western Power's unique situation and network which must consider non-traditional solutions to continuing to invest in poles and wires in regional and remote areas as they may become obsolete over time. We understand that GTEng links into existing asset replacement and maintenance platforms as well as the Network Risk Management Tool (NRMT).

In these cases, open questions remain over the long-term validity of the GTEng trade-off decisions between network and non-network solutions. This is because of the wide uncertainty band that is applicable to the cost curve assumptions for solar and storage and changes in customer demand for electricity (e.g., cost of subsequent upgrades under a strong electrification of transport, heating etc. scenario). Western Power's approach does not appear to consider the various development scenarios, or value the optionality of deferral under a range of probabilistic planning scenarios in a manner that is employed by other Australian transmission networks (for example TransGrid, ElectraNet and Powerlink have historically adopted probability weighted, scenario based forecasting for their regulatory proposals at various times over the past 15 years) to evaluate the efficient value of projects in an uncertain development environment.

On this basis, we consider the that the scope of the GTEng tool may not represent leading practices for addressing high levels of planning uncertainty, the scope of the project is reasonable to assess the relative benefit and timing of moving to different technology <u>under the single development scenario and costing assumptions reference third party models rather than actual market cost estimate analysis</u>. The assessment of input sensitivities can assist to understand scope and timing impacts, but still does not value the optionality of either solution to network constraints or condition (such as, piecemeal replacement typically occurs of poles in response to a specific condition issue which spreads the investment, and therefore cost impact, over decades).

Other matters where the GTEng scope does not take account of material uncertainties include:

- Western Power has excluded the impact of electric vehicle charging from its demand and energy forecasts for AA5. AEMO's forecast of significant electric vehicle uptake in the late 2020's and through the 2030's means the electricity needs of regional and rural customers could change significantly over the notional life of the SPS.
- It is not clear if Western Power will be obliged to service this additional demand through further investment into the RAB, or whether it will be treated like a connection where the customer notionally pays for the assets that only service them (rather than the shared network). If it is the latter, customers are likely to find it more attractive to install their own solar/BESS in parallel to the Western Power SPS which would bypass revenue from the Western Power BESS (as current market prices for similar scale turnkey offgrid systems are already significantly below Western Power's estimates for the SPS program). The decisions by customer will be impact on how the SPS are priced and there is an open question on how aged asset replacements would take into account reasonable growth in demand by customers.
- Careful monitoring of market pricing for SPS assets is critical to ensure that metropolitan customers do not overpay for the regional SPS solutions. The GTEng will need to be run frequently to establish and optimise the scope of overhead network program as technology costs reduce, Western Power delivery costs reduce and similar market-based off grid power solutions can be delivered by third party providers at lower cost. It appears, SPS costs are modelled to match the CSIRO projections for PV and batteries (CSIRO Gencost 2020-21) rather than any direct market pricing.
- The line assets retain a residual life that goes beyond their notional life. Indeed, the notion of the 'Mean Replacement Life' (MRL) in Western Power's documentation implies that it represents the arithmetic average of the population's replacement life. Using a normal statistical replacement distribution around the mean life, half of the poles in the original population are not yet at end-of-service-life (and the other half have notionally been replaced). The reliance and use of MRL's that approximate Western Power's replacement lives means that this variable is considerably impacts the GTEng analysis.

Western Power has identified a desire to expand GTEng at the transmission level by adopting tools such as Plexos to align with the Whole of System Plan. Engevity notes that the ERA should monitor the efficiency of future investment in grid transformation programs to ensure that it compliments, rather than duplicates, AEMO modelling processes and platforms. Whilst it appears that Western Power did not explicitly reference GTEng in its AA4 proposal it was included in ICT expenditure plans to optimise asset and risk network planning practices.

Timing

It is clear that Western Power has a need for improved modelling and scenario testing capability. Customers in regional areas generate approximately 1 per cent of revenue with a forecast of most of the regional areas having a 'negligible' RAB value by 2027[182]. As a result of this assumption, Western Power claim the development of GTEng aligns with its ongoing and future needs.

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182 Engevity highlights that a low 'RAB value' for assets could occur for a variety of reasons and does not represent a prudent or efficient point at which to replace an asset. This should be based on the serviceability, condition and risk of the asset at a particular point in time. For rural customers in areas where the cost to serve is high (due to the low customer density/long line distances).

Engevity notes that a low RAB value rarely means that there is no engineering life remaining. A prudent and efficient operator, acting to minimise costs would seek to extend the life of these assets based on physical inspection of condition, the risks that would be crystalised in the event of a failure and the cost of mitigation works (refurbishment, reinforcing, partial replacement, wholesale replacement) to identify and pursue, the least cost option.

Older, largely depreciated assets are an important source of benefit to consumers as they provide ongoing service without attracting significant capital charges (usually the largest contributor to bills). As a result, large scale replacement of older assets based on their low value in the RAB is not a reasonable justification for investment, but rather a flag for concern regarding the efficient management of the transition.

The completion of Enterprise GTEng has been delayed from August 2021 to January 2022 which has no material effect on costs or the realisation of benefits. Overall, the timing of the project is appropriate to support Western Power's planning and development of its AA5 proposal.

Risk Management

Engevity found that GTEng appears to be a complementary modelling tool to existing platforms operationally used in WA. It provides a more sophisticated means of analysing network performance and power quality impacts of alternative network renewal or replacement options.

We do note that GTEng is used to inform Western Power's planning and replacement programs, and to some extent overlaps the function of Western power and AEMO planning tools for the SWIS. Despite noting concerns over key person risks associated with the platform, it has been internally developed and now is supported by Western Power. Engevity raises a concern that the cost of ongoing maintenance and updating the system may become significant in the future.

The procurement of the GTEng has followed Western Power's Investment Governance Framework and the Project Management Plan. However, despite third party validation of the Proof-of-Concept version of GTEng being completed by third parties and SME internally, Engevity has not observed a similar review of the enterprise implementation.

Overall, we are satisfied that the delivery risks for the GTEng project were reasonably managed within the notional AA4 allowance for the project. However, we were unable to confirm whether a number of risks created by the project had been fully addressed. These include:

- The key persons risks from reliance on internal SME's may not have been overcome;
- It is not clear if the CSIRO red flags, such as more sophisticated customer demand projections, have been addressed;
- the ongoing inhouse investment required to maintain GTEng may be substantial, which is supported by Western Power's AA5 proposal for continued investment;
- From the graphs provided, SPS appear to be a higher risk option, without a clear explanation of how risk / cost trade-offs were made;
- The staging of the outputs from GTEng analysis results appear high level without detailed sensitivities applied. This implies a very large volume (and value) of 'at risk' assets that are, in effect, already past their notional use-by date according to the failure forecasting algorithm. Rather than indicating that Western Power has been managing its assets imprudently, this 'backlog' effect is almost universally a sign that there is an artificially forced age-condition or condition-failure relationship in the calculation that has not been calibrated to the actual failure history of the network.

Prudent and efficient operators create value for their customers by identifying the risks on their network, mitigating them through targeted inspection, maintenance, refurbishment and replacement works to keep assets in service for as long as practicable. For some asset classes where the consequence of failure is low (such as much of the rural network), it is not unusual for assets to simply be operated for as long as they last and then replaced or repaired on failure.

For critical assets like sub transmission transformers serving the CBD, the consequence of failure is such that the reliability impact on customers is sufficient to bring forward replacement to mitigate the exposure. Whereas other assets should be monitored for defects before replacement is required.

Consequently, replacement for network transformation purposes should be considered separately and not be conflated with obsolescence due to risk to the network in the short term. Engevity has not been able to differentiate the risk and transformation drivers in the GTEng model.

We consider that the GTEng project itself was delivered subject to reasonable risk management practices. We note however, the project has also created potential concerns that will affect the AA5 forecast CAPEX program.

Cost Efficiency

The Enterprise version of GTEng utilised commercial Off the Shelf (COTS) modelling platforms and considered market pricing through preferred vendor tendering process. We understand that from the 24 submissions received through the tender process, 5 vendors were shortlisted. However, given the substantial cost, none of the vendors where selected.

Instead, Western Power opted to deliver GTEng in-house, with the support of a system integrator using COTS platforms. Engevity appreciates that although this may have represented a higher risk option it does provide more flexibility for a challenge that is currently quite unique to Western Power and may well be more sustainable in the longer term.

Within the detailed business case (Page 56), the 10-year business case is stated to have a provisional sum of $25.1m although the AA5 estimate appears to exceed this.

Other concerns noted in Engevity's review were:

- The value from GTEng has not been quantified however additional expenditure is forecast for AA5;
- Despite costing figures provided, Engevity was not provided detailed cost breakdown;
- It was not clear whether the R&D tax credit was applied to the AA4 figures, and their potential for an overallocation into the RAB.

Despite the above concerns, Engevity considers the GTEng expenditure to be reasonable for scope and scale of the project.

Scope Efficiency

We understand that Western Power explored the global market for products that could support its need. To support these efforts, Baringa Associates were engaged to support sourcing activities, scope definition, options assessment and commercial positioning. It appears that Western Power also engaged the support of CSIRO and CutlerMerz to validate the assumptions underlying the GTEng PoC. It appears that an extensive global search was undertaken to find a suitable off-the-shelf solution however this did not yield a suitable solution.

As noted above, the GTEng scope appears to have omitted a robust scenario-based planning functionality and is driven by relatively static inputs which will need to be monitored closely given the scale of expenditure that is reliant or influenced by the GTEng. Noted exclusions include the electrification of transport, technology cost curves for solar, storage, electric vehicles, third party SPS systems and demand side factors such as individual customer demand and energy consumption (relative to SPS size).

Furthermore, whilst the scope of the GTEng project itself is efficient, the exclusion of the consideration of the residual service life of assets beyond the Mean Replacement Life will significantly understate the value of maintaining the existing network (statistically speaking, half of the asset population can be expected to remain in service beyond the mean replacement life, with the other half already replaced). Western Power appears to take a conservative view of operating older assets when compared to other Australian electricity networks.

Engevity considers that the expansion of GTEng in AA4 from PoC to Enterprise was appropriate.

Strategic Alignment

The Western Power corporate plan identifies the need for a modelling toolset to support the organisation as it considers the range of possible scenarios to enable the sector to continue its decarbonisation pathway and operate a more decentralised asset fleet to efficiently meet customer needs. Engevity understands that GTEng is not only being used to support short term investment decisions but also to inform long term strategic planning.

The decision to expand GTEng beyond a PoC was as a result of expanding use cases through the development of the WA Governments policies (e.g. DER Roadmap and Energy Transformation Strategy), IT risks and growing key person concerns. We understand that GTEng has also been applied as a key input into WA's Whole of System Plan (WoSP).

Options Analysis

Western Power consider three options in its works planning report in April 2019. This was to:

1. Option 1 – Do Nothing.
2. Option 2 – Maintain and extend the PoC Model.
3. Option 3 – Develop an Enterprise planning solution.

Engevity supports the decision to scale the PoC to an Enterprise tool which was developed in house at an estimated cost of $16.5m ($14.5m CAPEX) and NPC of $18.5m. Although not the lowest cost option it does balance the cost, risks and functionality of the alterative cases considered. The chosen option also leverages prior investment and benefits by retaining the Intellectual Property (IP) from both Western Power's earlier learnings through the PoC GTEng and for future use cases.

Notwithstanding the above, Engevity has not sighted documentation that confirms that all outcomes of GTEng Enterprise have been achieved. However, we also did not observe anything that suggests that that the GTEng Enterprise project did not achieve its outcomes.

As a result, we consider that Western Power considered a reasonable range of potential options, and the chosen option was found to appropriately balance risk, delivery, cost and timing.

Delivery Model (incl. staging)

The novel nature of the GTEng project means that there is likely limited precedence for Western Power to draw upon both internally and in the market. Moving from PoC to an Enterprise level appears a reasonable staging methodology to manage project risk and total investment.

Engevity recognises that the development in the PoC stage is in itself a means to manage delivery risk and stage the project in a way that if the PoC stage is abandoned, the much more involved enterprise stage has not yet commenced – ensuring that the majority of the budget remains to deploy into alternative solution, projects or business priorities.

We do raise some concern regarding:

- the rigour of external procurement process and basis for excluding the respondents – especially given the number of vendors that responded;

- the basis for selecting Option 2(b) is explained to some extent, however it could use further justification in respect to the long-term implications. The dis-benefits and risk of Option 2(b) considered do not appear to have been fully investigated.

Overall, Engevity considers that the delivery model was appropriate for an IT project of this nature and represented prudent and efficient staging of the initial Proof of Concept implementation before moving to Enterprise level deployment.

Western Power's choice to deliver the project in house, does expose them to the ongoing development and maintenance costs, the management of key person risk for an important corporate system that will need to be efficiently managed in AA5 and beyond.

7.4 Reactive Voltage Rectification - AA4 NFIT Assessment

7.4.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **Reactive Voltage Rectification project delivered in AA4.** We found that **the expenditure complied with the NFIT requirements**. As a result, we have not made recommendations for ERA to make any adjustments in this expenditure category.

Over the AA4 period, the expenditure and scope of the reactive voltage rectification project is summarised in the table below.

Table 7–9: Western Power Actuals – NFIT Compliance - Reactive Voltage Rectification [$m nominal][183].

	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1 Actual	Yr2 Actual	Yr3 Actual	Yr4 Actual	Yr5 Forecast	Total
Western Power Actual AA4 CAPEX	-	-	3.7	10.6	11.7	**25.1**[184]
Expenditure that does not meet NFIT	-	-	-	-	-	**-**
Engevity Recommended	-	-	-	-	-	**25.1**
Stage	-	-	*1*	*2*	*3*	
Reactors (MVAr)	-	-	25	125	200	**350**

Assessment Overview

Table 7–10: Assessment Overview

Project/Program	**AA4 Reactive Voltage Rectification**
Actual Cost $m	The unforeseen CAPEX is appropriate as a longer-term network reinforcement solution to the 'System Low' issue first identified in 2019 and based on extreme over-voltage and blackout risk forecast for 'System Low' demand to occur in 2022/23.
Variance to approved $m	Total of $5.4m less than combined approval value of three business cases due to competitively tendered prices. The was no l allowance for this initiative in the ERA AA4 Further Final Decision.
Need	Voltage compliance and system security need has been clearly identified. The issue was unidentified by Western Power until 2019 and is forecast to result in extreme over-voltage and blackout risk by 2022/23 without provision of appropriate additional reactive power absorption capability.

183 Sources: AAS – Attachment 5.7 – AA4 – NFIT Compliance Summary – reactive voltage rectification – 1 February 2022, pp. 2-3 ($25.1m quoted as total cost in text. Summed stage costs for Tx voltage regulatory activity are $26m); AAS – Attachment 5.2 – AA4 Capital Expenditure Variance Analysis Report – February 2022 ($25.9m as summed total of voltage regulatory activity costs under Tx capacity expansion).

184 Engevity notes a discrepancy of $0.9m between the project total CAPEX of $25.1m stated by Western Power in the AA4 NFIT compliance summary and the sum of yearly total CAPEX (the same as the cost of each of the three project stages in the AA4 NFIT compliance summary) of $26m.

Project/Program	AA4 Reactive Voltage Rectification
Scope Definition	The scope is commensurate with the need - based on the forecast 'System Low' demand to occur in 2022/23.
Timing	The investment timing is consistent with the need date, with 350 MVAr of additional reactive reinforcement delivered in stages, to ultimately address to 2022/23 need to avoid extreme over-voltage (compliance) and blackout (system security) risk.
Risk Management	The risk of voltage non-compliance and system blackout due to 'System Low' has been appropriately managed by the program, in accordance with Western Power's project risk management practices.
Cost Efficiency	The costs have been estimated using Western Power's system and unit costs and subject to competitive tender. Cost estimates were derived from Western Power's historical unit cost estimates for medium voltage reactor installation. Some of the selected options were more expensive than alternatives but better fulfilled other requirements.
Scope Efficiency	The scope of the reactive voltage rectification program has been challenged for options to address a reduced scope within the AA4 period. However, the provision of 350 MVAr of additional reactive power absorption forms the basis for Western Power to respond to the most seriously considered options from the forecast in 2022/23.
Strategic Alignment	Aligned with Western Power's Voltage Management Strategy, Grid Transformation Strategy, Grid Strategy, WA WOSP and DER Roadmap
Options Analysis	Identified a reasonable range of alternative options, demonstrated how the recommended options were selected and articulated why. There does not appear to be any serious consideration of any options that total to less than 350 MVAr across the program.
Delivery Model	The delivery model, including staging and use of external, competitively tendered providers was appropriate to the urgency of the unforeseen need.

Findings

Engevity has reviewed Western Power's AA4 NFIT compliance relating to reactive voltage rectification and found that:

a. **The actual expenditure is considered to be efficient** with the objective of minimising costs. It is a longer-term network reinforcement solution to an unforeseen 'System Low' issue that was only identified in 2019. The program sought to address the forecast 'System Low' demand to occur in 2022/23. The costs were competitively tendered and were ultimately below Western Power's total estimate.

b. **The program captures the available and realisable economies of scale and scope.** The scale and scope were consistent with the required goal of mitigating extreme risk of potential over-voltage and system blackout associated with required additional reactive absorption capability at 'System Low' demand during the AA4 period. Additional constraints on solutions were due to the issue being unforeseen until 2019 and requiring a rapid solution by 2022/23. Options for investment were considered in each stage of a multiple stage investment plan across the AA4 period, with the recommended options chosen in accordance with lowest cost, satisfying all investment objectives and constraints.

c. The proposed investment **is consistent with reasonable expectations of the level of future network services required by customers**. System security and voltage compliance are maintained by the investment, based on avoiding extreme risk by 2022/23, by providing 350 MVAr of additional reactive absorption capability in alignment with forecast need. The rapidly increasing adoption of solar in recent years, demonstrates the need for voltage support to be available to supply future network services.

d. **A reasonable range of alternative options has been considered** for the proposed investment, with the most appropriate solution chosen. The options demonstrated consideration of a range of timing and flexibility for solutions. However, there does not appear to be any serious consideration of any options that total to less than 350 MVAr across the program. The scale of the forecast 22/23 shortfall as well as the continued and rapid increase in roof top solar installation are such that a program of this scale is certainly not unreasonable. Based on minimum demand forecast for the AA4 period, additional reactive power of 350 MVAr was forecast to be required by 2022/23 to avoid over-voltages and mitigate risk of system blackout.

Adjustment Recommendation

Overall, we consider that the Distribution Reactive Voltage Rectification Program for the AA4 satisfies the NFIT requirements.

7.4.2 AA4 NFIT Assessment

Overview

The program involves the installation of 350 MVAr of reactors in three stages. Completed in August 2021 for $25.1m[185]. Total of $5.4m less than combined approval value of three business cases due to competitively tendered prices.

The purpose of the program was to mitigate:

- localised non-compliant network over-voltages;
- risk of system blackout.

Both issues arose due to excessive reactive power in network during low demand periods in AA4 (‘System Low’). Nil forecast CAPEX was included in AA4 submission because the impact of ‘System Low’ events was not foreseen.

Minimum system demand forecast to continue to decline over the AA4 period, leading to higher risk of system blackout due to cascading tripping of synchronous generators and non-compliant system voltage levels. Additional reactive power absorption capability of 350 MVAr is forecast to be required by 2022/23 to avoid over-voltages and mitigate risk of system black-out[186].

Over the AA4 period, reactive voltage rectification accounted for the expenditure and scope summarised in the table below.

[185] AAS – Attachment 5.7 – AA4 – NFIT Compliance Summary – reactive voltage rectification – 1 February 2022, p. 2, 3 and 14.

[186] ibid. p. 2-3

Table 7–11: AA4 Expenditure and scale – NFIT Compliance - Reactive Voltage Rectification [$m nominal][187]

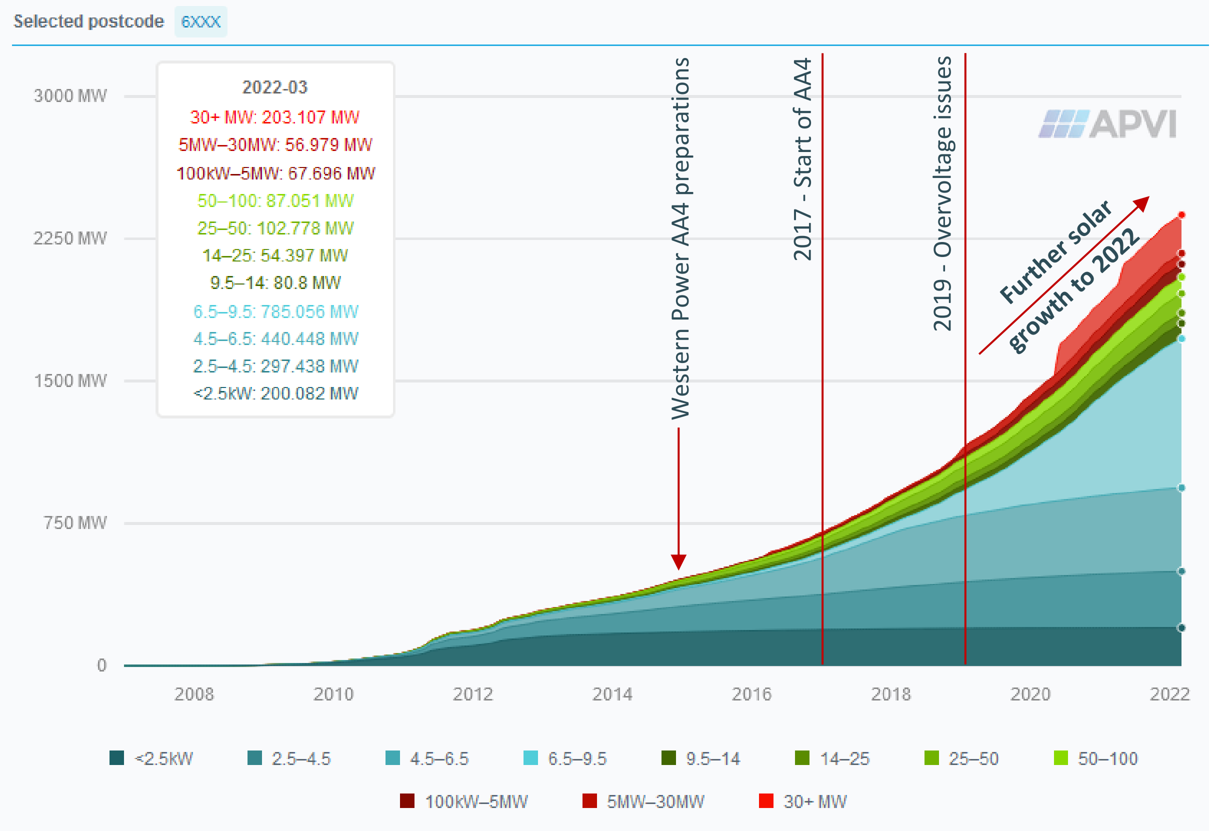
	AA4 Actual Expenditure – Western Power Proposed					
	Yr1 Actual	**Yr2 Actual**	**Yr3 Actual**	**Yr4 Actual**	**Yr5 Forecast**	**Total**
Total CAPEX	-	-	3.7	10.6	11.7	25.1
Direct CAPEX	-	-	3.1	8.8	9.7	**20.7**
Stage	-	-	*1*	*2*	*3*	
Reactors (MVAr)	-	-	25	125	200	350
AA5 OPEX Benefit	-	-	-	-	-	-

Historical Context

Whilst other Australian networks in NSW, QLD and SA had been tracking minimum demand risk since the mid 2010's, this issue was not foreseen in WA at that time, due to the volume of rooftop solar that would be needed to be installed before it would start to cause issues. The 'System Low' issue was not a historically relevant consideration prior to the AA4 period. Western Power first became aware of the issue from customer complaints due to high voltages and solar PV trips in early-to-mid 2019. This rate of growth was unforeseen at the start of the AA4 period. For reference, residential and small commercial roof top solar can broadly be approximated as systems less than 14kW (dark green and teal in the graph below).

[187] Sources: AAS – Attachment 5.7 – AA4 – NFIT Compliance Summary – reactive voltage rectification – 1 February 2022, pp. 2-3 ($25.1m quoted as total cost in text. Summed stage costs for Tx voltage regulatory activity are $26m); AAS – Attachment 5.2 – AA4 Capital Expenditure Variance Analysis Report – February 2022 ($25.9m as summed total of voltage regulatory activity costs under Tx capacity expansion).

Figure 7–1: Growth in Western Australian Postcodes Solar 2007-2022[188]



Need

Engevity draft considers that the voltage compliance and system security need has been clearly identified, based on the information provided.

'System Low' events are becoming more severe and common in the SWIS due to transformation of the network with more non-synchronous DER, including solar PV, and retirement of traditional synchronous generation. This leads to a deficit of reactive power absorption capability during mild, sunny days with high solar PV output and relatively low demand.

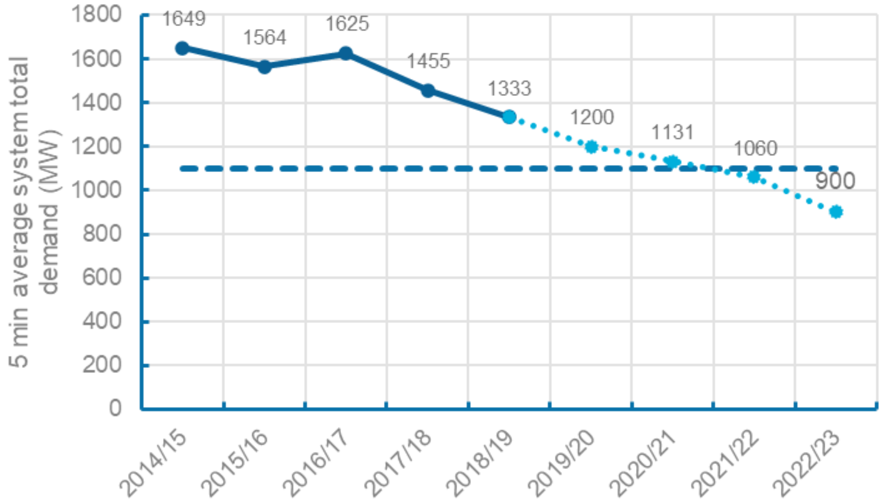
The result can be generator trips which in the worst-case can be cascading plus higher voltages unable to be controlled by zone substation transformers and potentially tripping solar PV systems and/or causing equipment damage and consequent outages. In 2019, the issue was first identified. The risk associated with widespread voltage non-compliance was rated as High by Western Power and if untreated, forecast to escalate to Extreme by 2022/23. System security risk was rated as Medium and forecast to increase to Extreme by 2022/23[189]. These ratings were consistent with AEMO views. The primary drivers for the program were to achieve compliance with legislative obligations around voltage regulation and to improve customer reliability by offsetting the rapidly increasing negative impacts of 'System Low'.

Figure 7–2 shows a Western Power forecast of System Low demand in October 2019. Below 1100 MW demand, system simulation studies showed 250 MVAr new reactive absorption required to retain efficient generator dispatch, increasing to 350 MVAr at System Low of 900 MW demand, forecast to occur in 2022/23.

[188] Source: APVI PV Postcode Data – Western Australian Postcodes (6xxx)

[189] Ibid. p. 5 and p. 8

Figure 7–2: 'System Low' history and Western Power forecast (October 2019)



Scope Definition

Engevity considers that the scope of the expenditure is commensurate with the need based on forecast 'System Low' demand to occur in 2022/23.

The longer-term network reinforcement solution to the 'System Low' issue was to install 350 MVAr of reactors plus undertake local corrective actions to address high priority localised non-compliant voltage excursions. The program was undertaken across three consecutive stages, with three reactors installed to deliver the required 350 MVAr to address the forecast 'System Low' demand to occur in 2022/23.

Timing

Engevity draft considers that the investment timing is consistent with the need date. The project probably could not be reasonably deferred due to risk, and it was not prudent to bring it forward, given that the issue was only identified in 2019 and was projected to result in extreme risk by 2022/23.

350 MVAr of additional reactive reinforcement was projected to be needed at a 'System Low' of 900 MW demand, forecast to occur in 2022/23. The project was appropriately staged and timed to deal with the evolving issue, given that it was only identified in 2019 and was projected to result in extreme risk for voltage non-compliance and system security (blackout) by 2022/23.

Risk Management

Engevity draft considers that the risk of voltage non-compliance and system blackout due to 'System Low' has been appropriately managed, in accordance with Western Power's project risk management practices.

The program was delivered under Western Power's project risk management practices. Risk was identified, assessed and treated in accordance with Western Power's Network Risk Management Standard.

'System Low' was a new issue that was not foreseen when the AA4 submission and revised proposal were prepared. It was first recognised in 2019, during the AA4 period. It was projected to result in extreme risk of voltage non-compliance and system blackout by 2022/23 without appropriate corrective actions. The staged program was undertaken according to three approved business cases, with options considered for each stage. It mitigated the risk of potential over-voltage and system blackout appropriately. The quantum of reactive reinforcement provided was 350 MVAr, matching the additional reactive power absorption capability forecast as required by 2022/23 to avoid over-voltages and mitigate risk of system black-out.

Cost Efficiency

Engevity's finding is that the actual costs likely have been estimated using an efficient system and unit costs. Western Power states that its procurement and delivery agreements were established via a competitive process to meet business requirements and deliver value for money. The cost reduction of $5.4m less than the combined approved value of the three business cases was primarily due to competitively tendered prices being less than estimated[190].

The Gate 2 approval process for proceeding to business case development was based on cost estimates derived from Western power's historical unit cost estimates for medium voltage reactor installation.

In all three stages, at least three options were considered and the least cost option that satisfied the technical requirements was selected as the preferred option. However, Western Power states that the Stage 1 selected option was 10 per cent more expensive than the least cost alternative on a $/MVAr basis but could be delivered more quickly. Western Power also states that the Net Present Cost estimate for the Stage 2 selected option was $3.6m more than the most viable alternative but was a more flexible incremental approach, providing optionality that was not explicitly valued[191].

Scope Efficiency

Engevity draft considers that the scope of the reactive voltage rectification program has been challenged for options to address a reduced scope within the AA4 period. This means options have been considered that have a reduced scope within the AA4 period. However, the provision of 350 MVAr of additional reactive power absorption by the program forms the basis of the most seriously considered options[192]. There does not appear to have been any serious consideration of provision of a smaller quantum of reactive power absorption capacity in the AA4 period. The forecast of 350 MVAr of extra reactive power absorption capability required by 2022/23 appears to have been taken as a necessity. Notwithstanding this, the continued aggressive growth in new solar capacity since 2019 means that any over provisioning of reactive power absorption plant would be quickly absorbed. This reduces the risk associated with system stability and voltage control under minimum demand conditions.

Stage 1 installed 25 MVAr of medium voltage (22 kV / 5 MVAr) reactors at 4 of 11 priority substations. Western Power states that these were about 10 per cent more expensive than 132 kV reactors on a $/MVAr basis but could be delivered a year earlier, allowing the voltage non-compliance to be addressed at all 11 priority substations. Other options included do nothing (reliance on operational procedures) and non-network solutions. However, doing nothing did not satisfy the evaluation criteria and non-network solutions could not be guaranteed to be delivered in time.

Stage 2 installed 125 MVAr of a hybrid of 22 kV and 132 kV reactors at four locations to absorb the forecast increase in reactive power during 'System Low' periods. Western Power states the option selected was estimated to be 9 per cent more expensive than the least cost alternative but included uncosted optionality that allowed for an incremental approach to addressing reactive power shortfall during shoulder periods (smaller reactor units) and was quicker to deploy[193]. Reliance on operational procedures was again an option but was rejected as being too costly and potentially prolonging and

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190 ibid. p. 2

191 ibid. p. 12

192 ibid. pp. 9-13

193 ibid. p. 12

extending the risk to system security. All other options were based on delivering 350 MVAr in total across all stages.

Stage 3 installed 200 MVAr of reactors at two terminal substations, based on individual 132 kV / 50 MVAr reactors. Reliance on operational procedures was again rejected. All other options were based on delivering 350 MVAr in total across all stages. Other (not shortlisted) options considered included batteries, synchronous condensers, STATCOMS and SVCs. These options did not satisfy timeframe and cost key selection criteria.

Strategic Alignment

The program is aligned with Western Power's Voltage Management Strategy[194]. Reactor installation improves DER uptake and integration, in alignment with the Western Power Network Management Plan[195], Grid Transformation Strategy and Grid Strategy[196], and the WA Whole of System Plan[197] and DER Roadmap[198].

Options Analysis

Engevity draft considers that Western Power has identified a reasonable range of alternative options, demonstrated how the recommended options were selected and articulated why. However, there does not appear to be any serious consideration of any options that total to less than 350 MVAr across the program.

As discussed previously, reactive voltage rectification in the AA4 period was undertaken in three consecutive stages with separate business cases developed. For each of these business cases, Western Power provides a summary of investment that identified at least three options, in some instances with substantially different scope and costing.

The business cases demonstrate how Western Power selected the most efficient option at various stages in the AA4 period. The recommended options were the least cost while satisfying all investment objectives and constraints. For Stages 2 and 3, options were chosen that were more expensive but could be delivered quicker for Stage 2 and were more flexible for Stage 3. There is in all cases a discussion of the merits and limitations of the various options, including the grounds for selection of the recommended option.

Delivery Model (incl. staging)

Engevity draft considers that the delivery model, including staging, was appropriate to the urgency of the need.

The reactive voltage rectification program was delivered in three stages, each with business cases. A key consideration of the delivery was the risk associated with any delay. Long Lead Commitments were used for purchases of reactors across stages 1-3 to mitigate delivery risk. The most immediately urgent additions of reactive power absorption capability were promptly delivered in the Stage 1 works.

The program was delivered with a mixture of internal and external participants. All civil construction works were delivered externally. All electrical construction for the 25 MVAr and 50 MVAr reactors was delivered by internal resources. Electrical construction for the 5 MVAr Stage 1 reactors were

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194 ibid. p. 3

195 AAS – Attachment 8.2 – Network Management Plan – 1 February 2022, p. 79

196 AAS – Attachment 8.3 - Grid Strategy – 1 February 2022, p. vii

197 Whole of System Plan 2020 – August 2020, Energy Transformation Taskforce WA,

198 Distributed Energy Resources Roadmap – December 2019, Energy Transformation Taskforce WA, p. 57

delivered externally due to resource constraints and to expedite the delivery schedule. All commissioning was undertaken by internal resources.

All materials and equipment were sourced in accordance with Western Power's corporate and procurement policies. Agreements were by competitive processes. The selection, evaluation and award processes were supported by engagement of relevant subject matter experts, to Western Power standards.

7.5 Stand Alone Power Systems – AA4 Assessment

7.5.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **Stand-Alone Power System Program in AA4.** We found that **the expenditure complied with the NFIT requirements**. As a result, we have not made recommendations for ERA to make any adjustments in this expenditure category.

The expenditure and scope of the Standalone Power System (SPS) Program is summarised in the table below.

Table 7–12: Western Power Forecast – NFIT Compliance – Standalone Power Systems [$m nominal][199] [200]

	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1 Actual	Yr2 Actual	Yr3 Actual	Yr4 Actual	Yr5 Forecast	Total
Western Power Actual AA4 CAPEX	-	-	-	-	-	**$51.2m**
Expenditure that does not meet NFIT	-	-	-	-	-	**-**
Engevity Recommended	-	-	-	-	-	**$51.2m**
Volumes	-	-	-	-	-	**187**

Assessment Overview

Table 7–13: Assessment Overview

Project/Program	**AA4 SPS program**
Actual Cost $m	$51.2m
Variance to approved $m	$51.2m
Need	Substantial sections of Western Power's Dx OH network are reaching their Mean Replacement Life (MRL), resulting in increasing risks to network performance. Western Power has piloted and subsequently considered SPSs as an alternative solution to like for like replacement of Dx OH assets as part of Western Power's asset replacement program for distribution assets. Western Power has found SPSs to be a least cost alternative to like for like replacement

199 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 15

200 Attachment 8.1 – AA5 Forecast capital expenditure report - 1 February 2022, p. 46

Project/Program	AA4 SPS program
	to provide power supply of appropriate quality, reliability and safety to customers in certain areas of the grid, particularly for customers on radial, long rural lines.[201] The need to consider Dx replacement for each section of line for which SPS's are considered is a broader question related to the validity of Western Power's asset management strategy. Engevity notes that MRL is heavily relied on as the indicator of replacement need for an asset, not the asset's current condition or performance.[202] This may mean that some SPS's are being considered to replace Dx assets prematurely. Engevity notes that the AA4 SPS program was rolled out in three programs: round 1 demonstration program, round 2 as a subsequently integrated part of the 2019/20 Asset Replacement Program and an emergency response to TC Seroja.[203] Engevity believes both the pilot program and the TC Seroja emergency response represent a valid need for consideration of SPSs. The need for the 98 SPS that constitute round 2 is less well defined by Western Power and relates to the broader outputs of its Asset Management Strategy[204], which has been examined in Chapter 4.
Scope Definition	Round 1 of the SPS program comprised of 52 SPS units. This was a demonstration program for SPS technology and was deployed to customers on an 'opt in' basis and with OH lines to remain connected. This program was approved by the Minister for Energy and Public Utilities Office.[205] Therefore, we find scope of round 1 is well justified. 37 SPSs were deployed to customers in response to network damage caused by TC Seroja. These SPS were delivered as part of emergency response to replace the damaged network and considered against like-for-like replacement of the damaged network. Western Power ensured appropriate extra governance and approval for this SPS program, including approval from Western Power's Executive Asset Management for each spur recommended for transition to SPS.[206] Therefore, we find scope of the TC Seroja SPS deployment is reasonable. Round 2 of the SPS program comprised of 98 SPS units. Assuming the need for asset replacement at each location is valid, an SPS still represents the full decommissioning of the group of assets that make up a spur of Dx OH network, as well as disconnection of the customer from the interconnected network. Western Power provides little further explanation on the details of the scoping exercise, including, the appropriateness of complete line removal and installation of SPS compared to like for like replacement of the specific aged assets on the line. Western Power cites outcomes of its GTEng Proof of Concept and NPC analysis to justify the 98 SPSs. However, only headline results of the NPC analysis for the 98 SPS in aggregate have been provided.

201 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, pp. 2-3

202 Distribution Structures Asset Management Strategy, Western Power, 2021, p.10

203 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 4

204 [redacted]

205 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 11

206 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, pp. 13-14

Project/Program	AA4 SPS program
	We did not observe documentation of customer support or preference for SPSs in this round. There is little information on how each SPS is sized, so it is not possible to tell if SPS units are correctly scoped to meet Western Power requirements for energy service to customers. Discussions with Western Power has revealed that SPSs are sized through collaboration with each customer considering their current and immediate future demand. SPSs do not seem to consider future demand growth of customers.
Timing	Timing of SPS rollout round 2 was a function of Western Power's Asset Management strategy and GTEng Proof of Concept tool identifying areas of network due for replacement and optimising replacement schedules of sections of networks for SPSs against performance, cost and risk of existing assets. As above, Engevity has concerns that assets are being prematurely replaced on a conservative asset age risk basis rather than actual asset condition basis. Engevity understands Western Power has undertaken a scenario and NPC analysis in August 2020[207] to inform the scope and timing for its broader SPS strategy, which overlaps with the AA4 round 2 SPS deployment. Engevity has been provided the AA4 round 2 modelling by Western Power which outputs SPS investment over network sustainment as a preferrable options, but it in itself does not clearly elaborate on the network investment need and timing.
Risk Management	It is not clear how the safety, reliability and performance of new Dx OH assets compare to an SPS, as SPS performance comparisons made by Western Power have been against the existing aged infrastructure. Western Power should provide more information on the expected and actual performance of its SPS units in comparison to new like-for-like replacement and its supply service requirements. SPS do remove the safety risks of OH conductors of bushfire, pole top fires and electric shock, provided SPS units are well contained.
Cost Efficiency	The costings of the SPS units across each round in AA4 are not detailed in the information provided. The average unit costs of the 98 round 2 SPSs are c. $229,000 in CAPEX (excl. risk and escalation allowance).[208] Engevity notes that precursory desktop study finds that a 15-20kWh retail off-grid solutions are costed between $25,000-$45,000 and is concerned that Western Power's unit costs are substantially higher than what may be available for customers directly over the counter.
Scope Efficiency	In round 1, the number and sizing of SPSs to deploy were modified throughout the program as a result of detailed site visits and further iterations of desktop scoping exercises.[209] [210]

207 ERA AA5 Walkthru#1 Modular Grid & SPS, Western Power, 2022, p. 15

208 [redacted]

209 [redacted]

210 [redacted]

Project/Program	AA4 SPS program
	Customer engagement process over round 1 demonstrated Western Power and contractor ability to adjust scope and rollout as appropriate as new information about customer needs came to light.[211] There is no equivalent information for round 2 or TC Seroja SPSs. All customers receiving SPSs in round 2 were consulted and opted in to the program.[212]
Strategic Alignment	Conversion of appropriate sections of the Dx OH network due to be replaced with SPSs is aligned with Western Power's asset management strategy and grid vision, and is supported by the WA Govt.
Options Analysis	Western Power has undertaken 50-year NPC analysis for each of the three SPS programs undertaken in AA4, the results of which are provided in three business cases. In each case, the SPS solution was compared against a like-for-like replacement of targeted overhead assets and was found to have a lower 50-year NPC. While the inclusions and assumptions of these NPC analyses seem to be sound, Engevity has concerns that the actual costs incurred by the programs exceeds those estimated in the business cases. Engevity highlights that the net benefit of the SPS solution over the like-for-like solution was only $2.93m for round 1 (50-year NPC of $25.11m) and $1.28m for round 2 (50-year NPC of $38.91m). These margins are quite tight and would be sensitive to changes to timings and costs of different components of each option. It is not clear to Engevity, on the basis of the information provided, how the SPS options, which have a comparable upfront CAPEX cost to a like-for-like replacement, greater or equal OPEX costs and include an 10-20% of CAPEX in NRO to decommission existing assets, can result in lower NPCs than the like-for-like options. Engevity notes that in round 1, total cost of the 52 SPS units increased by 44% between January 2019 and June 2021 ($13.96m to $20.07m), halving the net benefit initially calculated in January 2019.
Delivery Model	Western Power ran a competitive process to engage multiple vendors in round 1 to provide turnkey SPS solutions for comparison of different SPS solutions. For round 2, Western Power established a panel of SPS vendors through competitive process through which it awarded Deeds to five Preferred Vendors.[213] Western Power was able to divert resources from its round 2 program to the TC Seroja response.[214] Western Power has provided no updates on the progress of the round 2 or TC Seroja response and so Engevity is not aware of any deliverability issues, delays or customer experiences throughout these programs.

211 [redacted]

212 [redacted]

213 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, pp. 18-19

214 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 9

Findings

Overall, we consider that the Stand-Alone Power System Program for the AA4 satisfies the NFIT requirements.

7.5.2 AA4 NFIT Assessment

Introduction

Expenditure Overview

Western Power has been considering the suitability of SPS systems for a number of years as a more economical solution to supplying customers in rural areas of its network as opposed to network rebuild.[215]

Over AA4, Western Power will have delivered 187 SPSs over three projects following a trial of six SPS units in 2016. Chronologically, these rounds of investment can be summarised as follows:[216]

- Round 1: a demonstration project consisting of 52 SPS units delivered to customers without disconnection from the OH Dx network in FY21. This program required ministerial approval and was opt-in for customers. Following August 2021, line decommissioning was approved for the program, with relevant OH lines to be decommissioned by September 2022.
- Response to TC Seroja: an emergency response program to replace and restore supply to the sections of network destroyed or damaged by TC Seroja in April 2021, consisting of 37 SPS units.
- Round 2: deployment of 98 SPS units as part of Western Power's 'business as usual' Dx replacement program over FY21 and FY22.

Round 2 followed a number of legislation changes in late 2020 and early 2021 allowing SPSs without physical connection to the grid to be delivered as a regulated solution for supply on the Dx network. Included in this legislation was an amendment to remove the ability of identified SPS customers to 'opt out' and remain connected to the existing Dx network.[217]

In 2021, the Government of Western Australia made a commitment for Western Power and Horizon Power to deliver 1000 SPSs by 2025.[218]

The 187 SPSs delivered in AA4 are expected to be delivered at a base CAPEX of $38.2m and are expected to replace 771km of OH conductor and 3,563 poles.[219]

SPSs are energy units located on the customer's site which typically consist of PV cells, batteries, power electronics and controls and, where required, a back-up generator. A mix of SPS sizes were deployed, depending on the current energy demand of each customer.[220]

The SPS program is justified as a cost-effective alternative to traditional network solutions for the replacement of its ageing rural distribution network assets. The SPSs were targeted for deployment in areas of the network where their NPC were shown to be less than like-for-like network replacement.

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215 Attachment 5.8 – AA4 NFIT Compliance Summary – Stand-alone Power Systems, 1 Feb 2022, Western Power, pp. 4-5

216 Attachment 5.8 – AA4 NFIT Compliance Summary – Stand-alone Power Systems, 1 Feb 2022, Western Power, pp. 9-15

217 Electricity Industry Regulations Amendment (Stand-Alone Power Systems) Regulations 2021 Information Paper, 2021, Government of Western Australia, pp. 1-2

218 Energy Transformation Strategy Stage 2: 2021-2025, July 2021, Government of Western Australia, p. 14

219 Attachment 5.8 – AA4 NFIT Compliance Summary – Stand-alone Power Systems, 1 Feb 2022, Western Power, p. 20

220 Attachment 5.8 – AA4 NFIT Compliance Summary – Stand-alone Power Systems, 1 Feb 2022, Western Power, p. 14-15

Historical Context

In 2016, during the AA3 period, Western Power commenced an SPS pilot program. This 12-month trial aimed to test the suitability of SPS as an alternative solution to the replacement of network infrastructure across six rural properties on the Western Power network. [221]

Western Power found the SPS Pilot to confirm SPSs as a cost-effective alternative to replacing the distribution network. Western Power also states that customer feedback was positive, with customers avoiding over 200 hours of outages over a three-year period. [222]

Need

- Western Power identified that substantial sections of Western Power's Dx OH network are reaching their Mean Replacement Life (MRL), resulting in increasing risks to network performance and the need for network asset replacement.
- Western Power has piloted and subsequently considered SPSs as an alternative solution to like for like replacement of Dx OH assets as part of WPs asset replacement program for distribution assets. Western Power has found SPSs to be a least cost alternative to like for like replacement to provide power supply of appropriate quality, reliability and safety to customers in certain areas of the grid, particularly for customers on radial, long rural lines[223].
- The need to consider Dx replacement for each section of line for which SPS's are considered is broader question related to the validity of Western Power's asset management strategy. Engevity notes that MRL is heavily relied on as the indicator of replacement need for an asset, not the asset's current condition or performance.[224] This may mean that some SPSs were not strictly required and may have replaced existing OH Dx assets prematurely. Western Power's asset management strategy is discussed further in chapter 4.
- Engevity notes that the AA4 SPS program was rolled out in three programs: [225]
  - round 1 as a demonstration program.
  - round 2 as a subsequently integrated part of the BAU FY20 asset replacement program; and
  - an emergency response to TC Seroja.

Engevity believes both the demonstration program and the TC Seroja emergency response represent a valid need for consideration and deployment of SPSs. The need for the 98 SPS that constitute round 2 is less well defined by Western Power and relates to the broader outputs of its Asset Management Strategy[226], which is being examined in a separately, as discussed above.

Scope Definition

Overall, Engevity found that each round of SPS deployment in AA4 was reasonably scoped commensurate to the need of customers from the information provided.

Round 1 of the SPS program comprised of 52 SPS units. This was a demonstration program for SPS technology and was deployed to customers on an 'opt in' basis and with OH lines to remain

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221 Attachment 5.8 – AA4 NFIT Compliance Summary – Stand-alone Power Systems, 1 Feb 2022, Western Power, p. 5

222 Attachment 5.8 – AA4 NFIT Compliance Summary – Stand-alone Power Systems, 1 Feb 2022, Western Power, p. 5

223 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, pp. 2-3

224 Distribution Structures Asset Management Strategy, Western Power, 2021, p.10

225 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 4

226 [redacted]

connected. This program was approved by the Minister for Energy and Public Utilities Office.[227] Therefore, we find scope of round 1 is well justified.

In 2021, 37 SPSs were deployed to customers in response to network damage caused by TC Seroja. These SPS were delivered as part of emergency response to replace the damaged network and considered against like-for-like replacement of the damaged network. Western Power ensured appropriate extra governance and approval for this SPS program, including approval from Western Power's Executive Asset Management for each spur recommended for transition to SPS.[228] Therefore, we find scope of the TC Seroja SPS deployment is reasonable.

Round 2 of the SPS program comprised of 98 SPS units. Engevity understands that the Grid Transformation Engine (GTEng) Proof of Concept (PoC) model was central to informing the extent of SPS solutions that may be cost efficient compared to tradition replacement of OH Dx assets in AA4.[229] Engevity has not been able to sufficiently interrogate this model to verify its outcomes for the AA4 SPS program. Assuming the need for asset replacement at each location SPSs were deployed was valid, an SPS still represents the full decommissioning of the group of assets that make up a spur of Dx OH network, as well as disconnection of the customer from the interconnected network. Western Power provides limited further explanation on the details of the scoping exercise, including:

- The appropriateness of complete line removal and installation of SPS compared to like-for-like replacement of the specific aged assets on the line. Western Power cites outcomes of its GTEng Proof of Concept and NPC analysis to justify the 98 SPSs. Western Power has provided its NPC model for the round 2 SPS program but uses both the terms 'network replacement' and 'network sustainment'.[230] It is unclear to what extent assets that had not reached maturity but were on a feeder that was to be replaced by SPSs were valued by Western Power.
- We did not observe documentation of customer support or preference for SPSs in this round, though Engevity notes that customers had the option of opting out of their connection being transitioned to an SPS.
- There is little information on how each SPS is sized, so it is not possible to tell if SPS units are correctly scoped to meet Western Power requirements for energy service to customers. Discussions with Western Power have revealed that SPSs are sized through collaboration with each customer considering their current and immediate future demand. SPSs do not consider future demand growth of customers beyond what is immediately foreseeable by the customer.

Timing

Round 1 of the SPS program was a small-scale, opt-in demonstration project of 52 units in 2019 following an initial pilot project in 2016. Engevity believes the timing of this demonstration program was reasonable.

Between rounds 1 and 2, 37 SPSs were deployed as an emergency response program to replace and restore supply to the sections of network destroyed or damaged by TC Seroja in April 2021. The deployment of these units was approved shortly after TC Seroja in May 2021 and utilised SPS units

227 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 11

228 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, pp. 13-14

229 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 8

230 [redacted]

diverted from the upcoming round 2 program.[231] Engevity praises the swiftness of response by Western Power for these SPSs.

As discussed above, timing of the round 2 program was a function of Western Power's Asset Management strategy and GTEng PoC tool, which identified areas of network due for replacement and optimising replacement schedules of sections of networks for SPSs against performance, cost and risk of existing assets. As above, Engevity has concerns that assets are being prematurely replaced on a conservative asset age risk basis rather than actual asset condition basis.

Western Power's NPC analysis presented in the round 2 business case and provided modelling supports the timing of the program in comparison to a do nothing approach or traditional network replacement.[232] [233]

Risk Management

The SPS program is justified as a cost-effective alternative to traditional network solutions for the replacement of its ageing rural distribution network assets. The SPSs were targeted for deployment in areas of the network where their NPC were shown to be less than like-for-like network replacement.

Western Power uses its Network Risk Management Tool (NRMT) to assess risk of asset failure on a periodic basis. The decision of repair or replace solutions is governed by the Network Rebuild Strategy[234], which includes the Dx OH Network Rebuild Strategy. Transformational rebuilds under the Network Rebuild Strategy are guided by Western Power's Grid Strategy, which incorporates Short Term Risk Management (STRM) and Asset Management Strategy Standard (AMSS). [235] [236] Engevity understands the STRM is concerned with short term solutions to manage risks when an asset or group of assets has not reached end of life while AMSS determines the appropriate replacement solution once replacement is deemed efficient.

Engevity supports Western Power's risk management approach in principle. However, it is not clear how it has been applied historically to inform the AA4 SPS program.

Engevity also recognises that in its 2020 Asset Management System review, AMCL noted limitations in Western Power's asset risk management system that are highly relevant to replacement decisions for Dx OH assets, which are typically hard to monitor and survey resulting in reliance on statistical desktop analysis.

In general, Western Power's asset risk management system have been commended for their asset management system in past independent reviews, including by AMCL in its 2020 Asset Management System Review (AMSR).[237] However, a key recommendation from the 2020 AMSR was for Western Power to develop and implement a 'whole of lifecycle' cost assessment in its asset planning and investment processes, and that risk costs should also be better quantified and integrated, including in the Investment Gate Approval process. [238]

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231 [redacted]

232 [redacted]

233 [redacted]

234 Attachment 8.2 – Network Management Plan, Western Power, p. 141

235 Attachment 8.2 – Network Management Plan, Western Power, p. 134

236 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 47-48

237 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. v

238 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, pp. vi-vii

It is also not clear to Engevity how the safety and reliability of new Dx OH assets compare to an SPS, as the benefits of SPS performance in terms of reliability and safety are compared to existing aged infrastructure in business cases.[239]

Engevity recognises SPSs do remove the safety risks of OH conductors of bushfire, pole top fires and electric shock, provided SPS units are well contained. Western Power believes SPS units improves reliability of supply to customers, as supported by preliminary data from SPS demonstration projects.[240] [241] Western Power has little data to date to forecast the safety incidents experienced or avoided as a result of SPS deployment replacing OH Dx network.

Engevity also has concerns that there are shortcomings in Western Power's approach to sizing and scoping the components of SPS units for each customer. This risks supply of an SPS unit that at best is oversized over the 20-year lifespan of the asset or at worst does not meet the customers supply requirements and requires modification.

Engevity understands that SPSs sizing is a static decision-making process based on current customer needs and does not factor potential changes to customer usage patterns, such as uptake of electric vehicles or machinery, over the lifespan of the unit.

Cost Efficiency

Western Power has provided limited detail on how SPSs are costed on a per unit basis. Engevity recognises that Western Power was on a learning curve in AA4 for its SPS program and has achieved material unit cost reductions between round 1 and 2. However, the average unit costs for each program are much higher than Engevity would expect for typical rural customers.

The final base CAPEX average unit cost of the 52 SPS units deployed in round 1 was $287,000 (excl. risk and escalation allowance).[242] The 98 SPSs being deployed in round 2 have an average unit cost of $229,389.[243] Engevity recognises that this demonstrates a 20% reduction in unit costs over a 2-year period, but also notes that Western Power's initial approved business case for round 1 had an average unit cost of $231,000.[244]

Western Power has identified that *"within the autonomous region approximately 4,500 connections have an annual consumption of less than 5000kWhs and approximately 1800 connections have an annual consumption of less than 1000kWhs".*[245] In Engevity's experience, an average customer with a 5000kWh yearly consumption can be served by a 6.6kW PV array and a 10-20kWh battery depending on usage patterns. Market research on commercial SPS providers in Western Australia show that appropriate systems, including a diesel generator, can cost between $25,000-$40,000, before installation costs.[246] Example retail prices for larger units suitable for customers with a consumption around 14000kWh+ per annum have been found to start at $90,000-$95,000 including installation costs.[247] In comparison to these figures, Western Power's average unit costs for AA4 are much higher than expected given a customer should be able to get an equivalent systems over-the-counter for potentially half the cost.

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239 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, pp. 9-14

240 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 35

241 [redacted]

242 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 16

243 [redacted]

244 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 15

245 [redacted]

246 Commodore Independent Energy Systems, May 2022

247 Offgrid Energy Australia, May 2022

Western Power's supplier contracts include OPEX costs for two years after the SPS systems are installed. Following this initial period, Western Power forecasts OPEX to reduce to be in line with typical OPEX for maintenance of traditional OH lines. [248] However, Western Power has provided no further detail to support this OPEX costing or provided information on actuals to date.

Engevity also highlights that line decommissioning represents a substantial upfront cost for SPS rounds and is categorised as NRO (non-recurring OPEX).[249] Line decommissions accounts for $4.68m in round 1 and $4.13m in round 2. Western Power states that "Recovery of the overhead line associated with the SPS units is recovered in the 10th year after de-energisation of the line and is included in the NPC analysis but is not part of the business case value".[250]

Scope Efficiency

Engevity believes the Western Power has demonstrated flexibility and a reasonable approach to adjusting the scope of each round of the AA4 program.

In round 1, the number and sizing of SPSs to deploy were modified throughout the program as a result of detailed site visits and further iterations of desktop scoping exercises.[251] [252]

Customer engagement process over round 1 demonstrated Western Power and contractor ability to adjust scope and rollout as appropriate as new information about customer needs came to light.[253]

There is no equivalent information for round 2 or TC Seroja SPSs, however all customers receiving SPSs in round 2 were consulted and opted in to the program.[254] Additionally, the deployment of units for TC Seroja was approved in May 2021, shortly after the cyclone impacted the network. Western Power utilised SPS units diverted from the upcoming round 2 program.[255] Engevity recognises the swift response by Western Power in reprioritising the deployment of these SPSs.

Strategic Alignment

Western Power's AA4 SPS program is well justified to be aligned with its grid strategy, corporate strategy and State Government commitments.

The SPS program is a core pillar of Western Power's Dx OH Network Rebuild Strategy, being a 'transformational rebuild' solution guided by Western Power's Grid Strategy. [256] The Grid Strategy defines a portion of Western Power's Dx network as 'autonomous' to be replaced by SPSs.[257]

Western Power's Corporate Strategy also focuses on the transition to a modular grid.[258]

The SPS program also has government support. The Government of Western Australia made a commitment in 2021 for Western Power and Horizon Power to deliver 1000 SPSs by 2025.[259]

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248 [redacted]

249 [redacted]

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252 [redacted]

253 [redacted]

254 [redacted]

255 [redacted]

256 Attachment 8.2 – Network Management Plan, Western Power, pp. 132-134

257 Attachment 8.3 – Grid Strategy, Western Power

258 [redacted]

259 Energy Transformation Strategy Stage 2: 2021-2025, July 2021, Government of Western Australia, p. 14

The SPS program expands on the original pilot project that was aligned with customer desire to explore potential efficiencies of new technology.

Options Analysis

Western Power has undertaken 50-year NPC analysis for each of the three SPS programs undertaken in AA4, the results of which are provided in three business cases. In each case, the SPS solution was compared against a like-for-like replacement of targeted overhead assets and was found to have a lower 50-year NPC.

While the inclusions and assumptions of these NPC analyses seem to be sound, Engevity has concerns that the actual costs incurred by the programs will exceed those estimated in the business cases, as both round 1 and round 2 project activities are still ongoing. Engevity highlights that the net benefit of the SPS solution over the like-for-like solution was only $2.93m for round 1 (50-year NPC of $25.11m) and $1.28m for round 2 (50-year NPC of $38.91m), as shown in the extracts below.[260] [261] These margins are quite tight and would be sensitive to changes to timings and costs of different components of each option.

Options – with CCR# 3 amendments	Volumes	Nominal Capital Cost -$M (FY19 & FY20)	NPC across evaluation period ($M)	Type 1 – Gross Financial Benefit Applicable (Nominal $'s)
			50 years	10 Year (to end of FY29)
1. Replacement of assets (like for like)	70 km conductor, 523 poles	$13.77	$28.04	**$23.89**
3. Option 2 with inclusion of alternate SPS technology	52 SPS units	$14.87	$25.11	
NPV Benefit of Option 3 vs Option 1			**+$2.93[10]**	

Options	Volumes	Nominal Capital Cost - $M (FY2020/21 & FY2021/22)	NPC across evaluation period - $M		
			10 years	25 years	50 years
Network Sustainment (Replacement of assets like for like)	213km conductor, 930[1] poles	$24.93	$31.26	$36.40	$40.19
Stand-alone Power Systems	98 SPS units (330km, 1588 poles)[2]	$24.82	$30.70	$35.29	$38.91

It is not clear to Engevity, on the basis of the information provided, how the SPS options, which have a comparable upfront CAPEX cost to a like-for-like replacement, greater or equal OPEX costs and include an 10-20% of CAPEX in NRO to decommission existing assets, can result in lower NPCs than the like-for-like options. For example, the $1.73m in net nominal benefit for the round 2 SPS solution over a traditional solution is comprised of +$6.58m benefit in CAPEX and a -$4.85 (disbenefit) in OPEX, and a totex 50-year NPV of $1.28m.[262]

260 [redacted]

261 [redacted]

262 [redacted]

Engevity notes that in round 1, total business case value of the 52 SPS units increased by 44% between January 2019 and June 2021 ($13.96m to $20.07m), halving the net benefit initially calculated in January 2019.

Engevity notes that the benefits of the AA4 program to date are not well understood based on information provided. Western Power ascribes $96m lower actual CAPEX spend in its AA4 conductor management replacement program to undergrounding and SPS.[263] However, Western Power states in the same document that it has not seen significant reduction in replacement costs due to SPS.[264]

Delivery Model

Western Power ran a competitive process to engage multiple vendors in round 1 to provide turnkey SPS solutions for comparison of different SPS solutions. For round 2, Western Power established a panel of SPS vendors through competitive process through which it awarded Deeds to five Preferred Vendors.[265]

Western Power demonstrated capability to be flexible in its delivery as it was able to divert resources from its round 2 program to the TC Seroja response.[266]

Western Power has provided no updates on the progress of the round 2 or TC Seroja response and so Engevity is not aware of any deliverability issues, delays or customer experiences throughout these programs.

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263 Attachment 5.1 – AA4 Capital Expenditure Report, Western Power, p. 20

264 Attachment 5.1 – AA4 Capital Expenditure Report, Western Power, p. 9

265 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, pp. 18-19

266 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, p. 9

7.6 Wood Pole Management – AA4 NFIT Assessment

7.6.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **Wood Pole Management program delivered in AA4.** We found that **the expenditure complied with the NFIT requirements**. As a result, we have not made recommendations for ERA to make any adjustments in this expenditure category.

Over the AA4 period, wood pole management in the distribution network accounted for the expenditure and scope summarised in the table below.

Table 7–14: AA4 Expenditure and scale – NFIT Compliance – Distribution Wood Pole Management [$m nominal][267]

WOOD POLE MANAGEMENT	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1 Actual	Yr2 Actual	Yr3 Actual	Yr4 Actual	Yr5 Forecast	Total
Western Power Actual AA4 CAPEX	150.9	123.2	146.2	161.2	97.8	**679.3**
Adjustment Exclude from AA5 opening RAB						**Nil**
Engevity Recommended	150.9	123.2	146.2	161.2	97.8	**679.3**
# poles replaced **# poles reinforced**	12,303 18,331	10,049 14,973	11,921 17,762	13,140 19,578	7,970 11,875	**55,383** **82,519**

Assessment Overview

Table 7–15: Assessment Overview

Project/Program	AA4 Wood Pole Management - NFIT Compliance
Actual Cost $m	Over the AA4 period, the total project CAPEX was $679.3m nominal. This is commensurate with need when considered in historical context of the WA Wood Pole Order. Western Power states that it maintained the level of reliability and safety risk across the distribution overhead network during the AA4 period at AA3 level, while still delivering a ~$323m nominal decrease in CAPEX in comparison to the AA3 period. There remain cost concerns in terms of the pole management unit costs being at the higher end of expectations when compared with those of other networks. The influence of alternative solutions for overhead replacement does not appear dominant.
Variance to approved $m	Variance of $8.4m nominal decrease (~1.2 per cent) from the AA4 FFD of $687.7m nominal. This is consistent with a significant drop in the actual volume of pole replacements, which dominate costs, partially offset by a rise in the number of pole reinforcements, compared to that estimated for the AA4 FFD.

[267] Sources: AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 4 and p. 6; AAS – Attachment 11.7 – AA5 Regulatory Revenue Model. NOTE: These figures are for the Pole Management – REPEX regulatory activity in the pole management sub regulatory category of distribution asset replacement. They do not include wood pole capital expenditure and volumes for the transmission network.

Project/Program	AA4 Wood Pole Management - NFIT Compliance
Need	Asset condition, reliability and compliance (safety) needs for program clearly identified
Scope Definition	Probably commensurate with need, based on the Western Power statement that it maintained the level of reliability and safety risk across the distribution overhead network. Program staged, with business cases. Limited use of alternative solutions for overhead asset replacement likely did not greatly decrease the scope compared to the AA3 period.
Timing	Engevity considers the timing of the expenditure is consistent with the need date, based on the Western Power statement that they have maintained the level of risk across the distribution overhead network for safety and reliability performance in the AA4 period at the AA3 level, at minimum cost. Investment timing supported by three consecutive stages with business cases. The volume and timing of replacements and reinforcements is derived from the use of a risk-based renewal methodology. Limited use of alternative solutions[268] for overhead asset replacement likely did not influence timing in a major way.
Risk Management	Wood pole risk was managed in a similar manner to other asset risks. Overall network safety risk was maintained by improvements in the risk-based renewal approach plus better asset data, despite a large decline in CAPEX compared to the AA3 period. Relatively small volumes of assets addressed by alternative solutions probably did not influence wood pole risk management in a major way.
Cost Efficiency	Based on Western Power statements, the actual expenditure has been assessed using an efficient system and unit costs. Western Power benchmarking in 2014/15 for the AA4 submission showed a unit rate for pole replacements comparable to its peers. However, there remain cost efficiency concerns in terms of the pole management unit costs being at the higher end of expectations when compared with those of other networks such as Ausgrid.
Scope Efficiency	The scope has been challenged for reduction options. Staging with supporting business cases addressed scoping options. The Grid Transformation program probably did not have a dominant effect on the overall scope of the wood pole management program
Strategic Alignment	Influenced by the Grid Transformation program, a predecessor of the Distribution Overhead Network Rebuild Strategy and Grid Strategy.
Options Analysis	Identified a reasonable range of alternative options in business cases for a staged program, demonstrated how the recommended options were selected and articulated why.
Delivery Model	Governed by a risk-based renewal and prioritisation methodology, with programs prioritised and staged based on risk. Staging assisted efficient delivery and response to changes in circumstances. Internal and external packages of work grouped to efficiently deliver the work. Limited use of

268 Undergrounding and SPS

Project/Program	AA4 Wood Pole Management - NFIT Compliance
	alternative solutions for overhead asset replacement likely did not influence the delivery model, including staging, in a major way.

Findings

Our review is summarised below for the Western Power distribution wood pole management program NFIT compliance for the AA4 period. Wood pole management is a sub regulatory category of the asset replacement and renewal regulatory category of the distribution asset segment. Pole management – REPEX is the sole regulatory activity in the wood pole management sub regulatory category.

Engevity has reviewed Western Power's AA4 NFIT compliance relating to distribution wood pole management and found that:

a. **The actual expenditure is efficient** with the objective of minimising costs on the basis that Western Power has demonstrated the cost efficiency of the CAPEX for distribution wood pole management in the AA4 period. Our review noted weighted average estimates of unit rates of ~$10.3k for pole replacement and ~$1.3k for pole reinforcement across the AA4 period, which is at the higher end of expectations against the pole management costs reported by other networks[269]. This is understandable, given the legacy of the Wood Pole management order, where a large volume of poles was replaced or reinforced within a short period. Although we note that despite over $2b investment in pole management since AA3, the overall safety performance of Western Power's pole population (as measured by the number of unassisted pole failures) still remains substantially behind the east coast networks.[270] On the basis that there are still unique legacy, environmental and compliance issues that Western Power needs to manage, costs do not appear to unreasonably depart from efficient unit costs and estimating systems. There was a ~$323m (~32 per cent) nominal decrease in wood pole management actual CAPEX for the AA4 versus the AA3 period, but Western Power states that the level of reliability and safety risk related to the distribution overhead network was maintained in the AA4 period. A small decrease in wood pole management CAPEX was identified related to undergrounding and SPS as alternative overhead replacement options in the AA4 period. Several business cases for staged delivery of wood pole management were undertaken and indicated that the actual expenditure was efficient.

b. **The program captures the available and realisable economies of scale and scope.** The program is supported by a detailed risk-based renewal methodology aimed at maintaining overall safety and reliance performance at minimum cost. The scale and scope were consistent with the required goal of maintaining the level of reliability and safety risk across the distribution overhead network. Western Power states the reduced investment in wood pole treatment in the AA4 period was due to a lower volume of reinforcements, related to the much larger number of reinforcements in the preceding AA3 period. Western Power also states alternative solutions for overhead replacement (NRUPP and SPS programs) slightly decreased the cost of the Combined Overhead Asset Replacement Program in the AA4

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269 For example, Ausgrid reported a weighted average of $8,335 per pole for its 2020-24 Revised Regulatory Proposal. (refer Ausgrid, *Attachment 5.13.M.1 – Poles program CBA summary,* January 2019, p.4)

270 We note that Western Power most recent publications report 39 unassisted distribution pole failures in the Q1 and Q2 of 2021/22. Ausgrid reported 11 in the 12-month 2020/21 reporting period. When normalized to a 6-month period, This equates to 5.5 unassisted pole failures, or around seven times the number of failures that Ausgrid, a network that also spreads from major capital city CBD across suburban and rural areas. We highlight that Ausgrid has lagged in the AER's productivity benchmarking measures over the past round of regulatory determinations and is therefore a reasonable proxy for the 'lower threshold' of what can be considered efficient (without taking into account and corrections for the idiosyncrasies between networks). The Victorian networks frequently report some of the lowest unassisted pole failure rates.

period. Options for investment were considered in each of multiple stage investment plan across the AA4 period, with the recommended options chosen in accordance with lowest net present cost, satisfying all investment objectives and constraints. Economies of scale and scope were assessed 'bottom-up' from project level across all distribution overhead network renewal strategies. Treatments were grouped together where they were known to deliver economies and packages of work were grouped for efficient delivery. Again, Engevity remains concerned that pole replacement costs reported by Western Power remain on the high side of reported costs across the industry despite delivering over $2b in pole replacement and reinforcement works since AA3. [271] On this basis, it is possible that further economies of scale and/or scope for wood pole replacement could be realised.

c. The investment **is consistent with reasonable expectations** of the level of future network services required by customers. This is based on acceptance that the actual investment in distribution wood pole management during the AA4 period was consistent with maintaining the existing level of safety and reliability of the distribution overhead network. A comparable level of future network services was provided by the alternative overhead replacement approaches (SPS and undergrounding) that were employed in a limited number of cases in the AA4 period.

d. **A reasonable range of alternative options has been considered** for the investment, with the most appropriate solution chosen. This is shown by the staged delivery plan of the work, with multiple options considered in the business cases for each of the consecutive stages and recommended options chosen according to lowest net present cost, plus satisfaction of program objectives and constraints. Alternative solutions for overhead replacement were also considered and used in cases where it was shown to be economically efficient. Western Power presents quantitative evidence for the economically efficient use of alternative overhead replacement options in a limited number of cases during the AA4 period.

Recommended Adjustment

Overall, we consider that the Distribution Wood Pole Management Program for the AA4 satisfies the NFIT requirements.

7.6.2 AA4 NFIT Assessment

Expenditure Overview

Management of poles is critical to the distribution overhead network to prevent conductor failure or contact with vegetation or the ground. This can result in fire, electric shock, service disruption, physical impact injury and property damage.

During the AA4 period, Western Power focused on maintaining the safety and performance of the distribution network. Safety expenditure during the AA4 period focused on distribution wood poles, particularly in urban areas where a high public safety risk was identified due to the higher consequence of wood pole failure, and potential for electric shock[272].

Western Power undertook replacement and reinforcement of distribution wood poles to maintain the current level of public safety risk, current service standard performance, and environmental performance at current levels. There were 55,383 actual replacements and 82,519 actual reinforcements of distribution wood poles in the AA4 period, at a nominal cost of $679.3m[273].

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[271] We note that the Ausgrid proposal for their 2020-24 revised proposal was for replacement of 19,149 poles between FY20 and FY24, which compares with 55,383 poles replaced in the AA4 period.

[272] AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 5

[273] ibid. p. 6

Western Power states that investment in pole management is in two areas:

- Reactive replacement of assets that fail while in service. This is based on forecasts for assisted and unassisted failures.
- Proactive replacement and reinforcement of assets selected under the Distribution Overhead Network Rebuild Strategy.

Western Power faces challenges in respect an ageing distribution overhead network. Approximately 55 per cent of overhead assets will reach end of life maturity within 10 years[274]. Wood poles and bare overhead conductors form ~97 per cent of the Western Power distribution overhead network[275].

Western Power recognises that an overhead network is an affordable option but states it also presents a safety and reliability risk relative to other options, such as underground or standalone power systems. Western Power states it is seeking an optimum investment balance between short to medium term risk management and network transformation under its Grid Strategy.

Western Power has adopted a number of strategies to address the challenges they are facing in the distribution overhead network[276]. The Distribution Overhead Network Rebuild Strategy identifies mature sections of network for rebuild prioritised by risk. Western Power states this enables transformation of parts of the network as per the Grid Strategy. The Network Rebuild Strategy also identifies high risk assets for treatment to manage short term risk plus minimise 'regrettable' investment in areas earmarked to be transformed.

Historical Context

Western Power states that during the AA4 period, it sought to maintain the safety and performance of the distribution network. A key part of this was the replacement and reinforcement of distribution wood poles. This was necessary to maintain the current level of public safety risk, service standard and environmental performance.

A key issue in the Western Power distribution network has been the historical use of Jarrah wood poles which, at the beginning of the AA4 period, constituted around half of the wood pole population[277]. This pole species is now recognised to be subject to 'carroty rot', which is difficult to detect through inspections. A high number of undetected conditions have led to subsequent unassisted failures. Reinforcement is the main treatment for this failure mode. Western Power no longer installs Jarrah poles.

Western Power states that due to the pole management (reinforcement) program undertaken in the AA3 period, there was a reduction in failures of wood poles. The AA3 pole interventions were primarily to deal with bushfire safety risk in rural areas. However, many of the poles reinforced during AA3 were for palliative treatment only, with an expected life of up to 5 years. These poles were approaching end of life during the AA4 period, with a consequent projected increase in safety risk at the end of the AA4 period, extending into the AA5 period[278]. The implication is that to maintain the current level of safety risk during the AA4 period (within allowable limits and targets stated in the Network Management Plan), at least some of the wood poles reinforced in the AA3 period would need to be replaced or reinforced again during the AA4 period. At the start of the AA4 period, there was a large population of aged, untreated Jarrah poles. About 82 per cent of unassisted

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[274] Network Opportunity Map 2021, p. 66; Distribution Structures Asset Management Strategy – December 2021, p. 4

[275] Network Opportunity Map 2021, p. 66

[276] Network Opportunity Map 2021, p. 66

[277] AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 10

[278] ibid. p. 5

failures in the AA4 period were Jarrah poles[279]. To deal with the high operational risk associated with the aged, untreated Jarrah poles, there was still a large program of wood pole replacement and reinforcement, particularly in urban areas, during the AA4 period.

The total of about 138,000 wood pole treatments at a cost of $679.3m in the AA4 period was a substantial reduction from the 270,000 interventions at a cost of $1,002m in the AA3 period[280]. Western Power states progress made on their risk-based renewal approach to wood pole management, plus better asset data, allowed them to maintain the overall network safety risk associated with distribution wood poles in the AA4 period despite the lower replacement / reinforcement volumes compared to the AA3 period[281]. The significant population of rural wood poles that were reinforced in the AA3 period also led to identification of a reduced investment in wood pole treatment in the AA4 period. Western Power states the volume of pole reinforcements in the AA4 period decreased in comparison to the AA3 period. However, replacement volumes were sustained and would continue to be an area of investment to deal with the maturing wood pole population[282].

Need

Western Power states that the distribution overhead network presents the highest safety and reliability risks across their transmission and distribution networks[283]. The need for the proposed investment in wood pole replacement and reinforcement in the AA4 period has been identified by Western Power in terms of the following[284]:

- Overall network safety in accordance with jurisdictional obligations - eliminate / reduce risk as low as is reasonably practicable (ALARP) in accordance with AS 5577.
- Maintain safety risk due to wood pole failures within limits and targets of Network Management Plan.
- Deal with a large number of poles reinforced with palliative treatment only in AA3 period and approaching end of life in AA4 period.
- Deal with a large population of aged untreated Jarrah poles subject to a high incidence of failure.
- Deal with high public safety risk identified in urban areas in AA4 period due to consequences of wood pole failure.

Western Power identifies a key challenge as the need to effectively treat short term risk related to ageing wood power poles, particularly the substantial remaining population of Jarrah poles. Western Power also states that approximately 55 per cent of its overhead network assets will reach end of life maturity in the next 10 years. Over 13 per cent of the wood poles in the distribution network are operating beyond their Mean Replacement Life (MRL) and have been assigned a high operational current risk rating as of 30 June 2020[285]. This is driven by the safety (fire, electric shock and physical impact) through compliance, service (reliability and power quality), and environment risk criteria[286].

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279 ibid. p. 45

280 AAS – Attachment 11.7 – AA5 Regulatory Revenue Model

281 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 2

282 ibid. p. 9

283 [redacted]

284 [redacted]

285 [redacted]

286 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 5

Western Power has forecast that based on asset condition and past performance in the NMP, if asset replacement is only carried out on failure, unassisted wood pole failures would increase from an average of 305/yr in 2015/16 to 2,705 by 30 June 2022 and 6,549 by 30 June 2027. Wood poles requiring treatment (replacement / reinforcement) would increase from 253,537 in 2015/16 to 361,858 by 30 June 2022 and 409,646 by 30 June 2027. The predicted increase in unassisted wood pole failure rate (for asset replacement only carried out on failure) could reasonably result in a decrease in safety service reliability.

The Network Management Plan identified that, as of 30 June 2016, about 136,280 wood poles required replacement and 117,257 required reinforcement[287]. As of 30 June 2020, about 141,352 wood poles required replacement and 22,206 required reinforcement[288]. The NMP estimated numbers of pole treatments required based on asset condition (defect) or attribute (age, type). The NMP then recommended the replacement of more than 60,000 wood poles and reinforcement of more than 65,000 wood poles in the AA4 period, with risk-based prioritisation. The NMP recommendations formed the basis of the treatment volumes Western Power included in the AA4 submission.

Engevity draft considers that the asset condition, reliability and compliance (safety) needs for the Western Power actual pole management program for the AA4 period have been clearly identified.

Scope Definition

Western Power treated 137,902 wood poles, consisting of 55,383 replacements and 82,519 reinforcements, at a cost of $679.3m nominal, using risk-based prioritisation, during the AA4 period[289]. This was a ~49 per cent volume reduction from the 270,000 interventions in the AA3 period[290]. It was also a ~$323m (~32 per cent) nominal cost reduction from the $1,002m wood pole management CAPEX in the AA3 period[291]. There was a variance of $8.4m nominal decrease (~1.2 per cent) from the AA4 further final decision of $687.7m nominal[292].

Western Power states the reduction in total wood pole treatment during the AA4 period was due to a significant population of rural wood poles being reinforced during the AA3 period, resulting in a lower volume of reinforcements in the AA4 period[293].

Western Power states wood pole management work in the AA4 period was undertaken in three consecutive stages with separate business cases developed:

- **2017/18** – One year program taking into account uncertainty in the transition to the AA4 period;
- **2018/19-2019/20** – Two-year program considering continued uncertainty around AA4 decision and likely impacts of Grid Transformation program for consideration of alternative solutions to pole replacement, likely resulting in retiring overhead infrastructure;
- **2020/21-2021/22** – Two-year program to provide Western Power with flexibility to respond to any changes to Standalone Power System (SPS) and undergrounding power plans under development. Separate business cases for pole reinforcement and replacement.

287 ibid. p. 5

288 [redacted]

289 ibid. p. 2

290 ibid. p. 2

291 AAS – Attachment 11.7 – AA5 Regulatory Revenue Model

292 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 4

293 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 9

Selection of a portfolio of individual assets for treatment was undertaken using risk modelling with the target of maintaining the current level of reliability and safety risk across the distribution overhead network. Western Power states the approach addressed risk considering like-for-like replacement solutions but anticipating alternative solutions would likely emerge. For appropriate business cases for alternative solutions, replacement volumes could be reduced if the business cases for alternate solutions were acceptable[294].

The distribution wood pole management program over the AA4 period was part of the wider Combined Asset Replacement Program. This program included the replacement of wood poles, conductors and other assets. Western Power states the Combined Asset Replacement Program was designed to maximise risk reduction in the distribution overhead network and achieve efficiencies by bundling assets into a combined program of works[295]. Alternative solutions for overhead replacement were seen as dependent and related investments and consequently were influenced by (and influenced) the scope of wood pole management in the AA4 period.

In specific geographical areas, Western Power states that where it was economically efficient to do so, asset risks were addressed by alternate solutions such as SPS and undergrounding. Western Power states that in the AA4 period, the Combined Asset Replacement Program achieved its goals in terms of volume of pole replacements (target risk reduction), by a combination of undergrounding[296], SPS and like-for-like replacement solutions, for a $40m lower overall cost than the $1,113m approved[297]. This Western Power statement supports the view that risk reduction associated with SPS replacing poles has been achieved, with existing poles being removed to avoid the risk of poles falling over during storms. The combined actual cost for NRUPP and SPS was $63m (~5.9 per cent) out of a total of $1,074m for the Combined Asset Replacement program for the overhead corridor. Western Power provides numbers for NRUPP, SPS and like-for like replacement of poles in terms of distribution overhead corridor CAPEX and pole replacement volumes for the AA4 period[298]. These are summarised below, along with the consequent estimated normalised cost of pole replacement by NRUPP, SPS and like-for-like overhead replacement.

The table below shows that pole replacement by NRUPP was ~0.56 times as expensive as the like-for-like overhead option during the AA4 period. Pole replacement by SPS was ~0.61 times as expensive as the like-for-like overhead option during the AA4 period. However, it should be remembered that the volume of pole replacements associated with NRUPP and SPS was relatively small for the AA4 period, at ~3.6 per cent and ~5.8 per cent of total pole replacements. Additionally, the NRUPP and SPS projects associated with pole replacement were deliberately (and perhaps appropriately) selected as having the lowest possible CAPEX costs.

294 ibid. p. 6

295 ibid. p. 7

296 Network Renewal Undergrounding Pilot Program

297 ibid. p. 7

298 ibid. pp.7-8

Table 7–16: Distribution overhead wooden pole replacements during the AA4 period

Replacement Option	Volume of replacement (# poles)	Distribution overhead corridor CAPEX ($m)	Normalised pole replacement cost ($k/pole)[299]
NRUPP	2,226	23	10
SPS	3,563	40	11
Like-for-like OH	55,383	1,011	18[300]

Engevity considers that the scope of the proposed expenditure on distribution wood pole management during the AA4 period was commensurate with need, based on the Western Power's target to maintain the level of reliability and safety risk across the distribution overhead network. Western Power states the reduced investment in wood pole treatment in the AA4 period was due to a lower volume of reinforcements.

Western Power also states alternative solutions for overhead replacement (NRUPP and SPS programs) slightly decreased the cost of the Combined Overhead Asset Replacement Program in the AA4 period. However, Engevity considers that the limited use of alternative solutions for replacement in the AA4 period (~9.5 per cent of total replacements) likely did not have a dominant effect on the large decrease in the scope of the wood pole management program in that period in comparison to AA3.

Timing

There is clearly an ongoing need for distribution pole management to replace and reinforce significant numbers of ageing wood poles (many untreated) with high-risk ratings. Western Power states that the investment timing, in three consecutive stages with associated business cases, was consistent (in accordance with the scope) with maintaining the current level of risk across the distribution overhead network for safety and reliability performance at minimum cost during the AA4 period[301]. Western Power states the scope of works for the recommended option associated with each business case was modified based on delivery of the program of works as required, with review at each business case approval step.

The use of a risk-based renewal methodology for distribution overhead assets supports the view that the proposed volume and timing of replacements and reinforcements is well founded. **Engevity considers that the wood pole management investment timing is likely consistent with the need to date.**

To guarantee maintenance of network safety and reliability, the program likely could not be deferred significantly and was unlikely to be brought forward considering the even larger volume of wood pole treatment works in the AA3 period. Consideration of alternative solutions for overhead replacement such as SPS or undergrounding may have resulted in some delay of treatment works in areas identified as appropriate for alternative solutions. However, Engevity considers that the limited volume of alternative solutions associated with the AA4 period likely did not influence wood pole management investment timing in a major way.

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299 This is not a pole unit cost. It is based on total distribution overhead corridor CAPEX, which includes pole cost as a component, normalised by total number of poles replaced.

300 This Engevity calculated value is not a pole unit cost. It is based on Western Power NRUPP comparative cost data for total distribution overhead corridor CAPEX. It is significantly higher than the ~$10.3k/pole AA4 weighted average unit replacement cost directly stated by Western Power for this reason.

301 ibid. p. 6

Risk Management

The Western Power Network Risk Management Standard requires that it understands risks, eliminates unacceptable risks and reduces remaining risks to ALARP in accordance with AS 5577[302]. This means Western Power was required to treat a minimum number of wood poles during the AA4 period to maintain current risk and performance levels by addressing identified condition issues. Western Power states its wood pole management program in the AA4 period addressed poles with high risk of failure[303]. Western Power states it sought to minimise the level of network safety risk to ALARP in the AA4 period through ongoing review of wood pole condition information and associated safety risk. This information was also used in ongoing discussions with the safety regulator and review of treatment criteria.

Western Power has managed substantial risk associated with distribution wood poles in both the AA3 and AA4 periods. As outlined above, there was a ~$323m (~32 per cent) nominal decline in the actual CAPEX and ~49 per cent decline in the volume of interventions associated with wood pole management in the AA4 versus the AA3 period. However, Western Power states that progress on their risk-based renewal approach plus better asset data, allowed them to maintain the overall network safety risk (public safety, service standard and environmental performance) associated with distribution wood poles in the AA4 period[304]. **Engevity considers that Western Power managed wood pole risk in the AA4 period in a similar manner to other asset risks.**

Grid Transformation impact, along with condition and risk, was considered for wood pole selection in the second and third phases of the AA4 period[305]. However, Engevity draft considers that the relatively small volumes of assets addressed by alternative solutions in the AA4 period probably did not influence risk management for the overall wood pole program in a major way.

Western Power has an Asset Management Framework in accordance with the Australian and International Standard on Asset Management (ISO55001), ERA Audit Guidelines, Electricity (Network Safety) Regulations 2015 and the Electricity Network Safety Management Systems standard (AS 5577). Western Power was acknowledged in its ISO 55001 assessment as having "…a number of industry leading practices, particularly in the areas of asset risk management".

Western Power's Network Risk Management Standard requires risk assessments to be carried out at appropriate points throughout the asset lifecycle. The condition of an asset is identified during the operate/maintain phase of the asset life cycle by qualitative and quantitative risk assessments. Risks are prioritised into four categories, unacceptable (failed/imminent risk), high risk, varying severity (decisions to treat managed by the Short-Term Risk Management building block of the Network Rebuilding strategy), and acceptable risk.

Cost Efficiency

The actual costs may have been estimated using an efficient system and unit costs. Western Power treats risk from assets in the distribution overhead network either by replacement at the end of their service lives or by maintenance mitigating the probability of failure. The distribution wood pole management program was considered as part of a Combined Asset Replacement Program across AA4. This was done to maximise risk reduction in Western Power's overhead network and achieve efficiencies in delivery by bundling these assets into a combined program of works. Western Power states that in specific geographical areas, where it was economically efficient, they addressed

302 ibid. p. 5

303 ibid. p. 6

304 ibid. p. 5

305 ibid. p. 11-13

overhead asset risks in the AA4 period with alternative solutions such as undergrounding and SPS[306]. Analysis based on Western Power data indicates these alternatives have been provided for normalised distribution overhead corridor costs less than like-for-like replacement in the AA4 period[307].

Labour costs typically make up 50-60 per cent of direct costs for individual asset treatments. In the case of distribution wood pole replacements, unit costs are 52 per cent labour and 29 per cent materials. Labour costs are greatly dependent on travel distance and scheduling limitations[308]. The weighted average estimates of unit rates are ~$10.3k for pole replacement and ~$1.3k for pole reinforcement across the AA4 period[309]. The 2017/18 actual replacement unit rate was $9,211. A 2016 study for the AA4 submission said the Western Power pole replacement unit rate for 2014/15 was comparable to peers.

Western Power states it has applied a robust unit cost estimation methodology to estimate the unit rates for its wood pole management program. Unit rates are developed using a "bottom up" methodology, with all inputs and assumptions validated with key stakeholders and based on the best information at time of development[310]. Western Power provides yearly and weighted average pole replacement and reinforcement unit rates for the AA4 period. The efficiency of the unit rates is supported by 2016 benchmarking in preparation of the AA4 submission. This benchmarking determined that Western Power's unit rate for pole replacements in 2014/15 was comparable to its peers[311].

Western Power presents three primary business cases relating to the wood pole management program that were undertaken throughout the AA4 period. The objective of these business cases was to optimise the risk across assets in the distribution overhead corridor and to achieve the lowest Net Present Cost over the assessment period for a variety of options[312]. The cost efficiency of engineering design was provided through adherence to Western Power's suite of standards, guidelines and manuals in accordance with good electricity industry practice and relevant external standards requirements[313].

Western Power has not explicitly identified any contingency or project overhead components of costs associated with wood pole management CAPEX for the AA4 period. However, the $679.3m nominal CAPEX is inclusive of indirect costs. Labour cost escalation and indirect costs have been included in all CAPEX estimates, including for the pole management sub regulatory category[314].
OPEXOPEX

Western Power has clearly demonstrated the need and cost-efficient delivery of an appropriate scope of risk-based replacement and reinforcement works, to maintain the existing level of safety and reliability of the distribution overhead network. This is in conjunction with a limited number of cases of economic use of alternate overhead replacement solutions such as SPS and undergrounding. It is also despite a substantial reduction of CAPEX during the AA4 period in comparison to the AA3 period. Wood pole management CAPEX in the AA4 period did comply with the NFIT requirements.

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306 ibid. p. 7

307 ibid. pp. 7-8

308 ibid. p. 12

309 ibid. p. 16

310 ibid. p.16

311 Ibid. p. 18

312 ibid. p. 2 and pp. 9-14

313 ibid. p. 21

314 [redacted] AAS – Attachment 11.7 – AA5 Regulatory Revenue Model

Scope Efficiency

Engevity considers that the scope of the distribution wood pole management program has been challenged for options to address a reduced scope within the AA4 period. This means that Western Power has looked at options for scope reduction in relation to the distribution wood pole management program.

Western Power distribution overhead replacement, including wood pole management, is governed by a risk-based renewal methodology. Western Power states that the scope of the distribution wood pole management program in the AA4 period, even though it was reduced by ~49 per cent from the volume of treatments in the AA3 period, is consistent with maintaining the level of reliability and safety risk across the distribution overhead network.

The scope of some parts of the wood pole management program in the AA4 period has been reduced under the influence of the Grid Transformation program, which encourages alternative solutions such as SPS and undergrounding in cases where it is economically efficient. This means the removal of sections of the overhead distribution network and negation of the need for proactive asset replacement activities[315]. However, as discussed above, SPS and undergrounding only accounted for about ~9.5 per cent of total pole replacements in the AA4 period and hence probably did not have a dominant effect on the overall scope of the wood pole management program.

As discussed previously, wood pole management work in the AA4 period was undertaken in three consecutive stages with separate business cases developed. An additional business case was prepared for pole reinforcement in 2020/21 and 2021/22. For each of these business cases, Western Power provides a summary of investment that identified at least three options, in some instances with substantially different scope and costing for pole replacements and/or reinforcements. The recommended options were based on lowest net present cost while satisfying all investment objectives and constraints.

Strategic Alignment

Wood pole management in the AA4 period was influenced by the Grid Transformation program, which considers alternate solutions for overhead network replacement such as SPS and undergrounding and supports the transition to a modular grid. Wood pole management is governed by the Distribution Overhead Network Rebuild Strategy, which is based on the guiding principles of the Western Power Grid Strategy (prepared by the Grid Transformation program team in January 2022). The Grid Strategy includes a collection of strategies grouped into performance and transformation. Performance strategies target network reliability, voltage, utilisation, protection and power quality across the lifecycle. They are focussed on short to medium term responses to existing and emerging issues. Transformation strategies target changes to networks when they reach end of life. They are focussed on longer term responses to emerging and future issues. However, Western Power states transformation strategies also drive planning actions in the short term[316, 317].

Wood pole management is not mentioned in the WA Whole of System Plan.

Wood pole management is not identified as a priority program under the NFIT.

Options Analysis

Engevity considers that Western Power has identified a reasonable range of alternative options, demonstrated how the recommended options were selected and articulated why.

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315 Ibid. p. 11

316 Access Arrangement Information – 1 February 2022, p. 183

317 [redacted]

As discussed previously, wood pole management work in the AA4 period was undertaken in three consecutive stages with separate business cases developed, with an additional business case prepared for pole reinforcement in 2020/21 and 2021/22. For each of these business cases, Western Power provides a summary of investment that identified at least three options, in some instances with substantially different scope and costing for pole replacements and/or reinforcements. The business cases do demonstrate how Western Power selected the most efficient option at various stages in the AA4 period. The recommended options were based on lowest net present cost while satisfying all investment objectives and constraints. There is in all cases a discussion of the merits and limitations of the various options, including the grounds for selection of the recommended option.

Delivery Model (incl. staging)

Western Power distribution overhead replacement, including wood pole management, is governed by a risk-based renewal and prioritisation methodology[318]. The programs are prioritised and staged based on risk. Each stage progresses through Western Power's Investment Governance Framework, with approval at each stage (or gate) of the investment planning lifecycle[319]. The investment lifecycle allows for new information to be considered to ensure that the final investment decision reflects the most prudent and efficient option.

The distribution wood pole management program was delivered in several stages (as described above) in the AA4 period. Improvements were made to the design, estimating and delivery of the investments in following stages during review and close-out at the close of each consecutive stage[320]. Western Power states that the scope and staging of the distribution wood pole management program in the AA4 period, even though it was reduced by ~49 per cent from the volume of treatments in the AA3 period, was consistent with efficiently maintaining the level of reliability and safety risk across the distribution overhead network[321].

The reinforcement program had a fully outsourced delivery model in the AA4 period. The replacement program used a combination of internal and external resources, with internal resources being fully utilised first. The efficient delivery of the works program was supported by the Network Delivery Strategy[322]. Internal and external packages of work were grouped to efficiently deliver the work.

A variety of options were considered in each stage of delivery of the wood pole management program, but Western Power states these would have resulted in sub-optimal outcomes in terms of risk-based prioritisation. The delivery of the wood pole management program in the AA4 period was also impacted by the decision to proceed (or not) with projects under the SPS and undergrounding programs as part of Grid Transformation. However, as previously discussed, the volume of alternative solutions for overhead asset replacement in the AA4 period was relatively small and probably did not have a dominant effect on the staging of the wood pole management program.

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318 [redacted]

319 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 1

320 ibid. p. 22

321 ibid. p. 8

322 ibid. p. 21

7.7 IT, SCADA & Communications - AA4 NFIT Assessment

7.7.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **AA4 SCADA and Communications and IT Projects delivered in AA4.** We found that **the expenditure complied with the NFIT requirements**. As a result, we have not made recommendations for ERA to make any adjustments in this expenditure category.

Note that hereafter, Engevity has defined the distribution and transmission SCADA, Comms and Corporate IT programs into a broad category referred to Information and Communication Technology or ICT Program.

Over the AA4 period, ICT Program in the distribution network accounted for the expenditure and scope summarised in the table below.

Table 7–17: AA4 Expenditure and scale – NFIT Compliance – ICT Program [$m nominal]

SCADA, Comms and IT	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1 actual	Yr2 actual	Yr3 actual	Yr4 actual	Yr5 forecast	Total
Western Power ActualAA4						
SCADA & Comms	37.8	38.3	44.9	54.5	58.2	233.7
IT	48.0	53.5	54.5	65.6	64.0	285.6
Total CAPEX	85.8	91.8	99.3	120.1	122.2	**519.3**
Adjustment Exclude from AA5 opening RAB	-	-	-	-	-	-
Engevity Recommended	**85.8**	**91.8**	**99.3**	**120.1**	**122.2**	**519.3**

Assessment Overview

Table 7–18: Assessment Overview

Project/Program	IT, SCADA and Communications
Actual Cost $m	Engevity observed that all the ICT Program activities were mostly overspent during AA4 and only one of the Transmission activities in this regulatory category was underspent[323]. Overall, the ICT Program was 58 per cent overspend is $185.1m and Dx SCADA & Comms it was 290 per cent overspent[324]. Acknowledging that the ERA did not approve Western Power's proposed increase in AA4, Engevity is concerned this may be symptomatic of more significant issues in Western Power's ability to managing this program and/or an over estimation of the of the underlying risks associated in comparison to its peers benchmarked.
Need	Western Power states that the age of the equipment, as a significant and increasing driver for the need to upgrading Western Power ICT assets. In most

323 AAS – Attachment 5.2 – AAS Capital Expenditure Variance Report

324 AAS - Attachment 5.2 - AA4 Capital Expenditure Variance Analysis Report

Project/Program	IT, SCADA and Communications
	cases, Engevity has observed Western Power identify risk, safety and compliance needs for the expenditure. Despite this, Engevity is aware that other networks typically run systems that are not supported by OEMs. We have also observed relatively flat historic availability of ICT systems which further highlights the emerging risk identified by Western Power may be overstated.[325]
Scope Definition	We have observed Western Power outline the scope of some of the expenditure category and consider they have adopted standard practices for delivering this expenditure program. Engevity is however concerned that this regulatory expenditure category lacks clarity on the reasoning for the overspend and considers this may be because of project delivery issues and a lack of clear specifications that align to the need. Furthermore, Engevity did not observe sufficient details to ascertain the causes of all the differences in the original scope, particularly as some projects were expanded.
Timing	Engevity has observed Western Power clearly outlining a need for both bringing forward the ICT expenditure however we did not observe any sensitivity analysis on the impact of delaying the expenditure to future regulatory periods. Despite these concerns, the prioritisation of the expenditure appears to align with a prudent industry practice.
Risk Management	Western Power claims that many of the system can no longer be repaired nor replaced in the event of failure and are now deemed a high untreated risk of equipment failure. However, Engevity is aware of many networks operating ICT systems that are not supported by OEMs. Despite these concerns, we are aware that networks are increasing their ICT expenditure to overcome cyber, reliability and regulatory obligations.
Cost Efficiency	Engevity is concerned that overspending in this regulatory category and timing delays of key activities is symptomatic of more fundamental issues. Western Power justify the overspend in AA4 by noting unplanned CAPEX and a growing risk of obsolesce and non-compliance of ICT assets. We have not been provided with sufficient detail to adequately assess whether the overspend in AA4 is as a result of understating the AA4 forecasts/risk or mismanagement of the delivery of the program of works. We note that Western Power proposed higher ICT expenditure for AA4 however the ERA reduced it level of AA3 actual expenditure due to lack of evidence that the program could be delivered in the timeframe and that Western Power had underspent significantly against the ICT capex approved for AA3.
Scope Efficiency	Engevity notes that Western Power has adopted a like-for like replacement strategy of high-risk equipment (including associated systems). During AA4, it appears Western Power moved from a reactive to a proactive asset strategy to bring it into line with other networks in Australia.

[325] Att 8.2 Network Management Plan, Pages 317-319

Project/Program	IT, SCADA and Communications
Strategic Alignment	The AA4 replacement program is consistent with the SCADA and Communications Management Strategy.
Options Analysis	We observed Western Power undertake delivery options analysis to assess the preferred procurement pathway and scale of investment however were unable to assess within these options whether Western Power has adopted an efficient and prudent approach. We assume that Western Power's expenditure governance policies have been adopted and executive oversight has meant the program has been delivered in line with the Access Code objective in line with the long-term interest of consumers.
Delivery Model	Western Power has utilised external provider for many elements of the works and there appears to be efficiency gains obtained in grouping projects by location and geographical area as well as forming joint planning teams.

Findings

Engevity has reviewed Western Power's proposed expenditure relating to **ICT Programs** and found that:

a. **The proposed expenditure is efficient** with the objective of minimising costs despite the level of overspend in AA4. Engevity remains concerned that the ICT Programs are collectively overspent by $185m across almost all categories. We are of the opinion that the proposed CAPEX expenditure forecasts for AA4 were likely underestimated by Western Power and that this expenditure for the AA4 period be accepted by ERA. We note that ERA reduced the approved ICT approved expenditure for AA4 on the basis of deliverability concerns.

b. **The program does capture the available and realisable economies of scale and scope** by staging the expenditure with a proactive focus on the higher risk assets. Engevity considers the delivery model to be prudent and efficient delivery of the works. Engevity has however considered our concerns in this AA4 NFIT review to assess what lessons have been learnt from AA4 and are being carried forward.

c. The proposed investment **is consistent with reasonable expectations** of the level of future network services required by customers because it enables Western Power to meet the Technical Rules[326] and the AEMO Power System Data Communications Standard.

A reasonable range of alternative options has not been considered for the proposed investment, with the most appropriate solution chosen.

Recommended Adjustment

Overall, we consider that the ICT Program for the AA4 satisfies the NFIT requirements.

7.7.2 AA4 NFIT Assessment

Expenditure Overview

The variance analysis for IT, SCADA and Communications is summarised below:

[326] The Technical Rules (as defined by the Electricity Industry Act 2009, Section 32, Clause 2.9 & Clause 5.6.1 Technical Rules) is a document containing technical requirements that must be met by Western Power and all users of the SWIS.

Table 7–19: Summary of Distribution and Transmission SCADA and Communications in AA4 ($ Nominal, including indirect costs)[327]

Regulatory Category	AA4 Submitted Forecast	AA4 Actual + FY F1	Forecast less Actuals	Variance (%)
Dx SCADA & Comms	$21.5	$84.0	-$62.40	-290%
Tx SCADA & Comms	$78.2	$129.0	-$50.80	-65%
SCADA & Comms Total	**$99.70**	**$213.00**	**-$113.20**	**-355%**

Table 7–20: Summary of Corporate IT expenditure in AA4 ($ Nominal, including indirect costs)

Regulatory Category	AA4 Submitted Forecast	AA4 Actual + FY F1	Forecast less Actuals	Variance (%)
Corporate IT	$221.5	$293.4	-$71.90	32%

Much of this expenditure appears to be non-recurrent expenditure focused on meeting Western Power's regulatory obligations or risk appetite, meaning it cannot be simply assessed using trend or benchmark analysis. As a result, Engevity has considered Western Power's internal capital governance framework and where possible prudent industry practice to determine whether the overall program is efficient and prudent.

Engevity was only provided a subset of the AA4 business cases and associated NFIT compliance summaries for this regulatory category. As a result, our assessment approach has been to use these activities as a proxy for our review. The two NFIT Compliance Summaries reviewed were:

- **Control Centre – Upgrade Energy Management System**, which involves upgrades to the monitor and control of Tx and Dx network due primarily to the age and lack of support being covered by GE Grid Solutions Australia (GE).
- **Transmission Network SCADA & Communications**, this project replaces obsolete Tx SCADA and telecommunications equipment proactively and progressively in discrete, sequential stages, each approved under separate business cases.

Historical Context

During AA3, Western Power began preparing for the change that new technology is now having in the Australia's electricity systems. This was evidenced by proposed investments in ICT systems.

Prudent and efficient operators create value for their customers by identifying the risks on their network, mitigating them through targeted inspection, maintenance, refurbishment and replacement works to keep assets in service for as long as practicable. For some asset classes which may be the case for some SCADA and IT systems, the consequence of failure is low (particularly in the rural network), and it is not unusual for assets to simply be operated for as long as they last and then replaced or repaired on failure. Western Power's AA4 expenditure is primarily focused on replacing obsolete ICT assets and, where practicable, retrieving spares from the replaced units to manage the ongoing operational risk and safety of the network.

The AA3 actual expenditure was under spent in caparison to the approved forecast and AA4 expenditure forecast were further reduced. It is possible at the time, the underspend in AA3, led to an underestimate of expenditure required in AA4 or potentially the planned works were delayed

[327] Source AAS – Attachment 5.2 – AA4 Capex Variance Report. Note there is a mismatch between these figures and the AAS – Attachment 11.7 – AA5 Regulatory Revenue Model.

creating additional expenditure in AA5. Engevity cannot confirm these finding from the documentation provided although does highlight concern with the major variances between planned and actual expenditure.

Need

Engevity considers that Western Power ICT justification may not be aligned with a prudent and efficient network operator.

Control Centre Upgrade

Western Power has historically upgraded these systems every 4-6 years and given the risk associated with failure of these systems required to operate and manage the Tx and Dx systems, the need has been clearly identified to meet both compliance and reliability obligations.

Tx SCADA and Communications

When the Stage 2 business case was developed in 2015, 19 per cent of the SCADA and communication equipment was deemed obsolete[328] which could impact communication services in the Muja to Merredin, Muja to Manjimup, Geraldton, Goldfield among other regions. By the time the Stage 3 business case was written in early 2020, despite the work undertaken in Stage 2 up to that time, 46 per cent of the SCADA and communications electronic assets were assessed to be obsolete.

It is possible that 15 years may be an unrealistic useful life evaluation period in future business cases.

Scope Definition

Engevity considers that Western Power ICT NFITs lacks clarity on the reasoning for the overspend and considers this may be because of project delivery issues and a lack of clear specifications that align to the need.

Control Centre Upgrade

The proposed solution is to upgrade Western Powers existing systems provided by GE. Additional activities were also considered including improving the integration between Western Power and AEMO. We consider the scope and additional works to be commensurate with the identified need.

Tx SCADA and Communications

During AA3, the Western Power transmission SCADA & Communications equipment was in poor condition and represented a risk to the safe and reliable performance of the transmission network.

Timing

Engevity has observed Western Power clearly outlining a need for both bringing forward the ICT expenditure however we did not observe any sensitivity analysis on the impact of delaying the expenditure to future regulatory periods.

Control Centre Upgrade

Western Power considered several options and concluded that a delay or convergence of investment in upgrading the GE Platform for its Tx and Dx systems to both increase cost and risk. We consider the timing for this decision to align with Western powers obligations to maintain the performance of the system and were accepted in AA4 by ERA.

Tx SCADA and Communications

Western Power claims that due to age a significant proportion of Western Power's SCADA and communications assets cannot be repaired or replaced and have outlined some examples of the

328 Obsolete is defined by Western Power as the last batch of this type of equipment to be manufactured and were no longer supported.

impact of these risks. However, Engevity did not observe any detailed analysis to support what the impact could be of delaying the investment to future regulatory periods.

Risk Management

Engevity considers that Western Power risk approach may not be aligned with a prudent and efficient network operator.

Western Power claims that many of the system can no longer be repaired nor replaced in the event of failure and are now deemed a high untreated risk of equipment failure. However, Engevity is aware of many networks operating ICT systems that are not supported by OEMs.

Despite these concerns, we are aware that networks are increasing their ICT expenditure to overcome cyber, reliability and regulatory obligations.

Control Centre Upgrade

Whilst there is no change to the approved benefits, the change in the systems proposed in the delivery phase are expected to further reduce the delivery risk. The project was delivered in accordance with Western Power's standards and guidelines in order to comply with safety requirements and the Technical Rules.

Tx SCADA and Communications

A failure of these SCADA and communication system has a high risk of impacting the reliability and resilience of the SWIS and therefore non-compliant with the Technical Rules[329] and the AEMO Power System Data Communications Standard.

Cost Efficiency

Engevity observed that Western Power was significantly overspent for its ICT program in AA4.

Western Power outlines that the overspend is largely due the following factors:

- Unplanned CAPEX and bringing forward activities planned in later regulatory periods;
- Risk of growing obsolesce of ICT assets;
- Technical non-compliance issues and an inability to meet emerging network and operational requirements;
- Unit costs exceeded Western Power's expectations;
- Cyber security exposure.

Engevity considers these are all valid reasons however remains concerned that the forecast expenditure assumptions in AA4 were almost universally understated and is concerned with the lack of justification for the proposed increase in expenditure for AA5.

We note that Western Power proposed higher ICT expenditure for AA4 however the ERA reduced it level of AA3 actual expenditure due to lack of evidence that the program could be delivered in the timeframe and that Western Power had underspent significantly against the ICT CAPEX approved for AA3.

Control Centre Upgrade

Western Power outline in their NFIT Compliance summary that AA4 submission was $10.1m which was subsequently considered in a business case and approved $49.6m, with $39.5m incurred in AA4 and remaining $5.6m is expected to be incurred in the AA5 period. Western Power forecasts an

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[329] The Technical Rules (as defined by the Electricity Industry Act 2009, Section 32, Clause 2.9 & Clause 5.6.1 Technical Rules) is a document containing technical requirements that must be met by Western Power and all users of the SWIS.

underspend of these activities against the original budget of $33.9m overspend in its NFIT Compliance Summary[330].

The costs were based on a competitive procurement process which include full vendors and were assessed using both qualitative and quantitative criteria by a Western Power internal team. Given the significant overspend, we would have expected Western Power to seek independent external specialist evaluation and assurance support for the selected solution however this was not evidenced in the documents provided.

Tx SCADA and Communications

Western Power outline in their NFIT Compliance summary that AA4 submission was $49.4m which was subsequently considered in a business case and approved to split the cost between AA4 ($34m) and AA5 ($27m). The AA4 Further Final Decision was approved at $32.5m and actual expenditure including an estimate to complete in AA4 was $29.7m. Western Power forecasts an underspend of these activities.

Despite a variance of $2.8m below the approved FFD limit in AA4, Western Power state that only 40-60 per cent of the work items have been completed. The Stage 2 close out report[331] outlines an additional $11.3m[332] of outstanding scope items. Engevity will consider this issue in the forecast expenditure in AA5 to assess the impacts of these scope and timing delays.

Western Power estimates that this program will come under the approved AA4 forecast by 11 per cent or $3.6m.

Scope Efficiency

Engevity observed that Western Power was seeking some economies of scale and scope in its ICT program however we were unable to verify the underlying reasons for the large overspend to the AA4 approved forecast.

Control Centre Upgrade

The proposed solution is to upgrade Western Powers existing systems provided by GE. Additional activities were also considered including improving the integration between Western Power and AEMO. We consider the scope and additional works to be commensurate with the identified need.

Tx SCADA and Communications

During AA3, the Western Power transmission SCADA & Communications equipment was in poor condition and represented a risk to the safe and reliable performance of the transmission network.

Strategic Alignment

Engevity observed that Western Power delivered the ICT program in alignment with Government, regulations and policy.

Control Centre Upgrade

The convergence into a common platform was selected to provide alignment between the Tx and Dx functions, reducing duplication/improving productivity. The objective is to enable efficiency gains across the platforms potentially reducing future maintenance and support costs. These efficiency gains have not been observed in the forecast expenditure.

330 We note that the AAS – Attachment 5.2 – AA4 CAPEX Variance Report, outlines this variance to be $20.4m

331 [redacted]

332 We note that the AAS – Attachment 5.2 – AA4 CAPEX Variance Report, outlines this variance to be $10.9m.

Tx SCADA and Communications

Western Power's SCADA and Communications asset management strategy for in-service SCADA and communications assets changed in 2014 from a reactive to a largely proactive replacement strategy. The AA4 replacement program is consistent with the SCADA and Communications management strategy.

Options Analysis

Engevity observed that Western Power undertook some option analysis for the ICT program.

Control Centre Upgrade

Western Power has selected to adopt a single converged platform for both Dx and Tx networks. The result of this has led to a higher implementation cost, longer timeframe and growing dependence on GE as a single vendor. Despite these factors, the end-to-end system visibility, reduced complexity and removal of duplication outweighed the alternative options considered.

Tx SCADA and Communications

Western Power considered 3 options for the expenditure across a 2-stage program, that being; Option 1 – Complete Asset Replacement, Option 2 - Optimised Asset Replacement, and Option 3 – Defer investment until FY 2019. Across both stages Option 2 satisfied the evaluation criteria which corresponded with the project objectives.

Delivery Model (incl. staging)

Engevity observed that Western Power procured assets and service for the ICT program in accordance with Western Power's corporate and procurement policies

Control Centre Upgrade

Engevity was provided a presentation and the Network Management Plan which outlined at a high level the delivery strategy for the SCADA and Comms program. Unfortunately, this was not sufficient detail to thoroughly assess the delivery model for this project.

Tx SCADA and Communications

The replacement program has been delivered in a stage program, with stages 1 and 2 now completed and Stage 3 underway. For Stage 3, Western Power provided evidence that the lessons learnt from Stage 2 were applied (e.g. early engagement of landowners for proposed communication sites to avoid delays during project execution).

Western Power states that all materials and equipment required to undertake this program were or will be sourced in accordance with Western Power's corporate and procurement policies. There appears to be efficiency gains in grouping projects by location and geographical area as well as forming joint planning teams.

7.8 AMI – AA4 NFIT Assessment

7.8.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **Advanced Metering Expenditure in AA4.** We found that **the expenditure complied with the NFIT requirements**. As a result, we have not recommended any adjustments in this expenditure category.

Table 7–21: AA4 Expenditure - Advanced Metering Infrastructure - Meters ($m nominal) Total CAPEX

AMI Meters	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Reported AA4 Total CAPEX, Meters	17.79	28.47	36.00	36.91	38.74	**157.91**
Less Western Power Reported AMI Building Block Adjustment (Meters)[333]	0.54	1.66	4.75	14.54	14.43	**35.92**
Adjustment	-	-	-	-	-	-
Engevity Recommended Total CAPEX, Meters	17.25	26.81	31.25	22.37	24.31	**121.99**

Source: Western Power Attachment 5.2 CAPEX Variance Report[334]

An additional $115.36m ($real 30 June 2017) expenditure was approved in the Access Code[335] for AMI Communications and IT systems investment prior to June 30, 2022. This amount is to be recovered over a 10-year period. In the regulatory model, Western Power has made a CAPEX adjustment in the Regulatory Model to remove $99.41m (nominal) | $103.19m ($real June 2022) from the total CAPEX to be recovered via the AMI Building Block. When expressed on the same $real June 30, 2017, basis used in the Access Code, this accounts for $94.42m in AMI ICT and Communications expenditure out of the approved $115.36m amount – equating to an 18.2% underspend of the Access Code allowance.

The actual AMI ICT and Communications expenditure is calculated from the 'AMI Building Block' CAPEX Adjustment in Western Power's Regulatory Model and shown in the table below.

We note that we have been unable to reconcile the $210.3m (nominal) CAPEX reported in Western Power's NFIT documentation with the figures for AMI in the historical CAPEX variance analysis spreadsheet or the regulatory model spreadsheet provided by Western Power. This is likely a result

333 Western Power, *AA5 - Attachment 11.7 – AA5 Regulatory Revenue Model,* 'Dx_Inputs' sheet, Row 196 – converted to Nominal using the escalation factors in Row 54

334 Western Power, *AA5 – Attachment 11.7 – AA5 Regulatory Revenue Model (confidential)*, 'Dx Inputs' Sheet row 169 (Metering) less the Metering CAPEX adjustment in row 196 marked as 'AMI Building Block'. As the model expresses these values on a Real June 2022 basis, the figures are adjusted to nominal using CPI multipliers in row 54

335 WA *Electricity Networks Access Code 2004*, 18 September 2020, p. 92

of a modest amount (in the order of $10m | or 4-5% of the total AA4 metering CAPEX) of 'non-AMI' metering CAPEX included in the Regulatory Model totals for 'metering' along with the impact of customer contributions ($15.8m nominal[336]). As a result, we have relied on the figures reported in the regulatory model to ensure the correct treatment of AMI expenditure for regulatory purposes. This is because the regulatory revenue model is the basis for the calculation of Western Power's target revenue.

Table 7–22: AA4 Expenditure - Advanced Metering Infrastructure – AMI ICT and Comms ($m nominal) Total CAPEX

AMI ICT & Comms	Western Power AA4 Actual Expenditure					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Reported AA4 Total CAPEX, AMI ICT & Comms	13.29	13.23	30.50	20.14	22.26	**99.41**
Adjustment	-	-	-	-	-	-
Western Power Reported AA4 Total CAPEX, AMI ICT & Comms	13.29	13.23	30.50	20.14	22.26	**99.41**

Source: Western Power Attachment 11.7 Regulatory Revenue Model & Engevity Analysis[337]

Overall Engevity recommends that the actual CAPEX identified in the regulatory model and annual historical CAPEX breakdown is carried forward, noting that the AMI ICT and Communications CAPEX in significantly lower than the Access Code allowance.

7.8.2 AA4 NFIT Assessment

Overview

Over AA4, Western Power delivered an AMI program deploying 348,083 meters alongside associated IT and communications infrastructure to enable the automated reading, data hosting and network monitoring capability of the AMI deployment.

This exceeded the allowance for AMI within the ERA's AA4 decision, which essentially allowed for the installation of 'AMI capable' meter hardware but excluded the associated IT and communications infrastructure costs to deploy the AMI solution. In September 2020, several changes were gazetted to the Electricity Network Access Code providing for the recovery of expenditure associated with the AMI communications and IT infrastructure. This amounted to an additional $122.4m in additional funding for the project in AA4.

The potential benefits to customers of the AMI program were tested during the consumer engagement program leading up to the AA4 submission to the ERA. Engevity's review of the insights report for Time of Use tariffs and smart meters shows that much of the customer interest was in accessing 'near real time' information (via an in-home display or smartphone app) on their electricity

336 Western Power AA4 CAPEX Variance Report, *Summary Capital Contributions*,

337 Western Power, *AA5 – Attachment 11.7 – AA5 Regulatory Revenue Model (confidential)*, 'Dx Inputs' Sheet annual sum of rows 196 (Metering), 202 (SCADA & Comms), 206 (IT), Capital Expenditure Adjustments marked as 'AMI Building Block' adjusted to nominal using CPI multipliers in row 54

consumption to help them manage their usage and realise the benefit of Time of Use tariffs. The research noted:

> *"2 in 3 customers were interested in monitoring their electricity usage.*
>
> *The key appeal of 'real time' monitoring was the ability to understand usage and then amend behaviours to save money…*
>
> *…A majority of residents in the workshop were interested in monitoring their electricity usage and preferred an in-home display""*[338]

And that the willingness of customers to pay for the benefits was limited – noting that most of the benefits were attributable to the network, as Western Power's document summarises this as a key insight:

> *"The survey results showed that the benefits or savings Western Power may achieve was the key reason why customers felt they should not pay for the installation.*
>
> *Customers felt passionately about the charge, with sentiment particularly high amongst those who found it unjustified.*
>
> *Although monitoring usage was the key appeal of smart meters, even those who find the idea "very appealing" felt that the charge was unjustified."*[339]

This research highlights the level of concerns that customers had about AMI meter costs and the share of benefits that they receive vs Western Power. Importantly, Engevity notes that AMI solution in the Western Power rollout lacks the ability of customers to access 'near real time' information (such as the customer preferred in-home display or app) and will impose additional costs onto consumers through the recovery via Western Power's network charges.

Based on the aggressive input assumptions for the AMI1 program (AA4) that are contained in the financial analysis sheet for the AMI2 accelerated AA5 rollout, the benefits were likely to have been overstated by the aggressive rate of customers choosing to respond to Time of Use tariffs (starting at 25% in 2021 and having all 1.4m customers responding to a ToU structure by 2036), and overstating reliability impacts through higher VCR assumptions than would typically apply.

Notwithstanding the above, Western Power's AMI investment was approved by the Board in December 2016 for all new and replacement meters. The business case was based mainly on the deferral of CAPEX and reduction of OPEX as well as public safety and cost-saving benefits

Western Power asserts that AMI also enables greater information and choice for customers in addition to allowing retailers to offer more innovative products. AMI can also support greater hosting capacity for renewable energy, by providing Western Power with AMI data to enable better management of the overall power system.

Western Power notes that:[340]

- The AMI program's 15-year deployment approach was arrived at with a focus primarily on the recognition of the highest net-benefit outcome.
- Subsequent to the original analysis, the realisation of other benefits has now come into clearer focus. **Western Power continues to review and update its benefits plan** for the AMI program.

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338 Western Power, *Customer Engagement Insights,* 13 December 2016, p. 35

339 Western Power, *Customer Engagement Insights,* 13 December 2016, p. 37

340 Western Power, *AA5 – Attachment 5.13 – AA5 NFIT Compliance Summary- Advanced Metering Infrastructure*, 1 February 2022, p. 3

- **The safety and data benefits of advanced metering technology has developed** exponentially, providing many opportunities for the AMI network to be leveraged to support the strategies of Western Power and the WA government.
- **AMI is globally recognised an essential enabling tool** for the safe and efficient operation of an electricity market for all Market Participants.
- **The ERA approved the CAPEX for deployment of advanced capable meters**. However, the ERA did not approve the incremental expenditure associated with establishing a communications network, ICT infrastructure or provision of Network Interface Cards (NICs) as proposed by Western Power.
- **These items are critical to remotely access the data available from advanced meters**, and realisation of the estimated benefits to consumers, the State of Western Australia and the electricity network.
- Western Power sought and gained approval from the Minister for Energy to proceed with the AMI program and establish the requisite contracts.

As a part of the Western Australia Energy Transformation Strategy, the Energy Transformation taskforce considered that implementation of the complete AMI solution, including the communications network and ICT infrastructure, was essential to enable the technical functionality required to deliver safe and reliable supply, and manage a high-distributed energy future (DER) future**. In September 2020, several changes were gazetted to the Electricity Network Access Code (ENAC) providing for the recovery of expenditure associated with the AMI communications and Information Technology expenditure, $122.4 million, by Western Power during AA4.**

The AMI program was included in the AA4 submission based on extrapolation of the **initial business case approved in 2016 for the deployment of 355,493 new and replacement meters** over the AA4 period. As information was updated, including **reduction of the meter deployment to 331,925 meters, inclusion of market-based pricing of services and re-profiling of the program over 5-years (instead of the initial three), the estimated capital costs were updated to $237.7 million**. Based on current forecasts (October 2021), **Western Power will implement AMI over the AA4 period at a total capital cost of $210.3 million. This will include increased level of deployment to 348,083 meters**.

Engevity is concerned with the conflicting delivery priorities of the AMI program as it developed, with the delivery of the initial tranche stretched from 3 years to 5 and then various proposals to accelerate the program. The significant change due to the above 'reduction of the meter deployment' (from 355k meters to 332k meters and then 'increased' to 348k meters), 'inclusion of market-based pricing', and Western Power's statement that 'it continues to update its benefits plan' also point to significant uncertainty with the need, scope and timing of the program.

Despite this, the additional AA4 AMI program ICT and communications expenditure was supported by changes to both the Access Code and WA Government policy. As a result the program proceeded with both the ERA allowance for 'AMI Capable' metering CAPEX and the supporting ICT and Communications CAPEX.

As reported by Western Power, the project has been delivered at a total cost of $210.3m (nominal) against an approved budget of $237.7m (nominal) representing a 11.5% underspend against the approved budget. On the basis of the overall underspend and the separate funding mechanism provided for the AMI ICT and Communications expenditure in the Access Code, Engevity considers that the AA4 AMI program represents efficient delivery of a mandated program. Whilst we remain concerned about the validity of inputs to the benefits calculations, achievability of the assumed customer response to variable tariffs and the alignment with Western Powers demand forecast (as discussed in our review of the AA5 AMI program), we consider that the need, scope, timing and cost of delivering the AA4 program was appropriate.

Recommendation

Based on the information provided by Western Power, the AMI project for AA4 was supported by a clear need, government support, Access Code requirements for communication and supporting ICT system upgrades and enablement of tariffs that support more flexible operation of the network.

We are concerned that customers do not appear to have received the access to monitor their 'near-real-time' consumption of electricity – which was a key benefit sought by customers in Western Powers own 2016 customer research. Similarly, the research showed that customers were highly opposed to paying for the smart meter given that the benefits mainly accrued to Western Power rather than the customer themselves.

Overall, we do not recommend any changes to the AMI program for AA4 but note that care should be taken to ensure that the AMI Building Block adjustment is carried forward in a manner that reflects the actual expenditure reported in the AMI Building Block over AA4.

This recommendation for Metering CAPEX for AA4 is shown in the table below.

Table 7–23: AA4 Expenditure - Advanced Metering Infrastructure - Meters ($m nominal) Total CAPEX

AMI Meters	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Reported AA4 Total CAPEX, Meters	17.79	28.47	36.00	36.91	38.74	**157.91**
***Less* Western Power Reported AMI Building Block Adjustment (Meters)[341]**	0.54	1.66	4.75	14.54	14.43	**35.92**
Adjustment	-	-	-	-	-	-
Engevity Recommended Total CAPEX, Meters	17.25	26.81	31.25	22.37	24.31	**121.99**

Source: Western Power Attachment 5.2 CAPEX Variance Report[342]

Our recommendation for the AMI Building Block for AMI ICT and Communications systems is summarised below.

[341] This has been removed from the total to ensure that it is only reported once as it forms part of the $99.41m AMI ICT & Comms CAPEX noted in the table below

[342] Western Power, *AA5 – Attachment 11.7 – AA5 Regulatory Revenue Model (confidential)*, 'Dx Inputs' Sheet row 169 (Metering) less the Metering CAPEX adjustment in row 196 marked as 'AMI Building Block'. As the model expresses these values on a Real June 2022 basis, the figures are adjusted to nominal using CPI multipliers in row 54

Table 7–24: AA4 Expenditure - Advanced Metering Infrastructure – AMI ICT and Comms ($m nominal) Total CAPEX

AMI ICT & Comms	Western Power AA4 Actual Expenditure					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Reported AA4 Total CAPEX, AMI ICT & Comms	13.29	13.23	30.50	20.14	22.26	**99.41**
Adjustment	-	-	-	-	-	-
Western Power Reported AA4 Total CAPEX, AMI ICT & Comms	13.29	13.23	30.50	20.14	22.26	**99.41**

Source: Western Power Attachment 11.7 Regulatory Revenue Model & Engevity Analysis[343]

343 Western Power, *AA5 – Attachment 11.7 – AA5 Regulatory Revenue Model (confidential)*, 'Dx Inputs' Sheet annual sum of rows 196 (Metering), 202 (SCADA & Comms), 206 (IT), Capital Expenditure Adjustments marked as 'AMI Building Block' adjusted to nominal using CPI multipliers in row 54

7.9 Customer Management System – AA4 NFIT Assessment

7.9.1 Summary of Assessment

Engevity has reviewed the information provided by Western Power on the **Customer Management System in AA4.** We have found that **the expenditure did not comply with the NFIT requirements or represent efficient expenditure**. As a result, we have recommended the adjustments in the table below.

Table 7–25: AA4 Expenditure - Customer Management System [$m nominal]

Customer Management System	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Forecast AA4 CAPEX	-	-	-	-	-	24.9
Adjustment Exclude from AA5 opening RAB	-	-	-	-	-	-24.9
Engevity Recommended	-	-	-	-	-	Nil

Source: Western Power Attachment 5.12

7.9.2 AA4 NFIT Assessment

Overview

Engevity notes that the Customer Management System was proposed as a $31.2m[344] component of Western Powers proposed AA4 CAPEX portfolio. However, it was excluded by the ERA following the observation that the proposed cost appeared to be excessively high for a relatively routine Microsoft Dynamics implementation and subsequent rationalisation of legacy systems to support the customer facing part of the business. As a result, the ERA excluded the project from the AA4 allowance and noted that Western Power could still proceed and fund it from operating efficiencies, noting that:

> *'…delivery of the program and evidence that the most efficient option has been selected has not been adequately demonstrated. On the basis that a new CRM will deliver efficiencies, the ERA considers Western Power can proceed with the project without the need for an uplift in corporate expenditure.'*[345]

Western Power subsequently continued with the project, ultimately investing $24.9m[346 347] over the AA4 period in three stages as follows:

- **Phase 1 ($10.7m)** delivered a cloud-based Microsoft Dynamics 365 platform to replace legacy systems such as NetCIS, establishment of a new customer database and integration with other Western Power Systems.

344 Western Power, *AAS - Attachment 5.12 - AA4 - NFIT Compliance Summary - Customer Management System*, February 2022. p.4.

345 ERA, Western Power AA4 – Final Decision, paragraph 805

346 Western Power, *AAS - Attachment 5.12 - AA4 - NFIT Compliance Summary - Customer Management System*, February 2022. p.4

347 Engevity notes the $200k reconciliation error between Western Power's total for the project and constituent cost for the three phases.

- **Phase 2 tranche 1 ($8.3m)** sought to improve customer experience through operational performance and efficiency using the customer platform through measures such as development of a customer portal, improve fault information, automating planning processes and development of a customer data warehouse.
- **Phase 2 extension ($5.7m)** extended the scope to allow functionality such as customer self-reporting of faults on the website, virtual assistant functionality, automated text messages, automation of large customer connection and relocation invoices, planned outage communication and coordination, data cleansing of duplicate and inaccurate records.

Western Power contends that the project has been delivered, in accordance with business cases that demonstrate that the costs (both CAPEX and OPEX) are reasonable and the benefits are achievable.

Assessment

Engevity has reviewed the information provided by Western Power and notes that we accept that:

- **there was a need to renew the customer management systems** within Western power to deliver many of the services expected of modern distribution networks. We highlight that much of these functions had been increasingly common in other Australian networks sinch the early 2010's.
- **the timing was appropriate in AA4** given the presence of the need.
- **there were significant delivery efficiencies in addressing related systems** to enable further customer benefits to be leveraged from the new customer management system.
- **the benefits noted by Western Power are significant**, including a Present Value of $3.6m for benefits from items such as the avoided Salesforce upgrade expense and bringing customer surveys in house.
- the project was aligned with Western Powers customer management strategies.

With the need, timing, delivery efficiency, strategic alignment and benefits accepted, our discussion turns to the scope and cost.

The scope of the customer management system project extends to several systems beyond the initial Microsoft Dynamics implementation – resulting in a final expenditure that is multiples of the initial implementation. As with the ERA and their consultant GHD during the AA4 review, Engevity does not consider that the scope and cost of the project delivered by Western Power is efficient in addressing the identified need. The inclusion of these additional systems and integration issues with Western Power's makes it difficult to determine an efficient cost. We do note that Microsoft Dynamics systems can be implemented in small businesses for less than $100k plus ongoing per-user monthly subscription costs. Therefore, most of the cost is associated with integrating the system into the Western Power corporate IT environment so that customer service staff are able to access the information that is relevant to the individual customer.

We note that heavily integrated IT systems can involve tens of millions of dollars in configuration and integration costs when implemented in a complex electricity network environment. Other systems are primarily user configured 'plug and play' implementations with far fewer complex interactions across corporate systems.

The Customer Management System and additional scope beyond the Microsoft Dynamics platform has delivered benefits (mainly operating efficiencies) that are typically reflected in the base year OPEX within the AA period, or otherwise realised through the next AA period – where they will appear as an efficiency improvement. Western Power's information systems investments should focus on improving the efficiency of their services. This means that the benefits arising from the investment should generally justify the expenditure over the notional life of the system.

The short 5-year life that is applied by Western Power for IT investments means that these benefits will be realised within one (five year) regulatory period from the implementation date.

Therefore, if the customer management system expenditure was accepted as efficient under NFIT, then:

d. the capex would be added to the RAB and largely recovered over the AA5 period through the return of assets building block.

e. this would also mean that the base-year opex is set at the previous 'less efficient' level for AA5 which would result in a double recovery of costs through opex efficiency improvements against an artificially high target.

Western Power has identified substantial easily recognised efficiencies (such as avoiding renewal of the Salesforce licence) that are not subject to the uncertainty in benefit realisation that often affects IT system implementation projects. Therefore, to allow the Customer Management System project to be incorporated into the RAB would risk recovering the cost of the project twice. Once through the return of assets and once through operational efficiency improvements and incentives that can often exceed the project cost.

As a result of this, Engevity considers that it is a prudent operator, acting efficiently would not seek to include this expenditure in the RAB as it does not minimise cost for customers. This supports the prior position of the ERA that this project could most appropriately be funded out of efficiencies.

Recommendation

Based on the information provided by Western Power, the Customer Management System project delivered by Western Power in AA4 has effectively been funded within the AA4 period by business efficiencies, and any relevant incentives, realised by the network itself. (Any remaining benefits will be realised in AA5 and subsequently reflected in the base OPEX for AA6)

Given the short five-year life of IT projects in Western Power's regulatory depreciation calculations, we consider that it is inappropriate to also recover the cost of the investment from customers over AA6 by including the value of the project in the opening RAB for AA5.

This recommendation is shown in the table below.

Table 7–26: AA4 Expenditure - Customer Management System ($nom)

Customer Management System	Forecast Expenditure					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Forecast AA4 CAPEX	-	-	-	-	-	24.9
Adjustment – Exclude from AA5 opening RAB	-	-	-	-	-	-24.9
Engevity Recommended	-	-	-	-	-	0

Source: Western Power Attachment 5.12

7.10 Forrestdale Depot – AA4 NFIT Assessment

7.10.1 Summary of Assessment

We found that **the expenditure complied with the NFIT requirements** and otherwise represented prudent and efficient expenditure. As a result, we have not made recommendations for ERA to make any adjustments in this expenditure category.

Table 7–27: AA4 Expenditure and scale – NFIT Compliance – Forrestdale Depot [$m nominal]

Forrestdale Depot	Western Power AA4 Actual Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Forecast AA4 Capex	-	-	-	-	-	79.5
Adjustment Exclude from AA5 opening RAB	-	-	-	-	-	-
Engevity Recommended	-	-	-	-	-	79.5

Assessment Summary

Table 7–28: Assessment Overview

Project/Program	Forrestdale Depot
Actual Cost $m	The AA4 approved cost for the Forrestdale Depot was $105.9m and the actual & forecast cost is now $79.5m. The depot is expected to come under the original approved forecast by $26.4m in AA4.
Variance to approved $m	Western Power expect that the Forrestdale Depot project will be completed under budget. Engevity has not been able to verify the suitability of Western Power's estimate to complete the project.
Need	Engevity considers the need has been justified in line with the NFIT.
Scope Definition	Engevity considers the scope of the Forrestdale depot is clear and in line with the NFIT.
Timing	The project was proposed to be completed 31 Aug 2021 and has been delayed by a year and now is expected to be completed 31 Aug 2022. Given the impacts of COVID-19 this appears reasonable.
Risk Management	Engevity considers the risk of maintaining the status quo outweighs the investment in the South Metro (Forrestdale) Depot project.
Cost Efficiency	Western Power has confirmed that the Depot Program is on track to achieve the financial benefits (OPEX $5.58m and CAPEX $4.48m) and that 'current forecast financial benefits for the Depot Modernisation Program remain unchanged from initial forecasts'[348] for the Depot Modernisation Program.

348 [redacted]

Project/Program	Forrestdale Depot
	However, Engevity notes that elsewhere Western Power state that the Depot Optimisation and Consolidation Program is expected to net $10.58m in reoccurring expenditure benefits[349]. We do however hold some concern, although we were not able to verify this, that there may be duplication of approved funding for Corporate IT, telecommunications and SCADA expenditure and the Depot Program.
Scope Efficiency	Engevity considers the project scope is appropriate for the defined outcomes.
Strategic Alignment	The project appears to be following Western Power's corporate strategy and procurement policies, including the Investment Governance Framework ([redacted]).
Options Analysis	Western Power appear to have considered financial, legal, delivery, traffic and environmental risks in considering the options. They also specifically considered the option of retaining the existing depot locations and redeveloping them.
Delivery Model	The project appears to be appropriately staged in accordance with common industry practice.

Findings

Engevity has reviewed Western Power's proposed expenditure relating to **Forrestdale Depot** and found that:

a. **The proposed expenditure is efficient** with the objective of minimising costs on the basis that it aligns with the Depot Modernisation Program, has adopted a detailed option analysis with the support of external specialists.

b. **The program captures the available and realisable economies of scale and scope** with a reduction of 9 depots achieved through the amalgamation of 14 depots into 4 newly developed depots and a Head Office location.

c. The proposed investment **is consistent with reasonable expectations** of the level of future network services required by customers because it is prudent for Western Power to have fit for purpose facilities to enable crews to respond and support its customer base. Given recent declines in network SAIDI, crew response times should be reviewed throughout AA5, and efficient measures put in place (for example adjusting depot service boundaries, optimising dispatch of field crews to unplanned outages, automated or remote monitoring/switching, reclosers, sectionalisers etc.) to mitigate any negative impact from the depot rationalisation process on customer reliability.

d. **A reasonable range of alternative options has been considered** for the proposed investment, with the most appropriate solution chosen. This is evidenced by Western Power's consideration of financial, legal, delivery, traffic and environmental risks in each of options.

[349] AAS - Attachment 5.5 - AA4 - NFIT Compliance Summary - Forrestdale Depot, page 38-39

Recommended Adjustment

Overall, we consider that the Forrestdale Depot Project for the AA4 satisfies the NFIT requirements.

7.10.2 AA4 NFIT Assessment

Expenditure Overview

The establishment of a new South Metropolitan depot in Forrestdale (Forrestdale Depot) forms a part of Western Power's Depot Optimisation and Consolidation Program (Depot Program). The justification for the 10-year depot modernisation strategy commenced during the AA3 period.

Western Power state that the *'Forrestdale Depot investment comprised of:*

- acquiring a fully serviced site in Forrestdale.
- designing and constructing the new Forrestdale Depot.
- transitioning staff, equipment and activities currently undertaken at the existing Western Power at Kewdale, Mt Claremont, Forrestfield, Jandakot (Prinsep Road), together with Customer Connections staff currently located at Head Office into the new fit for purpose Forrestdale Depot.
- disposal of the existing Kewdale and Jandakot (Prinsep Road) depots that are owned under freehold title by Western Power and release the management order held by Western Power on State Government owned Mt Claremont site, following completion of transition to the new Forrestdale Depot.'[350]

The Forrestdale Deport (or South Metro Depot) was forecast to cost $105.9m in AA4 and was planned to be completed by August 2021. It now has an actual plus forecast estimate of $79.5m which is a $26.4m cost reduction and is scheduled to be completed in August 2022. The project was delayed by 12 months primarily due to COVID-19 impacting design, contract negotiations and construction works.

The reason for the underspend relates to variances from the original business case in land, construction and development costs. actual cost being much less than the original forecast. As with other projects Engevity highlights that this large underspend on a very significant building and property project raises further questions over the accuracy of Western Powers estimates at the Access Arrangement stage.

Historical Context

Western Power first considered the Depot Optimisation and Consolidation Program (Depot Program) in AA4 and it has three main elements:

- Depot modernisation Program – aim is to improve operational efficiency, rationalising depots in regional locations, improving safety and update ageing depots to meet current and future needs.
- Facilities and Asset Management Program – this is unplanned expenditure, as well as ongoing expenditure for depots pre and post development.
- Physical Security Program – focus is on enhancing physical security measures to protect personnel, property and network assets.

Western Power first considered the Depot Program in AA4, where it forecast to invest $244m and this was underspent by $39.1m (-16 per cent), which further highlights Western Power's systemic AA

[350] AAS – Attachment 5.5 – AA4 – NFIT Compliance Summary – Forrestdale Depot.pdf

stage overestimation. In the AA4 period, it planned to deliver Vasse, South Metro, Pinjarra, and Albany depots. Engevity understands that the AA4 Depot Program delivered the following depots:

- New Vasse Depot – completed;
- New Pinjarra Depot – completed;
- Major upgrades to Merredin Depot – completed;
- Major upgrades to Northam Depot – completed;
- New Albany Depot – completion Q3 – 2022;
- New South Metro Depot – completion Q3 – 2022.

The Depot Modernisation also delivered against a key objective of reducing the number of operational depots with the following eight depots closed - Perth Airport Fleet Facility, Bentley Depot, Fremantle Depot, East Perth Control Centre, Busselton Depot, Margaret River Depot, Waroona Depot and Mandurah Depot.

During AA4, GHD raised deliverability concerns with the program, and it appears some of the depot projects have run over on the original schedule, including the South Metro Forrestdale Depot. Engevity accepts this was mainly attributable to the impacts of COVID-19 than broader deliverability constraints.

Need

The South Metro Forrestdale Depot is part of the broader Depot Program and was specifically considered in a strategic review by Deloitte in 2015 as a means to increase financial and operational efficiency as well as increased safety and security of the depot.

Engevity considers the need has been justified in line with the NFIT.

Scope Definition

The South Metro Forrestdale Depot shall accommodate 859 staff and 517 vehicles and have a total building area of 26,121m^2 and will enable the closure of Kewdale, Mt Claremont and Jandakot (Prinsep Road) depots. The objective is that this site will also become a central training facility to replace the Jandakot site.

Western Power has considered alternative options to achieve the same outcome and based on cost, operational efficiency, safety and security has opted to develop and own the new South Metro Depot at Forrestdale. Engevity notes that Western Power intend to consider a build, sale and leaseback arrangement which may further reduce costs in the future. However, typically this approach is less attractive for real estate investors given the specialised nature of the depots, less competitive cost of capital and ongoing critical nature of these locations.

The project has followed Western Power's corporate and procurement policies, including the Investment Governance Framework ([redacted]).

Engevity considers the scope is commensurate with the need and is in line with the NFIT.

Timing

Engevity considers the timing of the project, although delayed, is appropriate.

It will be important that the benefits from the sale of the former depot sites is completed in a timely manner to ensure that the impact of the depot rationalisation program capex on customers is partially offset by the proceeds from these sales, as outlined in the business case. Some sales are reported to have already taken place ($103.23m), whilst further property divestment ($127.57m) is forecast to occur by during AA5 in the business case and it is not clear whether these have been incorporated into the AA5 forecast.

Risk Management

Engevity considers the risk has been identified and managed by Western Power and the investment in the South Metro (Forrestdale) Depot project.

We do note that the significant underspend on this project and the overall depot rationalisation program more broadly is concerning, especially in the context of similar large underspends on other material projects. This may suggest a systemic and material overvaluation of risk, and/or insufficient development of scope underpinning Western Power's Access Arrangement forecasts and option assessments.

Engevity has separately considered the need for an adjustment to correct for an overestimation bias in AA5 based on our detailed reviews of expenditure, consideration of Western Power's policies, procedures and governance practices, and an overall assessment of project budget vs outturn costs across the AA4 portfolio.

Cost Efficiency

The delivery of the Depot Optimisation and Consolidation Program, to ensure that Western Power has fit for purpose facilities to enable crews to respond and support its customer base represents prudent expenditure.

The Forrestdale Depot is being delivered using Western Power's stage gates. The original business case ([redacted]) was costed using actual costs of the Vasse Depot, tender costs for the Pinjarra Depot and external quantity surveyors. The underspend variance from the original business case was due to land, construction, development costs and allowance for risk. Engevity was unable to confirm what factors specifically led to the $26.4m variance from AA4 forecast however notes that a 24 per cent variance appears significant.

Despite the assertion in AA4 that there will be an OPEX benefit from the Depot program, Western Power appear to have justified the project as *maintaining safety and reliability* and Engevity did not cite any specific details outlining the efficiency benefits in the NFIT. It was subsequently confirmed that the Depot Program is on track to achieve the financial benefits (OPEX $5.58m and CAPEX $4.48m) as originally forecast in the original business case for the Depot Modernisation Program.

Notwithstanding this, the proceeds from the sale of the superfluous depot location is estimated to be $230.8m[351] of which $103.23m has been sold or settled as at April 2021. **Engevity has not confirmed that the value of these transactions has been removed from the asset base in the June 2021 Regulatory accounts. The balance should be reflected in Western Power's forecast asset disposals in the AA5 period, where the expected sales value is removed from the RAB'. ERA is recommended to check this.**

From the information made available, and the significant underspend of the AA4 forecast, Engevity considers the Forrestdale Depot has been delivered in a cost-efficient way.

Scope Efficiency

The scope and design have considered operational needs and focused on safety outcomes as well as the changing operating environment. The project has followed Western Power's corporate and procurement policies, including the Investment Governance Framework ([redacted]). Engevity has not cited change management and details of strategic option analysis considered as part of the broader depot program.

The scope allows a more consolidated footprint for the South Metro Region depots, with a substantial part of the program financed through the sale of retired sites.

351 [redacted]

Engevity considers the project scope is appropriate for the defined outcomes.

Strategic Alignment

Through the delivery of Phase 1 of the Depot Modernisation Program, Western Power has realised the following benefits:

- Optimised the number of depots operated by Western Power with a reduction of 9 depots achieved through the amalgamation of 14 depots into 4 newly developed depots and a Head Office location.
- provided appropriate 'fit for purpose' facilities to meet:
  - current and future operational requirements;
  - Building Code Legislation, Safety Legislation and Industry Building Standards;
  - Recurring annual operational expense savings of \$5.49m were achieved through the closure of 9 depots;
  - Forecast annual capital allowance expenditure avoidance of \$4.85m per annum.

Engevity considers the project is aligned with the original strategic intent of the Depot Modernisation Program.

Options Analysis

Western Power reviewed alternative location for the depot and engaged with state government and property agents to assess the available sites. Western Power appear to have considered financial, legal, delivery, traffic and environmental risks in considering the options. They also specifically considered the option of retaining the existing depot locations and redeveloping them.

Western Power considered 3 options as part of this investment:

- **Option 1 – Retain and develop existing depots** (Estimated CAPEX \$145m, and \$170.3m Net Present Cost (NPC));
- **Option 2 – Develop the new South Metro Depot at** Forrestdale (Estimated CAPEX \$94.8m[352], and \$95.3 NPC);
- **Option 3 – Lease a new South Metro Depot** (despite this being the least cost option it was deemed not viable following feedback from the Minister for Energy).

Option 2 was selected as preferred after considering the present value (PV) of avoided redevelopment of existing depots (\$36.68m PV), reduced operating costs (\$8.16m PV), avoided relocation costs (\$11.2m PV) and net revenue from disposal of existing sites (\$19.14m). Western Power asserts that the project will provide a PV benefit of \$63m over 22 years.

Delivery Model (incl. staging)

Western Power has provided the following activity status milestones:

- Acquisition of the Depot site from Development WA (previously LandCorp) was completed in May 2020;
- Development Approval received from Development WA;
- Design and Construct contract signed with ADCO Builders;
- Construction scheduled to commence in May 2021;
- Construction currently scheduled for completion in 2022.

352 [redacted]

The project appears to be appropriately staged in accordance with prudent industry practice. There is limited opportunity to stage the investment beyond the approach adopted by Western Power. We recognise that there are elements of future enhancements to the site such as the 'GridLab' and training facilities that may be subject to future investment. We consider that this is a prudent and efficient approach to stage this lower criticality investment to occur at the site after the core operational needs are met.

Attachment 8:
Forecast CAPEX Assessment

Overview

Engevity notes that Western Power has provided a large amount of information for its AA5 projects, however, in most cases supporting detail including cost breakdowns, business case analysis, change process, evidence of governance, executive oversight and approvals were not provided.

The original and subsequent supporting documentation packages provided did not provide a complete suite of contracts, cost estimates or details on change requests and in some cases the information was provided at different resolutions, and we noted changes in project scope over time which made it difficult to follow the impact of changes on our review. As a result, the assessment and our review remained difficult to assess in detail.

In some cases where we have not been able to follow the full progress of the project, we have made assessments of efficiency against industry pricing, typical network management expectations and normal Australian construction contract management practices to assess whether any absent or unclear information would affect our assessment. Where data provided was either incomplete or insufficient detail, we have applied conservative assumptions in our analysis.

AA5 Review Summary

Engevity has also conducted a review of a sample of the projects proposed in AA5 and the below table is a summary of our findings.

Table 8–1: AA5 Forecast Assessment[353]

Project/Program	AA5 Forecast Total Cost	AA5 Forecast Direct Costs	AA5 Direct Costs Adjustment	%Δ	AA5 Recom-mended
Undergrounding Programs	685.2	376.6	-66.8	-18%	309.8
Wood Pole Management	423.1	362.7	-	-	362.7
SPS & Microgrids	330.8	283.3	-102.6	-36%	180.8
Depot Program	145.8	125.3	-27.6	-22%	97.7
Replacement Program	912.0	781.6	-147.7	-19%	634.0
Distribution Augex	874.3	245.4	-	-	245.4
SCADA/Comms IT & Cyber	872.2	745.9	-223.8	-30%	522.2
AMI	311.3	257.5	-97.5	-38%	160.0
Total Expenditure Assessed	4,554.7	3,178.4	**-665.9**	**-21%**	**2,512.5**

353 Forecast Total Cost [$Real 2022 (Gross), includes indirect costs and labour cost escalation], Forecast Direct Costs [$Real 2022, net of capital contributions, excludes indirect costs and labour cost escalation], Recommended Adjustment of Direct Costs [$Real 2022, excludes indirect costs and labour]

8.1 Undergrounding - AA5 Assessment

8.1.1 Summary of Assessment

Engevity has reviewed Western Power's proposal for the AA5 period and found that it **DOES NOT COMPLY** with the Access Code requirements for an AA submission. We found that some expenditure **DOES NOT COMPLY** with the NFIT requirements or represent efficient expenditure. As a result, we have made recommendations for ERA adjustments in the table below.

Assessment Overview

Over the AA5 period, the undergrounding program in the distribution network accounts for the forecast expenditure and scope summarised in the table below. Direct CAPEX and suggested adjustments are net of all indirect costs and customer contributions.

Table 8–2: AA5 Expenditure and Scale – Undergrounding Programs (NRUP+SUPP customer contributions[354]) [$m real at 30 June 2022][355]

Undergrounding	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Forecast Total CAPEX[356]	*84.9*	*113.3*	*160.8*	*161.8*	*164.4*	***685.2***
Western Power Forecast Direct CAPEX[357]	48.0	64.1	94.7	85.3	84.4	**376.6**
Adjustment	-8.5	-11.3	-16.8	-15.1	-15.0	**-66.8**
Engevity Recommended Direct CAPEX	**39.5**	**52.8**	**77.9**	**70.2**	**69.4**	**309.8**
Line length[358]	108	145	205	207	210	**875**

354 Categorised under SUPP for modelling reasons

355 [redacted]

356 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs' Sheet Row 8 (NRUP) and 'Reg cat summary – real $' Sheet Row 23 (SUPP)

357 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'Project list – base $'CAPEX Sheet Row 15 (NRUP) and 'Net CAPEX by regcat – base $' Sheet Row 25 (SUPP)

358 Relates to urban overhead network converted to underground cabling (km)

Table 8–3: Assessment Overview

Project/Program	Undergrounding
Forecast Cost $m	Western Power is proposing a very large increase in undergrounding CAPEX in AA5 compared to AA4. In the AA5 period $685.2m gross CAPEX, $439.9m net of capital contributions, and $376.6m direct CAPEX net of capital contributions.
Recommended Cost $m	In the AA5 period $607.2m gross CAPEX, $361.9m net of capital contributions, and $309.8m direct CAPEX net of capital contributions.
Need	Not been clearly identified
Scope Definition	Not clear scope is commensurate with need
Timing	Not clear the scope of work is needed in AA5
Risk Management	Not clear that 'like-for-like' overhead asset replacement may be less appropriate for some of the large number of projects forecast for undergrounding
Cost Efficiency	No analysis that undergrounding costs have been estimated using an efficient system and unit costs. Cost efficiency of proposed large program not clearly established.
Scope Efficiency	Not yet challenged for ability to spread program over successive AA periods. No clear evidence of risk-based prioritisation of undergrounding.
Strategic Alignment	Aligns with Grid Strategy and Corporate Strategy
Options Analysis	Most efficient option for overhead asset replacement not identified on a project basis
Delivery Model	Requires risk-based prioritisation and options analysis that clearly establishes in a business case or investment evaluation model lower cost than 'like-for-like' replacement, outside of the margin of error between estimates of underground and 'like-for-like' overhead replacement CAPEX, for each project. This analysis should explicitly include local factors such as soil condition and rock on a project-by-project basis. It should also consider historical experience such as the substantial increases in costing and timing associated with the Scarborough, Hilton and St James NRUP pilot undergrounding projects in AA4. Project staging should consider the availability and costs of required contractors based on current market conditions.

Findings

Our review is summarised below for the Western Power Undergrounding Program, which is comprised of the Network Renewal Undergrounding Program (NRUP) and the State Underground Power Program (SUPP). NRUP is a regulatory activity under the Asset Replacement Sub Regulatory Category of the Distribution Asset Replacement and Renewal Regulatory Category. SUPP is a Sub Regulatory Category under the Distribution Asset Replacement and Renewal Regulatory Category and is funded by customer contributions. Engevity notes that only the NRUP program contributes to direct costs for undergrounding in the AA5 period.

Engevity has reviewed Western Power’s proposed expenditure relating to undergrounding and found that:

a. **The proposed expenditure is not efficient** with the objective of minimising costs on the basis that Western Power has not clearly established the cost efficiency of the CAPEX for undergrounding in the AA5 period. We did not observe clear justification of undergrounding CAPEX, with no business cases or investment evaluation models at a project level for the AA5 period made available. Engevity notes that Western Power has made business cases and investment evaluation models available for the Scarborough, Hilton and St James NRUP pilot projects in the AA4 period.

b. **The program does not capture the available and realisable economies of scale and scope.** There is an increase of $540m or ~372 per cent in undergrounding total CAPEX proposed for the AA5 in comparison to AA4 period (including capital contributions, indirect costs and labour cost escalation). There is an increase of $417m or ~1827 per cent of undergrounding CAPEX net of capital contributions, associated with NRUP. However, evidence is not provided that this CAPEX is commensurate with need or is economically justified.

c. The proposed investment **is not consistent with reasonable expectations** of the level of future network services required by customers because it does not demonstrate that the proposed major additional CAPEX associated with undergrounding is derived from risk-based assessment of prioritisation and is equivalent to what would be required for like-for-like overhead replacement. We did not observe convincing demonstration of the benefit for future network services provided by the major expenditure.

d. **A reasonable range of alternative options has not been considered** for the proposed investment, with the most appropriate solution chosen. There is a lack of options analysis for overhead assets replacement in the proposal, particularly at a project level. Western Power does not quantitatively demonstrate the relative value of undergrounding and like-for-like overhead asset replacement on a project basis.

e. **Incremental revenue** has not been claimed by Western Power and is not relevant to this expenditure.

f. **The proposed investment does not deliver an expected net benefit** over a reasonable period of time that justifies recovery through tariffs. Although Western Power considers there are benefits such as lower total cost of ownership through gifted assets, improved safety and reliability, lower maintenance costs, facilitation of more renewable connections by increased ability to host DER, supporting the future uptake of EVs by enhancing distribution network capacity to accommodate charging, enhanced customer choice, and better amenity and streetscapes, these benefits have not been quantified or supported by evidence, particularly at a project level.

g. **The proposed investment is not necessary to maintain the safety and reliability** of the network or its ability to provide the required network services. We consider that Western Power could reasonably meet its safety, reliability and service obligations through conservative risk-based prioritisation of replacement of overhead assets. This replacement may primarily be by like-for-like overhead assets, with undergrounding only in cases where the economic benefits are clear on a project level. There is also a case for CAPEX neutrality between decreases in related distribution wooden pole and conductor management and increases in undergrounding in the AA5 period. The scope and cost of undergrounding in the AA5 period would be greatly decreased, while maintaining network safety and reliability, and providing the required network services.

Recommended Adjustment

The Western Power proposed undergrounding total (gross) CAPEX in AA5 of $685M represents a large increase (~372 per cent) compared to the AA4 period. We are concerned as to the deliverability of this proposed high level of expansion in undergrounding. This is based on issues Western Power experienced in delivery of the Scarborough, Hilton and St James NRUP pilot undergrounding programs during the AA4 period, with significant cost and delivery time over-runs due to inaccurate scoping estimates of costs and contractor pricing and availability issues due to prevailing market conditions. Western Power states that the increase in costs coincided with COVID and the WA economic stimulus package. We are also concerned that some LGA funding commitments will not be met by local partners in the proposed expanded NRUP undergrounding program in the AA5 period, resulting in significant pressures to either decrease the scope of the program or expand alternative funding. Western Power states that it has received overwhelming support from LGAs for the undergrounding program. Western Power also states that should an LGA not support undergrounding, alternative funding will not be sought and instead the relevant overhead network will be replaced like-for-like at an equivalent cost.

As a result, Engevity's recommendation is that the Western Power undergrounding proposal for the AA5 period should not be approved, unless Western Power can provide business cases or investment evaluation models that demonstrate clear need and efficient CAPEX when compared to other options on a project-by-project basis. There is an increase of about $357m in NRUP direct CAPEX for the AA5 in comparison to AA4 period. The NRUP direct CAPEX in AA5 is about 19 times the NRUPP direct CAPEX in AA4. The need for these levels of increase in NRUP undergrounding direct CAPEX in the AA5 period needs to be clearly established from the project level upwards. Western Power states that though the scope of the program is increasing, it has a 20-year history of undergrounding through SUPP.

In the absence of a detailed conservative risk-based prioritisation of overhead asset replacement, with clear cost efficiencies for undergrounding over like-for-like options, on a project-by-project basis we recommend the undergrounding program be reduced by applying a principle of CAPEX neutrality such that the CAPEX net of capital contributions on distribution overhead replacement in the AA5 period is capped at the same level as during the AA4 period. Forecast increases in undergrounding (NRUP) net spending would be matched to decreases in relevant wood pole and conductor management net costs in the AA5 period. At Western Power's proposed level of distribution wood pole and conductor management CAPEX in the AA5 proposal, the Engevity recommendation would represent a $66.8m (~18 per cent) reduction in direct CAPEX only, net of capital contributions ($Real at 30 June 2022, excluding indirect costs and labour cost escalation).

The Engevity recommended adjusted NRUP direct only CAPEX for AA5 is $309.8m, net of capital contributions ($Real at 30 June 2022, excluding indirect costs and labour cost escalation).

Western Power has provided documentation, including business cases and request for change forms, for the Scarborough, Hilton and St James NRUP pilot projects in the AA4 period. This documentation indicates substantial cost and schedule increases over initial estimated values for these undergrounding projects. The revised undergrounding capex costs were ~9-65 per cent higher than estimated overhead like-for-like replacement costs. Western Power can provide additional information on historical risk-based prioritisation and cost-efficiencies of undergrounding projects in any revised proposal.

The proposed adjustment still allows a large increase in NRUP direct CAPEX for the AA5 in comparison to the AA4 period. In our opinion the proposed adjustment maintains distribution overhead network reliability and safety while still allowing significant grid transformation to occur in the tightly meshed grid during the AA5 period. It allows for lessons learned in NRUP pilot undergrounding projects during the AA4 period and across the 20-year period of SUPP, especially improved contractor management and scoping estimates of costs considering local conditions, to be demonstrated in projects delivered on time and to budget in the AA5 period. This may potentially lead to a larger undergrounding program being delivered in AA6.

The financial adjustments associated with our review recommendations are summarised in the table below.

Table 8–4: AA5 Forecast and recommended adjusted expenditure and scale – Undergrounding Programs (NRUP+SUPP) [$m real at 30 June 2022][359]

Undergrounding	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Forecast						
CAPEX						
NRUP	55.5	74.3	110.1	100.1	99.9	**439.9**
SUPP	29.4	39.0	50.7	61.7	64.5	**245.3**
SUPP (net of capital contributions)	0.0	0.0	0.0	0.0	0.0	0.0
Total CAPEX (Gross)	**84.9**	**113.3**	**160.8**	**161.8**	**164.4**	**685.2**
Total CAPEX (net of capital contributions)	**55.5**	**74.3**	**110.1**	**100.1**	**99.9**	**439.9**
Direct CAPEX (net of capital contributions)	**48.0**	**64.1**	**94.7**	**85.3**	**84.4**	**376.6**
Line length[360]	108	145	205	207	210	**875**
Engevity Recommended						
CAPEX						
NRUP	45.7	61.1	90.5	82.3	82.2	**361.9**
SUPP	29.4	39.0	50.7	61.7	64.5	**245.3**
SUPP (net of capital contributions)	0.0	0.0	0.0	0.0	0.0	**0.0**
Total CAPEX (Gross)	**75.1**	**100.1**	**141.3**	**144.0**	**146.7**	**607.2**
Total CAPEX (net of capital contributions)	**45.7**	**61.1**	**90.5**	**82.3**	**82.2**	**361.9**
Direct CAPEX (net of capital contributions)	**39.5**	**52.8**	**77.9**	**70.2**	**69.4**	**309.8**
Line length [361]	96	128	180	184	187	**775**

359 Figures consider conservative risked-based prioritisation of overhead replacement and clear cost efficiencies for undergrounding on a project-by-project basis was unavailable.

360 Includes urban overhead network converted to underground cabling (km)

361 Includes urban overhead network converted to underground cabling (km)

8.1.2 AA5 NFIT Assessment

Overview

Western Power states that a significant part of the metropolitan overhead network is reaching the end of its service life and will soon need to be replaced[362]. **Undergrounding projects are being timed to address much of the overhead assets that require replacement**. The benefits of undergrounding are described by Western Power as lower total cost of ownership through gifted assets, improved safety and reliability, lower maintenance costs, facilitation of more renewable connections by increased ability to host DER, supporting the future uptake of EVs by enhancing distribution network capacity to accommodate charging, enhanced customer choice, and better amenity and streetscapes. Western Power states the proposed investment aligns with the strategic objective of meeting future demand for safe and reliable power that efficiently meets customer needs[363]. **Western Power states it will seek to underground the network through financial partnerships with local communities**, via the relevant local governments. Western Power also says that **customers have reiterated support for further investments to improve network resilience in response to increasingly frequent extreme climate events through undergrounding**[364].

NRUP is designed to undertake a targeted conversion of existing urban network overhead areas to underground power. Constituent projects (individual project information is not available from Western Power) are proposed for areas in the meshed urban network where overhead assets are deteriorated and require replacement. Western Power states that underground replacement is only proposed in areas where it is the same or lower cost than a like-for-like replacement[365]. NRUP undergrounding is also described by Western Power as being for projects proposed in areas where the costs are comparable to a like-for-like overhead replacement[366]. Western Power states that that they identify prospective underground projects based on future forecast energy density, residential usage (likelihood of receiving a customer contribution), and sandy soil types for low excavation costs. Western Power additionally states that undergrounding is cost comparative to overhead network on a greenfield basis only. However, if a large majority of overhead needs replacement, undergrounding becomes cost-efficient. The NRUP pilot projects in AA4 only required the resident to pay for their consumer mains between the pillar and the premises main switchboard on the property. Western Power additionally states that this was because they were some of the most favourable projects that could be identified, and this is not normal practice. Western Power states they covered the entire infrastructure costs up to the pillar[367].

SUPP is an initiative to replace overhead lines in established areas with underground power infrastructure. It is a co-funded partnership between the WA Government, Western Power and local governments. Investment and volumes of SUPP during the AA5 period are described by Western Power as being highly dependent on community and local government support and funding[368]. LGAs nominate their contribution (50-90 per cent), Western Power contributes net benefit (replacement and maintenance costs avoided), and the WA Government funds the remainder. The planning process for SUPP rounds is described as complex by Western Power and involves looking at current and future network requirements and economic conditions. Western Power has not included any

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362 Western Power Access Arrangement Information – 1 February 2022, p. xi and p. 202

363 Ibid. P. 202

364 Ibid. p. iv

365 Ibid. p. xi

366 Ibid. p, 202

367 Western Power website, FAQs, Underground Power

368 AAI, 2022, p. 222

forecast expenditure for SUPP during AA5 except for a small amount ($2.9 million direct CAPEX) in 2022/23), which ERA has stated is for the South Perth/Hurlingham project[369].

Western Power has proposed undergrounding total CAPEX in AA5 of $685M (of which $245m is covered by capital contributions) to convert approximately 875 kilometres of poles and wires to underground cabling during the AA5 period (see expenditure and scale table above).

Historical Context

In 1991 the WA Government legislated so that networks for all new urban subdivisions were underground. In 1996 there was an increase in interest in undergrounding due to major storms and outages, resulting in the establishment of the SUPP.

The Western Power NRUP and SUPP undergrounding programs were active during the AA4 regulatory period. The SUPP program completed 21 projects in metropolitan and rural locations. **The Western Power AA5 proposal continues the existing undergrounding programs but the scale is much larger.** NRUP CAPEX was $23m across AA4 and is proposed to increase to about $440m including indirect costs[370] but excluding customer contributions allocated to SUPP. This represents an increase of about $417m (~1820 per cent) in comparison to NRUP AA4 CAPEX, excluding capital contributions allocated to SUPP in AA5. The total undergrounding expenditure is about $685m, including customer contributions allocated to the SUPP regulatory activity, across AA5[371]. This represents an increase of about $662m (~2900 per cent) in comparison to NRUP AA4 CAPEX, including capital contributions allocated to SUPP from AA4 to AA5. A Western Power comparison of total AA4 and AA5 forecast distribution asset renewal and replacement CAPEX says that for the NRUP expenditure category, CAPEX was about $13m across AA4 and is proposed to increase to $583m across AA5[372] (excluding forecast labour escalation and indirect costs). This represents an increase of $571m (~4,500 per cent) from AA4 to AA5 of NRUP CAPEX, excluding forecast labour escalation and indirect costs. SUPP CAPEX actual was about $122m over AA4[373] and Western Power has included $2.9 million (direct costs) across AA5.

The combined undergrounding programs total actual CAPEX in AA4 was $145m[374], including $72m in actual capital contributions for a $122m CAPEX SUPP[375]. Undergrounding total (gross) CAPEX is proposed to increase to about $685m in AA5, including indirect costs and labour escalation. This includes about $245m in capital contributions[376]. This represents an increase of $540m (~372 per cent) in undergrounding total (gross) CAPEX from AA4 to AA5. This increase is 52 per cent of the Western Power proposed increase in CAPEX for the distribution asset segment from AA4 to AA5 and 42 per cent of the total proposed increase in CAPEX across all ERA asset segments from AA4 to AA5. Net of capital contributions, the Western Power proposed AA5 **NRUP** CAPEX is **about** $440m**, including indirect costs and labour escalation. In terms of direct costs only (net of capital contributions), the Western Power proposed AA5 NRUP CAPEX is $376.6m, about 19 times higher than for the AA4 period.** It should be noted that in some parts of their Access Arrangement Information (AAI) documentation, Western Power refers to total undergrounding program expenditure during the AA5 period as NRUP only. For instance, Western Power also says they plan to

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369 [redacted]

370 [redacted]

371 [redacted] AAS – Attachment 11.7 – AA5 Regulatory Revenue Model

372 Attachment 8.1 – AA5 Forecast capital expenditure report - 1 February 2022, p. 46

373 AAS – Attachment 11.7 – AA5 Regulatory Revenue Model, 'Dx_Inputs' sheet, line 168

374 AAS – Attachment 5.2 – AA4 Capital Expenditure Variance Analysis Report

375 AAS – Attachment 11.7 – AA5 Regulatory Revenue Model

376 AAI, 2022, p. xi

invest $681.8m in the NRUP during the AA5 period, including $241.9m in capital contributions[377]. Engevity notes that Western Power has stated that undergrounding (customer contribution) is not a part of the State Underground Power Program, however, for modelling purposes, it has been allocated to the SUPP CAPEX regulatory activity to ensure the correct economic life is applied for depreciation purposes in the Regulatory Revenue Model. Engevity notes that the Western Power AA5 proposal does refer to SUPP throughout the AA5 documentation.

Need

We did not observe **planning or risk management need** identified by Western Power for undergrounding. Western Power states **the need for investment in undergrounding is driven by a significant part of the metropolitan overhead network reaching the end of its service life**[378]. However, we did not observe asset condition assessment analysis that shows how much of the metropolitan overhead network (and where), will reach the end of its service life during the AA5 period or matches this with the approximately 875 km of poles and wires that Western Power states will be converted to underground cabling during the AA5 period[379]. We did not observe corresponding analysis that links this to individual projects in the AA5 period. Western Power states however that across its business, it uses a risk-based renewal and maintenance approach that accounts for asset condition, criticality and lifecycle strategy[380].

Western Power considers **undergrounding is a means to maintain reliability performance by improving network resilience in response to an increasing frequency of extreme climate events**. However, we did not observe analysis to show that undergrounding is effective or necessary in this regard, particularly in comparison to like-for-like replacement for specific projects or programs. Engevity notes that Western Power additionally states that resiliency and reliability of undergrounding projects are not quantified in the AA5 submission and do not impact the submitted AA5 expenditure. Further, that reliability and resiliency benefits of underground networks were recognised in the ERA's 2011 inquiry into SUPP cost-benefit study (section 5).

Western Power states that residential customers have expressed a willingness to pay for increased reliability, renewables and potentially a combination of elements, provided the cost impacts range between 1-5 per cent of their current bill[381]. Small and medium enterprises are also said to support future focused investments, provided cost increases are within the 1-9 per cent range.

The results of the AA5 Customer and Community Engagement Program indicate that there is customer priority given to undergrounding but customers are not seeking greater investment in undergrounding powerlines compared to other attributes[382]. Qualitative research indicates that there is in-principle support for further investments in undergrounding in relation to providing a perceived increase in network resilience through decreased vulnerability to weather and other natural disasters, although the network is seen as reasonably resilient[383]. Quantitative research modelling suggests residents would be willing to pay 7-14 per cent more for increased investment across a combination of attributes, including undergrounding[384]. However, the same report also says

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377 Ibid. p. 202

378 Ibid. p. 202

379 Ibid. p. xi

380 Ibid. p. 56

381 Ibid. p. x

382 AAI- Attachment 4.1 – Community & Customer Engagement Program Report – July 2021, p. 6

383 Ibid. p. 27

384 Ibid. pp. 30-31

customers aren't seeking greater investment in undergrounding powerlines and there is low willingness to pay when ranked among competing investment priorities[385].

We did not observe an **efficiency need** or **compliance need** identified by Western Power for undergrounding.

Scope Definition

It is not clear that the scope of the proposed expenditure on undergrounding in the AA5 period is commensurate with the need. The $685m total in CAPEX for the AA5 period to replace approximately 875 km of poles and wires with underground cabling may be consistent with asset condition need. **We did not observe detailed analysis that demonstrates this proposed expenditure is any less than or equal to what would be necessary for like-for-like overhead replacement. Engevity also did not observe any assessment of the benefits of deferring some of this undergrounding expenditure to the AA6 period.**

The Western Power estimates of proposed undergrounding CAPEX and line length converted suggest normalised CAPEX of about $0.78m per km. Western Power has also provided business cases and other documentation for the NRUPP Scarborough, Hilton and St James AA4 projects. The revised CAPEX and length of low voltage overhead conductor removed for these projects suggests an average cost of about $0.81m per km for these NRUP pilot undergrounding AA4 projects. There are no other AA4 NFIT compliance summaries, AA5 or AA4 business cases or investment evaluation models, that have been made available in the AA5 proposal that can be used to demonstrate CAPEX per km for delivered undergrounding projects in the Western Power distribution network area. Western Power additionally states that comparative actual costs are available for the 20-year SUPP undergrounding program. Western Power can provide additional information on historical SUPP actual costs of undergrounding projects in any revised proposal.

A cost of about $0.8m per km for Western Power undergrounding (based on AA5 estimated and AA4 historical actual CAPEX and line length information), can be compared to an **Ausgrid estimate of about $2.5m per km for undergrounding across their network**. Ausgrid says this is 15 times more expensive than the cost of overhead wiring[386]. Western Power and Engevity both note that Ausgrid does not state where its overhead network costing (implicitly $167K/km) is derived. Western Power additionally states that overhead network costs are heavily location dependent, such that in highly built-up areas they can be 5+ times more expensive than in regional areas. Additionally, that laying underground cable is significantly more expensive in rocky ground. This analysis suggests Ausgrid estimated undergrounding costs per km are about 3.5 times larger than those estimated by Western Power.

If Western Power has accurately estimated the costs of undergrounding in major metropolitan WA in its AA5 proposal (said to be low due to the area being built on sand) and the NRUP pilot project historical record of actual undergrounding costs is representative of what could be expected, the **cost per kilometre would still be about 5 times larger than the overhead replacement costs suggested by Ausgrid for their network**. Notwithstanding that there may be significant differences in the network density and ground conditions in areas of the Western Power and Ausgrid distribution networks that could attract consideration for undergrounding, this analysis does not support the case that the Western Power proposed expenditure on undergrounding in the AA5 is commensurate with the need or is cost efficient in most cases.

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[385] Ibid. p. 36

[386] Undergrounding Powerlines Frequently Asked Questions, Ausgrid, October 2020

Timing

Western Power say that the timing of the investment in undergrounding of 875 km of poles and wires during the AA5 period is consistent with an assessment that a significant part of the metropolitan overhead network is reaching the end of its service life. Approximately 27,000 wood poles will be removed from the distribution network during the AA5 period as part of forecast SPS and undergrounding investment[387]. **Western Power has not provided any evidence that demonstrates the need for the proposed level of undergrounding during the AA5 period.** The possibility that the project could be staged across AA5 and AA6 has not yet been discussed.

Risk Management

Risks associated with the condition of distribution overhead assets could be handled with a BAU approach, by replacement with like-for-like overhead infrastructure. Western Power acknowledges that this could be done for comparable cost to undergrounding[388].

Western Power continues to make a substantial investment in wood pole management ($423m in AA5 compared to $703m in AA4). This includes reactive replacement of assets that fail while in service, with a reactive forecast based on expected assisted and unassisted failures. It also includes proactive replacement and reinforcement of assets selected through the application of the Distribution Overhead Network Rebuild Strategy.

Western Power's Network Risk Management Standard requires that it understands hazards and risks, eliminates unacceptable risks and reduces remaining risks to 'As-Low-as Reasonably Practicable' (ALARP), in accordance with AS 5577[389]. Western Power states there is ongoing review of wood pole condition information and associated safety risk, and ongoing discussions with the safety regulator. These safety management procedures for wooden poles remain in place in the AA5 period and could be applied to like-for-like replacement of overhead infrastructure originally slated for undergrounding conversion projects. Western Power states that wood poles and bare overhead conductors present an increased safety and reliability risk relative to other network construction options such as underground or SPS[390].

Western Power has an Asset Management Framework in accordance with the Australian and International Standard on Asset Management (ISO 55001), ERA Audit Guidelines, Electricity (Network Safety) Regulations 2015 and the Electricity Network Safety Management Systems standard (AS 5577). Western Power was acknowledged in its ISO 55001 assessment as having "…a number of industry leading practices, particularly in the areas of asset risk management"[391]. Western Power's Network Risk Management Standard requires risk assessments to be carried out at appropriate points throughout the asset lifecycle[392]. The condition of an asset is identified during the operate/maintain phase of the asset life cycle by qualitative and quantitative risk assessments. Risks are prioritised into four categories, unacceptable (failed/imminent risk), high risk, varying severity (decisions to treat managed by the Short-Term Risk Management building block of the Network Rebuilding strategy), and acceptable risk. Western Power has not provided any analysis of the risks posed by overhead assets proposed for specific undergrounding project areas or for the undergrounding programs.

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387 AAI, 2022, p. 180

388 Ibid. p. 202

389 Attachment 5.9 – AA4 – NFIT Compliance Summary – Distribution Wood Pole Management - 1 February 2022, p. 5

390 Network Opportunity Map 2021, p. 66

391 AAI, 2022, p. 182

392 AAS – Attachment 8.2 – Network Management Plan, 2022, pp. 50 - 53

Cost Efficiency

No business cases or investment evaluation models have been put forward by Western Power for individual undergrounding projects or the Underground Program as a whole. Reference is made to undergrounding business cases [redacted] associated with the NRUP pilot for the AA4 period[393].

Western Power states that underground replacement only occurs in areas where it is comparable to, or lower cost than, a like-for-like overhead replacement. Western Power has based the NRUP customer contributions on the incremental costs of undergrounding relative to a like-for-like replacement of the overhead network[394] and will be determined on a case-by-case basis for each area[395]. The Western Power end-of-life strategy rules say that underground installations in the distribution meshed network require LGA funding commitment, otherwise replacement is by overhead lines[396].

Western Power has not explicitly identified any contingency or project overhead components of costs associated with undergrounding CAPEX for the AA5 period.

Western Power has not clearly established the cost efficiency of the CAPEX for undergrounding in the AA5 period. We observed limited clear justification of undergrounding CAPEX scope components, other than to say they are needed because a significant part of the metropolitan overhead network is reaching the end of its service life and will soon need to be replaced. **We did not observe analysis from Western Power to demonstrate that undergrounding costs have been estimated using an efficient system and unit costs.**

Scope Efficiency

The scope of the combined undergrounding programs has not yet been challenged for options to stage the proposed undergrounding, with a reduced scope within the AA5 period. Western Power has not provided evidence of risk-based prioritisation of undergrounding of overhead assets. Such risk-based prioritisation should consider the risk category of the condition of the existing overhead assets grouped in individual proposed undergrounding project areas. It should also consider the potential of undergrounding to alleviate reliability issues associated with like-for-like replacement due to anticipated extreme weather events adversely affecting individual proposed project areas.

Strategic Alignment

Western Power states the implementation of their Grid Strategy is one of the factors in the forecast increase of investment in undergrounding in the AA5 period[397]**.** Investments in undergrounding (along with SPS, deployment of AMI, a roadmap for microgrids and a DSO capability) are identified as critical to facilitate the transformation of the network and support future customers' needs[398]. The Grid Strategy identifies undergrounding as a transformation strategy to target changes to networks at the end of their life[399]. Distribution network undergrounding is identified as a grid strategy in alignment with Western Power Corporate Strategy. Undergrounding projects are described as improving network reliability and expanding EV and PV hosting capacity. Western Power again state

393 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management – 1 February 2022

394 Ibid. p. 16

395 Ibid. p. 56

396 Ibid. p. 47

397 Ibid. p. 174

398 Ibid. p. 178

399 AAS – Attachment 8.3 – Grid Strategy, p. v

that underground installations require LGA funding commitment and overhead assets should be installed if that commitment is not provided[400].

Options Analysis

Western Power has not attempted to identify a reasonable range of alternative options to undergrounding, other than to note that undergrounding is an alternative to like-for-like overhead asset replacement. The most efficient option is not identified other than to say that the undergrounding is only considered in cases where the cost is comparable to, or lower than, like-for-like overhead asset replacement. Western Power does not explicitly discuss the relative value of undergrounding and like-for-like overhead asset replacement.

Delivery Model (incl. staging)

Undergrounding could be most efficiently delivered by Western Power first applying conservative risk-based prioritisation to replacement of distribution overhead assets in individual potential project areas. This could be followed by preparing a business case or investment evaluation model that clearly demonstrates each prioritised replacement project has lower cost if the replacement assets are underground rather than like-for-like overhead.

The condition of overhead assets in a project area could be prioritised by the four-category risk system identified by Western Power as being applied to maintain network safety and resilience. In cases where the risk of non-replacement is assessed and anticipated to be unacceptable or high over the AA5 period, replacement could be earmarked. In such cases, an options analysis, including estimate of the undergrounding cost versus pole replacement and reconductoring could be provided in the business case or investment evaluation model for the particular project. In circumstances where the undergrounding cost is clearly established to be less than the like-for-like replacement cost (outside of the margin of error between estimates of underground and like-for-like overhead replacement CAPEX costs at the project level), the project could then be assigned that undergrounding cost and priority to be undertaken over the AA5 period. This analysis should explicitly include local factors such as soil condition and rock on a project-by-project basis. It should also consider historical experience such as the substantial increases in costing and timing associated with the Scarborough, Hilton and St James undergrounding projects in AA4. Project staging should consider the availability and costs of required contractors based on current market conditions. Engevity has concerns that notwithstanding the experience Western Power has gained in historical delivery of the SUPP program, the difficulties in delivery of the Scarborough, Hilton and St James projects in the AA4 period may indicate that the substantially increased level of undergrounding proposed for the AA5 period will not be deliverable. Factoring in a projected improvement in network resilience by undergrounding in preference to like-for-like overhead replacement should only occur if it can be convincingly quantified on a project basis as a reduced cost for undergrounding or increased cost for like-for-like replacement and included in the options analysis.

The suggested approach should result in a more staged and gradual delivery of undergrounding projects, as economically appropriate, without compromising network safety or reliability.

An alternative approach could be based on historical estimates for wood pole and conductor management. Any decline in these combined costs in metropolitan areas under consideration for undergrounding could be matched by an increase in CAPEX (net of capital contributions) that can be assigned to undergrounding. A principle of CAPEX neutrality could be maintained for undergrounding versus like-for-like overhead replacement and reinforcement across the Western Power distribution network between the AA4 and AA5 periods. There is presently a proposed $288M decrease in combined wood pole management and conductor management CAPEX between the AA4 and AA5

[400] Ibid. p. xvii

periods (a total of $605M is proposed for distribution Wood Pole Management and Conductor Management in the AA5 period). The proportion of the proposed reduction in wood pole and conductor management CAPEX between the AA4 and AA5 periods that Western Power can demonstrate is associated with proposed undergrounding could then be assigned to increasing undergrounding CAPEX (net of capital contributions) in the AA5 relative to the AA4 period. The increase in undergrounding CAPEX could then be assigned to specific projects by risk-based prioritisation over the AA5 period. This would likely result in longer time scales for undergrounding and could be seen as a form of resource levelling.

8.2 Wood Pole Management – AA5 Assessment

8.2.1 Summary of Assessment

Engevity has reviewed Western Power's proposal for the AA5 period and found that it **DOES COMPLY** with the Access Code requirements for an AA submission. We found that expenditure **DOES COMPLY** with the NFIT requirements or represent efficient expenditure. As a result, we have made nil recommendations for ERA adjustments in the table below.

Assessment Overview

Forecast expenditure and scope for wood pole management is summarised in the table below.

Figure 8–1: AA5 Expenditure and Scale – Wood Pole Management Program (sub regulatory category)[401]

Wood Pole Management - Dx	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Forecast Total CAPEX[402]	*89.8*	*90.2*	*78.0*	*82.3*	*82.8*	*423.1*
Western Power Forecast Direct CAPEX [403]	77.7	77.9	67.1	70.1	69.9	362.7
Adjustment	-	-	-	-	-	-
Engevity Recommended Direct CAPEX	**77.7**	**77.9**	**67.1**	**70.1**	**69.9**	**362.7**
# poles replaced **# poles reinforced**	7,369 5,500	7,338 5,500	6,533 5,500	6,763 5,500	6,970 5,500	34,974 27,500

[401] Sources: AAS – Attachment 8.10 – Capital Expenditure Model; Access Arrangement Information – 1 February 2022, p. 180. NOTE: These figures are for the Pole Management – REPEX regulatory activity in the pole management sub regulatory category of distribution asset replacement. They do not include Western Power plans to replace 2,030 wood poles and reinforce 2,250 wood poles in the transmission network. [$m real at 30 June 2022]

[402] Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs', Column AF - AK

[403] Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs', Column H - M

Table 8–5: Assessment Overview

Project/Program	Wood Pole Replacement
Forecast Cost $m	The reasons for the large decrease in forecast CAPEX compared to AA4 given continuing high risk and the linkage to large increases in SPS and undergrounding CAPEX are not clear. In the AA5 period $423.1m gross CAPEX and $362.7m direct CAPEX.
Recommended Cost $m	In the AA5 period $423.1m gross CAPEX and $362.7m direct CAPEX net of capital contributions.
Need	Asset condition, reliability and compliance (safety) needs for the proposed program have been clearly identified
Scope Definition	From the information provided it was not clear how the AA5 scope is commensurate with asset condition, reliability and safety needs, plus the influence of SPS and undergrounding.
Timing	Unclear whether the proposed expenditure is consistent with maintaining overall safety and reliability performance at minimum cost. Influence of Distribution Overhead Network Rebuild Strategy was also unclear.
Risk Management	The role of transformational rebuild of the network in wood pole risk management was observed to be unclear.
Cost Efficiency	Costs have been estimated using an efficient system and unit costs. The cost efficiency is open to question given the large decrease in CAPEX.
Scope Efficiency	Unclear because we did not observe options analysis at a project level.
Strategic Alignment	Governed by the Distribution Overhead Network Rebuild Strategy and Grid Strategy
Options Analysis	Analysis needed that explicitly identifies a reasonable range of alternative options
Delivery Model	Risk-based prioritisation applied to staging but influence of SPS and undergrounding unclear on a project level

Findings

To establish our position Engevity has conducted a structured assessment of a sample of material issues, projects and programs to establish whether or not the investment proposed by Western Power satisfies the requirements of the NFIT. Our review is summarised below for the Western Power distribution wood pole management program proposed for the AA5 period. Wood pole management is a sub regulatory category of the asset replacement and renewal regulatory category of the distribution asset segment. Pole management – REPEX is the sole regulatory activity in the wood pole management sub regulatory category.

Engevity has reviewed Western Power's proposed expenditure relating to **Distribution Wood Pole Management Program** and found that:

a. **The proposed expenditure may not be efficient** with the objective of minimising costs on the basis that Western Power has not clearly proven the cost efficiency of the CAPEX for distribution wood pole management in the AA5 period. More information is required to definitively address this issue. The costs have been estimated using an efficient system and unit costs. However, we did not observe clear justification of the ~40% decrease in wood pole management CAPEX forecast for the AA5 versus the AA4 period, given the Western Power identified continued high-risk level associated with overhead assets. The decrease in wood pole management CAPEX is likely related to increased undergrounding and SPS CAPEX as alternative replacement in the AA5 period. The cost-efficiency of the split in CAPEX between like-for-like overhead and alternative replacement on a project basis needs to be clearly established. No business cases or investment evaluation models for wood pole management at a project level have been made available.

b. **The program may not capture the available and realisable economies of scale and scope.** The program is supported by a detailed risk-based renewal methodology aimed at maintaining overall safety and reliance performance at minimum cost. However, the decrease of $280m (~40%) in wood pole management CAPEX proposed for the AA5 in comparison to AA4 period and corresponding decreased scope of work, is not clearly supported by evidence that it is commensurate with identified need or is economically justified. The proposed substantial decrease in wood pole management CAPEX should be considered in association with the proposed substantial increase in CAPEX for alternative overhead network renewal strategies (undergrounding and SPS). Increased proposed CAPEX in the AA5 versus AA4 period is $539m (~371%) for the NRUP and SUPP undergrounding programs and $277m (~514%) for the SPS program. Engevity would expect economies of scale and scope are assessed 'bottom-up' from project level across all distribution overhead network renewal strategies.

c. The proposed investment **is consistent with reasonable expectations** of the level of future network services required by customers. This is provided it is accepted that in association with the proposed substantially increased use of alternative overhead network renewal strategies, the proposed investment in distribution wood pole management maintains the existing level of safety and reliability of the distribution network.

d. **A reasonable range of alternative options has not been considered** for the proposed investment, with the most appropriate solution chosen. There is a lack of options analysis for overhead assets replacement in the AA5 proposal, particularly at a project level. Western Power does not quantitatively demonstrate the relative cost-efficiency of like-for-like overhead asset replacement (including wood pole management) versus undergrounding and SPS alternatives on a project basis.

Recommendation

Engevity's recommendation is that there be no adjustment to the Western Power proposed wood poles management program. However, adjustment has been proposed to the undergrounding program to ensure that the Western Power capital expenditure allowance is for a total level of investment to manage overhead network risk that is comparable to AA4 expenditure. Western Power is free to reprioritise overhead management within that total scope of expenditure. Engevity notes that Western Power is making progress on dealing with wood pole issues, with a proposed $280m (~40%) decrease in wood pole management CAPEX for the AA5 versus the AA4 period. Engevity suggests it would be prudent for WP to provide audit assurance for the AA6 proposal to support inclusion in RAB at that point. Engevity also notes that we were not able to review forecast numbers in detail.

8.2.2 AA5 NFIT Assessment

Overview

Management of poles is critical to the distribution overhead network to prevent conductor failure or contact with vegetation or the ground. This can result in fire, electric shock, service disruption, physical impact injury and property damage.

Western Power's proposal outlines that safety expenditure during the AA5 period continues to be prioritised on distribution wood poles. There are 34,974 planned replacements and 27,500 reinforcements of wood poles forecast in the AA5 period[404]. About 27,000 wood poles will be removed as part of forecast Standalone Power System (SPS) and undergrounding investment[405]. In total, about 47, 000 wood poles are planned to be removed[406].

Western Power has proposed a total investment of $423m in distribution pole management replacement expenditure (REPEX) during the AA5 period[407]. This is $280m (~40%) less than the investment of $703m in distribution pole management REPEX in the AA4 period. Western Power states that investment in pole management is in two areas:

- Reactive replacement of assets that fail while in service. This is based on forecasts for assisted and unassisted failures.
- Proactive replacement and reinforcement of assets selected under the Distribution Overhead Network Rebuild Strategy.

Western Power faces challenges around an ageing distribution overhead network. Approximately 55% of overhead assets will reach end of life maturity within 10 years[408]. Wood poles and bare overhead conductors form ~97% of the Western Power distribution overhead network[409].

Western Power recognises that an overhead network is an affordable option but says it also presents a safety and reliability risk relative to other options, such as underground or standalone power systems. Western Power states it is seeking an optimum investment balance between short to medium term risk management and network transformation under its Grid Strategy.

Western Power has adopted several strategies to address the challenges they are facing in the distribution overhead network[410]. The Distribution Overhead Network Rebuild Strategy identifies mature sections of network for rebuild prioritised by risk. Western Power states this enables transformation of parts of the network as per the Grid Strategy. The Network Rebuild Strategy also identifies high risk assets for treatment to manage short term risk plus minimise 'regrettable' investment in areas earmarked to be transformed.

Over the AA5 period, wood pole management in the distribution network accounts for the expenditure and scope summarised in the table below.

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404 Access Arrangement Information – Access Arrangement revisions for the fifth access arrangement period – 1 February 2022, p. 180

405 ibid. p. 180

406 AAS – Attachment 8.2 – Network Management Plan – 1 February 2022, p. 14

407 Access Arrangement Information – 1 February 2022, p. 199

408 Network Opportunity Map 2021, p. 66; Distribution Structures Asset Management Strategy – December 2021, p. 4

409 Network Opportunity Map 2021, p. 66

410 Network Opportunity Map 2021, p. 66

Table 8–6: AA5 Expenditure and Scale – Wood Pole Management Program (sub regulatory category) [$m real at 30 June 2022][411]

Wood Pole Management - Dx	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Total CAPEX (Gross)	89.8	90.2	78.0	82.3	82.8	**423.1**
Direct CAPEX	77.7	77.9	67.1	70.1	69.9	**362.7**
# poles replaced # poles reinforced	7,369 5,500	7,338 5,500	6,533 5,500	6,763 5,500	6,970 5,500	**34,974** **27,500**

Historical Context

Key historical issues concerning wood pole management are addressed in the relevant AA4 NFIT assessment.

Treatment of wood poles in the AA4 period was prioritised in order of those in the poorest condition and/or posing the highest public safety risk. This included ~55,000 replacements and ~83, 000 reinforcements, out of a total of 621, 195 wood poles in the distribution network in 2020[412]. Despite significant wood pole ground line reinforcement works being carried out during AA4, poles are still susceptible to failure at mid and pole top[413]. Some reinforcements are also reaching the 15-year end of life. Western Power has similarly identified that a significant part of the metropolitan overhead network is currently reaching the end of its service life.

The Western Power Grid Transformation program was referenced in discussions around investment in wood pole management in the AA4 period. It was noted that the Grid Transformation program would likely result, in cases where it was cost effective, in retiring overhead infrastructure[414].

A portfolio of individual distribution wood pole assets was selected by risk modelling, with the target of maintaining the current level of risk across the distribution overhead network for customer reliability, workforce safety and public safety during the AA4 period. Western Power states the approach addressed risk considering like-for-like asset replacement solutions but anticipating that within the investment period alternate (including non-network) solutions would likely emerge. The pole replacement volumes could be reduced if the business cases for alternate solutions were acceptable[415].

Distribution overhead wooden pole replacements by NRUPP, SPS and like-for-like during the AA4 period are discussed in detail in the relevant AA4 NFIT assessment. The relevance to the AA5 period is noted below.

Western Power provides numbers for NRUPP, SPS and like-for like replacement of poles in terms of distribution overhead corridor CAPEX and pole replacement volumes for the AA4 period[416]. These are

411 Sources: AAS – [redacted] Access Arrangement Information – 1 February 2022, p. 180; AAS – Attachment 8.2 – Network Management Plan – 1 February 2022, p. 289). NOTE: These figures are for the Pole Management – REPEX regulatory activity in the pole management sub regulatory category of distribution asset replacement. They do not include Western Power plans to replace 2,030 wood poles and reinforce 2,250 wood poles in the transmission network.

412 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 6 & p. 10

413 Distribution Structures Asset Management Strategy – December 2021, p. 4

414 ibid. p.6

415 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 6

416 ibid. pp.7-8

summarised below, along with the consequent estimated normalised cost of pole replacement by NRUPP, SPS and like-for-like overhead replacement.

Table 8–7: Distribution overhead wooden pole replacements during the AA4 period

Replacement Option	Volume of replacement (# poles)	Distribution overhead corridor CAPEX ($m)	Normalised pole replacement cost ($k/pole)
NRUPP	2,226	23	10
SPS	3,563	40	11
Like-for-like OH	55,383	1,011	18

Table 8–15 shows that pole replacement by NRUPP was ~0.56 times as expensive as the like-for-like overhead option during the AA4 period. Pole replacement by SPS was ~0.61 times as expensive as the like-for-like overhead option during the AA4 period. However, we note that that the volume of pole replacements associated with NRUPP and SPS were relatively small for the AA4 period at ~3.6% and ~5.8% of total pole replacements. Additionally, the NRUPP and SPS projects associated with pole replacement were deliberately selected as having the lowest possible CAPEX costs. This means that the relative cost estimates for pole replacement in the AA4 period may not be applicable to substantially larger proposed undergrounding and SPS programs in the AA5 period.

Need

Western Power states that the distribution overhead network presents the highest safety and reliability risks across their transmission and distribution networks[417]. The need for the proposed investment in wood pole replacement and reinforcement in the AA5 period has been identified by Western Power in terms of the following[418]:

- Overall network safety in accordance with jurisdictional obligations - eliminate / reduce risk as low as is reasonably possible (ALARP).
- Maintain current service standard levels measured by Service Standard Benchmarks (SSBs) and ensuring ongoing network sustainability.
- Optimising the transition to the modular grid.

Western Power identifies a key challenge as the need to effectively treat short term risk related to ageing wood power poles, particularly the substantial remaining population of Jarrah poles, while network transition plans are implemented. Western Power expects that with the large number of Jarrah poles still in the distribution network, it will take considerable time at current renewal rate before the population is completely phased out. Hence Jarrah pole risks will continue to dominate asset health in the AA5 period[419]. Resilience to extreme weather / climate events is also mentioned as a key challenge for the distribution overhead network in terms of reliability and economic impacts[420].

Western Power states that approximately 55% of its overhead network assets will reach end of life maturity in the next 10 years. Over 13% of the wood poles in the distribution network are operating

417 [redacted]

418 Access Arrangement Information – 1 February 2022, p. 200

419 [redacted]

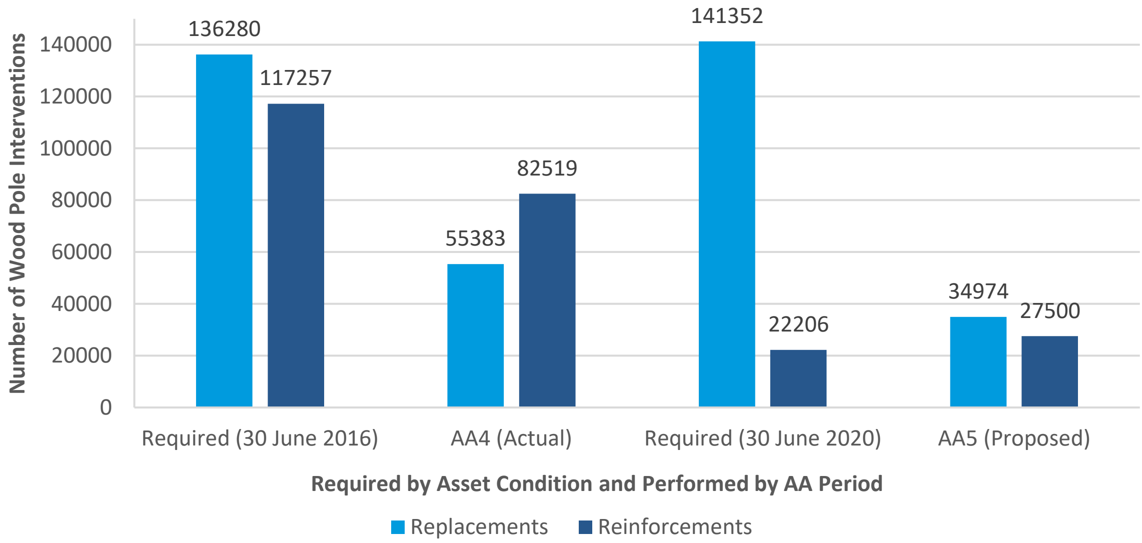
420 AAS – Attachment 8.2 – Network Management Plan – February 2022, p. 14; Access Arrangement Information – 1 February 2022, pp. iii-iv and p. 20

beyond their Mean Replacement Life (MRL) and have been assigned a high operational current risk rating as of 30 June 2020[421]. This is driven by the safety (fire, electric shock and physical impact) through compliance, service (reliability and power quality), and environment risk criteria[422]. Western Power estimated by visual defect identification and a Serviceability Assessment Model, that as of 30 June 2020, ~141,000 wood poles required replacement, while ~22,000 required reinforcement[423].

The figure below shows the number of poles requiring replacement or reinforcement due to asset condition in 2016 and 2020. It also shows the actual number of replacements and reinforcements in the AA4 period and the proposed number of replacements and reinforcements in the AA5 period. There is an increase of ~4% in the number of replacements required due to asset condition between 30 June 2016 and 30 June 2020. The proposed replacements in the AA5 period address ~25% of the poles requiring replacement due to asset condition as of 30 June 2020. The actual replacements in the AA4 period addressed ~41% of the poles requiring replacement due to asset condition as of 30 June 2016. The number of reinforcements required due to asset condition declined by ~81% from 30 June 2016 to 30 June 2020.

The number of replacements performed declined by ~37%, while the number of reinforcements performed declined by ~70% from AA4 to AA5 (proposed). The reasons for the decline in replacements and reinforcements proposed to be performed in AA5, relative to the increase in number of replacements required due to asset condition in 2020, are not clear and some additional information may be required. It may be due to the proposed increased use of alternate solutions such as SPS and undergrounding.

Figure 8–2: Number of wood pole interventions due to asset condition (2016 & '20), performed in AA4 (actual) and AA5 (proposed)



Over 18% of the wood poles in the distribution network are predicted to be operating beyond their MRL by the end of the AA5 period under the asset management plan and the forecast operational risk of wood poles is predicted to remain high. The failure rate, as of 30 June 2020, is 185 wood poles per annum and is forecast to increase to 266 wood poles per annum by the end of the AA5 period[424]. The predicted increase in wood pole failure rate could result in a decrease in service reliability.

421 [redacted]

422 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 5

423 [redacted]

424 ibid. p. 4

Western Power has developed and applied what may be a sound and detailed Risk Based Renewal Methodology to support pole replacement and reinforcement plans with a risk-based prioritisation of investments[425]. The goal of this methodology is to maintain overall safety and reliability performance at minimum cost[426]. At an individual asset level, Western Power applies risk models to quantitatively estimate a risk value for risk assessment criteria including safety, environment, legal/compliance, customer, reputation and financial exposure.

The residual level of risk associated with distribution structures as of 30 June 2020 is rated as high for safety and reputation. The Western Power safety management system complies with AS 5577 (in accordance with the *Electricity (Network Safety) Regulations 2015*), with safety risk managed to ALARP. Western Power has a good understanding of the spatial distribution of network risk, which is mapped across 2000 maintenance zones in the South-West Interconnected System[427]. Treatments are grouped together where there are known delivery efficiencies. Planning and delivery accept practical (including financial) constraints[428]. Treatments are selected and prioritised according to the Network Rebuild Strategy, based on asset economic life, risk, condition and defect Mean Time to Failure[429].

Engevity's finding is that the asset condition, reliability and compliance (safety) needs for the Western Power proposed pole management program for the AA5 period have been clearly identified. The proposed investment is a balance between reactive replacement of assets that fail while in service and proactive replacement and reinforcement of assets identified by the Distribution Overhead Network Rebuild Strategy.

Scope Definition

It is not clear, based on currently available information, that the Western Power proposed $423m total in distribution wood pole management CAPEX for the AA5 period to replace approximately 35,000 poles and reinforce 27,500 poles is commensurate with asset condition, reliability and compliance needs. This could require detailed 'bottom-up' information on wood pole projects for the AA5 period. However, the proposed total wood pole management CAPEX is consistent to within ~2.5% of an estimate based on the proposed volume of replacements and reinforcements in the AA5 period and the relevant actual unit rates at the end of the AA4 period[430].

The Western Power proposed AA5 wood pole management CAPEX has declined by $280m (~40%) in comparison to the AA4 period. There is a decline of 20,000 (~36%) in the volume of wood pole replacements and a decline of 55,500 (~67%) in the volume of reinforcements. We did not observe explicit detailed analysis of the reasons for the substantial decline in wood pole management CAPEX and volumes of both replacements and reinforcements in the AA5 period. The large decline in the volume of reinforcements forecast for the AA5 period requires explanation. The scope of the AA5 proposed expenditure on wood pole management will likely be influenced by the Distribution Overhead Network Rebuild Strategy, which is designed to enable transformation of parts of the network in accordance with the Western Power Grid Strategy plus identifying high risk assets for treatment to manage short term risk and minimising regrettable investment in areas to be transformed[431]. The scope of works in wood pole management is subject to the balance between

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425 Risk Based Renewal Methodology – Distribution Overhead – July 2017, p. 9

426 ibid. p. 7

427 ibid. pp. 11-12

428 ibid. p. 17

429 AAS – Attachment 8.2 – Network Management Plan – February 2022, p. 141

430 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 16

431 ibid. p. 14

conventional and transformation rebuilds, plus Short-Term Risk Management (STRM)[432]. In short, it is likely that the number of replacements and reinforcements will decline as parts of the distribution network transform into a hybrid including underground and SPS.

Western Power has detailed the proposed CAPEX investment volumes for distribution wood pole replacement and reinforcement for the AA5 period by year, according to grid transformation zone, category and program[433]. The combined replacement and reactive replacement programs for poles in the STRM and conventional rebuild categories across the distribution network sum to the expected 34, 974 poles, with roughly matching disposal. The combined reinforcement programs sum to the expected 27, 500 poles. The rebuild and STRM categories in the tightly meshed grid transformation zone of the distribution network list a total of 51, 201 additional poles for disposal/removal. These poles are not associated with the distribution wood pole management program and are presumably being removed as part of undergrounding conversion. There is a total of 86, 990 poles listed for removal in the AA5 period. The combined pole replacement programs therefore only represent ~40% of the total poles removed. It is plausible that the total number of poles listed to be removed is more in alignment with asset condition, reliability and compliance needs in the AA5 period.

Western Power states that distribution network asset management strategies in the AA5 period are aimed at ensuring the current levels of performance are maintained. This has required some step change increases in expenditure, largely in terms of CAPEX, compared to the AA4 period[434]. However, these increases in CAPEX are dominated by optimising the modular grid (SPS and microgrid trials) plus proactive undergrounding. There is an increase of 5% mooted in distribution overhead network safety. Western Power states this is to eliminate safety risk in tightly meshed and autonomous areas by removing OH assets, maintain fire, electric shock and unassisted failure rates caused by Dx OH assets, and adhere to the Electrical Network Safety Management System as legislated by *Electricity (Network Safety) Regulations 2015* (WA).

Timing

There is clearly an ongoing need for distribution pole management to replace and reinforce significant numbers of ageing wood (including Jarrah) poles with high-risk ratings. However, it is unclear from the available information whether the proposed investment timing, in accordance with the proposed scope, is consistent with maintaining overall safety and reliability performance at minimum cost during the AA5 period. The use of a risk-based renewal methodology for distribution overhead assets supports the view that the proposed volume and timing of replacements and reinforcements is well founded. However, additional information on the influence of the Distribution Overhead Network Rebuild Strategy on the timing and scope of wood pole management CAPEX during the AA5 period should be provided. A clarification is needed on how the timing and scope of wood pole management expenditure in AA5 is influenced by the application of a transformational rebuild approach to areas of mature overhead assets in the densely meshed and autonomous parts of the network, leading to substantial proposed increases in undergrounding and SPS CAPEX in the AA5 period.

Risk Management

Western Power has managed substantial risk associated with distribution wood poles in both the AA3 and AA4 periods. As outlined above, there is a ~40% decline in the proposed CAPEX associated with wood pole management in the AA5 versus the AA4 period. This decline in CAPEX is not in accordance with a lower level of risk associated with distribution wood poles in the AA5 period. Some of this decline in CAPEX may be associated with transformational rebuild of the network by

432 AAS – Attachment 8.2 – Network Management Plan – 1 February 2022, pp. 132-134

433 AAS – Attachment 8.2 – Network Management Plan – 1 February 2022, p. 289, Table 12.5

434 ibid. pp. 298-299

undergrounding and SPS, leading to a reduction in required distribution wood pole rebuild and reinforcement expenditure. Risks associated with the condition of distribution overhead assets could be handled with a BAU approach, by replacement with like-for-like overhead infrastructure. Western Power acknowledges that this could be done but does not align with the grid transformation objective of the Grid Strategy.

Western Power continues to make a substantial investment in wood pole management ($423m in AA5 compared to $703m in AA4). This includes reactive replacement of assets that fail while in service, with a reactive forecast based on expected assisted and unassisted failures. It also includes proactive replacement and reinforcement of assets selected through the application of the Distribution Overhead Network Rebuild Strategy. Western Power's Network Risk Management Standard requires that it understands hazards and risks, eliminates unacceptable risks and reduces remaining risks to ALARP, in accordance with AS 5577[435]. Western Power states there is ongoing review of wood pole condition information and associated safety risk, and ongoing discussions with the safety regulator. These safety management procedures for wooden poles remain in place in the AA5 period and could be applied to like-for-like replacement of overhead infrastructure originally slated for undergrounding or SPS projects.

Western Power has an Asset Management Framework in accordance with the Australian and International Standard on Asset Management (ISO55001), ERA Audit Guidelines, Electricity (Network Safety) Regulations 2015 and the Electricity Network Safety Management Systems standard (AS 5577). Western Power was acknowledged in its ISO 55001 assessment as having "…a number of industry leading practices, particularly in the areas of asset risk management". Western Power's Network Risk Management Standard requires risk assessments to be carried out at appropriate points throughout the asset lifecycle. The condition of an asset is identified during the operate/maintain phase of the asset life cycle by qualitative and quantitative risk assessments. Engevity observed Western Power prioritise risks into four categories, unacceptable (failed/imminent risk), high risk, varying severity (decisions to treat managed by the Short-Term Risk Management building block of the Network Rebuilding strategy), and acceptable risk.

Cost Efficiency

The costs have been estimated using an efficient system and unit costs. Western Power treats risk from assets in the distribution overhead network either by replacement at the end of their service lives or by maintenance mitigating the probability of failure. The selection of treatment is according to the Network Rebuild Strategy, as described above. The distribution wood pole management program was considered as part of a Combined Asset Replacement Program across AA4. This was done to maximise risk reduction in Western Power's overhead network and achieve efficiencies in delivery by bundling these assets into a combined program of works. Western Power states that in specific geographical areas, where it was economically efficient, they addressed overhead asset risks in the AA4 period with alternative solutions such as undergrounding and SPS. Analysis based on Western Power data indicates these alternatives have been provided for normalised distribution overhead corridor costs less than like-for-like replacement in the AA4 period[436].

Labour costs typically make up 50-60% of direct costs for individual asset treatments. In the case of distribution wood pole replacements, unit costs are 52% labour and 29% materials. Labour costs are greatly dependent on travel distance and scheduling limitations[437]. The weighted average estimates of unit rates are stated by Western Power as ~$10.3k for pole replacement and ~$1.3k for pole

[435] Attachment 5.9 – AA4 – NFIT Compliance Summary – Distribution Wood Pole Management - 1 February 2022, p. 5

[436] AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, pp. 7-8

[437] AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management – 1 February 2022, p. 12

reinforcement across the AA4 period[438]. This is based on delivered cost of the pole replacement and reinforcement programs for 2016/17 divided by actual volumes (Western Power states that it is further reduced to cater for various assumptions), with movements between years assumed in subsequent business cases. The estimated AA4 weighted average unit cost of ~$10.3k for pole replacement is significantly lower than the estimate of ~$18k based on Western Power information concerning AA4 NRUPP comparative costs. Western Power states it has applied a robust unit cost estimation methodology to estimate the unit rates for its wood pole management program. Unit rates are developed using a "bottom up" methodology, with all inputs and assumptions validated with key stakeholders and based on the best information at time of development[439]. Western Power provides yearly and weighted average pole replacement and reinforcement unit rates for the AA4 period. The efficiency of the unit rates is supported by benchmarking in preparation of the AA4 submission. This benchmarking determined that Western Power's unit rate for pole replacements was comparable to its peers[440].

Western Power refers to three primary business cases relating to the wood pole management program that were undertaken throughout the AA4 period. The objective of these business cases was to optimise the risk across assets in the distribution overhead corridor and to achieve the lowest Net Present Cost over the assessment period[441]. The efficiency of engineering design was provided through adherence to Western Power's suite of standards, guidelines and manuals in accordance with good electricity industry practice and relevant external standards requirements[442]. The same methodology will presumably apply to the AA5 period.

The cost efficiency of the scope of the wood pole management program remains open to question because of the ~40% decrease in CAPEX forecast for the AA5 versus the AA4 period. This is in association with large increases in undergrounding and SPS CAPEX in the AA5 period.

Western Power has not explicitly identified any contingency or project overhead components of costs associated with wood pole management CAPEX for the AA5 period. However, the $423m CAPEX is inclusive of labour escalation and other indirect costs. Labour cost escalation and indirect costs have been included in all CAPEX estimates, including for the pole management sub regulatory category[443]. Western Power's says its approach is consistent with the AER's recent decisions to apply labour cost escalation to total OPEX and consistent with the approach used for network growth. Western Power does discuss labour cost escalation and other indirect costs in respect of OPEX. This includes allocation of such costs to all activities as per Western Power's Cost and Revenue Allocation Methodology, including stating that a portion of these costs are capitalised[444].

Scope Efficiency

Western Power states that distribution overhead replacement, including wood pole management, is governed by a risk-based renewal methodology. However, the Distribution Overhead Network Rebuild Strategy is also designed to facilitate transformation of the network.

The scope efficiency of the distribution wood pole management program in the AA5 period is unclear because we did not observe options analysis available for the AA5 period at a project level, particularly in addressing the split of works between reactive replacement and proactive

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438 ibid. p. 16

439 ibid. p.16

440 ibid. p. 18

441 ibid. p. 2

442 ibid. p. 21

443 [redacted]

444 Access Arrangement Information – 1 February 2022, pp. 171-176

replacement and renewal, and the use of alternative solutions such as SPS and undergrounding. The ~40% reduction in CAPEX forecast for the AA5 versus the AA4 period is related to a decrease in scope, probably due to the use of alternative approaches (SPS and undergrounding). The proposed $423m total wood pole management CAPEX in the AA5 period is consistent to within ~2.5% of an estimate based on the proposed volume of replacements and reinforcements in the AA5 period and the relevant actual unit rates at the end of the AA4 period[445].

However, it is not clear from the evidence available that this reduction in scope is efficient. Business cases were developed for the AA4 period and examine options around the scope of works for both pole reinforcement and pole replacement at various stages of the regulatory period. A similar level of analysis is required for the AA5 period, with Western Power making available business cases or investment evaluation models at a project level that demonstrate consideration of scope options.

Strategic Alignment

Wood pole management is governed by the Distribution Overhead Network Rebuild Strategy, which is based on the guiding principles of the Western Power Grid Strategy. The Grid Strategy includes a collection of strategies grouped into performance and transformation. Performance strategies target network reliability, voltage, utilisation, protection and power quality across the lifecycle. They are focussed on short to medium term responses to existing and emerging issues. Transformation strategies target changes to networks when they reach end of life. They are focussed on longer term responses to emerging and future issues. However, Western Power states that transformation strategies also drive planning actions in the short term[446].

Options Analysis

Western Power has provided general information around NRUP, SPS and 'like-for-like' options for overhead replacement. However, Western Power has not provided any analysis that explicitly identifies a reasonable range of alternative options concerning wood pole management for specific projects in the AA5 period. As discussed above, business cases were developed for the AA4 period that examined options around the scope of works for both pole reinforcement and pole replacement. These business cases do demonstrate how Western Power selected the most efficient option at various stages in the AA4 period. Selection of recommended options was based on Net Present Cost and satisfaction of all investment objectives. A similar level of analysis is required for the AA5 period, with Western Power making available business cases or investment evaluation models at a project level that demonstrate consideration of options and how a preferred option was selected.

An assessment of life cycle options is part of the Western Power approach to developing asset management strategies. The Distribution Overhead Network Rebuild Strategy guides decision making concerning which asset and when to rebuild, ensuring prudent investment decisions and achieving the modular grid vision[447]. It contains a Solution Assessment building block that is used to determine conventional or transformational rebuild for mature systems (asset systems that are not mature according to end-of-life maturity assessment are subject to short term risk management). This building block uses the guiding principles from the Asset Management Strategy Standard options analysis to identify the optimal rebuild technology solution, while recognising risk-based prioritisation and known constraints. Key assessment parameters include net present and net cost to community (whole of life cycle cost comparison), cost to serve, inherent risk, future of the network, impact on tariff, debt, revenue, and customer preference.

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445 AAS – Attachment 5.9 – AA4 – NFIT Compliance Summary – Dx Wood Pole Management, p. 16

446 Access Arrangement Information – 1 February 2022, p. 183

447 AAS – Attachment 8.2 – Network Management Plan – 1 February 2022, p. 132

Delivery Model (incl. staging)

Western Power states that it is applying risk-based prioritisation to staging of all proposed programs in the AA5 period, including wood pole management[448]. Each stage progresses through Western Power's Investment Governance Framework. Western Power has provided the projected yearly volumes of wood pole reinforcements, replacements, reactive replacements and disposals/removals during the AA5 period[449]. Reinforcements and replacements are roughly evenly distributed across each financial year in this analysis.

There may be other options for staging of delivery of the wood pole management program, but these could result in sub-optimal outcomes in terms of risk-based prioritisation. The proposed delivery of the wood pole management program may also have been impacted by the decision to proceed (or not) with projects under the SPS and undergrounding programs. A resource levelling approach could be applied through a principle of CAPEX neutrality for like-for like overhead (including wood pole) replacement versus undergrounding and SPS across the Western Power distribution network between the AA4 and AA5 periods. This could result in revised staging of delivery of the wood pole management program.

448 ibid. p. 275

449 ibid. p. 289

8.3 SPS & Microgrids - AA5 Assessment

8.3.1 Summary of Assessment

Engevity has reviewed Western Power's proposal for the AA5 period and found that it **DOES NOT COMPLY** with the Access Code requirements for an AA submission. We found that some expenditure **IS NOT EXPECTED** to satisfy with the New Facilities Investment Test. As a result, we have made recommendations for ERA adjustments in the table below.

Assessment Overview

Over the AA5 period, the SPS & Micrògrids Program in the distribution network accounted for the forecast expenditure and scope summarised in the table below.

Table 8–8: AA5 Expenditure and Scale – SPS & Microgrids Program [$m real at 30 June 2022]

SPS & Microgrids Program	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	**Yr2**	**Yr3**	**Yr4**	**Yr5**	**Total**
Western Power Proposed Total CAPEX[450]	*59.98*	*61.57*	*60.95*	*73.10*	*75.23*	***330.83***
Western Power Proposed Direct CAPEX[451]	51.91	53.16	52.44	62.29	63.54	**283.34**
Adjustment	-32.58	-25.42	-16.28	-17.72	-10.56	**-102.56**
Engevity Recommended Direct CAPEX	**19.33**	**27.74**	**36.16**	**44.57**	**52.98**	**180.78**
Total CAPEX	61.04	62.47	61.75	73.03	74.82	**333.10**
Supply Abolishment	-9.13	-9.31	-9.31	-10.74	-11.28	**-49.76**
Net CAPEX	**51.91**	**53.16**	**52.44**	**62.29**	**63.54**	**283.34**
Total Volumes	341	349	345	408	418	**1861**
Supply Abolishment	-51	-52	-52	-60	-63	**-278**
SPS units	**290**	**297**	**293**	**348**	**355**	**1583**

450 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs', Column AF - AK

451 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs', Column H - M

Table 8–9: Assessment Overview

Project/Program	SPS & Microgrids
Proposed Cost $m	$283.34
Recommended Cost $m	$180.78 (-36.2%)
Need	Engevity agrees there is a need to consider SPS units as an alternative solution to traditional replacement solutions for the long rural network as part of Western Power's ongoing asset replacement program. Substantial sections of Western Power's Dx OH network are reaching their Mean Replacement Life (MRL), resulting in increasing risks to network performance. Western Power is considering SPSs as an alternative solution to like for like replacement of Dx OH assets as part of WPs asset replacement program for distribution assets. Western Power submits that SPSs to be a least cost alternative to like for like replacement to provide power supply of appropriate quality, reliability and safety to customers in certain areas of the grid, particularly for customers on radial, long rural lines.[452] The need for SPSs themselves is driven by the need to replace certain section of the distribution network. Western Power's proposed need for distribution asset replacement for AA5 is a broader question related to the validity of Western Power's asset management strategy. Engevity notes that MRL is heavily relied on as the indicator of replacement need for an asset, not the asset's current condition or performance.[453] This may mean that some SPS's are being considered to replace Dx assets prematurely. In some documentation, Western Power positions SPS rollout as a 'requirement' to enable a modular grid. There seems to be no legislation, regulation or other mandate to require a modular grid as an end in of itself. Engevity notes that Western Power is required to make capital investment decisions based on factors defined by their regulatory mandates for efficient energy supply. [454]
Scope Definition	Engevity does not find the scope of the AA5 SPS program to be well justified on the basis of need and cost efficiency. Western Power's proposed AA5 SPS program consists of 1,861 SPS units or equivalent. Of this, Western Power proposes 231 SPSs (or equivalent) will be configured into two new microgrids. Western Power also forecasts 15% of SPS 'equivalents' identified to be rolled out to connections are to be Supply Abolishment arrangements instead of the installation of an SPS unit. The proposed AA5 SPS program represents a tenfold increase on Western Power's AA4 program. Western Power targets 4000 SPSs deployed by 2031. The AA5 program is estimated to result in 19,000 poles removed from service and approximately 3,618km of OH line.[455] Western Power accepts it

452 Attachment 5.8 – AA4 – NFIT Compliance Summary – Stand-alone Power Systems, Western Power, 2022, pp. 2-3

453 Distribution Structures Asset Management Strategy, Western Power, 2021, p.10

454 Access Arrangement Information, 1 Feb 2022, Western Power, p. 36

455 Attachment 8.2 – Network Management Plan, Western Power, p. 137

Project/Program	SPS & Micrognids
	will be replacing some non-mature assets as part of this program and their terminal value is accounted for in its cost-benefit modelling.[456] In general, while the high-level justification, strategy and assessment approach to SPS rollout has been provided, there seems to be limited detail. In particular: • We did not observe a collated document that sets out the current timing, staging, scale and end objective of SPS program. • We have not seen quantified justification of cost savings for the AA5 period and for the 4,000 units by 2031 target. No business case/investment plan has been provided for total program or AA5 SPS investment. • Engevity questions the reliability and safety argument that has been used to support a mass rollout of SPS as most customers 'do not value additional investment to improve reliability'. [457]
Timing	Engevity believes the accelerated timing of the current SPS program and resultant proposed AA5 roll out is not aligned with a prudent and cost-efficient approach. Timing of proposed SPS rollout is a function of Western Power's Asset Management strategy and GTEng tool, identifying areas of network due for replacement and optimising replacement schedules of sections of networks for SPSs against performance, cost and risk of existing assets. Engevity believes that proposed unit costs for AA5 are inefficiently high and identifies several cost efficiencies that will likely increase with time and experience which would make delayed SPSs more cost effective, including reductions related to: • technology costs curves,[458] • market maturity,[459] • maintenance efficiencies, and[460] • decommissioning costs. [461] Engevity also has concerns that assets are being prematurely replaced on a conservative asset age risk basis rather than actual asset condition basis.
Risk Management	Engevity has concerns about the existing asset risk management approach of Western Power resulting in premature replacement of Dx OH assets from the AA5 SPS program. In general, it is not clear to Engevity how risk management considerations have supported the quantification of the 1,861 SPS units proposed for AA5.

456 ERA AA5 Walkthru#1 Modular Grid & SPS, Western Power, 2022, Verbal

457 Access Arrangement Information, 1 Feb 2022, Western Power, p. 71

458 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 14

459 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 14

460 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 25

461 Stand-alone Power Systems Asset Management Strategy, Feb 2022, Western Power, p. 14

Project/Program	SPS & Micrgrids
	It is not clear how the safety, reliability and performance of new Dx OH assets compare to an SPS, as SPS performance comparisons made by Western Power have been against the existing aged infrastructure. SPS do remove the safety risks of OH conductors of bushfire, pole top fires and electric shock, provided SPS units are well contained. As above, Engevity has concerns that assets are being prematurely replaced on a conservative asset age risk basis rather than actual asset condition basis. Engevity notes that in its 2020 Asset Management System review, AMCL found that Western Power has not had a robust and consistent approach to whole of life costs or quantifying risk costs for projects. [462] Engevity shares these concerns.
Cost Efficiency	Engevity found the SPS program is 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 OH Dx network assets. Engevity agrees that the SPS program can have material net benefits in principle, however, has not observed sufficient evidence to justify net benefits of the AA5 program. Overall, Engevity has not been provided with a business case for the AA5 SPS program. The costings of the SPS units for the AA5 program are based off the average costs of units in the AA4 Round 2 SPS program, with materials, contracting and internal cost reductions applied. Western Power forecasts its AA5 SPS units to have an average cost of $178,992[463], a 30 per cent cost reduction on the unit costs derived from the estimates in the AA4 round 2 business case. [464] Engevity has not seen any further justification of this cost reduction and notes that these unit costs are higher than suggested in previous modelling by Mainsheet Capital. Engevity also notes that precursory desktop study of commercial SPS providers finds that a 15-20kWh retail off-grid solutions are costed between $25,000-$45,000 not including installation and overheads, suggesting much lower unit costs are achievable for Western Power. Engevity also finds that the proposed AA5 SPS CAPEX does not seem to align with reductions to CTS for autonomous network customers or be reflected in the proposed reduction in Dx REPEX.
Scope Efficiency	Engevity has little information on the options for scope and timing considered for the AA5 SPS program. Engevity understands that the number and sizing of SPSs to deploy can be modified throughout the program as a result of detailed site visits and

462 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. 24

463 ERA AA5 Walkthru#1 Modular Grid & SPS, Western Power, 2022, p. 20

464 Stand-alone Power Systems – Business Case Round 2, Western Power, 2020, p.28

Project/Program	SPS & Microgrids
	further iterations of desktop scoping exercises, assumed to include iterations of GTEng models. Due to new legislation, Western Power now has the regulatory power to enforce customers to take an SPS or equivalent (PSA), while previous SPS programs were opt in.[465] Despite this, Western Power is in early stages of understanding the level of incentive required for customers to accept a proactive supply abolishment (PSA) instead of receiving an SPS unit. Western Power targets a PSA rate of 15% but has not justified whether this is achievable. PSAs avoid future legacy risk of SPS units and additional network costs to Western Power customers, while also enabling the cost benefits of a reduced Dx OH network. WA legislation also requires Western Power to develop a robust SPS Customer Engagement Strategy to ensure customers understand the consequences of a PSA agreement.
Strategic Alignment	Western Power's AA5 SPS program is well aligned with their grid strategy, corporate strategy and government commitments. Conversion of appropriate sections of the Dx OH network due to be replaced to SPSs is aligned with Western Power's asset management strategy and grid vision and is supported by the WA Govt. [466] The SPS program is a core pillar of Western Power's Dx OH Network Rebuild Strategy, being a 'transformational rebuild' solution. [467] Transformational rebuilds are guided by Western Power's Grid Strategy. The Grid Strategy defines which part of the network is 'autonomous' as the parts of the network slated to be replaced by SPS.[468]
Options Analysis	In general, while the high-level justification, strategy and assessment approach to SPS rollout has been provided, Engevity has limited project specific detail. Documentation provided to Engevity provides inconsistent information on the timing, staging, scale and end objective of SPS program. Engevity has not been provided with any options analysis, NPC analysis or planning models showing quantified justification of costs and benefits for the AA5 period and for the 4,000 units by 2031 target. Engevity does not have sufficient information to determine whether appropriate options considerations have been made.
Delivery Model	Engevity is not confident that Western Power has the capability to install the volumes of SPS proposed for the AA5 period, particularly in a cost-efficient manner. Western Power has little experience to date with delivering and managing SPSs. In order to efficiently deliver and manage SPSs at a larger scale,

465 ERA AA5 Walkthru#1 Modular Grid & SPS, Western Power, 2022, Verbal

466 Attachment 8.3 – Grid Strategy, Western Power, p. x

467 467 Attachment 8.2 – Network Management Plan, Western Power, pp. 132-134

468 Attachment 8.3 – Grid Strategy, Western Power, p. x

Project/Program	SPS & Microgrids
	Western Power identifies a number of improvements required in internal processes, ICT, risk management and resourcing. Western Power's self-identified lack of maturity does not support a large step change in the volumes of SPS to be delivered in AA5 in comparison to the end of AA4.

Findings

Engevity has reviewed Western Power's proposed expenditure relating to the **Stand-alone Power System program** and found that:

a. **The proposed expenditure is not efficient** with the objective of minimising costs on the basis that the scope of the program, i.e. the number of proposed SPS units to be deployed over AA5, has not been justified by Western Power through the information provided to have a positive net benefit and is not evidenced to be deliverable to the scope and costs proposed by Western Power. Engevity acknowledges and supports the potential value of SPSs in supplying rural customers and replacing the need to maintain and replace long-rural overhead network in certain areas of the network. However, Western Power has not sufficiently demonstrated efficiencies of scope, timing, unit costs, resultant OPEX and CAPEX, and delivery that justify the extent of the proposed AA5 SPS program.

b. **The program does not capture the available and realisable economies of scale and scope** as it is unclear whether the trade-off between autonomous OH Dx transmission assets for SPSs for the number of SPSs proposed for AA5 represents a positive economic benefit. Western Power proposes to deliver 1861 SPSs or equivalent over the AA5 period, which is a tenfold increase on the SPSs delivered in AA4. Engevity has not been provided with NPC or NPV modelling to justify the extent of this program. It is recognised that Western Power is attempting to realise economies of scale and scope and that these will improve with Western Power experience in deploying SPSs.

c. The proposed investment **is consistent with reasonable expectations** of the level of future network services required by customers because SPSs are reasonably considered as an alternative to autonomous OH Dx replacement and so can represent a least-cost solution to providing a power supply to customers to the quality they expect. 40 per cent of Western Power's overhead Dx network serves less than 1 per cent of Western Power customers[469], making roll out of SPS solutions at scale a valid consideration for Western Power as these network assets continue to age.

d. **A reasonable range of alternative options has not been considered** for the proposed investment, with the most appropriate solution chosen. Engevity has not been provided with sufficient information, such as NPV models and options assessments, to be confident that Western Power has undertaken options analysis for autonomous OH Dx replacement that has thoroughly considered the costs, risks and benefits of all options and shown that the scope and timing of the AA5 proposed SPS program is the most efficient solution to providing reliable, high-quality supply to its customers.

Recommended Adjustment

Engevity found that Western Power's SPS program is justified in principle as an investment program to pursue but that there are currently concerns around the deliverability and efficiency of the

469 Access Arrangement Information, 1 Feb 2022, Western Power, p. 35

proposed AA5 investment for the program that warranted a more gradual deployment of SPS units over the AA5 period.

SPSs represent a potentially low-cost option to supplying customers in Western Power's rural network area. Indeed, business cases for Round 1 and Round 2 deployments of SPSs have found positive net benefits for SPSs as an alternative to like-for-like network replacement and Mainsheet Capital found that, on completion, the total SPS program could yield up to $66m a year in Dx cost savings for Western Power[470]. Engevity was unable to verify the analysis in either Western Power's business cases or Mainsheet Capital's benefits evaluation but recognises that in principle the SPS program should deliver net benefits to customers. In particular, the first portions of network targeted for investment by Western Power should be 'low hanging fruit' and so provide greatest benefits in transitioning, lowering the risk of the initial phases of the SPS program being inefficient.

However, Western Power will have delivered only 187 SPSs over the AA4 period and is still collecting data, developing internal processes and otherwise in learning stages to deliver SPSs at scale. From the information provided, Engevity is <u>not</u> confident that:

- Western Power has the capability nor systems in place to efficiently scale up to delivering 300+ SPSs from the first year of AA5, and
- the costs and benefits of the AA5 program as scoped in Western Power's proposal are justified sufficiently to support investment, as there is no detail on the cost components that constitute the forecast unit costs nor is there any quantification of project net benefits.

As such, Engevity believes Western Power should develop more experience in the deployment of SPSs through a more gradual 'ramp up' approach across AA5 from current volumes of SPS deployment in the final year of AA4 towards the volumes targets for AA6, instead of an immediate threefold step change. This supports the progression of the overall SPS program while allowing Western Power to:

- demonstrate the benefits of SPSs to customers at scale, including providing an experience basis for detailed justification of furthering the program at scale in AA6 and beyond;
- realised unit cost reductions through learning curve efficiencies and technology cost reductions;
- scale up the delivery of SPS units in a feasible and sustainable manner;
- refine customer engagement and consultation processes, including getting a better understanding of the uptake volumes and costs of proactive supply abolishment;
- better understand the management of SPS assets; and
- begin to implement necessary ICT and internal processes required to manage SPSs so that such systems are in place and tested prior to rollout of SPSs at scale.

In summary, a scale back of the program may be prudent to reduce inefficient investment while allowing Western Power to demonstrate the cost reductions and efficiencies it should achieve over AA5 to support a cost efficient, full-scale rollout in AA6 aligned with broader SPS program.

As a result, we recommend that that the forecast rate of SPS installations during AA5 should be reduced. We recommend the AA5 program does not result in a step increase from AA4 volumes but scale-up from AA4 round 2 towards the volumes of SPSs Western Power forecast to deploy in AA6. This provides Western Power time and experience in SPS deployment at a smaller scale to develop

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[470] Phase Two: Portfolio Benefits Evaluation Report, Feb 2021, Mainsheet Capital, p. 22

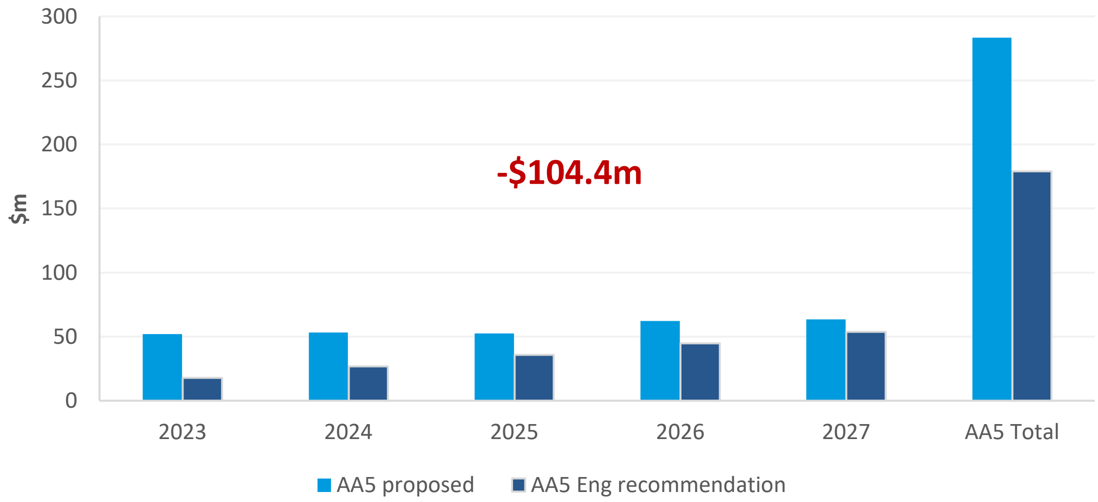
greater understanding, capability and supporting processes for the greater SPS program in regulatory periods to come.

Our recommendation includes a reduction in total SPS units from 1583 actual units[471] to 1010 actual SPS units, representing a 36.2% reduction (-$102.56m[472]) in CAPEX from that proposed by Western Power. To determine these volumes, we have applied a 10% increase from last year of AA4 to first year of AA5, then a linear ramp from the last year in AA4 to the first Year in AA6. This results in 1010 SPS units in AA5, allowing for WP to test its current processes in the immediate term, support the WA Govt SPS rollout ambitions of 850 units in Western Power's network over AA5 and scale up the delivery capability to for the planned AA6 annual SPS installation volumes.

Engevity also recommends that costs that are consequential to SPS CAPEX program be reduced proportionally to Engevity's proposed reduction in CAPEX of 36.2%. Such costs include, NRO for line decommissioning, ICT CAPEX and OPEX required to support the SPS program, and O&M OPEX for SPS units.

The financial adjustments associated with our review recommendations are summarised in the figures below.

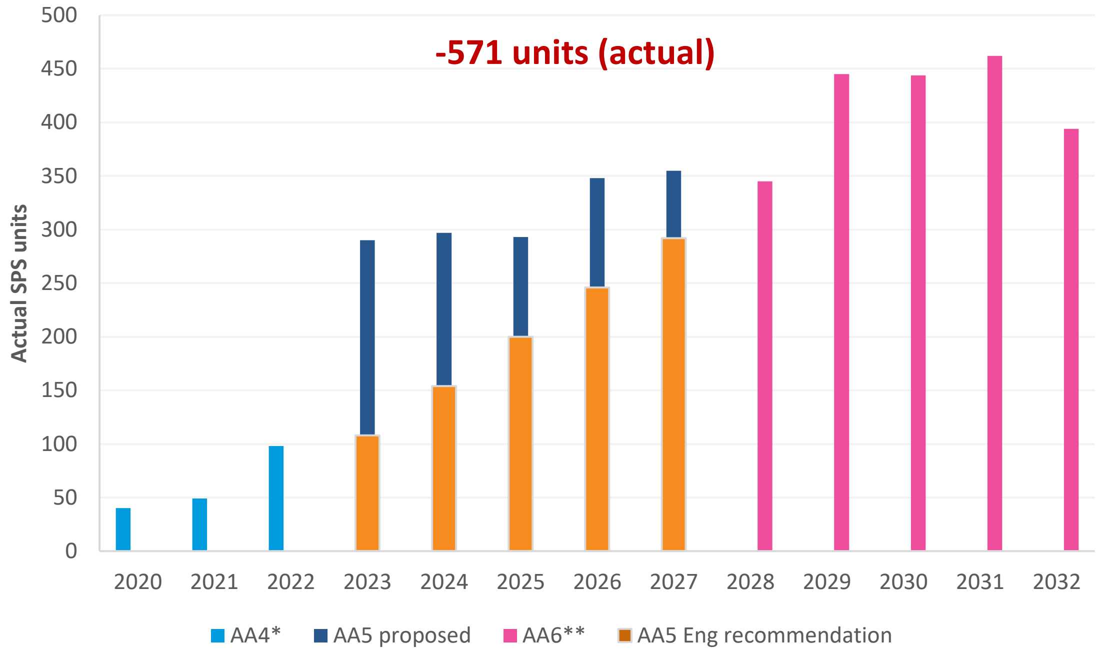
Figure 8–3: Proposed v Recommended CAPEX



471 Western Power proposes 1861 SPS units or equivalent in AA5, of which 15% are expected to be supply abolishment and therefore not actual SPS assets.

472 $2021 Real

Figure 8–4: Proposed v Recommended Volumes[473]



8.3.2 AA5 NFIT Assessment

Overview

Western Power has identified that is has an ageing Dx OH network with approximately 55 per cent of assets reaching end-of-life maturity in the next 10 years and therefore requiring replacement.[474] 40 per cent of Western Power's overhead Dx network by length serves less than 1 per cent of Western Power customers[475], resulting in high network costs per customer in these regions of the network where customers are supplied predominantly by radial, long rural feeders. Western Power has Western Power is proposing that a large-scale rollout of 1,861 stand-alone power systems (SPSs) or equivalent are deployed as an alternative to like-for-like replacement of OH Dx assets in this region of the network.

Western Power plans to transition 9,384 connections identified to be part of the SPS region or 'Autonomous Dx network' to SPSs, microgrids or supply abolishment over a 20-year period from 2021.[476] [477] This includes the transition of 4,000 connections by 2031, with 1861 SPS units or equivalent scheduled for AA5. Of these 1861 SPS units, 230 are planned to enable two microgrids and the development of the original Kalbarri microgrid.[478]

Western Power justifies the benefits of the SPS program on the basis that SPS units deliver better reliability and safety of supply outcomes to customers and that there are net benefits due to avoided

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473 *187 units to be delivered, c. 98 in 2022, 2020 and 2021 estimated. ** SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 4 (incl. assumed 15% PSA)

474 Network Opportunity Map 2021, p. 66; Distribution Structures Asset Management Strategy – December 2021, p. 4

475 Access Arrangement Information, 1 Feb 2022, Western Power, p. 35

476 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 11

477 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 2

478 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, 1 Feb 2022, Western Power, p. 55

maintenance and replacement expenditure for 40% of the OH Dx network in the autonomous region that is planned to be decommissioned over the 20-year program.[479]

The proposed base CAPEX for the AA5 SPS program is $283.34m, which represents 24.7% of total proposed AA5 REPEX[480] and a 641% increase on AA4 SPS CAPEX.[481]

Historical Context

Western Power has been considering the suitability of SPS systems for several years as a more economical solution to supplying customers in rural areas of its network as opposed to network rebuild.[482]

Over AA4, Western Power will have delivered 187 SPSs, the details of which are covered in section 7.5.2.

The 187 SPSs delivered in AA4 were delivered at an estimated base CAPEX of $38.2m and are expected to replace 771km of OH conductor and 3,563 poles.[483] Western Power identifies that as part of this commitment, 850 SPSs would be delivered by Western Power including those delivered in AA4.[484] This commitment is not currently supported by any legislative mandate.

Western Power now plans to scale up its SPS program to transition 4000 connections by 2031 as part of a 20-year program to transition the whole of its autonomous distribution network.

Need

Engevity recognises that SPS units represent a valid and potentially efficient alternative solution for consideration in Western Power's ongoing Dx asset replacement program.

Western Power has identified that it has an *'ageing Dx OH network with approximately 55 per cent of assets reaching end-of-life maturity in the next 10 years.'* [485] requiring substantial investment in either traditional replacement solutions or alternative approaches to maintaining quality supply to its Dx customers.

Stand-alone power systems (SPSs) are energy supply units that consist of solar PVs, a battery and a backup diesel generator (if required). [486] Western Power plans to deploy SPSs as an alternative solution to replacing and maintain OH Dx assets in areas of the grid where SPSs are found to be the least cost solution. [487] Western Power has identified a portion of its grid suitable for transition to SPSs and microgrids it terms the 'autonomous grid', which predominantly consists of a low density customer base served by long, radial OH conductors.[488] Western Power also refers to this as the 'Stand-alone power system (SPS) grid.[489] Western Power also plans to develop certain parts of this

479 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 3

480 Attachment 8.10 – Capital Expenditure Model, 29 April 2022, Western Power

481 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, 1 Feb 2022, Western Power, pp. 45-46

482 Attachment 5.8 – AA4 NFIT Compliance Summary – Stand-alone Power Systems, 1 Feb 2022, Western Power, pp. 4-5

483 Attachment 5.8 – AA4 NFIT Compliance Summary – Stand-alone Power Systems, 1 Feb 2022, Western Power, p. 20

484 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 2

485 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 41

486 Access Arrangement Information, 1 Feb 2022, Western Power, p. xii

487 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 55

488 Attachment 8.2 – Network Management Plan, Western Power, p. 30

489 Attachment 8.2 – Network Management Plan, Western Power, p. 30

network into microgrids which consist of a number of interconnected SPSs that can either remain connected to the grid or disconnected.[490]

Western Power justifies the need for SPSs is based on the future benefits related to cost efficiency for necessary network replacement, reliability and safety compared to traditional OH Dx replacement[491], noting that SPS would be deployed where they are the least cost solution.[492]

Engevity has expanded on the details of the need for SPSs in AA5 in the subsequent sections.

Network replacement

Western Power has identified that 28%[493] of its wooden poles and 2.84%[494] of its OH conductor will exceed their Mean Replacement Life (MRL) by the end of AA5. Of this, an estimated 30000 wooden poles and less than 500km of OH conductor exceeding their MRL are part of the autonomous grid.

Engevity notes that MRL is not the only input used by Western power to determine the need to replace an asset and so not all of the above assets beyond their MRL as identified by Western Power may need replacing in AA5.[495] Western Power also notes that approximately 52% of wooden poles are reinforced, which should also extend the technical and economic lives of these assets.

Western Power forecasts 19000 poles to be replaced through SPS program in AA5, making up 63 per cent of poles beyond MRL, if all poles replaced are beyond MRL autonomous feeders. It also forecasts 6415km of Dx conductor to be removed from service in AA5, implicitly due to SPS and undergrounding, accounting for c. 10 per cent of total Dx conductor in network. [496]

Engevity therefore believes there is justified need to consider some level of SPS deployment in AA5.

Reliability

Western Power believes SPS units improves reliability of supply to customers, as supported by preliminary data from SPS demonstration projects. [497] [498] However, reliability metrics for long-rural customers over AA4 were strong and do not justify the need for SPSs on the basis of improving reliability network wide.

Rural Long SAIDI and SAIFI in AA4 met Western Power's SSBs and were close to their SSTs for the period. Western Power's rural long SAIFI improved on AA3 levels while its rural long SAIDI marginally declined on AA3.[499] Western Power cites SPS rollout as a contributing factor to improved SAIFI performance, especially the Kalbarri Microgrid to manage on of Western Power's worst performing feeders.[500] Western Power also states that its AA4 investment practices have enabled an industry level standard of reliability and that customers are happy with this level of reliability and do not see value additional investment to improve reliability. [501]

490 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 46

491 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 3

492 Access Arrangement Information, 1 Feb 2022, Western Power, p. xii

493 Attachment 8.2 – Network Management Plan, Western Power, p. 137

494 Attachment 8.2 – Network Management Plan, Western Power, p. 144

495 See Asset Management Strategy

496 Access Arrangement Information, 1 Feb 2022, Western Power, p. 169

497 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 35

498 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, pp. 21-22

499 Access Arrangement Information, 1 Feb 2022, Western Power, p. 83

500 Access Arrangement Information, 1 Feb 2022, Western Power, p. 84

501 Access Arrangement Information, 1 Feb 2022, Western Power, p. 71

As a result, while Engevity recognises that there may exist hot spots of unreliability, Western Power's overall reliability for the autonomous network is stable and meeting standards. Customers also seem to be content overall with current standard and level of investment to support reliability. Therefore, reliability requirements are not relevant as a justification to support the need for large scale SPS rollout.

Engevity highlights that climate change impacts are an increasing risk to network reliability. This can contribute to factors such as bushfire risk, which has been materially increasing for the Western Power network over recent years. The DFES has declared around double the total fire ban days over 2021 and 2022 as compared to 2015/16.[502]

Safety

Western Power has identified an increasing trend of pole top fires in the Dx OH network[503], a safety issue that would be avoided with the replacement of this network with SPSs. However, Western Power has little data to date to forecast the safety incidents experienced or avoided as a result of SPS deployment replacing OH Dx network.

As such, Engevity does not find improved safety to be a strong justification for the need for the AA5 accelerated roll-out SPS program.

Government commitment and network strategy

In 2021, the Government of Western Australia made a commitment for Western Power and Horizon Power to deliver 1,000 SPSs by 2025.[504] However, there is not currently any legislation or mandate from the Government that mandates Western Power to deliver any number of SPSs over AA5.

Similarly, Western Power positions the SPS program as a requirement to enable a 'modular grid' in line with its grid strategy.[505] Engevity supports prudent long-term planning by networks but emphasises that network investments must meet the NFIT to be deemed efficient, of which alignment with corporate and network strategy is one consideration of many.

Engevity therefore highlights that announced Government commitments and alignment with a 'modular grid' strategy do not in themselves justify the need for scale of investment proposed in AA5.

Scope Definition

Engevity does not consider that Western Power has adequately justified the proposed scope of the AA5 SPS program and finds that the broader SPS program is inconsistently defined and lacks quantified justification. On this basis, Engevity recommends the scope of the AA5 SPS program should be reduced to limit inefficient or premature deployment of SPSs.

Western Power proposes to deploy 1861 SPS units or equivalent over AA5, consisting of:[506]

- 1,386 actual SPS units for the transition of individual connections;
- 244 customers negotiating a proactive supply abolishment (PSA);
- 230 SPS equivalents to enable microgrids.

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502 Access Arrangement Information, 1 Feb 2022, Western Power, p. 76

503 Attachment 8.2 – Network Management Plan, Western Power, p. 14

504 Energy Transformation Strategy Stage 2: 2021-2025, July 2021, Government of Western Australia, p. 14

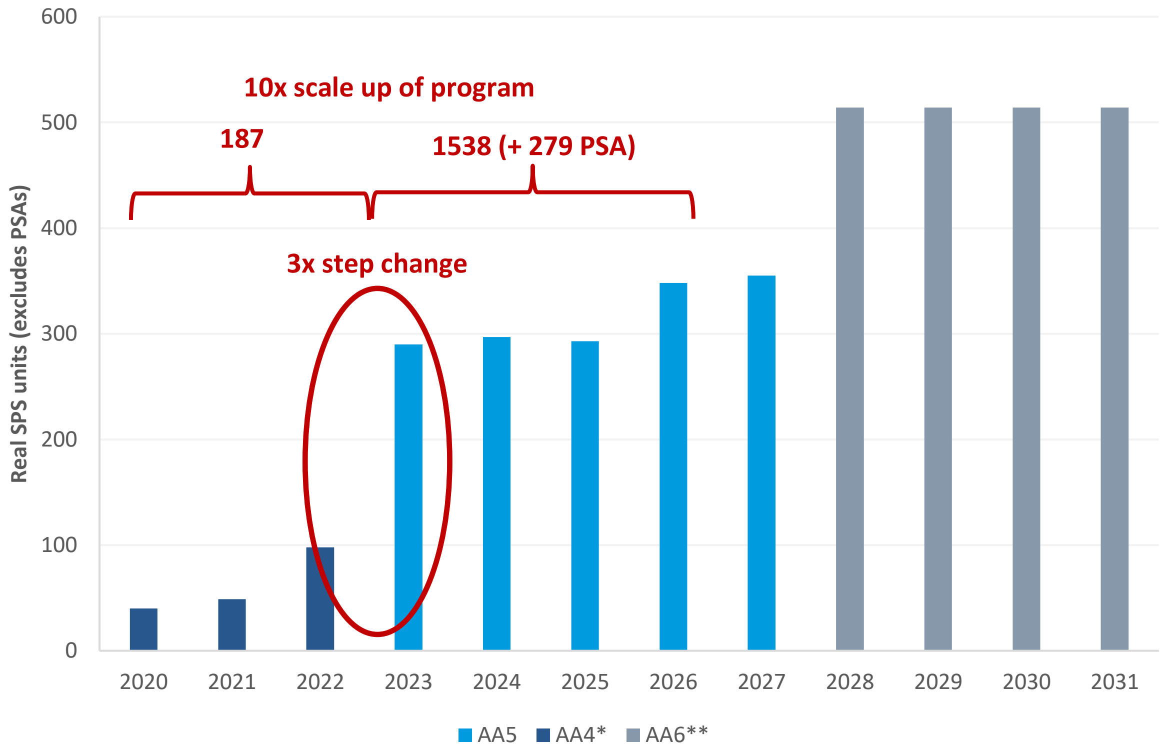
505 Access Arrangement Information, 1 Feb 2022, Western Power, p. 36

506 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 55

Western Power plans to transition 4,000 connections to SPSs or equivalent by 2031[507] as part of its broader SPS program to transition up to 9,384 customers to SPSs or equivalent across the entire autonomous network over a 20-year period.[508]

Western Power has not provided any models or business cases that justify the 1,861 SPS units planned for AA5 or support the broader SPS strategy. Engevity notes that these 1861 units represent a tenfold increase on the volumes of SPSs delivered in AA4, with the 290 actual SPS units planned for the first year of AA5 being almost three times the volume of SPSs delivered in the AA4 round 2 program over 2021 and 2022.[509]

Figure 8–5: Proposed SPS program[510]



Assuming the need for asset replacement at each location is valid, an SPS still represents the full decommissioning of the group of assets that make up a spur of Dx OH network, as well as disconnection of the customer from the interconnected network. Western Power provides little further explanation on the details of the scoping exercise.

The appropriateness of complete line removal and installation of SPS compared to like for like replacement of the specific aged assets on the line. Western Power has explained that they develop a whole-of- system NPC using the GTEng to inform the scope of the modular grid program.[511] No NPC analysis has been provided.

Engevity understands that Western Power's Future Grid model (Grid Transformation Engine or GTEng) is used to undertake whole-of-system NPC analysis to define an optimised modular grid

507 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 55

508 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 11

509 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, p. 20

510 *187 units to be delivered, c. 98 in 2022, split for 2020 and 2021 estimated, **4000 units by 2031 (incl. assumed 15% PSA)

511 ERA AA5 Walkthru#1 Modular Grid & SPS, Western Power, 2022, Verbal

program.[512] The scope of OH Dx network rebuild versus transformation to SPSs for end-of-life assets, including switchable sections of network identified for removal and replacement with SPSs, is also informed by Western Power's Asset Management Strategy Standard (AMSS). Engevity understands this system to be the decision-making tool that incorporates modular grid strategy and end-of-life asset management considerations as input and output investment pathways for SPS and Microgrids.[513] Engevity recognises that this approach is reasonable in theory but has been unable to interrogate or verify the assumptions, inputs or outputs. Given the early stages of SPS deployment in the Western Power network, Engevity is aware that such models may not currently capture all key factors relating to SPS investment efficiency and that many assumptions are likely to evolve with experience, both of which can substantially modify model results.

Engevity is concerned with the maturity of Western Power's SPS program planning and highlights that information on the overall SPS program, including timing and volumes, vary significantly between documentation with detailed analysis alluded to in but absent from the documentation provided. For example, the SPS program has been described or implied as being a 30-year program[514] [515], a 20-year program[516], an accelerated program[517] [518] or a 10-year transition[519], targeting between 6,000[520] and 9,384[521] connections over a plethora of documents dated from 2019 to early 2022. Western Power recognises that the extent of SPS opportunities will become more apparent as the program evolves.

Given the information provided, Engevity understands Western Power's proposal to be aligned with a 20-year SPS program, accelerated from a 30-year rollout, covering 9384 and informing a target of 4,000 connections by 2031. Engevity believes that the immaturity of Western Power's understanding of the total scope and benefits of the SPS program does not support the volumes proposed in AA5 for its initial phase. Instead, full scale rollout of the SPS program should be delayed until better understanding of project scope is developed and justified for AA6 and beyond.

Timing

Engevity found the proposed timing of the AA5 SPS program is overly aggressive without sufficient justification.

Engevity understands the AA5 proposal for 1861 SPS units aligns with a 20-year SPS program, which itself is accelerated from an original 30-year program. 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 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:[522]

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512 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, pp.7-10

513 Attachment 8.2 – Network Management Plan, Western Power, p. 134

514 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 14

515 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, p. 11

516 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 11

517 Access Arrangement Information, 1 Feb 2022, Western Power, p. 180

518 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 5

519 Stand-alone Power Systems Asset Management Strategy, Feb 2022, Western Power, p. 17

520 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 9

521 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 11

522 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 22

Aggressive assumptions need to be applied to justify SPS acceleration from a financial perspective. If more conservative assumptions are applied, a longer transition timeframe is likely to be optimal, whilst actively continuing to progress cost reductions and supply abolishment.

Mainsheet Capital identified that financial justification of an accelerated SPS program required a reduction of capital and maintenance costs of 30% and a PSA rate of 10% to achieve a pre-tax payback period of 11 years.[523] Engevity notes that the average unit rate[524] derived from Mainsheet Capital's costing of $881m ($2019)[525] for 6000 SPS units is $146,833 ($152,325, $2021), which is 32% lower than the Round 2 unit rates ($253,061, $2021)[526] and 18% lower than the average unit rate proposed for the AA5 program ($178,992 FY21/22 base dollars).[527] Western Power targets a PSA rate of 15% for the AA5 period, but has not demonstrated how this may be achieved, noting that only 4% of connections in AA4 Round 2 were PSAs.[528]

Furthermore, Western Power identifies several cost efficiencies that will likely increase with time and experience which would make delayed SPSs more cost effective, including reductions related to:

- technology costs curves;[529]
- market maturity;[530]
- maintenance efficiencies; and[531]
- decommissioning costs. [532]

As a result, Engevity found that current proposed SPS unit costs do not justify the proposed rollout speed for the SPS program and the timing of SPS volumes in AA5. Deferral of the AA5 SPS program would likely result in internal and external cost efficiencies being realised.

Risk Management

Risk management relating to the deployment of SPS units falls under Western Power's overarching approach to asset management and asset replacement strategies in the Dx network. These are explored in chapter 4 Asset management. Engevity has found systemic issues with Western Power's approach to asset and risk management resulting in potential premature replacement of network assets. Engevity views 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 Dx network to replace with SPSs when proposing further investment in AA6 and beyond.

Western Power targets SPS deployment for areas of the network with 'optimal balance of asset deterioration and cost efficiency'. Ideal deployment of SPS units is to replace all connection points on a feeder on which the majority of OH network assets replacement is needed. Western Power

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523 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 22

524 CAPEX, excluding indirect costs

525 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 15

526 Stand-alone power systems – Business Case Round 2, Nov 2020, Western Power, p. 2

527 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, p. 20

528 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 27

529 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 14

530 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 14

531 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 25

532 Stand-alone Power Systems Asset Management Strategy, Feb 2022, Western Power, p. 14

recognises that there will be assets on feeders identified for transition to SPSs that have not reached maturity, and that the residual value of such assets is factored into cost benefit analysis.

Western Power plans to undertake SPS roll out in stages as line asset replacements become required, continuing to undertake benefits analyses to scope future rounds that includes benefits of safety, reliability and NPC than like-for-like replacement.[533]

Western Power's end of life management for all autonomous Dx feeders is to consider conversion to SPSs or microgrid, as set out in the Distribution Overhead Network Rebuild Strategy.[534]

Western Power uses its Network Risk Management Tool (NRMT) to assess risk of asset failure on a periodic basis. The decision of repair or replace solutions is governed by the Network Rebuild Strategy[535], which includes the Dx OH Network Rebuild Strategy. Transformational rebuilds under the Network Rebuild Strategy are guided by Western Power's Grid Strategy, which incorporates Short Term Risk Management (STRM) and Asset Management Strategy Standard (AMSS). [536] [537] Engevity understands the STRM is concerned with short term solutions to manage risks when an asset or group of assets has not reached end of life while AMSS determines the appropriate replacement solution once replacement is deemed efficient.

Engevity supports Western Power's risk management approach in principle. However, it is not clear how it has been applied historically to inform the AA4 round 2 program or how it has been used to forecast the 1,861 SPSs proposed for AA5.

Engevity also recognises that in 2020 AMCL noted limitations in Western Power's asset risk management system that are highly relevant to replacement decisions for Dx OH assets, which are typically hard to monitor and survey resulting in reliance on statistical desktop analysis.

In general, Western Power's asset risk management system has been found to be generally well developed in past independent reviews, including by AMCL in its 2020 Asset Management System Review (AMSR).[538] However, a key recommendation from the 2020 AMSR was for Western Power to develop and implement a 'whole of lifecycle' cost assessment in its asset planning and investment processes, and that risk costs should also be better quantified and integrated, including in the Investment Gate Approval process. [539]

AMCL observed limitations in the areas of: …

- Use of whole of life cycle costing in asset planning and investment decisions (including understanding and quantification of risk costs and risk outcomes in transmission asset investment decision making).[540]

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533 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 55

534 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 47-48

535 Attachment 8.2 – Network Management Plan, Western Power, p. 141

536 Attachment 8.2 – Network Management Plan, Western Power, p. 134

537 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 47-48

538 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. v

539 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. vi-vii

540 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. 24

AMCL found that Western Power has not had a robust and consistent approach to whole of life costs or quantifying risk costs for projects, which would have a direct impact on the valuations of existing ageing OH Dx assets and lifetime valuations of SPS assets. In particular, AMCL provided by example that it is not evident whether:[541]

- value of Statistical Life is factored into safety risk outcome deliberations;
- value of Customer Reliability is factored into reliability and capacity investments;
- there is a value placed upon reputational risk impacts.

AMCL notes that inclusion of such risks is not simple but is being achieved by other Australian networks.[542] AMCL also found that “business cases and economic evaluations ... had little detail regarding operational cost impacts for the life of the proposed assets".[543] AMCL warned that such omissions from risk management analysis leads to qualitative decisions which remain “potentially frustrate the ability to objectively justify and prioritise different activities or investment decisions”.[544]

Engevity has not found evidence that these concerns have been addressed by Western Power for its AA5 proposal.

Western Power has developed a risk management strategy dedicated to its SPS program.[545] At this stage, the strategy is high level and likely to evolve as Western Power gains more experience in deploying and managing SPSs.

Cost Efficiency

Overall, Engevity found the SPS program has not been demonstrated to be not cost efficient due to comparatively high unit costs for the SPS units and lack of evidence that SPSs currently offer a more cost-effective solution for supply to customers that like-for-like replacement of OH Dx 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 Dx replacement costs or other benefits in AA5 or beyond.

Engevity explores each of these further in the sections below.

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541 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. 36-48

542 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. 42

543 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. 42

544 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. 42

545 Stand-alone Power Systems Asset Management Strategy, Feb 2022, Western Power

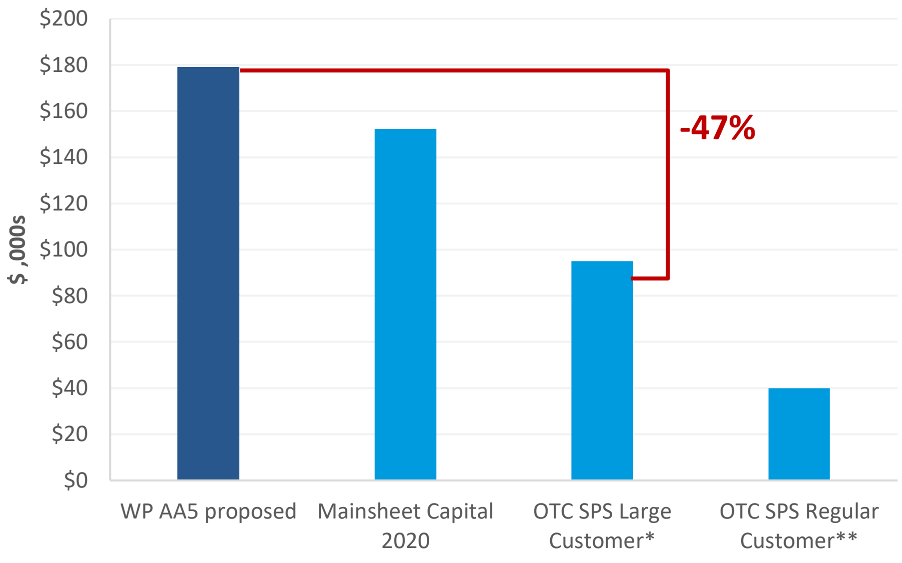
Unit Costs

Western Power forecasts an average unit rate for SPSs in its AA5 program at $178,992.[546] This figure is base CAPEX excluding indirect costs. Western Power has identified that *"within the autonomous region approximately 4,500 connections have an annual consumption of less than 5000kWhs and approximately 1800 connections have an annual consumption of less than 1000kWhs".*[547] In Engevity's experience, an average customer with a 5000kWh yearly consumption can be served by a 6.6kW PV array and a 10-20kWh battery depending on usage patterns. Market research on commercial SPS providers in Western Australia show that appropriate systems, including a diesel generator, can cost between $25,000-$40,000, before installation costs.[548] Example retail prices for larger units suitable for customers with a consumption around 14000kWh+ per annum have been found to start at $90,000-$95,000 including installation costs.[549] In comparison to these figures, Western Power's proposed average unit cost for AA5 of $178,992 for a bulk program of 1861 SPS units is much higher than expected given a customer should be able to get an equivalent systems over-the-counter for almost half the cost.

Western Power bases its AA5 unit cost forecast on the assumed unit costs from the AA4 round 2 business case with expected cost efficiencies applied across material, contractor and overhead costs.[550] It has not demonstrated how such unit cost reductions would be achieved.

Engevity also highlights that the average unit cost derived from Mainsheet Capital's NPC analysis for a 30-year SPS program of 6000 units is $152,325 ($2021).[551] Mainsheet Capital also stated that Western Power should be targeting up to a 30% reduction on these unit costs to justify an accelerated SPS program beyond the 30-year program originally found to have the lowest NPC. [552]

Figure 8–6: SPS unit cost comparisons[553]



546 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, p. 20

547 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 11

548 Commodore Independent Energy Systems, May 2022

549 Offgrid Energy Australia, May 2022

550 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, p. 20

551 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 15

552 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 22

553 * 14000kWh+ p.a., ** 5000kWh p.a. (excl. installation costs)

Engevity acknowledges the SPS program will require the transition of a range of customer sizes and that Western Power is currently on a learning curve to increase the efficiency of its overheads related to the rollout of SPSs. Western Power SPSs also include a number of additional components that may increase costs, including communication and monitoring equipment, and ancillary equipment. [554] However, Engevity understands that the majority of SPS procurement and capital work is undertaken by Western Power's SPS contractors and so unit costs would be an outcome of these contract negotiations.[555] Engevity has not been provided with a cost breakdown of Western Power's SPS units.

Engevity believes Western Power's SPS unit costs could be substantially reduced. At the least, Western Power identifies a number of cost efficiencies that will likely increase with time and experience which would make delayed SPSs more cost effective, including reductions related to:

- technology costs curves;[556]
- market maturity;[557]
- maintenance efficiencies; and[558]
- decommissioning costs, which are costed at $19,542/km and a focus of Western Power to reduce. [559] Decommissioning costs are not accounted for in the base capital SPS unit cost as they are defined as Non-Recurring OPEX.[560]

Cost to Serve SPS customers

Western Power has identified that its 2020 baseline cost to serve (CTS) for customers in the autonomous grid is $330,000.[561] The CTS measure is a greenfield 50-year NPC calculation per customer.[562] Western Power targets a 44% reduction of this CTS to $185,000 per customer by 2050 as a result of the SPS program. [563]

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554 Attachment 8.2 – Network Management Plan, Western Power, pp. 192

555 Attachment 8.2 – Network Management Plan, Western Power, pp. 192

556 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 14

557 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 14

558 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 25

559 Stand-alone Power Systems Asset Management Strategy, Feb 2022, Western Power, p. 14

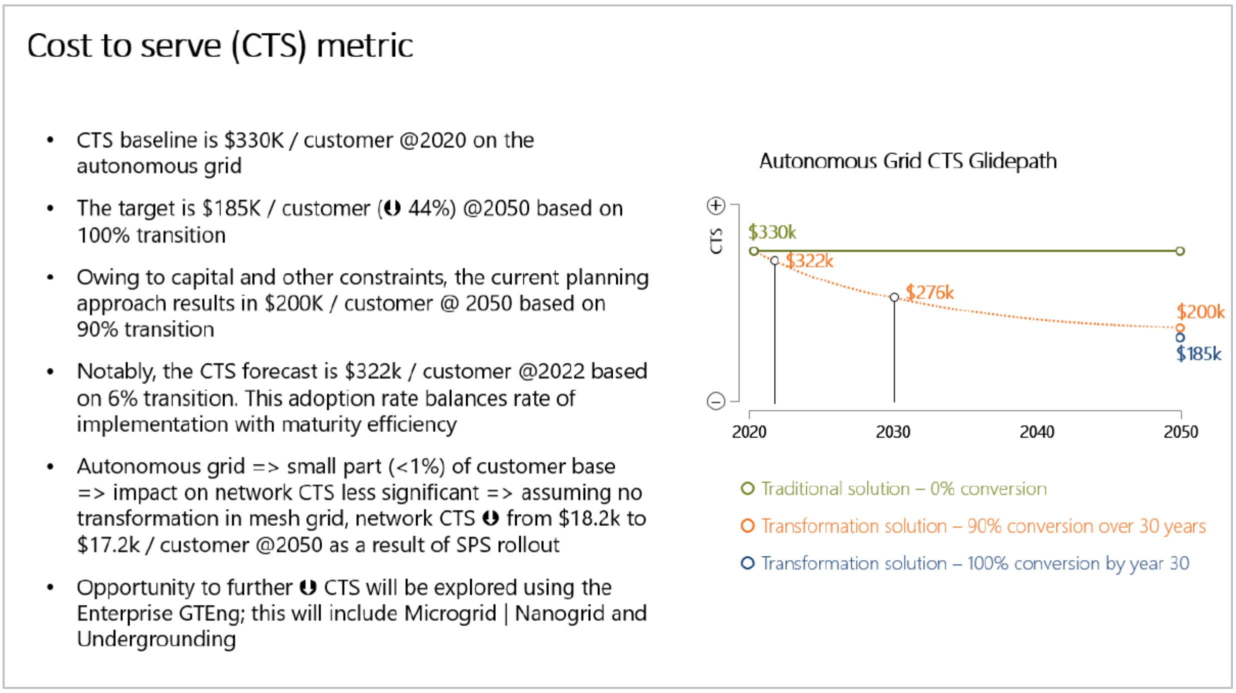
560 NFIT Compliance Summary – Stand-alone Power Systems, Feb 2022, Western Power, p.16

561 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, p. 11

562 Attachment 8.3 – Grid Strategy, Feb 2022, Western Power, p. xv

563 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, p. 11

Figure 8–7: Western Power Cost to Serve forecast for SPS customers



Engevity has not been provided with justification of the SPS program's impact on CTS for customers on the autonomous network. Engevity notes that Mainsheet Capital calculated 50-year NPCs for four sizes of SPS ranging between 6-37kWh of storage capacity at $183,682-$368,388 ($2021), before inclusion of Western Power overhead costs. Shown in the table below.

Table 8–10: Mainsheet Capital 50-year NPCs for SPS units

SPS Options	Mini	A	B	C
Energy Storage (KWh)	6	15	30	37
PV Capacity	20 panels	20 panels	20 panels	40 panels
Backup Generator	No	Optional	Included	Included
Indicative Footprint	20m x 15m	20m x 15m	20m x 15m	35m x 15m
Primary Connection	Fence + small pumps	Shearing sheds/small houses	Houses	Larger farms
Installed Cost*	$100,000	$155,000	$171,000	$195,000
Annual Maintenance	$1,500	$1,500	$2,500	$3,100
Replacement Cost	$40,600	$127,500	$154,100	$178,000
NPC – 50 year	**$179,500**	**$251,500**	**$311,000**	**$360,000**

* Installed Costs excludes WP Overheads estimated at 35% (Labour + LON + CDS)

These NPCs based on Mainsheet Capital unit costs, which Engevity notes are on average 18% less than Western Power's proposed AA5 unit costs, suggest the current SPS program may not be aligned with a reduction in CTS from this $330,000 baseline. That is, proposed AA5 unit costs could be similar or higher than baseline CTS per customer of complete replacement of traditional network in the absence of detailed justification to the contrary being provided.

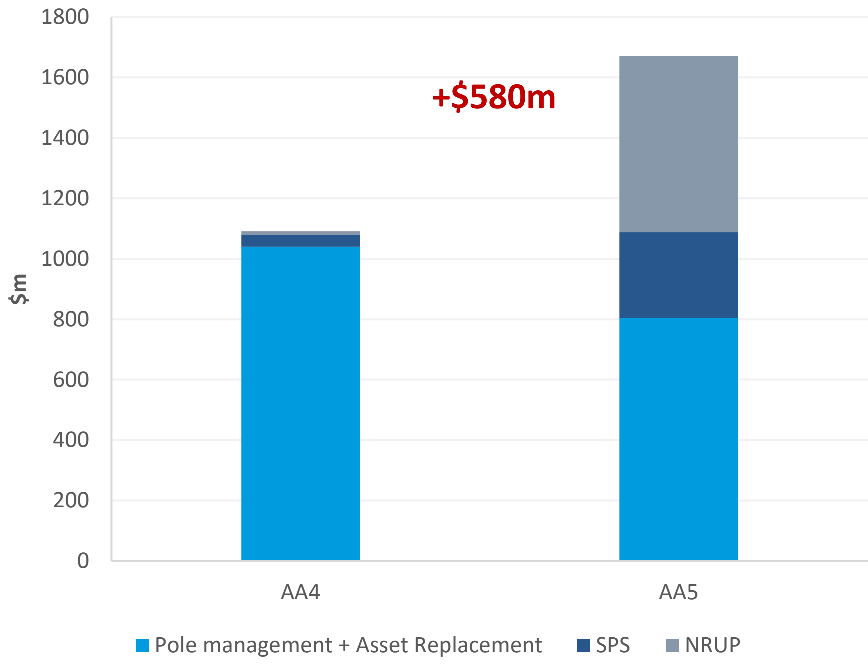
Expenditure benefits

Engevity has not been provided with a business case, NPC or NPV modelling to justify the 1861 SPS units or equivalent proposed for the AA5 SPS program. In principle, Engevity accepts and supports the potential benefits of SPSs and PSA to replace the need to maintain and replace large sections of OH Dx network. Mainsheet Capital found that, on completion, the SPS program could deliver savings of $66m a year in the distribution network.[564] However, while Engevity supports the logic behind these potential savings, it was unable to verify this analysis or how it applied to the proposed AA5 program.

Engevity understand the proposed AA5 SPS CAPEX of $283.34m is simply the proposed unit cost ($178,992) multiplied by the proposed 1582 actual SPS units. With no further detail or program planning provided, it is assumed that risk, escalations, and contingencies are included in this figure to the extent they are not categorised as indirect costs. Total proposed CAPEX for the AA5 SPS program, including real escalation and indirect costs, is $330.8m.[565]

The overall base CAPEX of $283.34m is not matched by commensurate reduction in Dx Repex for poles and wires which theoretically should be decommissioned within AA5 as a result. In its AA5 proposal, Western Power forecasts a decrease in Pole Management and general Asset Replacement distribution CAPEX of -$236.0m. However, it also forecasts an increase in SPS and NRUP CAPEX, being the key distribution programs replacing current Dx network infrastructure, of $815.9m.[566] Engevity sees this net increase of over half a billion dollars being at odds with the theoretical cost reductions from the avoidance of like-for-like replacement of substantial portions of Western Power's network from both programs.

Figure 8–8: Replacement direct CAPEX AA4 v AA5



564 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 46

565 Access Arrangement Information, 1 Feb 2022, Western Power, p. 199

566 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 45

Table 8–11: Western Power proposed AA5 Distribution CAPEX, $million real, 30 June 2022

Expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5
Pole management	77.7	77.9	67.1	70.1	69.9	362.7
Asset replacement	119.7	107.7	80.3	67.6	66.1	441.5
SPS	51.9	53.2	52.4	62.3	63.5	283.3
NRUP	70.5	97.8	138.4	137.8	138.9	583.4
Metering	60.9	59.0	65.6	58.2	53.4	297.0
Streetlight	10.0	10.0	10.0	10.0	10.0	49.9
Gross capex	**390.7**	**405.5**	**413.8**	**406.0**	**401.8**	**2,017.9**
Less contributions	27.3	35.5	45.5	54.4	56.4	219.2
AA5 capex to be added to the RAB	**363.4**	**370.0**	**368.3**	**351.6**	**345.5**	**1,798.7**

Engevity has not found any consistent indication of the beneficial impacts of the SPS program on Western Power proposed CAPEX. Western Power identifies only $5m reduction in Dx conductor management attributed to both NRUP and SPS.[567] Western Power ascribes $96m lower actual CAPEX spend in its AA4 conductor management replacement program to undergrounding and SPS.[568] However, Western Power states in the same document that it has not seen significant reduction in replacement costs due to SPS.[569]

Engevity must also note that the AA5 SPS program also requires contingent CAPEX and OPEX in ICT and material NRO in line decommissioning.

Western Power forecasts $18.9m in ICT CAPEX to meet DER integration needs in AA5, of which Engevity expects SPS management to be included.[570] Western Power also forecasts a step change in ICT OPEX of $19.5m in SCADA and Telecommunication OPEX to support SPSs, Cybersecurity and AMI and $6.4m in SPS specific maintenance.[571] [572]

Western Power also forecasts and additional spend of $70.7m in line decommissioning as a result of the AA5 SPS rollout. [573] At $19,542/km, this implies approximated 3618km of line removed. Again, the reductions in REPEX as a result of this removed line does not seem to be reflected in the balance between Dx REPEX and SPS and NRUP expenditure.

Not explicitly costed is O&M maintenance for SPS units. Engevity notes that Western Power will risk paying OPEX twice as a result of the SPS program. This would be due to the fact that Western Power will need new resources and systems for maintenance and repair activities of SPS units, yet the majority of the autonomous network will still be standing at the end of AA5 requiring most if not all current overhead OPEX costs to manage the existing network. There should be some reduction in traditional Dx OH maintenance OPEX due to the lines that are removed, however overhead costs that are not directly proportional to volume of assets, such as staff, ICT and fleet may largely stay the

567 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 50

568 Attachment 5.1 – AA4 Capital Expenditure Report, Western Power, p. 20

569 Attachment 5.1 – AA4 Capital Expenditure Report, Western Power, p. 9

570 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 83

571 Access Arrangement Information, 1 Feb 2022, Western Power, p. 147

572 Access Arrangement Information, 1 Feb 2022, Western Power, p. 138

573 Access Arrangement Information, 1 Feb 2022, Western Power, p. 169

same throughout AA5. This risk would persist into AA6 and beyond until facilities are rationalised. Western Power has not provided information on whether this potential OPEX double up has been considered in their SPS investment decisions.

Engevity recommends that NRO for line decommissioning, ICT CAPEX and OPEX required to support the SPS program, and O&M OPEX for SPS units be reduced proportionally to Engevity's proposed reduction in CAPEX of 36.8%.

Scope Efficiency

As discussed in section L.3.5 and L.3.6., Engevity has little information on the different options for scope and timing considered for the AA5 program but understands it is aligned with an accelerated 20-year program to transition up to 9384 customers.

Engevity does not believe the current scope to be the efficient option and recommends a reduced scope.

Strategic Alignment

Western Power's AA5 SPS program is well justified to be aligned with its grid strategy, corporate strategy and State Government commitments.

The SPS program is a core pillar of Western Power's Dx OH Network Rebuild Strategy, being a 'transformational rebuild' solution guided by Western Power's Grid Strategy. [574] The Grid Strategy defines a portion of Western Power's Dx network as 'autonomous' to be replaced by SPSs.[575]

Western Power's Corporate Strategy also focuses on the transition to a modular grid.[576]

Western Power proposes to deliver 880-1228 actual SPS units by the end of 2025.[577] This is aligned with the commitment made by the Government of Western Australia in 2021 for Western Power and Horizon Power to deliver 1000 SPSs by 2025.[578]

Customers are also generally receptive to the transition to SPSs[579] and Western Power finds customers are open to paying more for rolling out more SPS.[580]

Options Analysis

Western Power has not reasonably demonstrated appropriate options analysis to support investment in 1861 SPSs or equivalent in AA5 as it has not provided any detailed documentation or models relating to NPV or similar analysis.

Engevity recommends a reduction in scope based on the fact that some SPS are likely beneficial, with the first SPSs most likely to be deployed to areas of the network that are 'low hanging fruit' in terms of cost-benefit trade-offs. AA more gradual increase in the scale of the SPS program would enable experience and knowledge gained over AA5 toto be incorporated in a fully detailed and justified SPS program for AA6 to proceed with broader SPS program.

It is clear to Engevity that end-of-life consideration for autonomous and hybrid feeders, SPS and microgrids are considered as alternative options to like-for-like replacement or short-term risk

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574 Attachment 8.2 – Network Management Plan, Western Power, pp. 132-134

575 Attachment 8.3 – Grid Strategy, Western Power, p. x

576 Board Paper - 2022/23 Business Outlook – 10 years, 19 May 2021, Western Power, p. 1

577 AA5 Walkthru#1 – Modular Grid and SPS, April 2022, Western Power, p. 20

578 Energy Transformation Strategy Stage 2: 2021-2025, July 2021, Government of Western Australia, p. 14

579 Western Power Stand-alone Power System (SPS) Customer Research Report, Feb 2022, Viv Warren Consulting, p. 33

580 Access Arrangement Information, 1 Feb 2022, Western Power, p. 52

management solutions such as reinforcement. As part of this, Western Power has stated that it considers the medium and long term benefits of SPS deployment, including potential improvements in whole-of-life costs, safety, reliability, access to supply, and supporting decarbonisation of the economy. [581]

Engevity understands that Western Power's Grid Transformation Engine determines lowest NPC pathways for Western Power's network that informs the extent of transition to SPS over each regulatory period. However, no sufficient details of inputs, assumptions, outcomes or benefits analysis of such modelling have been provided to Engevity for us to verify the appropriateness of the AA5 SPS proposal.

Engevity acknowledges and supports that in principle the SPS program should deliver net benefits to customers and notes that the business cases for the AA4 round 1 and round 2 demonstrate a positive net benefit of SPS deployment over traditional like-for-like network replacement solutions, though these benefits were relatively modest for SPS rounds that were of substantially lower scale than the AA5 proposal.[582] As previously stated, Mainsheet Capital found that, on completion, the total SPS program could yield up to $66m a year in Dx cost savings for Western Power.[583]

Engevity highlights that business cases for the AA4 program demonstrate an options analysis comparing SPSs with traditional network replacement and a 'do nothing' delay replacement option. While a reasonable spectrum of options, Engevity is concerned that the option to delay replacement in certain parts of the network may not be efficiently considered as a result of overly conservative life span assumptions from Western Power's asset management strategy. This is discussed further in Chapter XX.

Western Power also considers proactive supply abolishment (PSA) as a potential alternative to SPS deployment in certain cases and where the customer is receptive. PSAs are negotiated on a case-by-case basis with Western Power offering a financial incentive for customers to abolish their supply where it is more economical than deploying an SPS. Western Power is targeting a PSA rate of 15% over the next 10 years and expects payments to be between $1k-$100k depending on the size and type of customer.[584] Given Western Power's forecast distribution of PSA payments, as shown in the figure below, Western Power estimates an expenditure of approximately $12m on PSAs over the next 10 years. PSA payments are not recoverable costs for Western Power.

Engevity supports Western Power's pursuit of PSAs where they are agreeable to the customer, as a PSA results in the same network benefit for Western Power as an SPS unit without the capital and ongoing costs. This is provided Western Power has or develops a stringent customer engagement and education approach such that customers are aware of the long-term impacts and responsibility for their energy supply following a PSA. The Electricity Industry Regulations Amendment (Stand-Alone Power Systems) Regulations 2021 required Western Power to develop an SPS Customer Engagement Strategy for this very purpose. [585]

Engevity notes that only 4%[586] of customers in AA4 round 2 were negotiating PSAs and that the 15% target is yet to be demonstrated as achievable. Engevity flags that failure to negotiate a PSA on a feeder targeted for transition to SPS would result in more SPS units being deployed. Western Power

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581 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 55

582 NFIT Compliance Summary – Stand-alone Power Systems, Feb 2022, Western Power, pp.9-21

583 Phase Two: Portfolio Benefits Evaluation Report, Feb 2021, Mainsheet Capital, p. 22

584 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 12

585 Electricity Industry Regulations Amendment (Stand-Alone Power Systems) Regulations 2021 Information Paper, 2021, Government of Western Australia, p. 2

586 Phase two: Portfolio Benefits Evaluation, Feb 2021, Mainsheet Capital, p. 27

may find their target network scope for AA5 reduced, and the cost to benefit ratio of the SPS program increased, if it cannot meet its target PSA rate.

Delivery Model

Engevity is not confident that Western Power has the capability to deliver three times or more SPS units per year in AA5 than currently being deployed in AA4 round 2. Engevity instead recommends an alternative 'scale up' approach instead of a step change approach to delivering large volumes of SPSs.

Currently, the design, supply, installation, commissioning, operation and maintenance of SPS units are managed by contractors to Western Power. [587] Western Power has undertaken a competitive tender for SPS turnkey solution providers and has a panel of multiple providers that have helped deliver SPSs in AA4. [588]

Western Power is still determining its delivery process and how it will manage large volumes of SPSs on its network, including internal processes, resourcing, ICT and risk management.[589] Western Power's SPS Asset Management Strategy itself states that *"The lack of maturity to deliver utility grade SPS at scale, is an ongoing risk."* [590] The SPS Asset Management Strategy sets out a number of risks and related strategy implementation projects Western Power believes are required to facilitate large-scale rollout of SPS units, as summarised in the figure below. [591]

587 Attachment 8.2 – Network Management Plan, Western Power, pp. 192

588 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Western Power, p. 55

589 Stand-alone Power Systems Asset Management Strategy, Feb 2022, Western Power, pp. 15-20

590 Stand-alone Power Systems Asset Management Strategy, Feb 2022, Western Power, p. 15

591 Stand-alone Power Systems Asset Management Strategy, Feb 2022, Western Power, p. 2

Table 8–12: Current challenges of Western Power's SPS program

Table 1.1: SPS asset management challenges and strategies

Key challenges	Summary of challenges	Strategy Implementation Project
Future obsolescence	Lack of SPS standardisation is a risk to Western Power's corporate objectives. Extended outage duration, increased cost and complexity to safely replace failed SPS components, in a sustainable way, is expected to emerge.	Standardisation of SPS design Reliability Centred Maintenance
Transition of SPS to WP workforce and BAU processes	Western Power inspections, maintenance, emergency response, financial & asset management are not routine, due to lack of business processes maturity and limited ICT systems integration for SPS.	SPS transition program ICT Systems Integration Remote Monitoring Standardisation of SPS design Introduction to Service Guideline
Limited operational visibility of SPS	Limited ability to remotely check if SPS is ON/OFF; check Battery/Solar/Generator operational status; condition monitoring based maintenance triggers.	Remote Monitoring ICT Systems Integration Advanced Metering Infrastructure
New technology	Limited knowledge of SPS asset management in Western Power and the wider industry network (e.g. failure modes, deterioration time, optimum maintenance frequency).	Reliability Centred Maintenance Performance Monitoring Introduction to Service Guideline

Engevity supports Western Power's structured approach to identifying the challenges and mitigation strategies for its SPS program. However, Engevity believes that overcoming the challenges identified is critical to laying the foundations for an efficient, long-term SPS program and recommends Western Power follows 'scale up' approach in AA5 aligned with their learning curve and to ensure the necessary processes, systems and efficiencies are in place prior to commitment to large scale rollout of SPSs in AA6 and beyond.

In addition to the challenges identified by Western Power above, Engevity also has concerns that there are shortcomings in Western Power's approach to sizing and scoping the components of SPS units for each customer. This risks supply of an SPS unit that at best is oversized over the 20-year lifespan of the asset or at worst does not meet the customers supply requirements and requires modification.

Engevity understands that Western Power determines the sizing of SPS units based on a customer's current and foreseeable energy use patterns via direct customer engagement. Engevity is concerned that Western Power's approach may have shortcomings related to:

- **Limited forward consideration of changing customer demand**. Engevity understands that SPSs sizing is a static decision-making process based on current customer needs and does not factor potential changes to customer usage patterns, such as uptake of electric vehicles or machinery, over the lifespan of the unit.

- **The need for back-up generators**. Western Power states that it includes a backup diesel generator in an SPS if it is deemed required. [592] Engevity notes that maintaining many remote diesel generators can result in high OPEX costs due to fuel costs and access times. Western Power's target for a minimum renewable energy rate for its SPS units of 75%[593] suggests that backup generators would be seldom used leading Engevity to question whether it may be more efficient over the long-term to simply upsize storage units, particularly as technology costs decrease.
- **Considerations of SPS deployment for customers that already have DER systems**. Western Power customer surveys have shown that a third of potential SPS customers already have solar PV systems.[594] It is not clear whether Western Power sizes an SPS to include such a customer's reduced energy demand, which then makes the customer responsible to maintain a portion of its energy supply themselves or ignores customer DER and includes redundant components in its SPS units.
- **The reticence of some customers to changing their consumption behaviour to suit an SPS unit**. Western Power customer engagement also found that some customers were not prepared to change their behaviours or energy efficiency to optimise the value of an SPS.[595] Customers have no additional incentive to change their energy consumption or usage patterns as a result of connecting to an SPS as opposed to a traditional connection and retail contract. It is not clear to Engevity how Western Power manages potential SPS customers that have consumption patterns that would require large margins of typical redundancy in an SPS.

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592 Access Arrangement Information, 1 Feb 2022, Western Power, p. xii

593 Stand-alone power systems – Business Case Round 2, Nov 2020, Western Power, p. 32

594 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 16

595 SPS Program Strategy FY23 – FY31, 1 Nov 2021, Western Power, p. 18

8.4 Depot Upgrade – AA5 Assessment

Engevity has reviewed Western Power's proposal for the AA5 period and found that it **DOES NOT COMPLY** with the Access Code requirements for an AA submission. We found that some expenditure **DOES NOT COMPLY** with the NFIT requirements or represent efficient expenditure. As a result, we have made recommendations for ERA adjustments in the table below.

8.4.1 Assessment

The forecast expenditure and scope for the Depot Upgrade Program is summarised in the table below.

Table 8–13: AA5 Expenditure and Scale – Depot Upgrade Program [$m real at 30 June 2022]

	Western Power AA5 Forecast Expenditure – Engevity Proposed					
Real Estate Program	**Yr1**	**Yr2**	**Yr3**	**Yr4**	**Yr5**	**Total**
Western Power Proposed Total Capex[596]	*25.0*	*39.0*	*61.3*	*10.2*	*10.3*	***145.8***
Western Power Proposed Direct Capex[597]	21.7	33.6	52.7	8.7	8.7	**125.3**
Adjustment	-	-8.1	-8.2	-5.7	-5.7	**-27.6**
Engevity Recommended Direct Capex	**21.7**	**25.6**	**44.4**	**3.0**	**3.0**	**97.7**

Assessment Overview

Table 8–14: Assessment Overview

Project/Program	**Distribution Augmentation**
Proposed Cost $m	Western Power propose to expend $130.5m in AA5 (excluding indirect costs) on corporate real estate, which is a $74.4m (-36 per cent) reduction on actual expenditure in AA4. Engevity has concern that this is further demonstration of the potential for overstating the forecast expenditure for AA5. Western Power has confirmed that the Depot Program is on track to achieve the financial benefits (OPEX $5.58m and CAPEX $4.48m) and that 'current forecast financial benefits for the Depot Modernisation Program remain unchanged from initial forecasts'[598] for the Depot Modernisation Program. However, Engevity notes that elsewhere Western Power state that the Depot Optimisation and Consolidation Program is expected to net $10.58m in

596 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'Capex Calcs' Column AF - AK

597 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'Capex Calcs', Column H - M

598 [redacted]

Project/Program	Distribution Augmentation
	reoccurring expenditure benefits[599]. Engevity was not able to verify the final figures in the documentation provided. Engevity was also unable to ascertain whether there was any duplication in forecasts between the real estate and cyber or corporate expenditure category. Engevity considers these differing figures and likely reduced expected benefits although impactful over the long term remain a positive and efficient outcome for customers.
Recommended Cost $m	Pursuant to Clause 6.51 of the Electricity Networks Access Code 2004, which outlines that forward-looking and efficient costs may include costs in relation to forecast NFITs for the access arrangement period which at the time of inclusion is reasonably expected to satisfy the test in section 6., Engevity has assess the unplanned or general depot expenditure specifically. Approximately $42.8m (32 per cent of the total Corporate Real Estate regulatory activity) of costs have been assigned to unplanned or general projects which appears high, whereas the large proportion of the expenditure forecast $98.3m (75 per cent) is targeted toward 8 separate depot modernisation projects. Engevity has not observed supporting justification for the second largest project which relates to *C0442080 - 41860258 - Depot Modernisation General*[600] which is estimated to be $27.6m. As a result, Engevity recommends removal of this expenditure. This reduction provides for a more prudent and reasonable allocation (~$15m) for unplanned or general depot related expenditure.
Need	Western Power first considered the Depot Optimisation and Consolidation Program (Depot Program) in AA4 and it has three main elements: • Depot modernisation Program – aim is to improve operational efficiency, rationalising depots in regional locations, improving safety and update ageing depots to meet current and future needs. • Facilities and Asset Management Program – this is unplanned expenditure, as well as ongoing expenditure for depots pre and post development. • Physical Security Program – focus is on enhancing physical security measures to protect our personnel, property and network assets. During AA5, Western Power plans further to modernise and rationalise ageing depots to meet current workplace safety practices and ensuring both cyber and physical security protection of critical infrastructure assets. Western Power has proposed ($125.3m / $145.8m) for corporate real estate with the majority relating to its depot program. The works are focused on three depots:

599 AAS - Attachment 5.5 - AA4 - NFIT Compliance Summary - Forrestdale Depot, page 38-39

600 [redacted]

Project/Program	Distribution Augmentation
	• Balcatta Depot (redevelopment). • Forrestfield Depot (new facility). • Picton Depot (redevelopment). The planned depot expenditure is stated by Western Power to be because of the facilities being beyond the economic life of the assets and necessary to overcome current operational inefficiencies concerns with the existing facilities. In addition, Western Power has also identified physical security and safety challenges with its current sites which it expects to rectify in the AA5 period. Western Power claims to be experiencing increasing incidents of unauthorised access which may create safety risks to the intruders as well as the workforce. This can potentially lead to financial, legal and reputation impacts. Engevity accept that the principle of modernising existing depots providing improved depot safety, better staff utilisation and less duplication in tasks is prudent.
Scope Definition	Western Power has listed 17 separate projects as part of it forecast expenditure for AA5 however we were unable to observe detailed assumptions underpinning these projects. [601] As an example, Western Power state that they intend on installing a 'GridLab' at South Metro Depot to test renewables, future technology and reduce reliance its external service providers. Many distribution and transmission networks have similar facilities as a way to manage and further understand the impact of the changing energy mix and emergence of new technologies. However, Engevity has not cited any details on scope and outcomes expected from this expenditure.
Timing	Despite some delays in the Depot Program, Western Power has confirmed the forecast benefits are somewhat unchanged from the original business case.
Risk Management	Western Power shared site inspection reports for some of the proposed depot upgrade which highlighted fair to poor conditions across some elements of the Depots commensurate with the age the sites.
Cost Efficiency	Forecast assumptions in AA5 have been developed using learnings and actual cost from previous projects, advice from external consultants and input from independent Quantity Surveyors. Although we again note our concerns with Western Power historically overestimating costs at the AA stage.
Scope Efficiency	Western Power state that they expect to move to a significantly reduced regional depot model at Merredin, Geraldton and Albany with potential repurpose depots such as Jerramungup, Kondinin, Koorda, Narrogin and Southern Cross depots.

601 [redacted]

Project/Program	Distribution Augmentation
Strategic Alignment	Despite Engevity suggested adjustments, the AA5 period has a large SPS program proposed, meaning there likely will be significant expenditure required in regional centres to account for this changing depot support function and need. Engevity has not observed this change in depot use cases to accommodate the Modular Grid and SPS program has been clearly identified in the AA5 expenditure plans.
Options Analysis	Western Power also outlines those alternate options are considered at an individual project level through 'business cases for each individual project, within the wider Depot Program, consider and evaluate alternate options, which informs the selection of a final recommendation for the individual depot consistent with the Investment Governance Framework'[602].
Delivery Model	We are of the opinion that, given the competitiveness of the construction market, an open tender will elicit a highly accurate cost for the development and construction of the new depot.

Findings

To establish our position Engevity has conducted a structured assessment of a sample of material issues, projects and programs to establish whether or not the investment proposed by Western Power satisfies the requirements of the NFIT. Our review is summarised below for the **Depot Program.**

Engevity has reviewed Western Power's proposed expenditure relating to the Depot Program and found that:

a. **The proposed expenditure is efficient** with the objective of minimising costs on the basis that Western Power has demonstrated continue savings from the program. Engevity has however not observed supporting justification for the second largest project which relates to [redacted] - *Depot Modernisation General*[603] which is estimated to be $27.6m. As a result, Engevity recommends removal of this expenditure.

b. **The program captures the available and realisable economies of scale and scope** by seeking to stage the depots and demonstration of how learnings from previous projects have been considered.

c. The proposed investment **is with reasonable expectations** of the level of future network services required by customers because the original strategy appears to be yield benefits without any impact to quality or network reliability. Our adjustment relates to a lack of justification of a general Depot Modernisation category.

d. **A reasonable range of alternative options has been considered** for the proposed investment, with the most appropriate solution chosen. This is shown by business cases provided that demonstrate Western Power considering alternative delivery options and evidence of governance processes being followed.

602 AA5-ENG32.05 - Depot Program - Alternative Options

603 [redacted]

e. Despite our concerns about [redacted] - *Depot Modernisation General*[604] expenditure forecast, **the benefits of the new facilities investment are reasonably expected to be recovered** by reduced CAPEX and OPEX benefits.

f. Despite our concerns about [redacted] - *Depot Modernisation General*[605] expenditure forecast, **the proposed investment does deliver an expected net benefit** over a reasonable period of time. This is evidenced by Western Power confirmation that the Depot Program is on track to achieve the financial benefits (OPEX $5.58m and CAPEX $4.48m) and that 'current forecast financial benefits for the Depot Modernisation Program remain unchanged from initial forecasts'[606] for the Depot Modernisation Program.

g. **The proposed investment is necessary to maintain the safety and reliability** of the network and its ability to provide the required network services.

Recommended Adjustment

Despite our concerns about [redacted] - *Depot Modernisation General*[607] expenditure forecast, and even with the expected reduced benefit, Engevity considers that overall the Depot Program will likely continue to meet the NFIT, generated by reducing overall CAPEX and a reduction in OPEX.

Pursuant to Clause 6.51 of the Electricity Networks Access Code 2004, which outlines that forward-looking and efficient costs may include costs in relation to forecast NFITs for the access arrangement period which at the time of inclusion is reasonably expected to satisfy the test in section 6., Engevity has assess the unplanned or general depot expenditure specifically.

Approximately $42.8m (32 per cent of the total Corporate Real Estate regulatory activity) of costs have been assigned to unplanned or general projects which appears high, whereas the large proportion of the expenditure forecast $98.3m (75 per cent) is targeted toward 8 separate depot modernisation projects. As a result, Engevity is recommending the Deport Real Estate Program be adjusted to $97.7m based on a lack of NFIT justification. This is a reduction of $27.6m relating to the [redacted] - *Depot Modernisation General* expenditure. This adjustment would enable Western Power to retain approximately $15m for unplanned or general depot projects which is more in line with industry practice.

Also of note, Engevity recommends that ERA seek to verify whether the outstanding property disposal proceeds calculated to be $127.57m[608] are included in AA5 forecasts. ERA are recommended to review this before making its determination.

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604 [redacted]

605 Ibid

606 [redacted]

607 Ibid

608 [redacted]

8.5 Replacement Program (Tx AND Dx) - AA5 Assessment

8.5.1 Summary of Assessment

Engevity has reviewed Western Power's proposal for the AA5 period and found that it **DOES NOT COMPLY** with the Access Code requirements for an AA submission. We found that some expenditure **DOES NOT COMPLY** with the NFIT requirements or represent efficient expenditure. As a result, we have made recommendations for ERA adjustments in the table below.

Assessment Overview

The forecast expenditure and scope for the replacement program is summarised in the table below.

Table 8–15: AA5 Expenditure and Scale – Replacement program (Tx and Dx) [$m real at 30 June 2022]

Replacement program (Tx and Dx)	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Proposed						
Dx[609]	*146.43*	*136.29*	*104.94*	*91.10*	*90.12*	*568.88*
Tx	*73.56*	*72.44*	*65.24*	*64.93*	*66.92*	*343.09*
Total CAPEX	*220.00*	*208.73*	*170.17*	*156.03*	*157.04*	***911.96***
Western Power Proposed						
Dx[610]	126.73	117.67	90.29	77.63	76.12	488.44[611]
Tx	63.55	62.38	55.94	55.09	56.22	293.17
Total Direct CAPEX	190.27	180.05	146.23	132.71	132.34	**781.60**
Adjustment						
Dx[612]	-16.18	-15.02	-11.53	-9.91	-9.72	**-62.35**
Tx	-18.49	-18.15	-16.28	-16.03	-16.36	**-85.31**
Total Direct CAPEX	-34.67	-33.17	-27.81	-25.94	-26.08	**-147.66**
Engevity Recommended						
Dx[613]	**110.55**	**102.65**	**78.76**	**67.72**	**66.40**	**426.09**
Tx	**45.05**	**44.22**	**39.66**	**39.06**	**39.86**	**207.86**
Total Direct CAPEX	**155.60**	**146.87**	**118.42**	**106.78**	**106.26**	**633.95**

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609 Total CAPEX Dx excludes replacement CAPEX for the SPS, NRUP, metering and wood pole management programs, which have been assessed separately in this appendix. However, these programs are also scoped through the same processes used to define Western Power's general replacement program and so are important to include when examining trends in expenditure. Where Engevity makes recommendations for adjustments to Tx and Dx replacement program expenditure, it excludes these programs and their CAPEX as they have been examined in detail separately.

610 Direct CAPEX Dx excludes replacement CAPEX for the SPS, NRUP, metering and wood pole management programs, which have been assessed separately in this appendix. This direct CAPEX is all direct replacement CAPEX besides that proposed for the aforementioned programs. Any recommendations for adjustment to Western Power's overall replacement program also excludes adjustment to these programs as recommendations have been made for these programs separately.

611 Attachment 8.10 – Capital Expenditure Model – Public, Feb 2022, Western Power, Capex Calcs

612 This adjustment to direct CAPEX Dx excludes adjustment to the replacement CAPEX for the SPS, NRUP, metering and wood pole management programs, for which recommendations have been made separately in this appendix.

613 This adjustment to direct CAPEX Dx excludes adjustment to the replacement CAPEX for the SPS, NRUP, metering and wood pole management programs, for which recommendations have been made separately in this appendix.

Replacement program (Tx and Dx)	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Volumes						
Dx	18,089	19,349	20,984	20,936	20,892	100,250
Tx	253	255	269	275	269	1,321
OPEX						
Dx	168.6	170.7	173.4	177.2	180.6	870.5
Tx	54.7	54.6	55.3	55.9	56.5	277.0

Table 8–16: Summary of Preliminary Findings

Project/Program	Replacement program (Tx and Dx)
Proposed Cost $m	488.4 (Dx) 293.2 (Tx)
Recommended cost $m	426.1 (Dx) (-12.8%) 207.9 (Tx) (-29.1%)
Need	The replacement program manages aging network assets, particularly poles in Dx network.
Scope Definition	Western Power's total replacement program considers many subprograms, including wood pole NRUP, SPS and metering, which all constitute solutions to replacing the existing network assets currently required to maintain supply. These subprograms have been assessed separately, and therefore this section relates only to general Dx and Tx replacement expenditure that falls outside of these defined subprograms. Total Dx replacement direct expenditure in AA5 is 55.1% more than AA4. This is a large step change, mostly driven by SPS and NRUP. Proposed Dx asset replacement outside of major subprograms is $488.4m[614], 12.8% greater than AA4 expenditure across equivalent categories ($426.09m[615]). Total Tx replacement direct expenditure in AA5 is 43.4% higher than AA4.
Timing	Western Power replacement rate is high in comparisons between networks replacement rates. For example, wood poles are replaced at a much higher (approximately 5 times) rate of unassisted pole failures as a legacy of the pole condition, ground and strength rating issues raised in the Wood Pole Order.
Risk Management	Western Power's risk management process seems to have a fundamental bias towards forecasting increasing asset failures, leading to potential overspend on replacement of assets that are not yet mature. Issues include:

614 Attachment 8.10 – Capital Expenditure Model – Public, Feb 2022, Western Power, Capex Calcs, Asset Replacement excl. SPS, NRUP, Metering, SUPP and Wood Pole Management.

615 Attachment 11.1 – AA5 Regulatory Revenue Model – Public, Feb 2022, Western Power, Dx_Inputs, Asset Replacement

Project/Program	Replacement program (Tx and Dx)
	• Forecast methodology and inherent bias to meet compliance standards (In all cases, Western Power is over performing on compliance requirements which implies that there they may be a higher rate of replacement than necessary). • The asset failure forecast models appear to apply a strong upward trend predicted failures due to the functions calculated within statistical tools such as mintab and R. Our analysis shows that failures almost universally trend upward, even with flat or declining historical failure trends. This indicated an overweighted reliance on asset age in the failure function.
Cost Efficiency	Unit costs of assets range from high to low. Further benchmarking against other networks, using the AER RIN data will be conducted to verify specific asset types that are unusually high or low.
Scope Efficiency	The scope of the replacement program is efficient where it balances the timing of replacement against the criticality of the asset, consequence of asset failure and known condition information for the assets. Many assets can be maintained in service until functional failure or condemned via inspection criteria. We consider that Western Power's analytical approach to forecasting failures will tend to overstate replacement needs within most asset categories.
Strategic Alignment	A large portion of replacement CAPEX has been reallocated from maintenance programs to transformation programs, which is aligned with Western Power grid vision and network rebuild strategy.
Options Analysis	Western Power assesses replacement needs using a thorough methodology which includes: • Risk and economic life of assets in end-of-life assessments • Options for Short-term risk management, conventional rebuild (slow or clustered) and transformational rebuild Engevity notes that this approach to options analysis needs further interrogation to ensure there is no bias towards network build over lower cost maintenance or efficient delay or major works.
Delivery Model	Western Power details a delivery model and key risks for each of its network programs in its network delivery strategy.

8.5.2 Findings

Engevity has reviewed Western Power's proposed expenditure relating to the overall transmission and distribution replacement program and found that:

a. **The proposed expenditure is not efficient** with the objective of minimising costs on the basis that Engevity believes the need for asset replacement has been overstated and as such assets are likely being replaced before becoming mature.

b. **The program captures the available and realisable economies of scale and scope** as Western Power's risk assessment process and GTEng model provide a whole-of-life cycle and whole-of-system economic assessment to inform the extent of replacement required.

c. The proposed investment **is not consistent with reasonable expectations** of the level of future network services required by customers because customers expect that existing infrastructure will be utilised to its fullest extent before expenditure is incurred to replace it.

d. **A reasonable range of alternative options has not been considered** for the proposed investment, with the most appropriate solution chosen. It is not clear what alternative options Western Power has assessed to determine the scope of its replacement program. Engevity believes that the alternative to delay some investment has not been adequately considered.

Engevity therefore recommends a reduction of 12.8% to total distribution replacement expenditure and a reduction of 29.1% to total transmission replacement expenditure to align each with AA4 levels. For transmission, this represents a $85.3m reduction to direct replacement CAPEX. For distribution, this represents a $280.2m reduction to direct replacement CAPEX.

8.5.3 AA5 NFIT Assessment

Introduction

Western Power's replacement CAPEX program covers all expenditure deemed required by Western Power to replace network assets that are at end-of-life and result in unacceptably high risk to Western Power's ability to maintain reliable supply.

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.[616]

Western Power proposes $293.2m in direct Tx REPEX, a 43.4% increase on AA4 direct Tx REPEX. Western Power proposes $2017.9m in direct Dx REPEX (including the SPS and NRUP programs), a 55.1% increase on AA4 Dx REPEX. Both Western Power's transmission (Tx) and Distribution (Dx) replacement programs themselves consist of a number of sub-programs. Engevity is not convinced these large increases on AA4 replacement expenditure is efficient. Engevity notes that the increase in Dx REPEX is mostly attributable to the SPS and NRUP program, which are largely scaled up from AA4. However, Engevity would expect that the replacement of traditional OH assets as a result of this program would be reflected in a commensurate decrease in pole management and asset management REPEX, which does not seem to be the case in the AA5 proposal.

Engevity has included Western Power's proposed replacement CAPEX for each Tx and Dx sub-program below. Engevity notes that Western Power allocates REPEX across REPEX categories in their CAPEX and regulatory models.

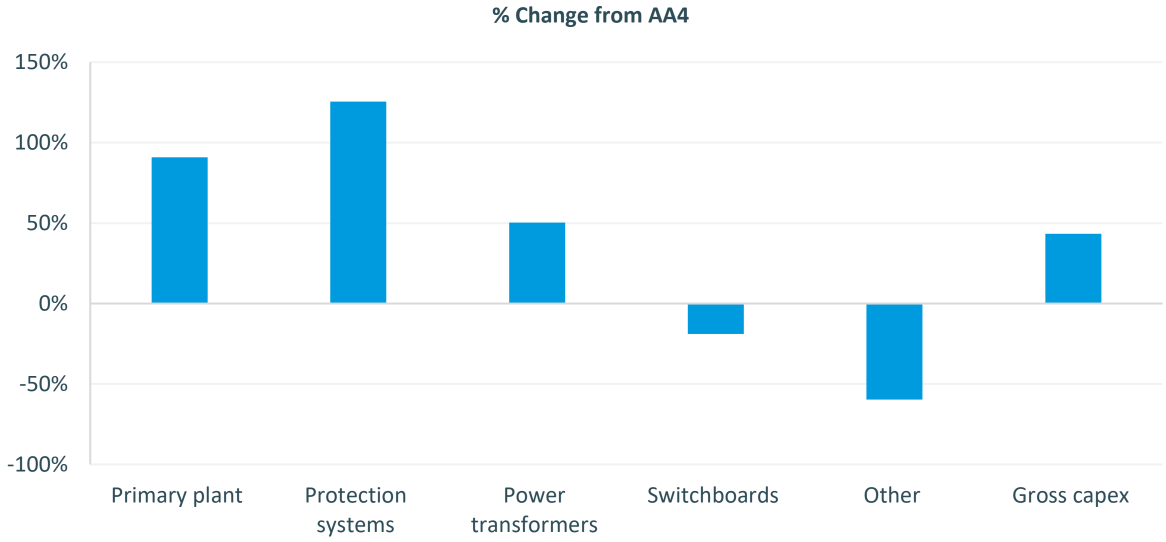
Table 8–17: Transmission replacement direct CAPEX by program - AA4 v AA5

Expenditure category	AA4 Period total	AA5 Period total	% Change from AA4
Primary plant	60.3	115.1	90.90%
Protection systems	33.2	74.8	125.40%
Power transformers	42.9	64.5	50.30%
Switchboards	27.8	22.5	-19.00%
Other	40.3	16.3	-59.60%
Gross CAPEX	**204.4**	**293.2**	**43.40%**

616 Attachment 8.1 – AA5 Forecast Capital Expenditure Report, Feb 2022, Western Power, p. 23

Source: Attachment 8.1 – AA5 Forecast CAPEX Report, Feb 2022, Western Power, p. 24

Figure 8–9: Transmission replacement direct CAPEX by program - AA4 v AA5



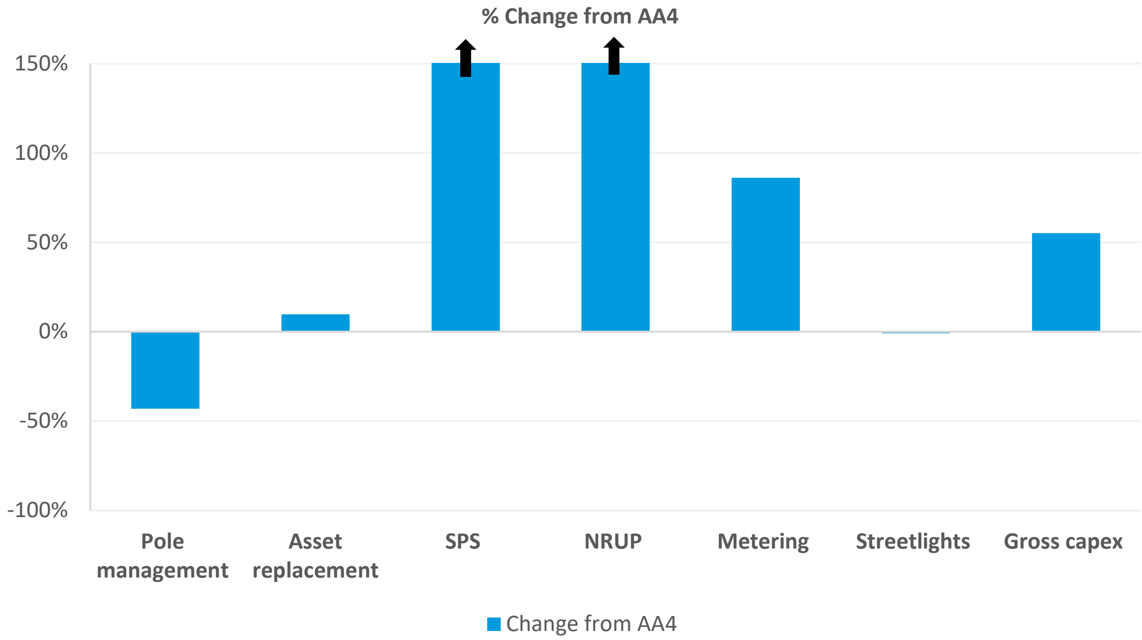
Source: Attachment 8.1 – AA5 Forecast CAPEX Report, Feb 2022, Western Power, p. 24

Table 8–18: Distribution replacement direct CAPEX by program - AA4 v AA5

Expenditure category	AA4 Period total	AA5 Period total	Change from AA4
Pole management	637.7	362.7	-43%
Asset replacement[44]	402.5	441.5	9.7%
SPS	38.2	283.3	641%
NRUP	12.6	583.4	4,520%
Metering	159.6	297	86%
Streetlights	50.4	49.9	-0.9%
Gross CAPEX	**1,301.1**	**2,017.9**	**55%**

Source: Attachment 8.1 – AA5 Forecast CAPEX Report, Feb 2022, Western Power, p. 43

Figure 8–10: Distribution replacement direct CAPEX by program - AA4 v AA5



Source: Attachment 8.1 – AA5 Forecast CAPEX Report, Feb 2022, Western Power, p. 43

Assessment

Engevity's primary concern relating to Western Power's general replacement program is its approach to risk management and the identification of assets to be replaced. Although Engevity has not been able to interrogate the core systems and models that forecast replacement requirements, from the information provided, Engevity found Western Power's risk and failure forecast algorithms consistently output increasing asset risk and failures over almost every Tx and Dx asset category. This is not consistent with the experience of other networks in which each asset class follows different failure curves, e.g. bath tub curves or flat with random events.

As a result, this suggests a systemic issue of Western Power prematurely replacing Tx and Dx assets resulting in higher costs to customers. Engevity therefore recommends a reduction to Western Power's Tx and Dx replacement CAPEX and Western Power should review the aggressiveness of its failure rate functions. Western Power should focus on monitoring performance of existing assets to optimise their technical and economic life rather than pursuing an aggressive replacement program where risk is overstated.

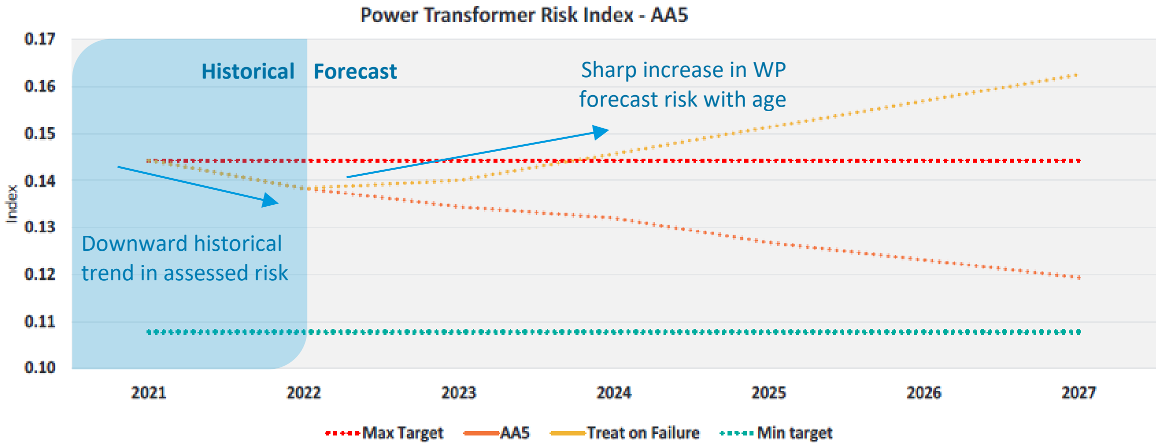
This issue has flow on effects influencing the need, scope, timing and cost efficiency of Western Power's AA5 Tx and Dx replacement sub programs, including the proposed SPS and NRUP programs.

Further detail and evidence

The figure below from Western Power's Network Management Plan plots the risk index of Western Power's power transformers from 2021 to 2027, the end of AA5.[617] This figure provides an example of the trend of risk or failure growth forecast by Western Power across AA5 historical failures being below targets and, in some instances, decreasing.

617 Attachment 8.2 – Network Management Plan, Feb 2022, Western Power, p. 344

Figure 8–11: Western Power power transformer risk index



As part of our assessment of this program, Engevity has analysed the trends in forecast failure rates of Western Power's Tx and Dx asset classes and how the actual failures of each asset class compare to Western Power's asset management targets.

Engevity's key findings are:

- Failure rates without Western Power network intervention are expected to increase over almost all Tx and Dx asset classes. In some cases, the failure rates are 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 suggests there is 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.
- Overall, the replacement program is a very significant component of any network CAPEX forecast. A systemic bias to over forecasting the risk and volume of failures across many asset categories can create a significant overstatement of asset requirements – even if the underlying assumptions are consistent with expert opinion and the logic of the forecasting process appears sound. This is highlighted in the AER's 2010 review of ETSA Utilities (now SA Power Networks) that included a 49% reduction to the replacement forecast due to systemic failure modelling imprecision.
- The AER's consultant, Parsons Brinckerhoff, noted that:

  *"With regard to the modelling presented, the SKM report outlines a purely age-based replacement scenario, **indicating that approximately $6b in assets exceed their assumed lives**. In contrast, the PB report identifies a purely **age-based replacement backlog in the order of $417m**. The difference between the two estimates highlights the sensitivity of age-based replacement models to the input assumptions about asset lives, replacement unit costs, and the specific modelling methodology adopted"*[618]

For the revised proposal ETSA Utilities engaged EA Technologies to apply their internationally deployed proprietary Condition Based Risk Management tool to the circuit breaker asset class. Upon regulatory scrutiny, it was established that the tool was unreasonably configured to rapidly increase failure risk over relatively short periods for older assets - regardless of the field condition information. Parsons Brinckerhoff noted that:

618 Parsons Brinckerhoff, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p 52

"EAT has acknowledged ***the absence of supporting data to define the shape and absolute magnitude in the 'wear out' phase****… … Despite the lack of supporting data, EAT has* ***assumed a cubic function to approximate the failure behaviour in the wear out zone based on 'a combination of mathematical modelling and pragmatism'*** *and used this to conclude that the probability of failure would increase by a factor of 10 over 5-10 years"*[619]

- Engevity recognises 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 will 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 can be coupled with properly calibrated predictive tools to further refine the forecasting approach – indeed that is what most network businesses do.
- Following the ETSA Utilities determination, the AER developed its Repex model as a top-down evaluation of replacement expenditure for regulatory purposes to avoid the need to engage and understand the different black box models that the NEM networks were employing to forecast replacement CAPEX requirements. Again, this is largely an age-based model, with calibration for recent replacement trends and implied unit costs based on the historical quantity and cost information provided by the businesses. Whilst the model has been subject to significant critique, it does place greater weight on the actual 'revealed' replacement decisions of the business rather than the output of a predictive black box model (that is likely to overweight age as a driver for failure volumes/risk based on known, or vendor proprietary forecasting algorithms).

Analysis

Figure 8–12 and Figure 8–13 map the forecast percentage increases or decreases in asset failures per annum without Western Power intervention between June 2020 and June 2027 for its Tx and Dx network assets respectively.[620] Engevity highlights those projected failures for almost all asset categories increase, some markedly so.

619 Parsons Brinckerhoff, *Review of ETSA Utilities revised regulatory proposal for the period July 2010 to June 2015,* pp. 9-10

620 Analysis derived from Western Power figures: Attachment 8.2 – Network Management Plan, Feb 2022, Western Power, pp. 283, 301-302

Figure 8–12: Transmission assets - forecast unassisted failures

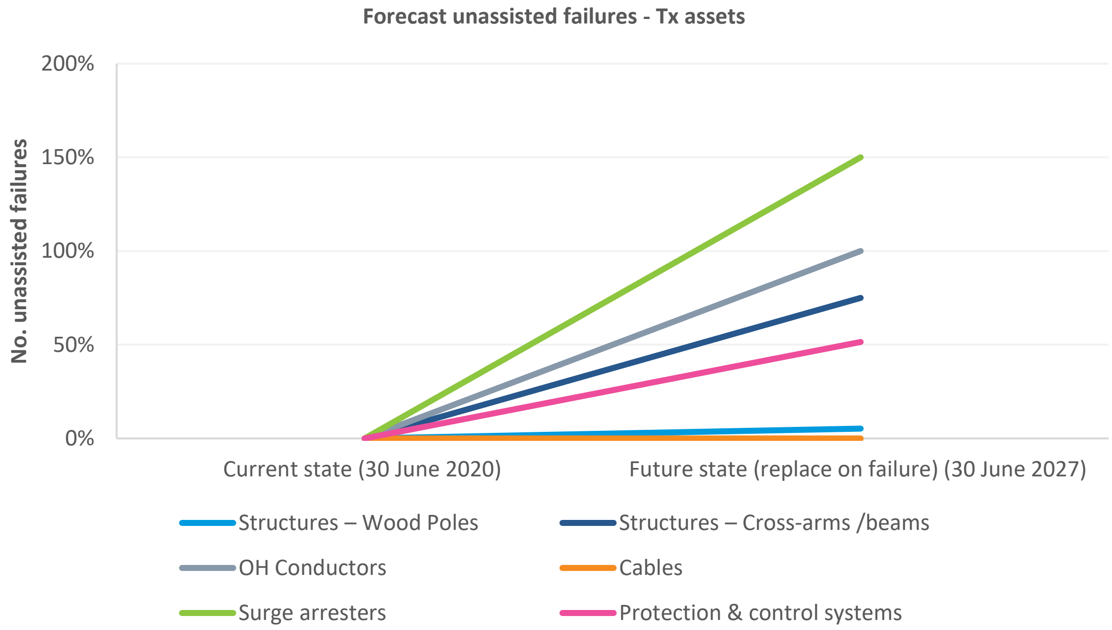
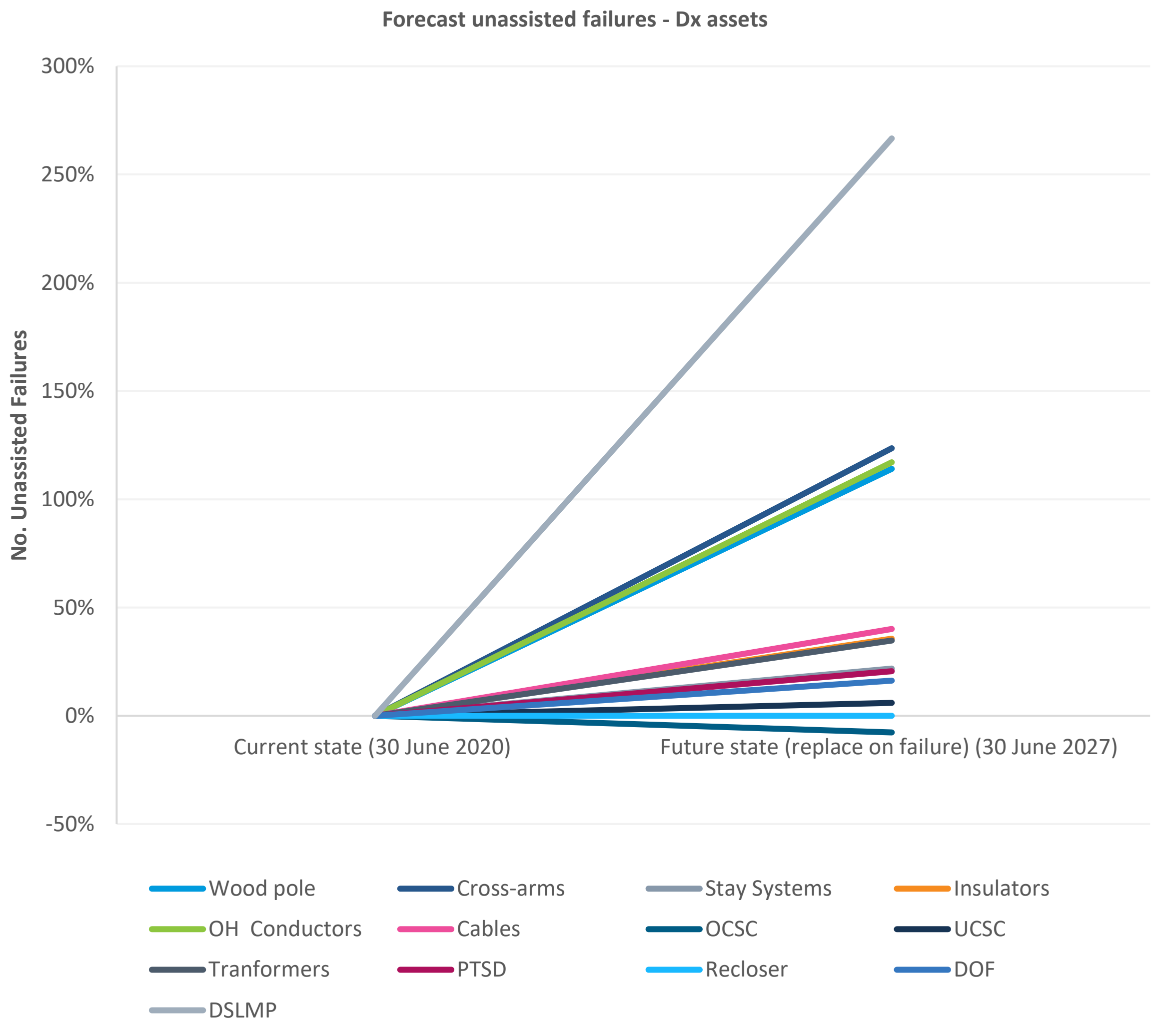
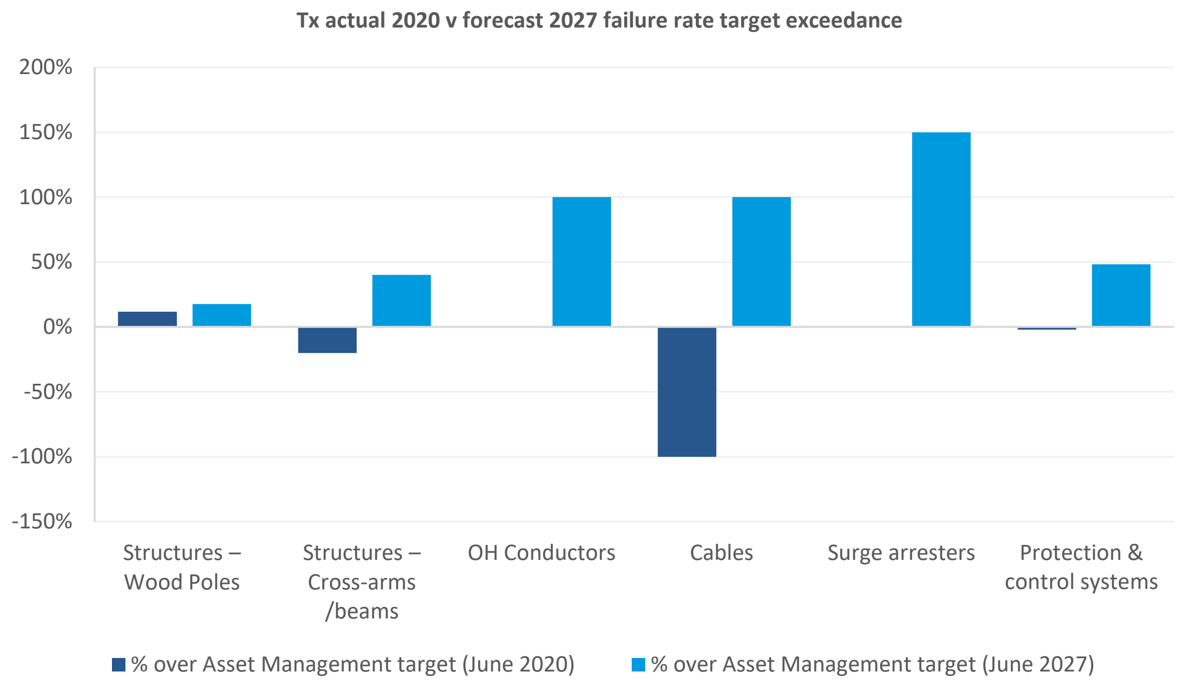


Figure 8–13: Distribution assets – forecast unassisted failures



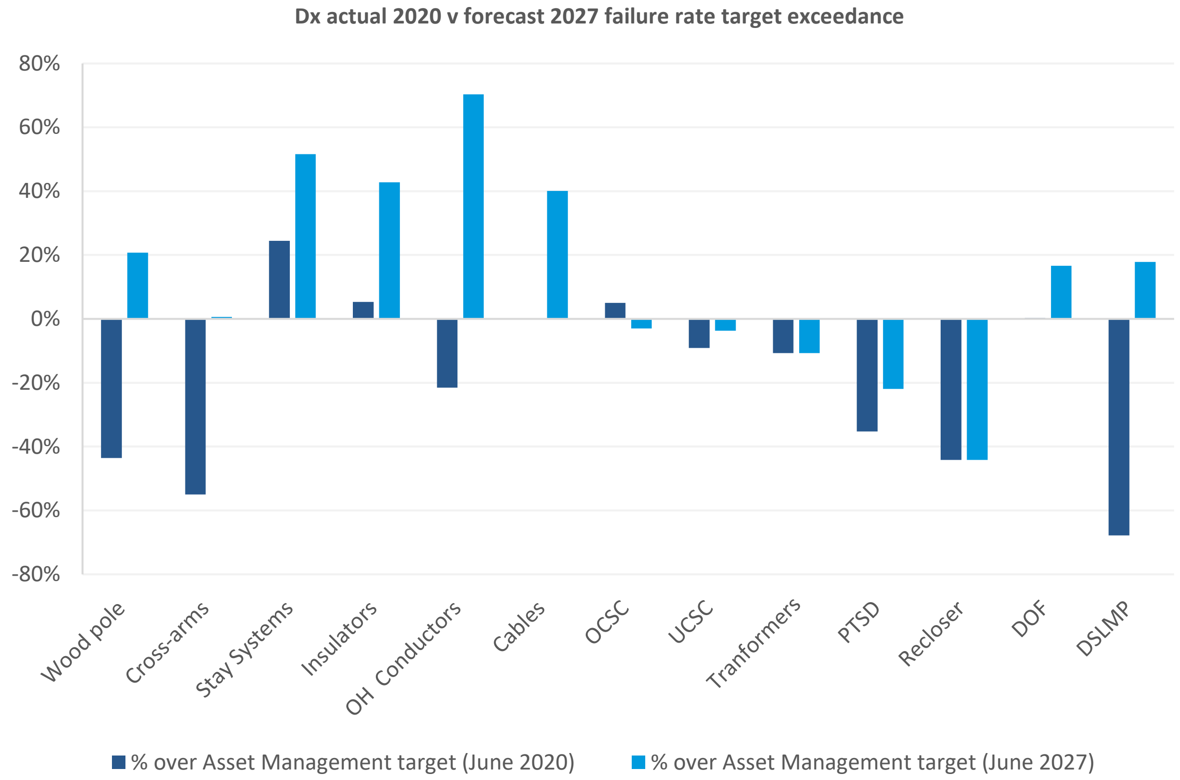
Further, Figure 8–14 and Figure 8–15 shows the extent to which the actual failures per annum in each asset class to June 2020 exceeded or remained under Western Power's asset management target failure rate for its Tx and Dx network assets respectively. The figures also include the percentage exceedance of the forecast asset failures over the asset management targets to provide a comparison of current performance with forecast performance.[621] Engevity notes that asset management over AA4 seems to have maintained most asset classes below failure rate targets, yet large failure increases are forecast to exceed these targets.

Figure 8–14: Forecast failures compared to failure targets - transmission assets



621 Analysis derived from Western Power figures: Attachment 8.2 – Network Management Plan, Feb 2022, Western Power, pp. 283, 301-302

Figure 8–15: Forecast failures compared to failure targets - transmission assets



As a result of the above, Engevity believes that Western Power's risk management algorithms that inform their Tx and Dx replacement programs are underestimating asset condition and therefore overstating the scope of replacement required.

Western Power itself has stated that it has capability to monitor actual performance and has made the decision to allow for asset failures to exceed targets for certain assets as they can "*ensure any deterioration in performance does not result in material increase in risk*".[622]

Engevity considers that the scope of Western Power's replacement program could and should be scaled back on a prioritisation basis to improve expenditure efficiency with the above approach monitoring being taken for less critical assets across AA5.

Engevity notes that total replacement expenditure across both Dx and Tx networks proposed for the AA5 period increases significantly compared to AA4 levels. Western Power proposes a total distribution replacement expenditure of $2354.27m ($real 2022)[623], a 66% increase on total expenditure actually incurred in AA4.[624] This figure also includes SPS and NRUP expenditure as distribution replacement expenditure. These programs are appropriate to include as they represent alternative solutions to traditional replacement activities and so the need and scope of these programs are informed by the same asset management process that informs general replacement requirements.

Engevity has looked at the SPS, NRUP, Wood Pole Management and Metering programs in detail separately and has made specific recommendations for these programs. Engevity identifies the amount of total proposed distribution REPEX not already assessed by Engevity across these programs

622 Attachment 8.2 – Network Management Plan, Feb 2022, Western Power, p. 283

623 Includes SPS and NRUP expenditure

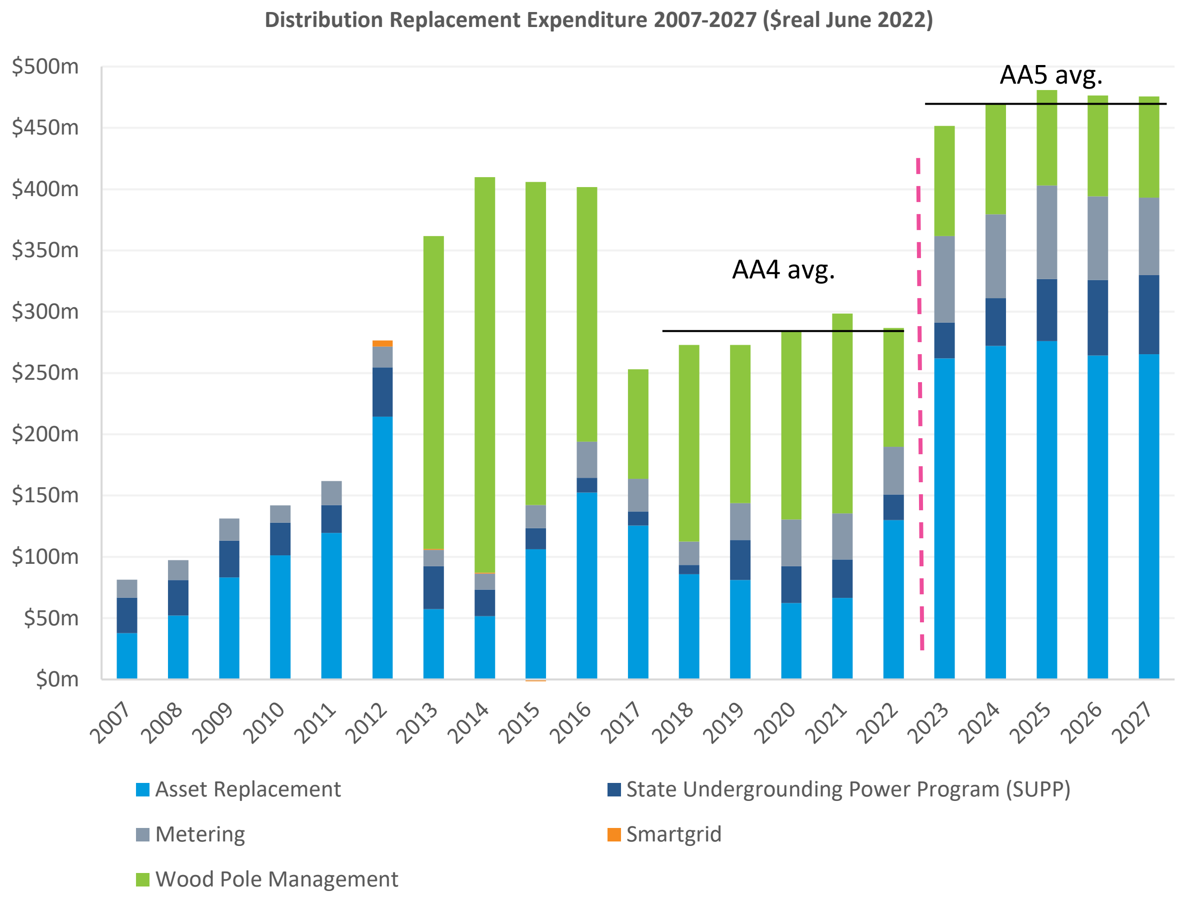
624 Attachment 11.1 – AA5 Regulatory Revenue Model – Public, Feb 2022, Western Power, Dx_Inputs

to be $488.44m[625] for AA5. This can be compared to $426.09m[626] distribution REPEX in AA4 in the equivalent subset of REPEX categories, which is 12.8% less.

Engevity also notes that we have not seen a detailed explanation of the interactions and trade-offs between the transformation replacement programs (NRUP and SPS) and the general BAU replacement program.

Similarly, Western Power proposes a total transmission replacement expenditure of $343.09m ($real 2022), a 41% increase on total expenditure actually incurred in AA4.[627] Western Power's distribution and transmission replacement expenditure is set out in Figure 8–15 and Figure 8–16 below.

Figure 8–16: Western Power distribution replacement expenditure 2007-2027

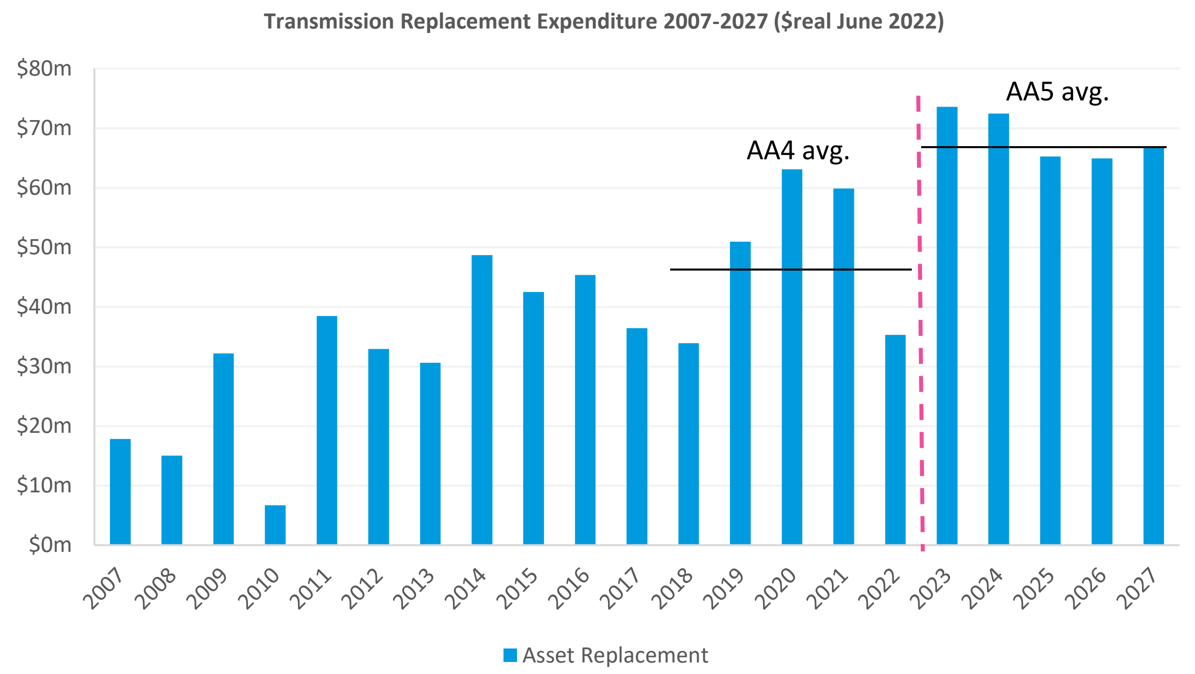


625 Attachment 8.10 – Capital Expenditure Model – Public, Feb 2022, Western Power, Capex Calcs, Asset Replacement excl. SPS, NRUP, Metering, SUPP and Wood Pole Management.

626 Attachment 11.1 – AA5 Regulatory Revenue Model – Public, Feb 2022, Western Power, Dx_Inputs, Asset Replacement

627 Attachment 11.1 – AA5 Regulatory Revenue Model – Public, Feb 2022, Western Power, Tx_Inputs

Figure 8–17: Western Power transmission replacement expenditure 2007-2027



In particular, Engevity highlights the large reduction in distribution replacement CAPEX from AA3 and AA4, primarily in reduced wood pole management costs. Following this reduction in distribution replacement expenditure and slightly higher expenditure in transmission replacement, Western Power both complied with its safety obligations[628] and met almost all of its reliability service standard benchmarks (SSBs) over the AA4 period.[629]

Engevity therefore does not find that the scope and resultant cost of Western Power's proposed AA5 replacement program is justified based on the information currently provided.

Recommendations

As a result, Engevity believes that the current proposed increases in both transmission and distribution replacement expenditure are unsubstantiated based on the information provided by Western Power to date. Engevity recommends 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.

Engevity therefore recommends a reduction of 12.8% to total distribution replacement expenditure and a reduction of 29.1% to total transmission replacement expenditure to align each with AA4 levels. For transmission, this represents a $85.3m reduction to direct replacement CAPEX. For distribution, this represents a $62.35m reduction to direct replacement CAPEX, which excludes REPEX relating to the NRUP, Metering, SPS and Wood pole management programs which has been assessed separately. Engevity considers any increase above this level requires substantiated evidence from Western Power that additional replacement expenditure beyond that spent in AA4 is necessary to meet its network requirements in AA5.

628 Access Arrangement Information, Feb 2022, Western Power, p. 59

629 Access Arrangement Information, Feb 2022, Western Power, p. 71

8.6 Distribution Augmentation – AA5 Assessment

8.6.1 Summary of Assessment

Engevity has reviewed Western Power's proposal for the AA5 period and found that it **DOES NOT COMPLY** with the Access Code requirements for an AA submission. We found that expenditure **DOES NOT COMPLY** with the NFIT requirements or represent efficient expenditure based on the information available. We have made nil recommendations for ERA adjustments in the table below.

Over the AA5 period, the Distribution Augmentation Program has forecast expenditure as summarised in the table below.

Table 8–19: AA5 Expenditure and Scale – Distribution Augmentation Program[630] [$m real at 30 June 2022]

Distribution Augmentation Program	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Proposed Total CAPEX[631]	*187.0*	*176.3*	*170.9*	*175.4*	*164.6*	***874.3***
Western Power Proposed Direct CAPEX[632]	59.6	49.9	44.7	47.3	44.0	**245.4**
Adjustment	-	-	-	-	-	-
Engevity Recommended Direct CAPEX	**59.6**	**49.9**	**44.7**	**47.3**	**44.0**	**245.4**

630 Western Power AAI, 1 February 2022, p. 204

631 [redacted]

632 [redacted]

Assessment Overview

Table 8–20: Assessment Overview

Project/Program	Distribution Augmentation Program
Proposed Cost $m	The proposed overall gross and net of capital contribution costs in AA5 are roughly consistent with those in AA4 and there are no adjustments recommended. In the AA5 period $874.3m gross CAPEX, $286.1m net of capital contributions, and $245.4m direct CAPEX net of capital contributions.
Recommended cost $m	It is recommended that approval of the program be made subject to provision of information to establish that the program is efficient and captures the available and realisable economies of scale and scope. Without this evidence, it is not reasonably expected to satisfy the new facilities investment test in section 6.51A. In the AA5 period $874.3m gross CAPEX, $286.1m net of capital contributions, and $245.4m direct CAPEX net of capital contributions.
Need	The need for the works has been demonstrated and the scope of the proposed expenditure is considered commensurate.
Scope Definition	However, the scope of capacity expansion projects should be predicated on load forecasts that consider all likely major influences including strong uptake of electric vehicles.
Timing	The timing and risk management of distribution augmentation works in the AA5 period may be appropriate. However, the accuracy of load forecasts is questionable, given that they are known to do not include foreseeable major influences.
Risk Management	The proposed investment may be both cost- and scope-efficient but insufficient information has been made available to allow definitive judgements to be made in these matters.
Cost Efficiency	
Scope Efficiency	Scope efficiency cannot be guaranteed because Western Power has not provided any detail on the composition of the substantial network extension works proposed. Further detail should be provided as to the major projects in this program.
Strategic Alignment	The program does have alignment with Western Power's Grid Strategy and Corporate Strategy.
Options Analysis	No options analysis has been made available. This makes it impossible to reasonably conclude that the proposed expenditure satisfies the new facilities investment test in section 6.51A.
Delivery Model	We did not observe discussion of delivery models.

Findings

Engevity has reviewed Western Power's proposed expenditure relating to **Distribution Augmentation** and found that:

a. **The proposed expenditure may be efficient** with the objective of minimising costs on the basis that Western Power has provided detail to the level of regulatory activities on gross and net of capital contributions CAPEX (and some information at project level for transmission driven capacity expansion) but has not proven the cost efficiency of the CAPEX for distribution augmentation in the AA5 period. However, there is insufficient detailed information available on major projects, particularly network extension works, to allow the efficiency of expenditure to be conclusively established. We did not observe analysis from Western Power to demonstrate that distribution augmentation costs have been estimated using an efficient system, unit costs and volumes. No business cases or investment evaluation models for distribution augmentation at a project level have been made available. There has been an increase of $32.4m (12.8%) in distribution augmentation CAPEX net of capital contributions. Further detail should be provided as to the breakdown of projects and planned works, particularly for network extension customer driven projects. Engevity notes that similar information deficiencies apply to a range of other programs.

b. **The program may capture the available and realisable economies of scale and scope, but this cannot be proven from the available information.** It contains a wide variety of infrastructure and works associated with capacity expansion and customer-driven projects. The capacity expansion works address future loading and voltage obligations with augmented distribution feeder and transformer capabilities in response to load forecasts for the AA5 period. The scope of the works is determined by the anticipated need, with the economies of scale and scope in this area accordingly limited. The customer driven works historically contains high volumes of low-cost works. This could permit significant economies of scale and scope, but this is not addressed in the Western Power documentation.

c. The proposed investment **is consistent with reasonable expectations** of the level of future network services required by customers. This is because the capacity expansion works deal with anticipated feeder over-use and voltage rise issues that could potentially adversely affect reliability, safety and customer equipment operation. The customer driven works deal with connection obligations for loads and generators under the Access Code.

d. **A reasonable range of alternative options has not been considered** for the proposed investment (based on the available documentation) and it is not clear that the most appropriate solution chosen. Options analysis for distribution augmentation is not available in the Western Power documentation. Options analysis should be provided for all major projects in the Western Power distribution augmentation program.

e. **The cost of distribution augmentation is partially recovered by incremental revenue.** The distribution augmentation gross CAPEX of $874.3m includes $191.5m of gifted assets and $396.7m of cash contributions for customer driven works. This is in accordance with section 6.52 of the Access Code, where the connecting customer contributes that part of the investment that does not meet the incremental revenue test. Capacity expansion works are being undertaken for reliability and safety reasons.

f. **The proposed investment is partly necessary to maintain the safety and reliability** of the network and its ability to provide contracted network services. The proposed investment in capacity expansion is necessary to deal with safety and reliability issues around overloaded distribution transformers and HV fault rating and protection issues with increased variable renewables penetration. It is also necessary to deal with reliability issues around anticipated over-utilised feeders due to increasingly prevalent hot weather events and over-voltage due to over-voltage due to increased rooftop solar PV uptake. The proposed investment in customer driven distribution growth is necessary to provide the network with its ability to meet anticipated increased need for required network services associated with new customers in the AA5 period.

g. Project Symphony, funded as a HV distribution driven regulatory activity within the capacity expansion sub regulatory category, is recognised as a WA government key project under the WA government's DER Roadmap.

Recommended Adjustment

As a result, our recommendation is that further information is required before confirming the approval of the Western Power distribution augmentation proposal for the AA5 period. Approval is subject to provision of information to establish that the proposed expenditure is efficient and captures the available and realisable economies of scale and scope. Information is also required to establish that a reasonable range of alternative options has been considered for the proposed investment. Western Power should consider EV uptake and other readily anticipated major influences in AA5 for load forecasting, when considering the required scope, timing, expenditure and risk management associated with HV distribution driven capacity expansion projects. Further details are required as to the breakdown of projects associated with network extension customer driven distribution growth. Some discussion of project delivery models and staging is also required.

At this stage there are no financial adjustments associated with our review recommendations for this program (see table below).

Table 8–21: AA5 Recommended Expenditure – Distribution Augmentation (Distribution Growth regulatory category)[633]

Distribution Augmentation	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Proposed						
Total CAPEX (Gross)	187.0	176.3	170.9	175.4	164.6	**874.3**
Total CAPEX (net of capital contributions)	68.8	57.8	51.9	55.5	52.1	**286.1**
Direct CAPEX (net of capital contributions)[634]	59.6	49.9	44.7	47.3	44.0	**245.4**
Engevity Recommended						
Total CAPEX (Gross)	187.0	176.3	170.9	175.4	164.6	**874.3**
Total CAPEX (net of capital contributions)	68.8	57.8	51.9	55.5	52.1	**286.1**
Direct CAPEX (net of capital contributions)	59.6	49.9	44.7	47.3	44.0	**245.4**

8.6.2 AA5 – Project Assessment

Overview

Distribution augmentation is referred to in the Western Power AA5 proposal as the distribution growth regulatory category. It deals with issues around distribution capacity expansion and customer-driven CAPEX investments. It also receives a significant amount of capital contributions in terms of gifted assets and cash. Most distribution growth CAPEX (including contributions) is associated with customer-driven projects. Western Power proposes to invest a total of $874.3m in distribution growth projects and there is a net distribution growth CAPEX of $286.1m during the AA5 period[635]. This represents an increase of $32.4m (12.8%) in distribution growth net CAPEX for the AA5 in comparison to the AA4 period.

633 Western Power AAI, 1 February 2022, p. 204

634 [redacted]

635 Western Power AAI, 1 February 2022, p. 204

The capacity expansion sub regulatory category addresses future load and voltage obligations, based on forecast customer load over the AA5 period. It includes CAPEX for HV distribution driven, HV Fault Rating and Protection, Overloaded Transformers and Transmission Driven regulatory activities in the AA5 period. Western Power states that the number of over-utilised feeders is forecast to increase in the AA5 period in comparison flat or negative growth in previous years. Investment is required to cater for load growth and avoid premature asset ageing, associated with customer responses to hot weather events. The proposed investment also mitigates risk associated with continued PV uptake on rooftops leading to a further decline in daytime minimum load and increased probability of non-compliance associated with consequent over-voltages. However, the Western Power analysis does not explicitly consider an increase in load due to electric vehicle (EV) uptake. Investment in HV distribution-driven projects is being made to ensure parts of the network that are experiencing growth have sufficient capacity and follow Technical Rules requirements. This includes investment of $6.0m in Project Symphony, an active Distributed Energy Resources (DER) demonstration project that is designed to inform changes in the Distribution System Operator (DSO) role and is a key project under the WA government's DER Roadmap[636]. The Project Symphony pilot will also create virtual power plants (VPPs) by aggregating solar panels, batteries and other controllable appliances[637]. There are no forecast cash contributions associated with capacity expansion in the AA5 period[638]. Western Power proposes to invest a total of $136.9m in distribution capacity expansion growth projects during the AA5 period[639].

Western Power additionally states that any reductions to the undergrounding program, which transforms high energy density metropolitan customers towards larger ground-based transformers in support of underground networks, would effectively reduce distribution transformer work as part of distribution augmentation to meet future demands.

The customer-driven sub regulatory category addresses all works associated with connecting customer loads or generators plus third-party requests for relocation of distribution assets. This includes small residential connections and network extensions for large industrial customers. It includes CAPEX for Network Extension, Major Relocations, Relocations, Subdivision, Major Access and Connection regulatory activities in the AA5 period. These works may involve significant cash contributions. There is a total of $396.7m of cash contributions associated with customer-driven projects in the AA5 period. Western Power proposes to invest a total of $545.8m in distribution customer-driven growth projects during the AA5 period[640].

There is a total of $191.5m reported by Western Power in the gifted assets sub regulatory category of distribution growth for the AA5 period.

Engevity notes that Western Power has adopted the ERA's Final Decision on the framework and approach to removing connecting new generation capacity and load and augmentation of the network to provide covered services, from the Investment Adjustment Mechanism for the AA5 period[641].

636 Ibid., p. 206

637 Western Power AAI – AA5 Forecast capital expenditure report, 1 February 2022, p. 65

638 AAS – Attachment 11.7 – AA5 Regulatory Revenue Model

639 Western Power AAI, 1 February 2022, p. 204

640 Ibid., p. 207

641 Ibid., p. 222

Historical Context

Distribution growth total CAPEX was $939.1m in AA4 in comparison to $874.3m proposed for AA5[642]. This represents a decline of $64.9m (6.9 per cent) in distribution growth total CAPEX from AA4 to AA5. The growth regulatory category total CAPEX net of capital contributions was $253.7m in AA4 in comparison to $286.1m proposed for AA5. Western Power describes the total CAPEX net of capital contributions as comparable for AA4 and AA5. It represents an increase of $32.4m (12.8 per cent) in distribution growth total CAPEX net of capital contributions from AA4 to AA5. The underlying reasons for this proposed increase in distribution growth total CAPEX net of capital contributions are reflected in significant changes to CAPEX associated with the capacity expansion and customer-driven subcategories.

The capacity expansion CAPEX was $74.3m in AA4 in comparison to $136.9m proposed for AA5. This is an increase of $62.5m (84.1 per cent), with no related offsetting cash contributions. This increase is largely associated with HV distribution driven activities, with an increase of $72.8m (661 per cent) in associated CAPEX due to undertaking works deferred from the AA4 period. Western Power states these works were deferred because there was flat to negative actual load growth over the AA4 period, whereas the AA4 forecast based on AEMO data was for some growth over AA4[643]. High demand and overloading in AA4 prior to summer 2020 was not significant. However, Western Power states that to avoid widespread outages as experienced over Christmas 2021, there is a need to address over-utilised feeders in AA5[644].

The customer-driven CAPEX was $588.6m in AA4 in comparison to $545.8m proposed for AA5. This is a significant decrease of $42.7m (7.3 per cent) in CAPEX. Cash contributions associated with customer-driven projects were $409.2m in AA4 in comparison to $396.7m proposed for AA5. This is a relatively small decrease of $12.5m (3.1 per cent) in cash contributions CAPEX.

Gifted assets decreased from $276.2m in AA4 to $191.5m in AA5. This is a large decrease of $84.7m (30.7 per cent) but does not contribute to distribution growth CAPEX net of capital contributions.

Need

Engevity considers that the need for distribution augmentation works in the AA5 period has been clearly identified. The need for the proposed investment has been identified by Western Power in terms of the following:

- Capacity expansion to address future loading and voltage obligations based on forecast customer load demand over the AA5 period.
- Building understanding of how the DSO role will evolve and capability to safely and securely integrate increasing levels of DER within the distribution system.
- Customer-driven growth primarily due to network extensions for large industrial customers plus relocations.

Western Power has identified a need for a significant (661 per cent) increase in HV distribution driven activities to $83.9m during the AA5 period, to ensure parts of the network that are experiencing growth have sufficient capacity and meet Technical Rules requirements:

- Distribution feeders do not exceed optimal utilisation levels;
- Voltage is within required limits;

642 AAS – Attachment 11.7 – AA5 Regulatory Revenue Model

643 AAS – Attachment 5.2 – AA4 Capital Expenditure Variance Analysis Report

644 Western Power AAI, 1 February 2022, p. 205

- Network load is balanced across three phases;
- Network redundancy is at the required level.

The explanation for the large increase in expenditure is that high demand and overloading in AA4 was not significant prior to summer 2020, resulting in flat or negative load growth and deferral of associated work to AA5. There is a forecast increase in need to address over-utilised feeders in AA5, to avoid widespread outages as experienced over Christmas 2021. Western Power states that anticipated increases in hot weather events in AA5 means increased investment in HV distribution driven activities is necessary to meet customer load growth and avoid premature asset ageing. This is also partially a risk mitigation response to continued PV uptake on rooftops leading to a further decline in daytime minimum load and increased probability of non-compliance associated with consequent over-voltages adversely affecting customer equipment. Load imbalance on the three-phase network due to load from extensive rural single-phase networks is also being addressed by these works. An area that has not been explicitly addressed in the Western Power proposal is an increase in forecast load due to EV uptake. **Engevity considers that the lack of consideration of EV uptake may cause a significant underestimation of load forecast for AA5, and consequent required scope and expenditure for HV distribution driven activities.**

The need for investment of $6.0m in Project Symphony during AA5 as an active DER demonstration project, is stated in terms of the project informing the evolution of the DSO role and building of required capability within Western Power[645]. Project Symphony is a key project under the WA government's DER Roadmap, being a collaboration between Energy Policy WA, Western Power, AEMO and Synergy, with some funding by ARENA. The aim is to build industry capability to integrate DER safely and securely in the SWIS, by developing and testing DER customer, market and technical capabilities and functions. The investment in the AA5 period is to cover Western Power's role until the completion of the project in December 2022 (it began in April 2020) and implementation post project completion.

Transmission driven activities have a proposed total CAPEX of $33.7m in the AA5 period, for distribution works that will be undertaken in conjunction with relevant transmission capacity expansion projects. The need for this investment is to:

- provide distribution capacity for new zone substation capacity and interconnection;
- provide distribution feeder load transfer capability for existing zone substation capacity;
- maintain clearances between distribution and transmission assets as transmission lines are developed or augmented;
- reinforce the distribution network for a change in voltage from the zone substation;
- provide distribution capacity to resupply a decommissioned zone substation.

Investment in transmission driven activities in AA5 includes $9.9m to support decommissioning of the Kellerberrin and Carrabin substations, $8.5m for reinforcement of the Black Flag distribution feeder to support an installed third transformer, $5.2m for transferring load off the Wellington Street substations, $5.1m for decommissioning of the Wundowie zone substation, and $2.5m to support the decommissioning of the Tate Street zone substation[646].

Western Power proposes to invest $12.9m to address HV Fault Rating and Protection in the AA5 period. The need is rising fault levels at some locations in the distribution network because of the connection of new generation, network upgrades, changes in network topology, and more sensitive

[645] Ibid., p. 206

[646] Ibid. p. 206

protection settings to deal with increased PV variable generation. Western Power also proposes to invest $6.4m to address overloaded distribution transformers. This is to ensure service levels in accordance with the Access Code and lower the likelihood of failure resulting in disruptions to customer supply and public safety risk[647].

Most of forecast distribution growth CAPEX is for customer-driven projects. The proposed investment in customer-driven projects of $545.8m gross CAPEX ($396.7m cash contributions) in the AA5 period has declined from the actual gross CAPEX of $588.6m ($409.2m cash contributions) in the AA4 period. Network extensions and connections for customer loads and generators, plus third-party request relocation of distribution assets represent 77.5% of the distribution growth gross CAPEX. Western Power states that customer-driven projects are generally high volumes of low-cost works, with historical expenditure being a good indicator of future investment[648]. Network extension works represent $283.6m (52 per cent) of the total gross CAPEX for distribution customer driven growth in the AA5 period[649]. This is comparable to the network extension works total gross CAPEX in the AA4 period[650]. The composition of network extension works is not included in the Western Power AA5 proposal documentation. Western Power notes that customer-driven works are driven entirely by customer requests and is influenced by the broader economic environment. Major capital investments requiring network extension did not reach the forecast level in the AA4 period, due to the economic environment and other events, including COVID[651].

Scope Definition

The scope of the proposed expenditure on distribution augmentation in the AA5 period is commensurate with the need. The $874.3m total in CAPEX for the AA5 period ($286.1m net of capital contributions) is to add a wide variety of infrastructure and undertake augmentation works associated with capacity expansion and customer-driven projects. For capacity expansion projects, this is addressing future loading and voltage obligations with appropriately augmented distribution feeder and transformer capabilities in response to forecasts for the AA5 period. **Engevity does caution that the scope of capacity expansion projects should be predicated on AA5 load forecasts that consider all likely major influences, including strong uptake of EVs.** Western Power additionally states that it does recognise that additional distribution augmentation is likely required following the 2021 summer event (not incorporated into Western Power's AA5 submission) and to meet long-term EV demand scenarios, particularly regarding feeder reinforcement.

Project Symphony, which is included in the distribution augmentation scope, will play an important role of informing the evolution of the DSO role with the advent of large additional volumes of DER in the SWIS as capacity expansion in the AA5 period. **Engevity acknowledges Project Symphony is a key project in the WA government's DER Roadmap and its completion and implementation should be funded appropriately in the AA5 period.** For customer-driven projects, the CAPEX is roughly in accordance with historical experience over the AA4 period, as per expectation. **Engevity suggests further detail should be provided as to the breakdown of projects associated with the substantial ($283.6m) proposed CAPEX associated with network extension projects, as part of customer driven distribution growth, in the AA5 period.**

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647 Ibid., p. 206

648 Ibid., p. 207

649 Ibid., p. 207

650 Western Power AAI – AA5 Forecast capital expenditure report, 1 February 2022, p. 69

651 AAS – Attachment 5.2 – AA4 Capital Expenditure Variance Analysis Report

Timing

Engevity considers that the timing of distribution augmentation works in the AA5 period is probably appropriate. The use of load forecasting that does not include the possibility of significant EV vehicle uptake raises the risk of an underestimation of the required scope of distribution augmentation works that needs to be undertaken in the AA5 period. Western Power state that the timing of the investment in distribution augmentation is in accordance with the need. This is particularly the case with the significant expansion of HV distribution driven activities in the AA5 period. Works are included that are deferred from the AA4 period due to the absence of the expected demand growth at that time. The proposed HV distribution driven works are to meet a forecast need to address over-utilised feeders in AA5, largely associated with anticipated increases in hot weather events. Again, Engevity cautions that all possible significant drivers, including significantly increased electrical vehicle uptake, should be considered in the underpinning load forecasts that are driving the scoping of capacity expansion works. Failure to do this could result in an underestimate of the required capacity expansion works in the AA5 period. The timing of other augmentation works on feeders and transformers appears to be in accordance with the required need, with reference to specific activities. Customer-driven works are largely in accordance with historical experience in the AA4 period. However, the lack of detail concerning the breakdown of projects associated with $283.6m of gross CAPEX associated with network extension projects makes it impossible to comment on the timing, other than to say it is comparable to the network extension works total gross CAPEX in the AA4 period.

Risk Management

Distribution augmentation includes risk management associated with capacity expansion but is limited by the underlying load forecast assumptions, which do not include potentially important drivers such as EV uptake. Again, Western Power additionally states that it does recognise that additional distribution augmentation is likely, including to meet long-term EV demand scenarios. Capacity expansion projects for the distribution network in the AA5 period are designed to mitigate risk associated with the possibility of widespread outages in the AA5 period due to over-utilised feeders in response to increased demand during hot weather events. The investment is also designed to mitigate risk of non-compliance to voltage standards due to expected continuation of rooftop PV uptake resulting in a continued decline in daytime minimum load[652]. Addressing anticipated feeder loading and voltage issues represents prudent investment in risk mitigation around Western Power network performance obligations in the Technical Rules (including from long duration outages and voltage incompatibility with customer equipment). Western Power uses risk-based planning techniques to address overloaded feeders[653]. Western Power is also addressing reliability, public safety and fire risk by appropriate investment in HV fault rating and protection to address rising fault levels at some locations in the distribution network and issues with the addition of more variable solar PV generation to the network. Investment to deal with overloaded distribution transformers is also appropriately mitigating public safety and reliability risk.

Customer driven projects for the distribution network in the AA5 period deals with connecting customer loads or generators plus relocation requests. New facilities investments are in accordance with the requirements of Access Code and hence are a Western Power obligation. Customer contributions meets that part of the customer driven investment that relates to connection assets or does not meet the incremental revenue test, which substantially reduces the proposed gross CAPEX from $545.8m to $149.2m in the AA5 period ($396.7m customer contributions). The main risk associated with this CAPEX is the broader economic conditions and unforeseen events during the

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652 Western Power AAI, 1 February 2022, p. 205

653 Western Power AAI – AA5 Forecast capital expenditure report, 1 February 2022, p. 64

AA5 period, as occurred for the AA4 period. This is well understood by Western Power and in that eventuality, would result in the deferral of associated proposed works, possibly to the AA6 period.

Western Power has an Asset Management Framework in accordance with the Australian and International Standard on Asset Management (ISO 55001), ERA Audit Guidelines, Electricity (Network Safety) Regulations 2015 and the Electricity Network Safety Management Systems standard (AS 5577). Western Power was acknowledged in its ISO 55001 assessment as having "…a number of industry leading practices, particularly in the areas of asset risk management and the "line of sight' linkages to organisational objectives, as well as the optimisation and prioritisation of programs and projects"[654]. Western Power's Network Risk Management Standard requires risk assessments to be carried out at appropriate points throughout the asset lifecycle[655].

Cost Efficiency

The proposed investment may be cost efficient, but this cannot be proven from the available information. We did not observe analysis from Western Power to demonstrate that distribution augmentation costs have been estimated using an efficient system and unit costs. No business cases or investment evaluation models have been put forward by Western Power for individual distribution augmentation projects and specific volumes and unit costs are not provided in documentation. However, the proposed gross investment of $874.3m in distribution growth projects reduces to $286.1m net of cash contributions and gifted assets. Cash contributions associated with customer driven investments are governed by the Access Code and reduce the CAPEX in this sub regulatory category to $149.2m. CAPEX associated with capacity expansion, which does not include any cash contributions, is $136.9m. There also continues to be substantial gifted assets ($191.5m) associated with distribution growth. The proposed total gross CAPEX in AA5 associated with distribution augmentation has decreased from the equivalent actual expenditure in AA4. However, there has been an increase of $32.4m (12.8%) in distribution augmentation CAPEX net of capital contributions.

Capacity expansion distribution growth involves projects under HV distribution driven, HV fault rating and protection, overloaded transformers and transmission driven regulatory activities. Procurement and delivery agreements associated with the constituent projects in these regulatory activities will be established via a competitive process to meet business requirements and deliver value for money, as per Western Power practices in previous AA periods. This will follow Western Power rules around approval processes for business case development.

There has been a substantial increase in CAPEX in the capacity expansion regulatory category, but this is largely associated with works deferred from AA4 and reasonably anticipated as being necessary to meet increased forecast load in the AA5 period. The HV distribution driven projects are not enumerated in the Western Power documentation and cannot be directly evaluated for cost efficiency. However, Western Power has enumerated the major projects in transmission driven capacity expansion expenditure, which includes estimates of expenditure on specific feeders and substations. The investment associated with Project Symphony, a collaborative project with some funding from ARENA, is included in HV distribution driven projects. This investment may be efficient if Project Symphony provides the anticipated tangible benefits to the SWIS network operation in terms of managing increased DER levels in the AA5 period. Engevity again recognises Project Symphony is a key project under the WA government's DER Roadmap.

Customer driven projects include works associated with network extension, relocations, subdivisions and connections which are standard capital works associated with all AA periods. The gross and net of cash contributions CAPEX associated with customer driven projects has decreased in AA5 in

[654] AAI, 2022, p. 182

[655] AAS – Attachment 8.2 – Network Management Plan, 2022, pp. 50 - 53

comparison to AA4. Again, procurement and delivery agreements associated with the constituent projects in these regulatory activities will be established via a competitive process to meet business requirements and deliver value for money, as per Western Power practices in previous AA periods. However, the major constituent projects in customer driven distribution growth are not enumerated in the Western Power documentation. **Again, further detail should be provided as to the breakdown of projects and planned works associated with the $283.6m proposed CAPEX associated with network extension projects in the AA5 period.**

Scope Efficiency

The distribution augmentation program is likely but not guaranteed to be scope efficient. There is a lack of detail around individual projects, volumes and unit costs in the Western Power documentation. The scope of the distribution augmentation program has not yet been challenged for options to stage the proposed works, with a reduced scope within the AA5 period. Western Power has not yet provided any evidence of prioritisation of works they state are required for capacity expansion and customer driven growth in the AA5 period.

The proposed work on capacity expansion is in accordance with customers' main priorities around support of renewables, future focus and maintenance of reliability standards[656]. It also includes deferred works from the AA4 period that are deemed essential to deal with risk mitigation for over-utilised feeders due to forecast hot weather event load growth and over-voltage due to increased rooftop solar PV uptake. This also applies to investment for load imbalance, transmission driven projects for zone substations and feeder works and overloaded transformer works. The investment in capacity expansion is largely for non-compliance risk mitigation and appears scope efficient. Funding for the completion and implementation of Project Symphony is as a key project under the WA government's DER Roadmap.

The proposed work on customer driven growth is comparable in cost to similar work undertaken in the AA4 period, with almost 73 per cent of the $545.8m gross customer CAPEX being covered by customer cash contributions. New facilities investments are in accordance with the requirements of the Access Code. Western Power recognises that the actual level of customer driven growth will depend on economic conditions and unforeseen events. The investment in customer driven growth is likely scope-efficient now. However, Engevity notes the lack of detail around network extension projects totalling $283.6m in forecast gross CAPEX, plus the lack of any information on volumes and unit costs associated with customer driven distribution growth projects, makes it impossible to guarantee scope-efficiency.

Strategic Alignment

The distribution augmentation program is in accordance with Western Power distribution performance strategies developed to guide network investments to meet future customer requirements. It is also consistent with the Western Power Grid Strategy and Corporate Strategy. Project Symphony is aligned with the WA government's Energy Transformation Strategy[657].

Options Analysis

Options analysis for distribution augmentation is not yet available. Western Power has not yet provided any documentation that discusses options around distribution augmentation. It is anticipated that options analysis will be undertaken in development of detailed business cases or investment evaluation models for all projects in both the capacity expansion and customer driven growth regulatory subcategories, with identification of the most efficient option in each case. Western Power provides a single gross CAPEX estimate and brief description for individual projects

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656 Western Power AAI – AA5 Forecast capital expenditure report, 1 February 2022, p. 12

657 Western Power AAI, 1 February 2022, p. 65

associated with transmission driven capacity expansion only. There is also discussion of Project Symphony but no related options analysis. **Engevity thinks options analysis should be provided for all major projects prior to ERA approval of the AA5 proposal. Engevity suggests that Western Power should in the first instance provide a list of all proposed major projects associated with distribution augmentation in the AA5 period.**

Delivery Model (incl. staging)

The delivery model for the distribution augmentation program is assumed to follow the Western Power practice in AA4 in terms of adherence to policies, procedures and standards. However, we did not observe information provided in Western Power's documentation on the delivery model for the distribution augmentation program. We also did not observe discussion of staging of works. Engevity anticipates that as for AA4 projects, all materials and equipment will be sourced in accordance with Western Power's corporate and procurement policies. Similarly, agreements will be by competitive processes, supported by engagement of relevant subject matter experts, to Western Power standards.

8.7 IT, SCADA, Communication & Cyber – AA5 Assessment

8.7.1 Summary of Assessment

Engevity has reviewed Western Power's proposal for the AA5 period and found that it **DOES NOT COMPLY** with the Access Code requirements for an AA submission. We found that some expenditure **DOES NOT COMPLY** with the NFIT requirements or represent efficient expenditure. As a result, we have made recommendations for ERA adjustments in the table below.

Over the AA5 period, the ICT Program (Tx and Dx) is forecast to account for the expenditure and scope summarised in the table below.

Table 8–22: AA5 Expenditure and Scale – ICT Programs (Tx and Dx) [$m real at 30 June 2022]

IT, SCADA and Communications (Tx & Dx)	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Proposed						
SCADA (Dx)	*37.1*	*36.8*	*42.3*	*50.3*	*52.6*	*219.1*
SCADA (Tx)	*46.2*	*47.2*	*55.9*	*55.7*	*59.4*	*264.3*
Corporate IT	*70.4*	*77.0*	*76.6*	*85.4*	*79.4*	*388.8*
Total CAPEX[658]	*153.6*	*161.0*	*174.7*	*191.4*	*191.4*	***872.2***
Western Power Proposed						
SCADA (Dx)	32.1	31.8	36.4	42.9	44.4	187.5
SCADA (Tx)	39.9	40.7	47.9	47.2	49.9	225.6
Corporate IT	60.9	66.4	65.8	72.7	66.9	332.8
Direct CAPEX[659]	132.9	138.9	150.1	162.8	161.3	**745.9**
Adjustment 1 - 30% reduction	-39.9	-41.7	-45.0	-48.8	-48.4	**-223.8**
Engevity Recommended Direct CAPEX	93.0	97.2	105.1	114.0	112.9	**522.2**

658 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs' Sheet, Column AF - AK

659 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs' Sheet, Column H - M

Assessment Overview

Table 8–23: Summary of Preliminary Findings

Project/Program	ICT program (Tx and Dx)
Forecast Cost $m	Western Power is forecasting $872.2m in AA5, which is a significant increase of 73% above the AA4 ICT program actual expenditure or 171% increase on the approved expenditure in the same period.
Recommended cost $m	It is recommended that ICT program approved expenditure be reduced by 30 per cent to $338.4m collectively for Dx and Tx SCADA and $272.2m for Dx and Tx IT.
Need	Western Power justify the overspend in AA4 by noting unplanned CAPEX and a growing risk of obsolesce and non-compliance of ICT assets. However, Engevity observed some inconsistency between the expenditure forecasts and the trends in ICT availability for AA4 and a needs justification for the forecasts in AA5.
Scope Definition	Engevity does not find the scope of the AA5 ICT program to be well justified on the basis of a clearly defined scope that is aligned to the identified need. In general, while the high-level justification, strategy and assessment approach to ICT program has been provided, there was limited additional detail. Engevity did not observe a collated document that sets out the current timing, staging, scale and end objective of ICT program. Limited evidence of business case/investment evaluation plans has been provided for total AA5 ICT investment program.
Timing	Engevity considers the accelerated timing of the current ICT program and resultant proposed AA5 expenditure is not aligned with a prudent and cost-efficient approach. We are also concerned that assets are being prematurely replaced on a conservative asset age risk basis rather than actual asset condition basis. As a result, Engevity found that a deferral of the AA5 ICT program would continue to result in an improvement in reliability, whilst also enabling cost efficiencies to be realised.
Risk Management	Engevity supports Western Power’s risk management approach in principle to the ICT program however questions the reliability and safety argument that has been used to support such a large ICT expenditure. Engevity has concerns that assets are being prematurely replaced on a conservative asset age risk basis rather than actual asset condition basis. Engevity has found systemic issues with Western Power’s approach to asset and risk management resulting in potential premature replacement of network assets. Engevity views this as further reason to reduce the scope of AA5 ICT investment such that Western Power can demonstrate a more robust approach to identifying targeted areas for the ICT expenditure when proposing further investment in AA6 and beyond.

Project/Program	ICT program (Tx and Dx)
Cost Efficiency	Engevity agrees that the ICT programs can have material net benefits in principle, however, has not observed sufficient evidence to justify net benefits of the AA5 program. Western Power has not clearly established the cost efficiency of the CAPEX for the scale of ICT expenditure in the AA5 period. Despite requests for information, we also did not observe clear justification of ICT expenditure scope components and that Western Power has demonstrated that ICT cost forecasts have been estimated using industry benchmarks of unit costs.
Scope Efficiency	Engevity is concerned that overspend in AA5 in this regulatory category and timing delays of key activities are symptomatic of more fundamental issues. We have not been provided with sufficient detail to adequately assess whether the overspend in AA4 is as a result of understating the AA4 forecasts or mismanagement of the delivery of the program of works. Engevity has been provided limited information on the options for scope and timing considered for the AA5 ICT programs. Engevity also observed some inconsistency between the expenditure forecasts and the trends in SCADA availability.
Strategic Alignment	Western Power's AA5 ICT programs are well aligned with their grid strategy, corporate strategy, regulatory obligations and government commitments. The ICT program is a core pillar of Western Power's Grid Strategy and the WA Government's DER Roadmap released in 2020.
Options Analysis	In general, while the high-level justification, strategy and assessment approach to ICT rollout has been provided, Engevity has limited project specific detail. Documentation provided to Engevity provides inconsistent information on the timing, staging, scale and end objective of ICT program. Engevity has not been provided with any options analysis, NPC analysis or planning models showing quantified justification of costs and benefits for the AA5 period. Engevity does not have sufficient information to determine whether appropriate options considerations have been made.
Delivery Model	Engevity is not convinced that Western Power has the capability and resources to deliver its proposed ICT program for the AA5 period, particularly in a cost-efficient manner.

Given the lack of forecasting accuracy in AA4 and large amount of additional costs proposed during AA5, Engevity has considers the ICT regulatory expenditure in further detail below.

Findings

Engevity has reviewed Western Power's proposed expenditure relating to **Corporate IT, Tx and Dx SCADA and Comms** Expenditure and found that:

a. **The proposed expenditure is not efficient** with the objective of minimising costs on the basis that Western Power has provided insufficient evidence to support its forecasts.

b. **The program does not capture the available and realisable economies of scale and scope** because Western Power has not demonstrated why delaying the expenditure would not yield a better outcome for customers. Given the early stage of Project Symphony and the modular grid expansion, Engevity believes that some delay to this expenditure would likely enable Western Power to draw on learning from these and other programs.

c. The proposed investment **is not consistent with reasonable expectations** of the level of future network services required by customers because it is significantly higher than Western Power peers.

d. **A reasonable range of alternative options has not been considered** for the proposed investment, with the most appropriate solution chosen. We observed a lack of options analysis for the ICT programs in the AA5 proposal, particularly at a project level. Western Power does not quantitatively demonstrate the relative cost-efficiency and its plan to deliver the scale of the ICT program proposed.

e. **The cost of ICT investment may not be recovered by incremental revenue** because a prudent and efficient operator creates value for its customers by identifying the risks on its network, mitigating them through targeted inspection, maintenance, refurbishment and replacement works to keep assets in service for as long as practicable.

    i. A modified test under section 6.53 of the Access Code of the proposed investment in ICT program is not proposed in the Western Power documentation.

f. **The proposed investment may not deliver an expected net benefit** over a reasonable period of time through tariffs. Western Power ICT overspend in AA4, the scale of expenditure in comparison to other networks, the evidence that Western Power customers 'do not value additional investment to improve reliability'[660] and a lack of risk and benefit quantification to support the substantial increase in ICT expenditure forecast.

Recommended Adjustment

Engevity considers Western Power's proposed ICT programs for AA5 of $872.2m – representing a 57% increase of costs above the AA4 actual expenditure – is not justified in line with the NFIT. We recommend that ERA apply an adjustment to the Western Power ICT programs to both ensure the program of works are deliverable, efficient and align with customers' expectations.

Western Power has not provided sufficient supporting business cases and analysis to demonstrate the need and its plan to deliver the significantly expanded programs and complexity – especially when compared to the experience of other distributors in the NEM. Therefore, Engevity considers Western Power's ICT program proposal does not meet the NFIT.

Engevity recognises Western Power's ICT programs are a key component of its business transformation program – which we consider plausible overall, albeit at a more manageable scale. We expect Western Power's forecast of related efficient costs to be higher than AA4. However, given the significant information asymmetry, it is challenging for us to identify an accurate efficient cost. Overall, we found a lack of justification for the accelerated increase in ICT program expenditure and did not observe how underlying issues that resulted in significant cost overruns in AA4 are intended to be manage.

We recommend that the ICT program approved expenditure be reduced by 30% on the basis that it is a gradual 21 per cent or $106m increase on AA4 actual expenditure and is likely more achievable. Our recommended adjustment represents a $261.6m[661] ($Real 2022) reduction to the proposed CAPEX for this program although a $106.2m increase in AA4 actual ICT expenditure. The reasoning for the recommended gradual increase in expenditure is in acknowledgement of the more complex operating environment, compliance obligations and the importance of ICT in network

660 Access Arrangement Information, 1 Feb 2022, Western Power, p. 71

661 This equates to a reduction of $145m for Tx and Dx SCADA and $116.6m for Dx and Tx IT

transformations required to manage an increase in decentralised and renewable energy sources. We consider the increased scaling over AA5 is achievable, although delivering this sized program will still be highly challenging.

Western Power's forecast for $483.4m SCADA & Comms expenditure is significantly higher than other regulated networks. Using benchmarking, our recommended adjustment to SCADA and Comms is $338.10m which is comparable to SA Power Networks and TransGrid's or Ergon and Energex combined approved expenditure in recent regulatory determinations by the AER. See below ICT benchmarking findings for further details.

To manage the risks stated above and either Western Power overstating its ICT CAPEX or underspending on these programs in AA5, ERA may consider whether a contingent project type-mechanism is available under the Access Code to allow Western Power to seek additional revenue within the AA5 period – that is, if it demonstrates it has successfully delivered against its allocated budget and further works would promote the Code objective.

Figure 8–18: Transmission ICT Expenditure Adjustment ($real June 22)

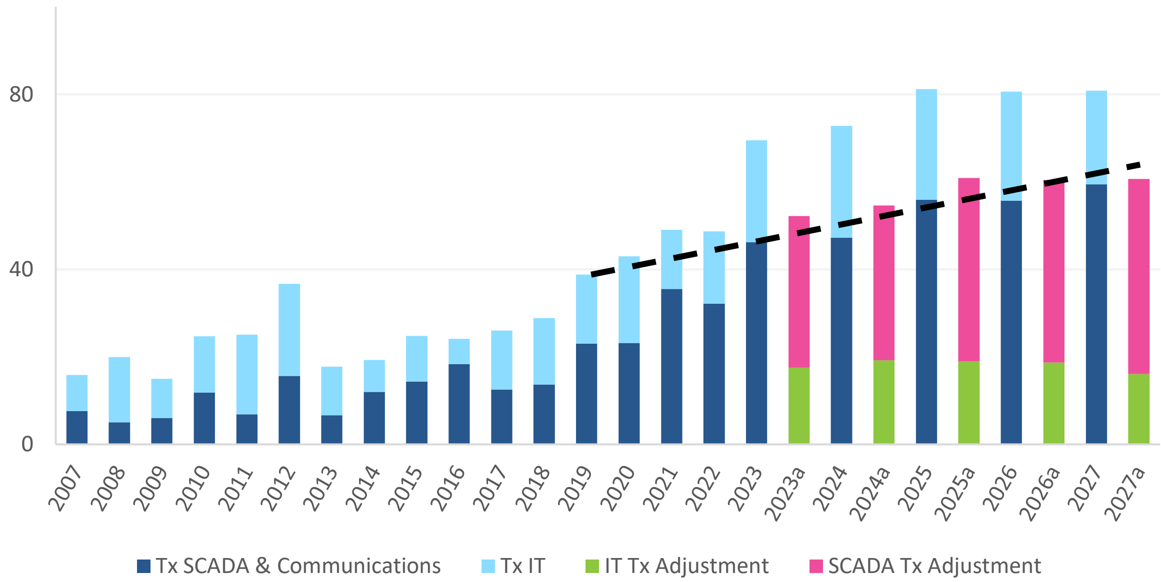
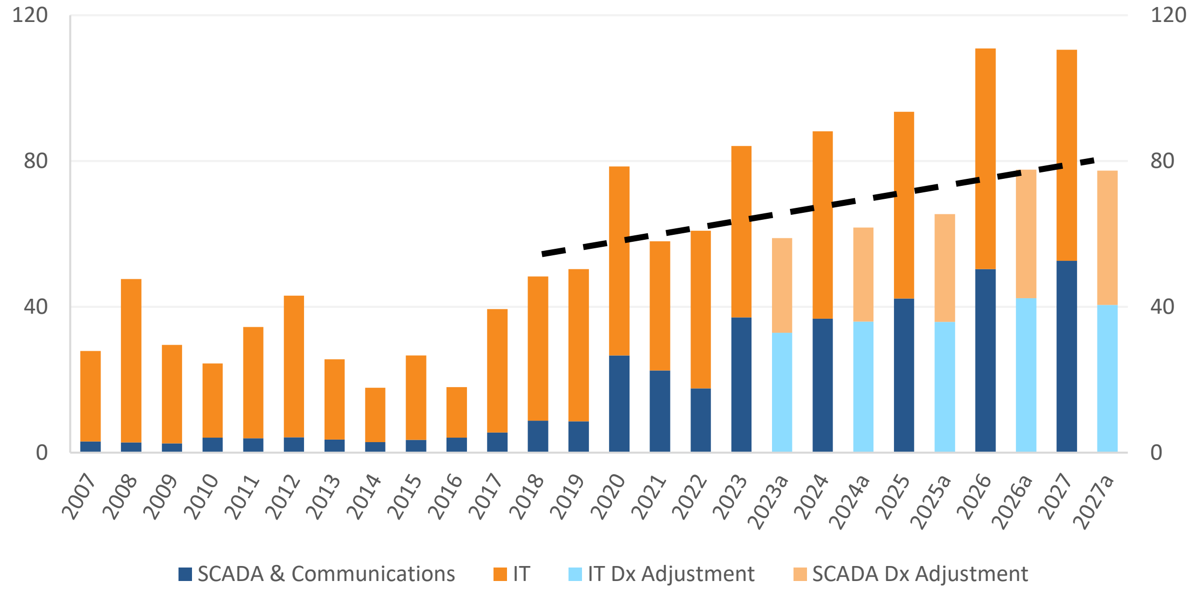


Figure 8–19: Distribution ICT Expenditure Adjustment ($real June 22)



8.7.2 AA5 Project Assessment

Expenditure Overview

Western Power states that the age of the equipment, increasing volume of renewables and greater DER as a significant and increasing driver for the need to upgrade Western Power IT, SCADA and communications assets.

The AA5 proposal includes $483.4m of CAPEX for SCADA and communication (Dx and Tx) and an additional $388.8m for Corporate IT. Collectively these two expenditure categories account for 17 per cent or $872.2 of gross forecast CAPEX for the AA5 period.

During AA4 Western Power actual expenditure for both these regulatory categories was $506.5m, which was 114 per cent over the original AA4 SCADA and Comms forecast and 32 per cent over for IT.

The reasons for the large increases in the AA5 forecast ICT Program CAPEX compared to AA4, appear to be because of a change in Western Power's ICT risk appetite, significant investment into a Tx and Dx Master Station, as well as large increases in SPS and AMI CAPEX programs. Noting that both for the AMI and SPS program, Engevity has recommended a downward adjustment.

As illustrated in the figure below, much of the expenditure is directed towards REPEX and Tx and Dx Master Station upgrades. The largest category is the IT Business Driven forecast expenditure for which Engevity was not provided details.

Figure 8–20: ICT Forecast Expenditure by Regulatory Category

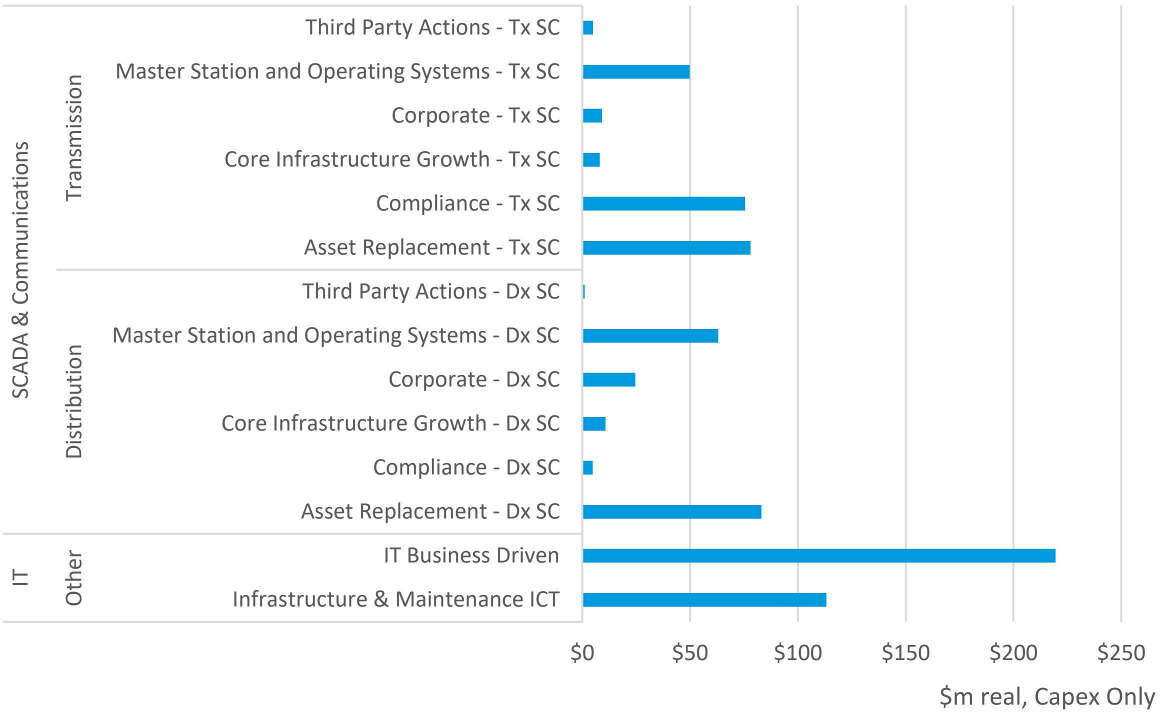


Table 8–24 Forecast SCADA & Comms Expenditure breakdown

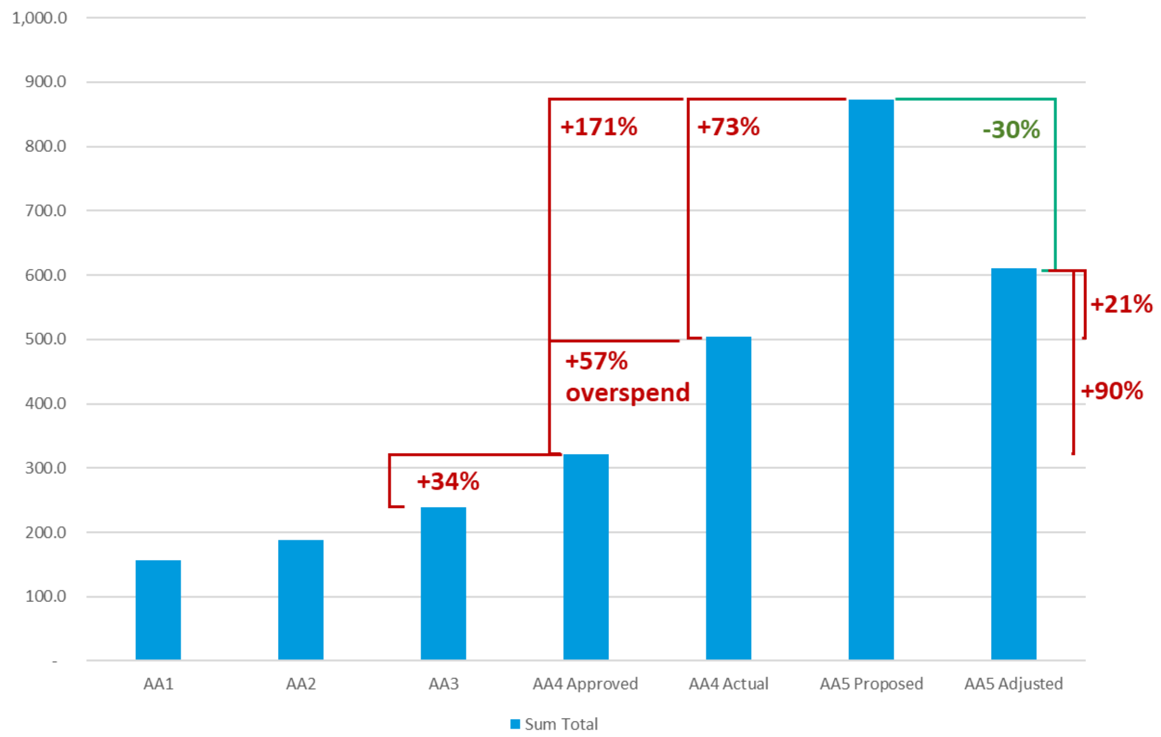
Regulatory Activity	Expenditure (m)
Replacement of obsolete SCADA and communication infrastructure	$188.4
Master station and operating system	$132.0
Compliance CAPEX for the SCADA and Telecommunications network	$94.4
DER and DSO integration requirements	$22.1
Replacement and addition of SCADA and Telecommunications assets	$39.4
External technological changes	$7.1
Total	**$483.4**

Western Power is proposing to commit $271.1m (128.5 per cent) more on SCADA during AA5. The proposal also includes a 32.2 per cent increase in IT costs, from $292.7m in AA4 to $338.8m in AA5.

The annual average ICT expenditure during AA3 was $47.8m per annum and Western Power increased this by 111 per cent during AA4 to $100.8m per annum, which was 58 per cent over the original forecast. For AA5, Western Power forecasts a 73 per cent increase, which is well above other networks benchmarked (see further details below).

As illustrated below, Western Power is forecasting a significant increase in Dx expenditure in AA5. Given the significant overspend and concerned raised on the AA4 expenditure we consider the case has not been made for this increase, raising deliverability and scope definition concerns.

Figure 8–21: ICT Expenditure ($real June 22)



Source: Engevity analysis using Western Power Regulatory Model

NFIT Overview

Historical Context

After a period of reactive investment, Western Power has gradually increased its SCADA and communications expenditure over AA4 and now proposes further expenditure in AA5. The primary driver for the expenditure is technical obsolescence which could impact the reliability and resilience of the network. Western Power claims additional OPEX, workforce productivity and transition benefits as network further decentralises and decarbonises.

Western Power's Network Strategy - SCADA and Telecommunications was updated in September 2021 and highlights its ambition to support a transition to a modular grid, integrate DER and support ongoing decarbonisation of the SWIS. It further outlines key legislative and compliance requirements, including reference to applicable national and WA jurisdictional specific obligations.

It is unclear however from the information provided what level of expenditure relates to AMI, DSO capability development and the SPS / modular grid program. Western Power states that the investment in the AA5 period will also replace assets predominantly within the telecommunication network access, radio systems, control automation cabling, DC power system and grid automation asset classes[662].

Need

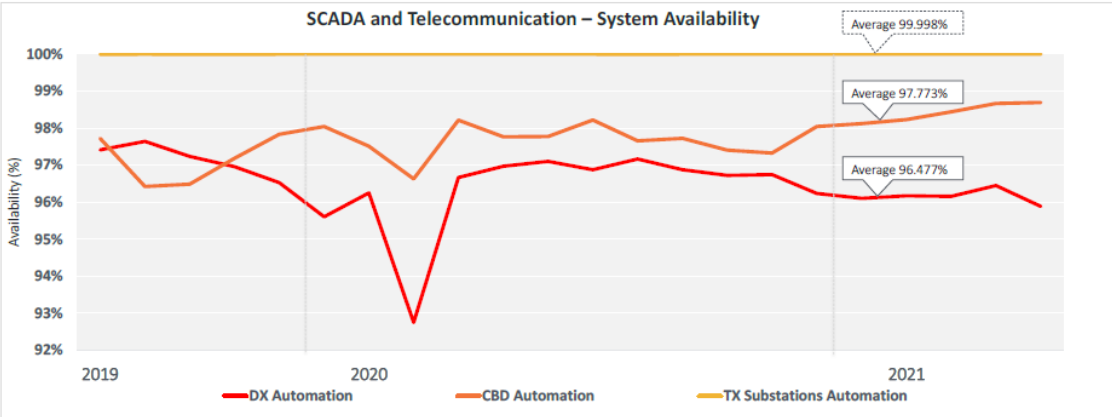
Engevity found that Western Power's ICT program is in -principle necessary over the medium to long term. However, we hold concerns around the deliverability and efficiency of the proposed AA5 investment for the program that warranted a more gradual deployment of ICT expenditure over the

662 Access Arrangement Information - Access Arrangement revisions for the fifth access arrangement period (1 Feb 2022)

AA5 period and beyond. We acknowledge the increasingly complex and challenging ICT environment in which Western Power operates.

Western Power overspend in AA4 was justified by unplanned CAPEX and a growing risk of obsolesce and non-compliance of IT, SCADA and Communication assets. However, Engevity observed some inconsistency between the expenditure forecasts and the trends in SCADA availability for AA5. We refer to Network Management Plan[663] which shows a relatively flat historic availability of SCADA and Telecommunication networks and forecasts an increase in reliability for CBD automation in the future.

Figure 8–22: SCADA and Telecommunications Availability[664]



We highlight that the graph above does not appear to align with the table below and Engevity is of the opinion that Western Power has not created a clear case that the underlying risk driver is commensurate with the significant increase in forecast investment.

663 AAS - Attachment 8.2 - Network Management Plan, pages 317-319

664 Attachment 8.2, Network Management Plan, Figure 12.17

Table 8–25: Automation Forecast Availability[665]

Scenario	Measure	June 2021	No Investment (end AA5)	Planned Investment (end AA5)
Tx Automation				
Metro typical	Availability	99.9965%	95.8219%	99.9965%
	Unavailable Minutes	17.883	21959.66	17.882
Metro long	Availability	99.9965%	95.8216%	99.9965%
	Unavailable Minutes	17.884	21961.34	17.882
Rural typical	Availability	99.9965%	95.8219%	99.9965%
	Unavailable Minutes	17.898	21959.83	17.897
Rural long	Availability	99.9965%	95.8215%	99.9963%
	Unavailable Minutes	17.996	21961.82	19.022
Dx Automation				
CBD Automation	Availability	99.46%	88.3863%	99.9080%
	Unavailable Minutes	2838.22	61041.24	483.11
Dx Automation	Availability	98.21%	83.7485%	99.8528%
	Unavailable Minutes	9408.24	85417.81	773.68

Feedback from customers on ERA's AA5 Issues Paper[666], namely the Australian Energy Council (AEC) and Alinta on Western Power's AA5 Proposal, highlights concern with the level of forecast SCADA and Comms expenditure proposed. They raise that they believe there remain uncertainties in the design of the '*future electricity system and the potential for a large amount of additional costs during AA5… [and] proposed SCADA works [to] be delayed limiting some of the price increases during the AA5 period*'[667]. They also highlight concerns with the impact on prices of the proposed expenditure on relatively shorter economic life (10.2 years for SCADA and Communications) assets using the straight-line depreciation method of these assets. The AEC notes that the forecast depreciation in 2026/27 of $633.1m is 47 per cent higher than the forecast depreciation in 2022/23 of $443.8m.

Engevity again notes that MRL is heavily relied on as the indicator of replacement need for an asset, not the asset's current condition or performance.[668] This may mean that some ICT assets may be considered for replacement prematurely.

Based on our experience, Engevity notes that a low RAB value or low economic life rarely means that there is no engineering life remaining. A prudent and efficient operator, acting to minimise costs would seek to extend the life of these assets based on physical inspection of condition, the risks that would be crystalised in the event of a failure and the cost of mitigation works (refurbishment, reinforcing, partial replacement, wholesale replacement) to identify and pursue, the least cost option.

Older, largely depreciated assets can provide ongoing service without attracting significant capital charges. As a result, large scale replacement of older assets based on their low value in the RAB or

665 Attachment 8.2, Network Management Plan, Figure 12.14

666 See https://www.erawa.com.au/AA5

667 AEC public submission on ERA AA5 Issue Paper https://www.erawa.com.au/cproot/22595/2/Australian-Energy-Council3.pdf

668 Distribution Structures Asset Management Strategy, Western Power, 2021, p.10

obsolescence is not a reasonable justification for investment, but rather a flag for concern regarding the efficient management of the transition.

Prudent and efficient operators identify the risks on their network, mitigating them through targeted inspection, maintenance, refurbishment and replacement works to keep assets in service for as long as practicable. For some asset classes where the consequence of failure is low, it is not unusual for assets to simply be operated for as long as they last and then replaced or repaired on failure.

Despite acknowledging the need to improve cyber security and to adapt to more complex ICT operating environment, Engevity observed a lack of risk and benefit quantification to support the substantial increase in ICT expenditure forecast.

Scope Definition

In general, while the high-level justification, strategy and assessment approach to ICT program has been provided, there was limited additional detail. In particular, we did not observe a collated document that sets out the current timing, staging, scale and end objective of ICT program. No business case/investment plan has been provided for total program or AA5 ICT investment.

From the information provided, Engevity is <u>not</u> confident that:

- Western Power has the capability or resources in place to efficiently deliver such as large volume of expenditure in AA5 because it is significantly larger than programs being delivered by other network facing similar challenges and risks; and
- the costs and benefits of the AA5 program as scoped in Western Power's proposal are justified sufficiently to support investment.

Engevity has not observed a detailed resourcing and delivery plan that considers how an accelerated increase in expenditure is achievable. Globally ICT resources and equipment is in high demand and Engevity is aware of skill shortages which may impact the delivery of this proposed expenditure.

Given the early stage of Project Symphony and our recommendations to downscale the AMI and SPS programs and the linkage to the ICT Program, Engevity believes Western Power has not developed a case for the step change in ICT program expenditure. Such a significant increase in expenditure was not demonstrated through future benefits. We do however support the progression of the overall ICT programs while allowing Western Power to:

- demonstrate the benefits of ICT to customers, including providing an experience basis for detailed justification of furthering the program in AA6 and beyond;
- realised cost reductions through learning curve efficiencies and technology cost reductions;
- alignment with our recommended staging of the SPS, AMI and learnings from the Symphony project.

It is not clear that the scope of the proposed expenditure on ICT in the AA5 period is commensurate with the need. We did not observe, detailed analysis that demonstrates how the AA5 proposed expenditure would be prioritised or any assessment of the benefits of deferring some of this undergrounding expenditure to the AA6 period or beyond.

Engevity agrees with the risk management requirements outlined by Western Power however holds significant deliverability and customer impact concerns for both these programs and therefore recommends ERA consider adjustments[669].

[669] See Appendix Q and M for details on our evaluation of the AMI and SPS regulatory expenditure categories respectively.

Timing

Western Power has provided limited evidence that demonstrates the need for the proposed level of ICT expenditure during the AA5 period. The possibility that the project could be staged across AA5 and AA6 has not yet been observed.

Engevity considers the accelerated timing of the current ICT program and resultant proposed AA5 expenditure is not aligned with a prudent and cost-efficient approach. Engevity also has concerns that assets are being prematurely replaced on a conservative asset age risk basis rather than actual asset condition basis.

Engevity found the proposed timing of the AA5 ICT program is overly aggressive without sufficient justification. Furthermore, Engevity identifies several efficiencies that will likely increase with a staged roll out, these include market maturity in DSO/DMO frameworks through learning from Project Symphony, reduction in technology cost curves, an alignment with our recommended staging of the SPS & AMI programs and a greater ability to deliver the program with regard to quality and cost management.

Risk Management

Western Power has conducted a risk assessment[670] however we noted some conflicts in the underlying assumptions support the case for the forecast investment in AA5. We agree that an increasing threat of cyber security, transition from a physical firm to open generator access framework will have its challenges, as well the continued increase in DER uptake by customers. Despite this we have suggested a planned staging to AMI and SPS programs which should include building on existing system rather than moving to new platforms.

The absence of any risk quantification for the ICT program makes it difficult to establish that the most efficient and prudent ICT is being objectively chosen. Noting the value and criticality of the ICT project, we would expect the risk management and options assessment process to include a quantification in terms of reducing Expected Unserved Energy (MWh) valued at the Value of Customer Reliability.

Engevity notes that in its 2020 Asset Management System review, AMCL found that Western Power has not had a robust and consistent approach to whole of life costs or quantifying risk costs for projects. [671] Engevity shares these concerns.

In general, Western Power's asset risk management system have been commended for their asset management system in past independent reviews, including by AMCL in its 2020 Asset Management System Review (AMSR).[672] However, a key recommendation from the 2020 AMSR was for Western Power to develop and implement a 'whole of lifecycle' cost assessment in its asset planning and investment processes, and that risk costs should also be better quantified and integrated, including in the Investment Gate Approval process. [673]

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670 See AA5-ENG22.15 (should be 22.16) SCADA and Telecommunications Strategy.docx

671 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. 24

672 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. v

673 Western Power 2020 Asset Management System Review, https://www.erawa.com.au/cproot/21688/2/Final-asset-management-system-review-report---2020-Review---EDL001-ETL002---Western-Power.PDF, AMCL, 2020, p. vi-vii

Engevity has not found evidence that these concerns have been addressed by Western Power for its AA5 proposal. Also, we noted from the information provided Western Power customers 'do not value additional investment to improve reliability'[674].

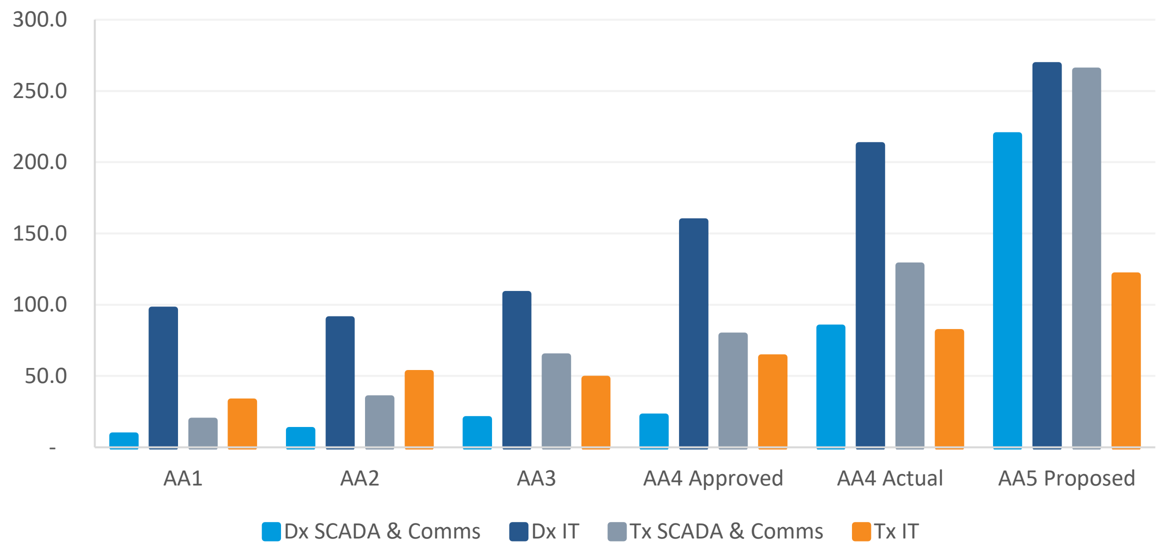
Cost Efficiency

Limited detail and business cases or investment evaluation models have been put forward by Western Power for individual ICT projects or the program as a whole. Western Power has not clearly established the cost efficiency of the CAPEX for the scale of ICT expenditure in the AA5 period. We also did not observe clear justification of ICT expenditure scope components and that Western Power has demonstrated that ICT cost forecasts have been estimated using industry benchmarks and unit costs.

The proposal does not present a business case for the expenditure net of replacement costs. Consequently, it is not clear whether there is a benefit (for example, through savings, or reduced outages) in exchange for the significant increase in expenditure.

The issues we found included the lack of cost-benefit analysis in support of the ICT CAPEX proposal, insufficient options analysis and a lack of evidence to support the ICT CAPEX proposal, lack of evidence in support of unit cost escalation, obsolesce concerns leading to decreasing availability of SCADA system. The lack of information to support the ICT asset CAPEX forecast and the significant level of investment in short lived asset has underpinned our justification for a recommended delay to the ICT expenditure program.

Table 8–26: Historical ICT CAPEX by regulatory category[675]



Engevity has completed a basic assessment of some of the other networks in the NEM to provide some context on the scale of expenditure forecast by Western Power in the table below. It should be noted that there may be some variation in the defined inclusions in each regulatory category between networks which may be a basis for the observed variations.

674 Access Arrangement Information, 1 Feb 2022, Western Power, p. 71

675 Ibid. p. 211

Table 8–27: Other Network ICT Expenditure

	$real	Period	Final Approved AER Expenditure
SAPN	2020	2020-25	279.4m[676]
Energex	2020	2020-25	$147.7m[677]
Ergon	2020	2020-25	$164.4m[678]
Endeavour	2019	2019-24	$120.16m[679]
Essential	2019	2019-24	$98.5m[680]
Ausgrid	2019	2019-24	$144.2m[681]
TransGrid	2018	2018-23	$84.3m[682]
Powerlink	2017	2017-22	$105.8m[683]

Using the above figures, Western Power's forecast for $483.4m SCADA expenditure is significantly higher than other regulated networks. Using the above analysis, Engevity would have expected to see a range of $200–$350m and has not observed evidence from Western Power to justify such a large increase in expenditure. As context, Western Power's forecast $483.3m for AA5 for Dx and Tx SCADA is more than Energex, Endeavour, Essential and Powerlink combined current approved total ICT expenditure. Using benchmarking, our recommended adjustment to SCADA and Comms is $338.10m, which is comparable to approximately SA Power Networks and TransGrid's or Ergon and Energex combined approved expenditure in recent regulatory determinations by the AER.

Scope Efficiency

Engevity has not observed evidence, in the scope of the combined ICT programs that considers options to stage the proposed expenditure, leading to a reduced scope whilst reducing risk within the AA5 period. Western Power has not provided sufficient evidence of risk-based prioritisation of ICT programs. Such risk-based prioritisation should consider the risk category of the condition of the existing assets grouped in individual proposed project areas. It should also consider the potential of the ICT infrastructure to alleviate reliability issues and improve customer outcomes associated with the replacement due to anticipated impacts of failure events adversely affecting reliability or its service obligations.

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676 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/final-decision

677 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/energex-determination-2020-25/final-decision

678 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/final-decision

679 Includes Communication & ICT regulatory category. Source https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/endeavour-energy-determination-2019-24/final-decision

680 Includes Communication & ICT regulatory category. Source https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/essential-energy-determination-2019-24/final-decision

681 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2019-24/final-decision

682 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/transgrid-determination-2018-23/final-decision

683 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powerlink-determination-2017%E2%80%9322/final-decision

Furthermore, Engevity did not observe sufficient evidence of how economies of scope could be obtained by staging the rollout or combining monitoring and control systems across both its Dx and Tx network areas. From the documentation provided to us, we did not observe rationalisation of the asset management decisions during AA4, to move from a reactive to a proactive replacement approach, which possibly has led to an overestimation of scale of expenditure required in AA5.

Western Power states that the age of the equipment, as a significant and increasing driver for the need to upgrading Western Power IT, SCADA and communications assets. In most cases, we observed Western Power identify risk, safety and compliance needs for the expenditure. However, we are aware of many networks operating SCADA systems that are not supported by OEMs.

Engevity observed relatively flat historic availability of SCADA and did not cite an underlying basis for such a step change in the forecast investment.[684] Furthermore, Western Power has stated that they 'are not forecasting any maintenance cost savings from the SCADA network during AA5, as the pace of assets deterioration is greater than the replacement pace'[685].

As a result, while Engevity recognises that there may exist hot spots of unreliable ICT assets, Western Power's overall reliability for the autonomous network is stable and appears to be largely meeting standards. Customers also seem to be content overall with current standard and level of investment to support reliability.

Strategic Alignment

Investments in ICT (along with SPS, deployment of AMI, a roadmap for microgrids and a DSO capability) are identified as critical to facilitate the transformation of the network and support future customers' needs[686].

ICT are not identified as priority programs under the NFIT.

Options Analysis

Western Power has not attempted to identify a reasonable range of alternative options to deliver the ICT program. Western Power does not explicitly discuss the relative value and risk sustaining the ICT asset. The amplified impact on customers of shorter ICT asset lives of such a large investment impact on both CAPEX and OPEX has not been clearly considered.

Upon request, Western Power provided some sensitivities on the impact of a reduced level of forecast expenditure. Using Western Power's own modelling a 25% reduction in expenditure would see a doubling in cyber compliance however a reduction in the availability of other systems in future regulatory periods.

Delivery Model (incl. staging)

Engevity is not convinced that Western Power has the capability and resources to deliver its proposed ICT program for the AA5 period, particularly in a cost-efficient manner.

During AA4, Western Power noted efficiency gains in grouping projects by location and geographical area as well as forming joint planning teams.

Engevity considers an efficiently delivered ICT program applies conservative risk-based prioritisation to replacement ICT assets in individual potential project areas. This would be followed by preparing a business case or investment evaluation model that clearly demonstrates each prioritised replacement project has lower cost and a benefit for consumers.

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684 Att 8.2 Network Management Plan, Pages 317-319

685 AA5-ENG38.01 ENG38.02 ENG38.06 ENG38.13 - OPEX - Breakdown and impact of Major Initiatives response

686 Ibid. p. 178

8.8 Advanced Metering Infrastructure – AA5 Assessment

Engevity has reviewed Western Power's proposal for the AA5 period and found that it **DOES NOT COMPLY** with the Access Code requirements for an AA submission. We found that some expenditure **DOES NOT COMPLY** with the NFIT requirements or represent efficient expenditure. As a result, we have made recommendations for ERA adjustments in the table below.

8.8.1 Assessment

Table 8–28: AA5 Expenditure and Scale – Advanced Metering Infrastructure [$m real at 30 June 2022]

AMI	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Proposed Total CAPEX [687]	*61.67*	*61.81*	*62.03*	*62.63*	*63.19*	***311.33***
Western Power Proposed Net Direct CAPEX [688]	51.50	51.50	51.50	51.50	51.50	**257.51**
Adjustment 1 – Remove acceleration[689]	-15.78	-15.78	-15.78	-15.78	-15.78	**-78.88**
Adjustment 2 – Remove Meter and ICT CAPEX contingency @ 8.2% of AA5 cost for AMI2 BAU[690]	-3.47	-3.23	-3.75	-4.23	-3.93	**-18.61**
Engevity Recommended Net Direct CAPEX	32.26	32.49	31.98	31.50	31.79	**160.03**
Adjustment 3 – Add back meter reading OPEX	0.37	0.75	1.16	1.58	2.03	**5.89**

Source: Western Power CAPEX Model and Engevity Analysis

687 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs', Column AF - AK

688 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs', Column H – M less Capcons from 'Capcon calc' sheet

689 Proportional adjustment based on Western Powers Reported $115.6m incremental CAPEX for acceleration and the $377.4m total cost reported for the accelerated program. (i.e. $115.6m / $377.4m = 30.6%)

690 Western Power, *AA5ENG22.07 – AMI Financial Analysis model 2021v6 (CCONFIDENTIAL),* 'SC7 AMI BAU' Sheet, Sum of contingency rows / AMI2 BAU Total for the years 2023-2027 = 8.2% total contingency component in the BAU program. 8.2% x cost of BAU program gives the adjustment amount.

Table 8–29: Assessment Overview

Project/Program	Advanced Metering Infrastructure
Forecast Cost $m	Western Power has proposed an investment of **$311.33m** for an accelerated AMI rollout
Need	The need for the program is supported by the WA Government and Energy WA to address voltage control problems during high solar exports, to enable Time of Use tariffs, and address system stability issues
Scope Definition	The acceleration is predicated on safety and reliability benefits that do not justify the additional cost or scope to accelerate the roll out.
Timing	The timing brings forward AMI meter replacements that would occur over the period to 2037 and implies that there is a significant write down of the metering asset base.
Risk Management	The acceleration of this program is predicated on improved safety from neutral integrity monitoring to reduce shocks and tingles arising from neutral degradation. This is an issue that has historically been managed to an appropriate level by Western Power over the history of the network. The successful past management approaches (customer reporting, and network inspection, proactive service wire replacement) is highlighted by the low 'find rate' of 75 issues p.a. in a population of 214,000 AMI meters (0.03%)
Cost Efficiency	Delivery of AMI programs have a chequered history in Australia and abroad. Particularly there was a key learning from the Victorian Mass Roll Out that costs tend to increase significantly at the tail end of the program as there are a higher proportion of 'difficult' and deferred installations. The AEMC has been assessing the relative merits of AMI, noting that meter replacement, new connections and upgrades have resulted in penetration rates around 20% in the NEM (excluding Vic) – this is below the level that was expected when the contestable metering framework was introduced. The AEMC's assessment indicates that at least 50%[691] penetration was needed to fully realise benefits. By the end of AA4 Western Power will have 500k AMI customers out of a total customer base of around 1.2m in 2022.
Scope Efficiency	The AMI program was originally scoped to occur from 2019 to 2037. As of July 2022, Western Power expects approximately 500,000 AMI installations to be completed due to additional government support for neutral integrity monitoring via additional AMI installation. This equates to an AMI meter penetration of over 40% at the commencement of AA5 and a required scope of around 80k meter installations over the AA5 period to reach the AEMC's > 50% penetration target on the 1.4m meters forecast in the AMI financial analysis to be required by the end of AA5. This adjusts the total volumes to account for around 120k meters in Western Power's analysis that arise from network growth forecast for AA5 (New customers typically meet the cost of the meter in their initial connection charges). Engevity highlights that the rate of new connection growth is

691 Australian Energy Market Commission, *Directions Paper – Review of Metering Services*, 16 September 2021, pp. 12, 18-19

Project/Program	Advanced Metering Infrastructure
	approximately double the volume of 12k p.a. forecast over 2021 to 2025 in the supporting document for Western Power's customer number forecast[692].
Strategic Alignment	The AMI program is supported by Energy Policy WA for its contribution to enabling more cost reflective tariffs and supporting control of inverters to improve network stability.
Options Analysis	Western Power has considered 3 options and chosen the middle option on the basis of deliverability concerns with a faster acceleration and a qualitative assessment that the original rate of AMI installation was insufficient to meet Western Power's needs in relation to DER hosting, control of customer generation and flexible pricing.
Delivery Model	Western Power's program risks increases in costs or delivery constraints in AA5 due to the very large acceleration in AMI installations. From Western Power's analysis, the acceleration is inefficient and unnecessary given a) it represents the highest cost option, b) its cumulative cost-benefit at 2036 remains negative, c) the BAU AA5 option provides a $51m higher cumulative return at 2036 and d) the acceleration exposes customers to greater financial risk between 2023 and 2034, with negative cumulative cost-benefits reaching -$254m in 2027. In comparison the AA5 BAU option remains around -$100m over period to 2030 before turning positive in 2033.

Findings

Engevity reviewed the information provided by Western Power, including the Business Case documentation and options assessment model for the proposed acceleration, and noted that:

a. **The safety benefit claimed by Western Power as a key justification for the acceleration is calculated to be statistically valued at between $72.9 to $729 p.a.** (in total across the accelerated population) for each of the five years using:

   i. **Western Power's observed 12-month neutral integrity issue 'find rate' across** a population of over 200,000 AMI meters - representing approximately **20% of Western Power's customer base**

   ii. The most recent **five years of WA reported safety statistics from the Energy Regulatory Authorities Council (ERAC)**

   iii. The Australian Government's most recently published **Value of Statistical Life (VoSL)**

   iv. The maximum **As Low As Reasonably Practical (ALARP)/So Far As Is Reasonably Practical (SFAIRP) gross disproportionality multiplier of 10** that is applied in Australian electricity networks in their Electricity Network Safety Management Systems (ENSMS) and accepted by the Australian Energy Regulator

b. **The option evaluation model identifies the acceleration as having the highest cumulative cost to 2036, with a negative $21.1m cumulative cost-benefit** outcome over the period (falling $51.3m less favourable that the AMI2 BAU option). [693]

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[692] Western Power, *AAI – Attachment 7.5 – Energy and Customer Number Forecast Report (2020)*, Section 4.1 Deceleration of connection growth (2015-2019), *"There is an average of 12k new residential NMIs per year forecast for 2021-2025."*

[693] Western Power, *AA5ENG22.07 – AMI Financial Analysis model 2021v6 (CONFIDENTIAL),* 'Charts expenditure' Sheet, Charts at rows 132-180

c. **The analysis also includes a number of input assumptions for both benefits and costs that are inconsistent** with Western Power's demand forecast assumptions or inappropriately include project management and delivery risks. These include:

   i. **The assumed rapid uptake of customer 'responding' to Time of Use (ToU) tariffs**, assumed to be 35% of AMI customers (173,859) in 2023, rising to 55% of AMI customers (620,101) by 2027. For comparison, at June 30, 2021, the AER reports that 16.6% of distribution customers in the NEM were on cost reflective tariffs[694]. SAPN had the highest uptake at approximately 40% followed by Ausnet Services at approximately 31%.

   ii. **The flat demand forecast provided by Western Power** in its AA5 proposal indicates that in a broad sense there is limited maximum demand pressure on the network (excepting a small number of substations). As a result, the significant value assigned to 'deferred augmentation' benefits in the AMI option analysis sheet is almost certainly overstated and we also note that the demand forecast itself may also be overstated on the basis that specifically excludes the impact of Time of Use pricing on AA5 demand.

   iii. **The historical information from Western Powers AMI1 program in the model also highlights a significant overrun of costs in AMI2** against the original AMI1 forecast. This raises concerns over the delivery and scoping assumptions of the original program and follows a similar trend in the delivery of the VIC AMI Mass Roll Out where costs escalated because installations became increasingly more complex and geographically distributed as the programs progressed. Given the scale of cost increase over the original forecast, we consider that it would be imprudent to accelerate the program until the business case and associated analysis for the program was reconciled with Western Power's historical forecasts and AA5 planning assumptions

   iv. Similar concerns about **the likely overstatement of benefits relating to Western Powers assumption of a VCR of $50,000/MWh** to value all customer reliability benefits, which is approximately double the AER 2021 residential customer VCR of $24,980/MWh[695] and above the AA5 VCRs proposed by Western Power of $40.4k/MWh- $43.3k/MWh (depending on feeder type)[696]. **This results in a 13-19% overstatement of the value of reliability and response time benefits in the AMI Business Case.**

Overall, we found that the justification of the AMI program, and most notably the acceleration proposal, justification did not satisfy the NFIT requirement to efficiently minimise costs.

Recommended Adjustment

Western Power has proposed a total CAPEX of $311.33m ($266.86m direct CAPEX) to replace 795,130 existing meters with AMI meters over the course of AA5. This represents a substantial acceleration over the previous proposals for the smart meter rollout.

Engevity has reviewed the program and recommends that:

1. The program is delivered in accordance with the original volumes. This results in the **downward Adjustment 1 of $78.88m (in direct CAPEX)** and related adjustments to indirect CAPEX, escalation).

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694 AER, *Network Tariff Reform,* website

695 Australian Energy Regulator, *2021 VCR Annual Adjustment Summary*, December 2021, p. 2

696 Western Power, AA5 Regulatory Revenue Model, 'Incentive_Rate_Inputs' Sheet, cells C4:C7

2. The explicit contingency for project management and delivery risks on metering and IT hardware is removed from the costs. This results in **the further downward Adjustment 2 of $18.61m (in direct CAPEX)** and related adjustments to indirect CAPEX, escalation).
3. To account for the meter reading costs that would notionally have been avoided under the accelerated program and therefore not included in Western power's OPEX forecast, **the upward Adjustment 3 totalling $5.89m should be added to the OPEX forecast**

The ERA should also ensure that the proposed asset disposals from the metering category for meters that are replaced before their end of life have been adjusted in the regulatory depreciation forecast.

8.8.2 Assessment of AA5 Proposal

During AA4, Western Power commenced an Advanced Metering Infrastructure rollout, with support from the WA Government. This program envisioned a roll out by 2037,

Overview

Western Power commenced an Advanced Meter rollout in 2019 with the intention of supplying all customers with AMI hardware by 2037[697]. This was supplemented by the Western Australian Government's Service Connection Condition Monitoring programs as well as meters installed as part of Western Power's Smart Cities trial. Together, these programs will result in approximately 500,000 AMI installations by 30 June 2022.

Need

In response to the WA Energy Transformation Strategy and the emergence of minimum load issues in AA4 driven by high levels of customer DER (rooftop solar and storage), Western Power has proposed a total of $412.8m ($377.5m CAPEX and $35.4m OPEX) of metering expenditure in AA5 with the $311.3m AMI program comprising the vast majority. This would effectively complete the AMI rollout to all customers during AA5 equating to 795,130 meter installations.

Western Power cites that the full-scale AMI rollout will:

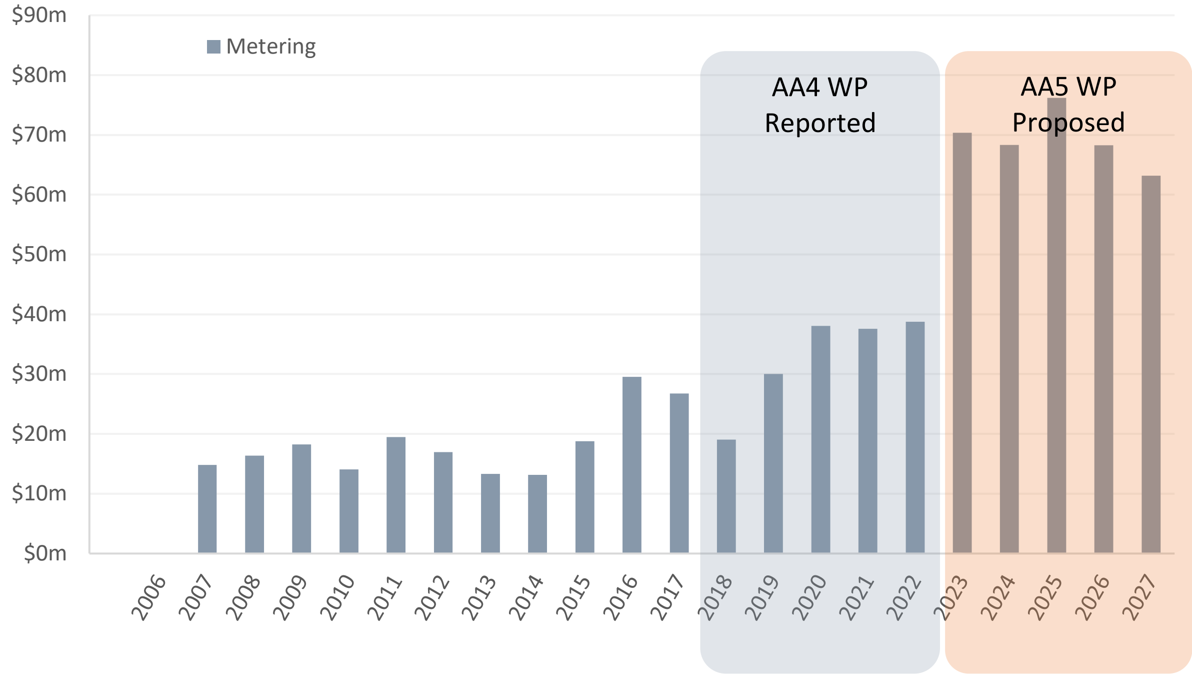
1. Allow all customers to have increased visibility and control of their energy usage
2. Enable more customers to install rooftop solar as part of the DER roadmap – reducing carbon emissions to help meet state targets.
3. Enable market reforms to allow more cost reflective electricity pricing for all customers.

Whilst Engevity agrees that there is a need to address these matters over AA5, we do not consider that accelerating the full-scale rollout of AMI is the most efficient or timely means of achieving these outcomes.

The proposed expenditure on metering from 2007 to 2027 is shown in the chart below.

[697] Western Power, *Attachment 8.6- AA5 Business Case Advanced Metering Infrastructure*, July 2021

Table 8–30: Meter Replacement Expenditure 2007-2027 ($real June 2022)[698]



It is clear that Western Power's proposal represents the largest 5-year metering investment since the regulatory data commences in 2006. Given the scale of expenditure and substantial increase in delivery volumes that has been proposed, we are concerned about Western Powers ability to efficiently deliver the program and realise sufficient benefits to justify the cost to consumers.

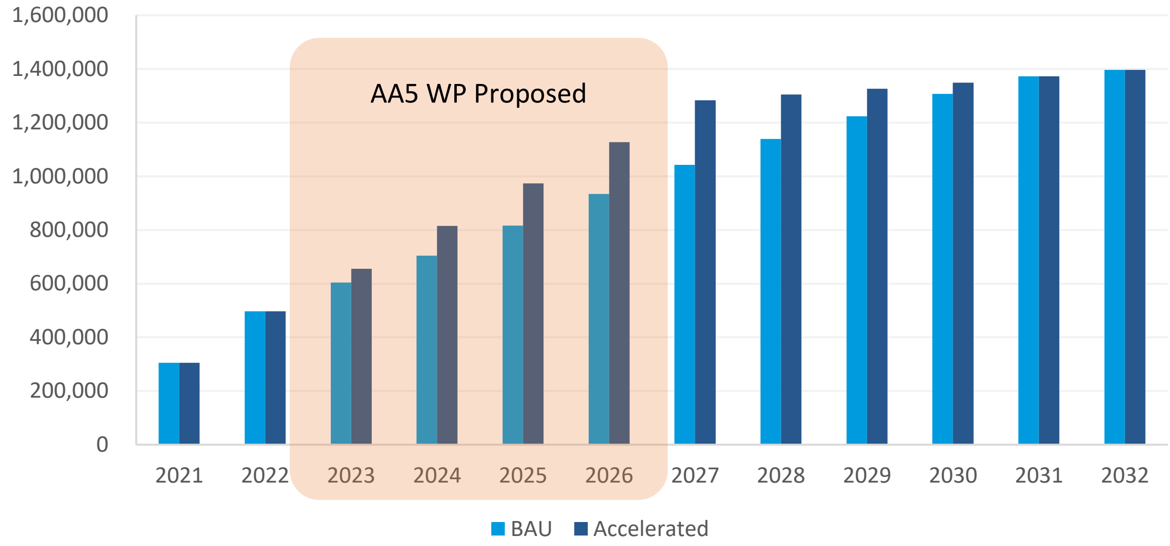
Timing

The AMI rollout was commenced during AA4 with an original goal to complete the rollout by 2037. This was accelerated under the WA Government's Service Cable Condition Monitoring program which sought to reduce shocks and tingles resulting from degradation of the neutral service wires/cables which connect houses to the street electricity infrastructure. Degradation of the neutral service wires or cables can result in plumbing fixtures and other metallic surfaces in the home or garden becoming live as electricity is directed to earth rather than back to the network via the neutral wire.

Engevity is not suggesting that neutral integrity monitoring is not a worthwhile benefit to the AMI project, but that the urgency appears to be overstated given the relatively young service wire population following the Western Power 'twisties' service wire replacement program in the early 2010's, the approximately 500,000 AMI customers expected to have condition monitoring by the end of AA4 and the reduction in the number of overhead customers (where the greatest neutral integrity risk occurs) through substantial investment in SPS and undergrounding proposed in AA5 (even following adjustments). Whilst Western Power has noted an increase in underground service neutral faults, these have mainly been attributed to vehicle collisions with the properties' electrical pillars.

698 Source: Western Power Regulatory Model

Figure 8–23: Cumulative AMI Installation Volume by Year



Source: Western Power AMI Financial Analysis Model[699]

The business case for the acceleration relies largely on a subjective justification of a 70% reduced risk of electric shock to approximately 20% (240k) customers over a 5-year deferral period when compared to the original 2037 program. Western Power notes that from August 2020 to July 2021 the SCCM project detected and remediated 75 electric shock hazards in a population of around 215,000 meters, or approximately 0.03% of installations.

Similarly, the case for acceleration is largely reliant on the assertion that it is justified by providing Neutral Integrity monitoring to 240,000 customers five years earlier. Below, Engevity evaluated the total quantitative value of this safety deferral as just $72.90 for five years - or $729.00 p.a. with the application of an extreme disproportionality factor of 10 for safety risks. This is based on the typical 'ALARP/SFAIRP' assessments that are conducted by Australian networks to justify safety investment.

Furthermore, we note that **Western Power obtained ERA approval to conduct a $71.1m overhead customer service cable replacement program** between July 2009 and June 2012 **to address 104,600 of the then 410,000 overhead service connections**[700] **in its network**. This is in addition to 60,000 replacements during AA1.

In practice, the proportion of recent service replacements is much higher with Western Power noting that around 75% of overhead service wires are under 10 years old, and 70 % of underground service connections are under 20 years old[701]**.** Furthermore, the SCCM and AMI programs in AA4 targeted overhead services populations that *"…exhibited a higher rate of electric shocks… …This is now complete and these sub-populations… …are expected to have a lower number of electric shocks through AA5 and beyond"*[702]

From Western Power's own assessment of the risk, and, supported by much improved safety performance statistics over the past decade, we note that the Network Management Plan identifies that *"Most electric shocks are related to neutral impedance issues and direct contact through*

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699 Western Power, *AA5ENG22.07 – AMI Financial Analysis model 2021v6 (CCONFIDENTIAL)*, 'AMI2 Parameters' Sheet, Rows 76:77

700 Western Power, *Replacement of Overhead Customer Service Connections 2009/10 to 2011/12*, June 2010 p.8

701 Western Power, *AA5 Attachment 8.2 Network Management Plan*, pp. 155-156

702 Western Power, *AA5 Attachment 8.2 Network Management Plan*, p. 156

excavation, and the remaining are attributed to cable failures. ***All the electric shocks in the reporting period have been minor with no injury****"*[703]

As well as noting that *"…sub-populations that exhibited a higher rate of electric shocks were targeted in AA4 by the investment in SCCM and AMI. This is now complete* ***and these sub-populations of OCSC***[704] ***are expected to have a lower number of electric shocks through AA5 and beyond****. Any remaining OCSC not targeted, will have SCCM deployed, when an advanced meter is installed."*

When these factors are taken into account, it is apparent that the substantial capital that has already been deployed to manage these risks in AA3 and AA4 has been successful, with a marked improvement in the relevant safety measures, including:

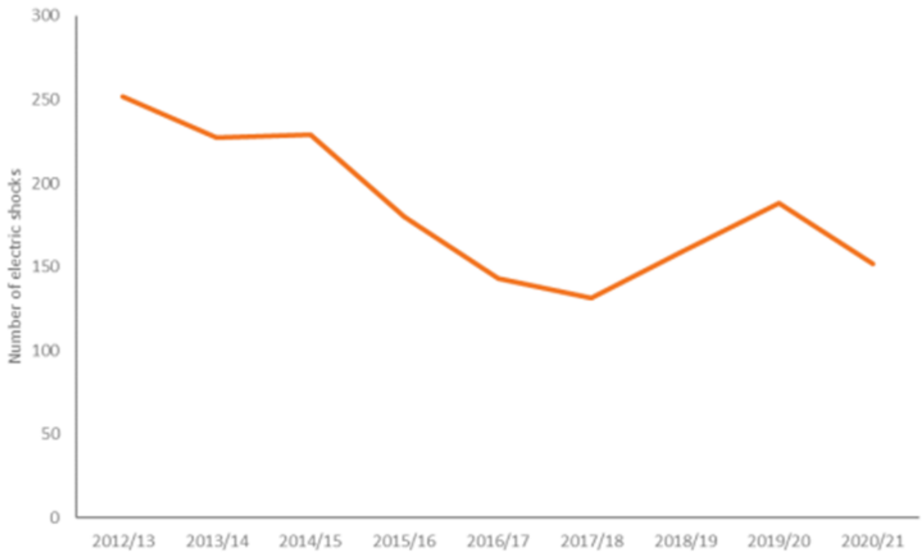
- **44% of reported shocks and tingles were not assessed to have been caused by a hazardous voltage**

  Western Power notes a significant increase in reports of electric shocks and tingles following public awareness campaigns, with no observed increase in injuries and a substantial portion of the reported shocks found not to be caused by a hazardous voltage.

- **Electric shock incidents reported to have declined from over 250 p.a. in 2012/13 to less than 150 p.a. in 2020/21**

  Western Power has achieved a significant reduction in electric shock incidents via the extensive overhead service connection replacement program that has seen over 75% of the total population addressed under the dedicated 'twisties' program and other maintenance and replacement activities.

Figure 5.23: Electric shock incidents



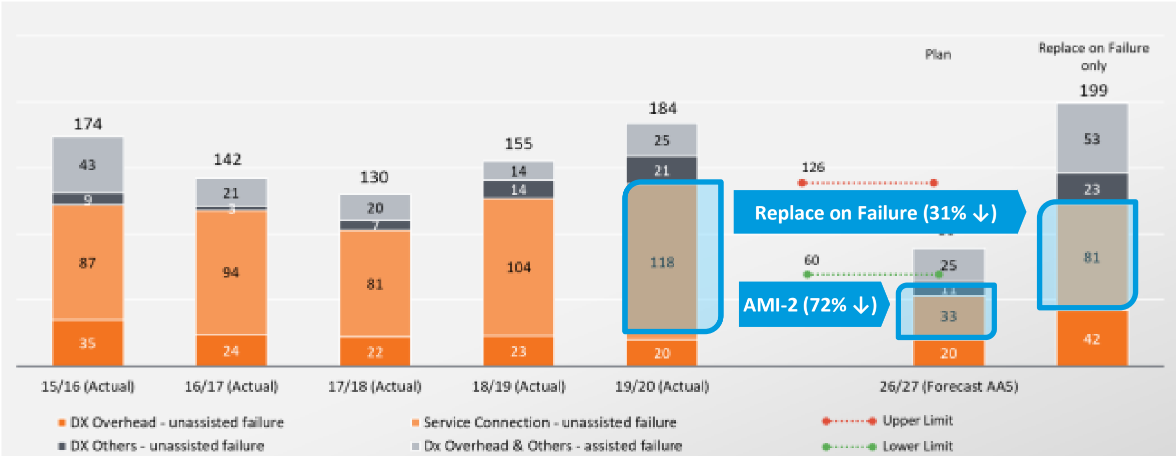
- **Public Impact incidents reducing from an average of 0.3 per month in 2016/17 to 0.0 per month in 2020/21.** Highlighting the limited scope for future improvements and the challenge in maintaining performance at current levels.

[703] ibid,

[704] Overhead Customer Service Connection (OCSC)

- Western Power's own forecast for AA5 asset performance indicating that shocks due to service connection issues will reduce from 118 p.a. in 2019/20 to 81 p.a. in 2026/27 (32%) under a 'replace on failure only' strategy – this strategy is forecast to achieve 44% of the benefit of the accelerated AMI program, without the large investment proposed by Western Power.

Figure 8–24: Western Power Electric Shock Forecast



Source: Western Power Network Management Plan p. 18, Engevity annotation in blue

- **The severity of electric shocks is reported as being '…minor with no injury'**

  "Most electric shocks are related to neutral impedance issues and direct contact through excavation, and the remaining are attributed to cable failures. ***All the electric shocks in the reporting period have been minor with no injury****"*[705]

Western Power has achieved effective safety outcomes over the last 10 years with regard to overhead service connection assets, at a not insignificant cost to customers. As a result it becomes necessary to consider what level of ongoing investment is warranted to further reduce the residual risk. The business case for AMI includes a qualitative (tick/cross) style assessment to exclude 2 of the three options, without any quantified assessment of risk. This is shown below and mirrors our AA4 observations from the Hay-MIL switchboard project that Western Power's risk and options analysis excludes viable options from consideration without a robust or reasonably quantified assessment of the relative benefits and costs.

705 Western Power, *AA5 Attachment 8.2 Network Management Plan*, p. 153

Figure 8–25: AMI2 Business Case – Assessment of Options against the Evaluation Criteria

#	Option Title	Timely & Effectively Mitigates Risk	Increases Network Safety	Timely Increase in Network Stability	Technically Feasible / Delivery Risk	Aligns with AA5 Corporate Strategy	Delivers Customer Outcomes	Reflects Prudent Investment
1	BAU Deployment completion	✗	✓	✗	✓	✗	✓	✓
2	5 year accelerated deployment completion	✓	✓	✓	✓	✓	✓	✓
3	3 year accelerated deployment completion	✓	✓	✓	✗	✓	✓	✗

Source: Western Power AMI2 Business Case p. 19

A more detailed discussion and summary of the impact on the 'strategic risk drivers' is also included which focuses on the impact on the core Network Transition (incl. Public Safety), Network Stability, and Policy risks that are monitored at the executive and board level. This summary is shown below and highlights the very limited customer safety impact that the business is expecting from the improved neutral integrity monitoring provided by the AMI system.

Figure 8–26: AMI2 Business Case – Strategic Risk Driver of the Recommended Investment

Risk ID and Risk Owner	Risk	Residual (Current) Risk Rating	Risk Treatment	Target Risk Rating
Risk Owner: EM Asset Management – [redacted] **S Risk ID: 1**	Network Transition (including Public Safety)	**High** (Unlikely / Catastrophic)	AMI Acceleration reduces the risk of electric shock at premises where remote monitoring is in place	**High**[28] (Unlikely / Catastrophic)
Risk Owner: EM Asset Management – [redacted] **S Risk ID:2**	Network Stability	**High** (Possible / Major)	In an emergency situation, AMI would enable the potential to disconnect power coming onto the grid	**High** (Unlikely / Major)
Risk Owner: EM Growth – [redacted] **S Risk ID:6**	Policy	**High** (Possible / Moderate)	The accelerated roll out of AMI supports new products for all customers and aligns with the Government's DER Roadmap.	**High** (Possible / Moderate)

Source: Western Power AMI2 Business Case p. 30

The absence of any change arising from the program in this category is explained in Western Power's footnote 28 as follows:

> *"[28] Target Risk Rating recognises that AMI2 will contribute to further mitigating this risk but is unlikely to reduce the likelihood of an incident to 'Very Rare' which is the likelihood needed to bring the target risk to Medium. The severity remains as catastrophic because there is always a risk of fatality) "*

The 'Deferred Investment Risk Assessment' section of the Business Case similarly avoids any quantification of risk despite the relative ease of simply discounting risk consequences and likelihoods over time. Rather than undertaking the formal risk assessment and cost benefit analysis noted in the Western Power Network Risk Management Standard as a minimum requirement for safety risks – shown below.

Figure 8–27: Minimum requirements for network risk treatment selection

Safety risks	Safety risks
Consider whether the safety risk can be eliminated. Record justification if unable to be eliminated e.g. not practical, not feasible.	Select treatments that are prudent and effective at ensuring: • Safety risks are eliminated SFAIRP, and if not practicable to do so, they are reduced SFAIRP • Asset management objectives are met.
Conduct a cost/benefit analysis of treatments for risk reduction. Record assessment of all possible options for treatment across the whole of asset life cycle against the hierarchy of risk control.	Agree selected treatments with stakeholders. Clearly document the rationale for all assessed and approved treatments, recording how this is considered to meet the requirement to eliminate safety risk SFAIRP or reduce risk SFAIRP. Ensure implementation is carried out in accordance with a plan.

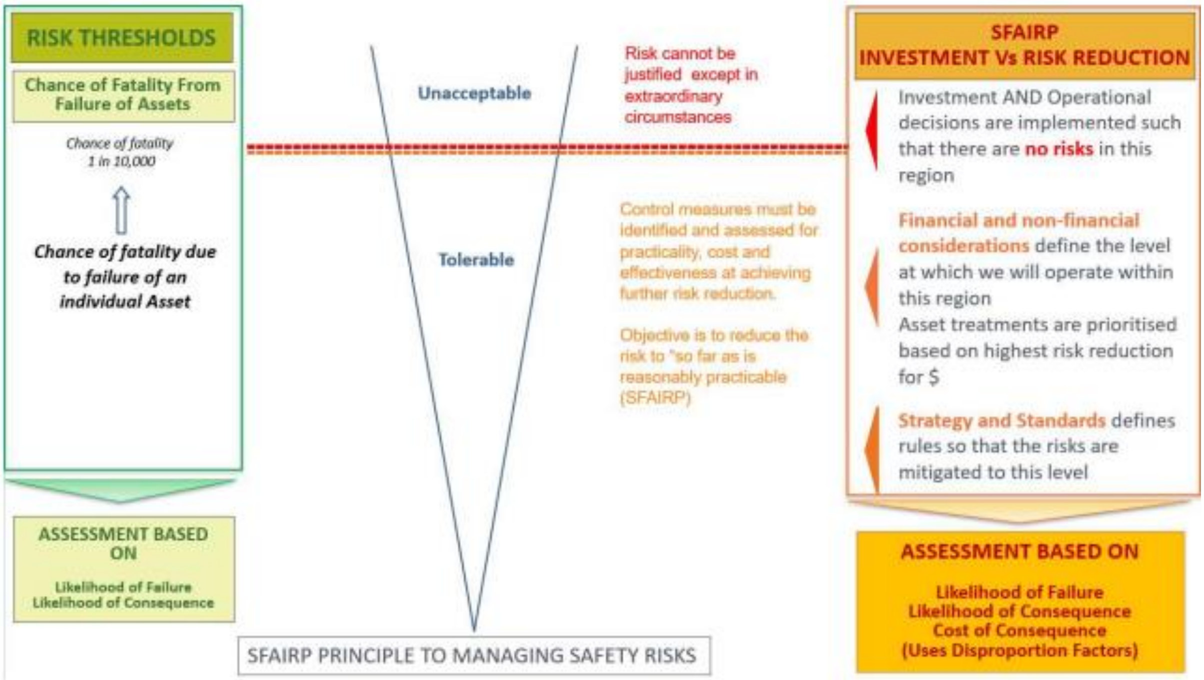
Source: Western Power, Network Risk Management Standard, p.20

The business case does not cover the Network Risk Management Standard requirements for a cost-benefit analysis, justification for the SFAIRP position and documentation of the alternative treatment, probabilities, consequences and disproportionality factors that have been used in decision making.

Noting that the Risk Management Standard adopts an approach that is widely applied across the industry, we have conducted a basic quantitative risk assessment to establish the safety benefit that would arise from the acceleration. This is to demonstrate that a useful quantitative risk assessment can be prepared with minimal effort and, even as a simple screening analysis it provides a much more robust basis for decision making.

The Western Power process is illustrated below.

Figure 8–28: Risk Tolerability Thresholds



Source: Western Power, Network Risk Management Standard, p.24

The process essentially requires an assessment of the:

- Likelihood of failure;
- Likelihood of consequence;
- Cost of consequence;
- Disproportionality factors to demonstrate that the cost of elimination or further reduction is grossly disproportionate to the cost.

Western Power then highlights that treatment is prioritised on a ‘bang for buck’ basis where the most cost-effective risk reduction solution is favoured.

Engevity has made these calculations based on Western Power’s information on failure rates and customers affected. This has been supplemented with published safety performance statistics and the Australian Government - Office of Better Regulation’s published Value of Statistical Life, as adopted by the NEM NSP’s and the AER. We then applied the most conservative disproportionality factor used by an Australian NSP of 10 (more typical values are in the range 4-6).

Surprisingly, we found that the Neutral Integrity monitoring safety benefit was effectively zero for the acceleration program that was proposed. Our calculations found approximately $3k of safety benefit from approximately $100m in proposed AMI investment, which offers a very poor risk reduction for the capital investment. Whilst our results do not support the efficiency of the acceleration proposal, we do note that the low value of risk reduction that is available is testament to Western Power’s improvements in customer safety over the past 10 years.

The specific legacy of the sustained overhead service connection replacement programs (‘twisties’) covering over 75% of overhead services over the last decade, alongside the AMI and Service Connection Condition Monitoring (SCCM) programs with the SCCM effectively targeted over AA4 at the areas where higher service cable faults were more likely to be discovered. This is ultimately a good outcome for Western Power as it verifies that the service connections now pose a relatively low risk to customers.

Figure 8–29: Engevity calculation of safety benefit of AA5 AMI2 acceleration scenario

Engevity analysis of the safety benefit of AMI acceleration

WP reported **75 detections of neutral integrity issues** in a population of 214,000 AMI customers over 12 months

This gives a detection rate of 0.03%

1 fatality has been reported by ERAC for WA the past 5 years of data attributed to deterioration of customer wiring

This gives an annual probability of 1 in 5 or 20%

The retained exposure affects 240,000 customers, or around 20% of WP customer base for 5 years

This restricts the annual probability to 20% of the customer base

The statistical likelihood of the safety risk from not accelerating the program is calculated as

0.03% x 20% x 20% = 0.0014%

Using the Australian Govt Value of Statistical Life (VoSL) of $5,227,500

0.0014% x $5,227,500 = **$72.9 p.a. total bring forward benefit**

Apply maximum NEM ALARP/SFAIRP disproportionality factor of 10 = $729 p.a.

Source: Western Power[706], ERAC[707], Australian Govt. Office of Best Practice Regulation[708]

To account for the ALARP (As Low As Reasonably Practical) / So Far As Is Reasonably Practical (SFAIRP) obligations for safety risks, **we have then applied a 'Disproportionality Factor' of 10** [709]to ensure that the decision holds when a much higher expectation is placed on safety related decision making. **This gives an upper value of the acceleration benefit of just $729 under highly favourable assumptions.**

On this basis, we consider that the accelerated proportion of the program is not justified on the basis that the investment of $95.4m in additional meters. **Accelerating the Neutral Integrity Monitoring program only supports quantifiable safety benefits of between $365 and $3,645 over 5 years. This equates approximately to less than 10 individual meters.** Western Power's own financial analysis

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706 We note that this will likely overstate the volume of detections going forward as the inherent backlog of degraded overhead service conductors will generally be picked up earlier in the monitoring program, with detection rates falling to the recurrent annual service wire failure rate over time.

707 We note that only five years reporting from 2015-16 to 2019-20 is available on the Electrical Regulatory Authorities Council (ERAC) website

708 Australian Government Office of Best Practice Regulations, *Value of Statistical Life Guidance Note*, August 2020 (figure indexed one year at 2.5% - representing the midpoint of the RBA's inflation target band)

709 For context, a factor of 10 represents an extreme case, with other DNSP's typically using values of 3 (Ausnet), 6, Transgrid, and 2-10 depending on the severity of the consequence (Energex).

shows that the accelerated option is the highest cost and has a negative cumulative value at the conclusion in 2036, that is approximately $52m less than the BAU scenario over AA5[710].

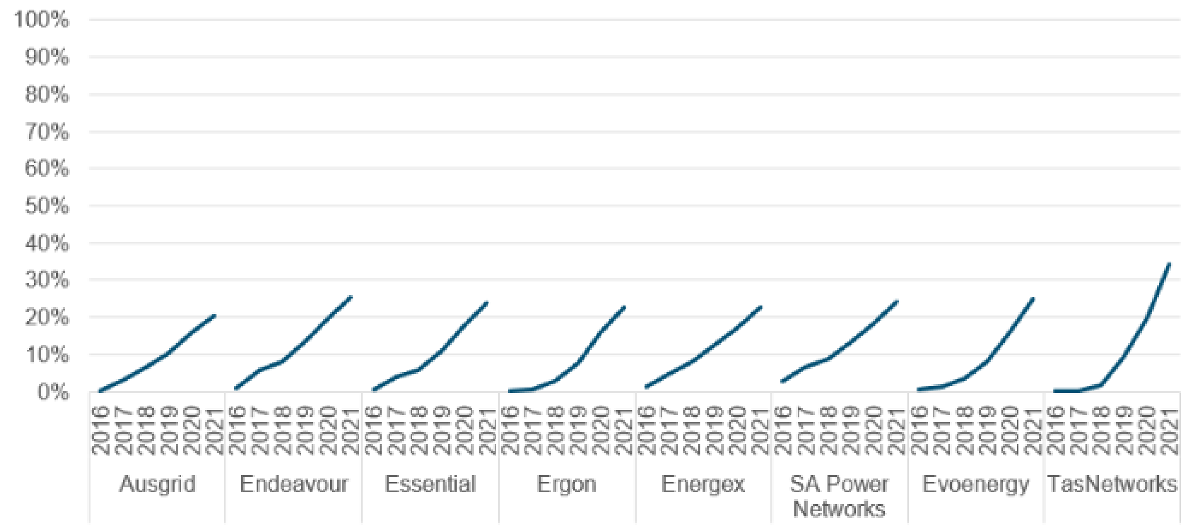
Western Power also appears to calculate the acceleration benefit of avoided meter reading costs for Manually Read Interval Meters (MRIM) and customer 'Self reads' in the 'Ben summary' sheet of its analysis, this shows that the total value of avoided meter reads is $5.9m in total over the period.

Scope

Similarly, the business case cites a potential $1.2b risk of a 10 hour 'system black' event (in the absence of changes to regulation and power system operation) and asserts that the AMI acceleration option to all customers could, and would, address the issue by enabling increased control of inverters to prevent system black events. Importantly, the Business Case identifies a change in meter specification to support the control of customer exports separately to consumption[711]. Ultimately this means that the existing 500,000 meters that have recently been installed do not support the export control capability – and therefore the benefit of network disconnection of inverters is limited to the new meters that will be installed during AA5.

Noting Western Power's expectation that solar penetration is expected to increase from approximately 35% in 2022 to reach 50% by 2025 (well in advance of the WA Government expected 2030 timeframe), the cost of providing approximately 15% of the Western Power customer base with export controllable AMI meters could be met through customer contributions for solar or battery additions and alteration work rather than the AMI-2-meter replacement program.

Figure 8–30: Smart meter penetration among small customers – NEM Networks excl. Victoria



Source: AEMC analysis of AEMO MSATS data.
Note: This chart shows the penetration of smart meters among small customers (residential and small business) as at 30 June of each year.

Source: AEMC[712]

We also note that alternative means of controlling inverters have been implemented in other jurisdictions (such as South Australia) that rely on inverter communication via the premises internet connection to effect the control. These capabilities are required for all new installations in SA and are

710 Western Power, *AA5ENG22.07 – AMI Financial Analysis model 2021v6 (CCONFIDENTIAL),* 'Charts expenditure' Sheet, Charts at rows 132-180

711 Western Power, *Attachment 8.6 Business Case – Advanced Metering Infrastructure,* 1 February 2022, p.2. (Detailed Business Case for Approval – Executive Summary)

712 Australian Energy Market Commission, *Directions Paper – Review of Metering Services*, 16 September 2021, p. 44

used to implement dynamic export limits for each customer to better ‘share’ the network capacity. Where communication with the inverter is down, the inverter reverts to a ‘static’ export limit, that falls below the dynamic levels assigned throughout the day – thus providing a customer incentive to maintain a working internet connection to their inverter.

Engevity notes that **the $1.2b risk of a system black event cited by Western Power assumes no changes to regulation or power system operation, and that no other technical option is available to meet the stated needs in AA5**. In practice, there are several technical solutions that have proven successful in the South Australian network and elsewhere to improve system resilience in light of high renewables, high rooftop solar, interconnector constraints and islanded operation over recent years.

With a more pronounced minimum demand, higher rooftop solar penetration than WA and lower existing AMI penetration, the learnings from SAPN’s enhanced Voltage Management Program[713] are highly relevant to the more effective, more prudent and more efficient management of these risks in Western Power’s AA5 period in a manner that demonstrably minimises costs to consumers when compared to Western Power’s proposal. Other initiatives involving State Estimation of the LV network rely on far fewer data inputs have successfully produced outcomes with an accuracy that is suitable for improving network operations. In some cases this has been identified as a more useful tool than full penetration AMI due to the reduced data set and lower meter polling/communications bandwidth requirements.

Given the discussion above, Engevity does not consider that the acceleration of the AMI program is prudent or efficient. We note that the existing scale of the AMI fleet (at approximately 500,000) is sufficient to access the benefits targeted by the AMI rollout such as the introduction of Time of Use retail tariffs – which the AEMC indicates become available as AMI penetration exceeds 50%.[714]

Control of inverters

Engevity recognises that the ability to control customer inverters is a useful tool to stabilise the network under critical circumstances, this could readily be achieved by focussing AMI installations on houses that already have solar and houses that are installing solar. We note that Western Power has records of the solar customers and their installations through the connection process that could be referenced against the meter identifier for that site to target the enablement/configuration of AMI based load or export control more effectively.

In the case of recent solar installations, Western Power several inverters will have the ability to be reconfigured for internet-based control via the Synergy ‘API Cloud’. This system provides an alternative mechanism for control that the WA Government states *"For most systems, particularly where there is household internet, the API cloud control solution will be lowest cost"*[715]. The process for reconfiguration would depend on the specific inverter model – but equipment information is provided to Western Power as part of the connection process. Therefore customers who already have compliant inverters that can be remotely reconfigured by the manufacturer or installer could be very accurately targeted offering an incentive payment to do so voluntarily.

This, coupled with the requirement for new solar installations to be configured to allow export control,[716] mean that the value of implementing a secondary control capability via a more expensive

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713 We note that SA Power Networks recent enhanced voltage management at around 140 substations (covering around 80% of the customer base) have been successful in in mitigating minimum demand risks by raising local network voltage above the disconnection threshold of inverters force disconnection and effectively increase state demand under extreme minimum load conditions it also claims to have doubled the hosting capacity of the network for DER

714 Australian Energy Market Commission, *Directions Paper – Review of Metering Services*, 16 September 2021, pp. 12, 18-19

715 WA Government, Information for Industry - Emergency Solar Management (www.wa.gov.au)

716 For example, SA Power Networks, *TS129 Small EG Connections – Capacity not exceeding 30kVA*, 6 July 2021, p. 18

AMI meter specification for all meters installed from AA5 onward mean that the proposed acceleration of the AMI program is unlikely to minimise the cost of achieving the emergency export control sought by AEMO and Western Power (or the day to day operational control that would help address voltage rise issues)

Lower cost solutions such as the SAPN enhanced voltage management program as well as the inclusion of Demand Response Enabling Devices (DRED) from Mondo, Wattwatchers and SwichDin as approved devices to enable existing inverters to comply with requirements for flexible export limits.

Given the existing rooftop solar penetration level in Western Power's network is around 35%, with expectations of reaching 50% by 2030, it is unreasonable to expect the AMI control strategy to be effective when it only applies to new solar installations or customer connections. **To provide the inverter export control functionality within the timeframe noted by AEMO, Western Power will need to enlist the existing solar customers – rather than focussing on new solar customers. This is because existing solar customers are the source of 100% of the solar export management challenges today, and will still make up 70% of the target rooftop solar customer base in 2030 when solar penetration levels are expected to reach 50%**

Therefore, whist Engevity recognises the benefits that AMI can provide, the mass rollout, and particularly the accelerated mass roll out is neither the most prudent nor efficient approach to delivering this infrastructure. As a result, we are unable to conclude that it minimises costs for consumers in accordance with the NFIT requirements.

Deliverability

Engevity highlights material concern with the deliverability risks arising from the mass roll out model proposed in Western Australia, and more so – if the program is accelerated in a manner that exacerbates these concerns.

The lessons learned from the Victorian AMI roll out led the other NEM states to adopt a customer led approach to AMI roll out. Installations accelerated with the establishment of contestable metering service providers, that were appointed by the retailer rather than the network. However, the rate of installations has still fallen short of expectations, and measures are under consideration that will be designed to accelerate the rate of change – as noted in the recent AEMC review.

Outside of Victoria, the AMI penetration in the NEM distribution networks has been steadily increasing through customer connections, alterations (such as solar installation) and retailer led changes to enable greater customer data visibility through apps and online portals. This approach avoids the capital inefficiency of the network replacing every meter when a significant proportion of the customer base will simply choose to remain on a single rate tariff - where there is limited immediate benefit from AMI other than avoided meter reading and Neutral Integrity monitoring. This is reflected in Western Power's previous (2016) customer research for time of use tariffs which found that: [717]

- "2 in 5 Residents disagreed with a ToU tariff in principle";
- "Over half (60% of participants who did not receive the upfront education in the workshop opted for a flat rate and felt confused and did not understand the purpose of a ToU tariff";
- "…despite the high interest in smart meters, few felt they should pay for installation at $30/year or $150 upfront";
- "Less than 1 in 5 indicated that they were likely to install a smart meter costing $150 in the next 2 years".

[717] Western Power, Time of Use Tariff Insights Presentation, 13 December 2016

The customer led approach, with a separate metering services provider means that meter replacements are initiated by individual customers – or their retailer as they access services such as solar export, or time of use retail tariffs that require interval metering. The costs are then incorporated into the retail offer of the customers who require AMI services, with the metering services then delivered in a contestable environment rather than being mandated on all customers and the cost added to network charges. We recognise that the Western Australia market is structured differently. However, the BAU program will enable Western Power to comfortably surpass the 50% penetration threshold noted by the AEMC to access the full benefit of AMI, whilst allowing unit cost escalation due to installer productivity declines (meters installed per day) to be more effectively managed in the later stages of the program than was the case in the Victoria mass roll out. The rollout can then be curtailed between the minimum efficient scale (such as the AEMC 'more than 50%' figure) to realise benefits, and the point where pursuing further installations no longer offers value to customers (such as where delivery challenges raise unit costs above an efficient level). Ultimately this means that the BAU AA5 program should not hinder the realisation of AMI benefits and will deliver a lower cost program, with higher benefits, less investment risk and a greater value delivered by the existing metering fleet.

Once a relatively high (greater than 50%) penetration is achieved, the timing for completing the changeover of meters becomes less critical benefits of AMI and AMI installations for the remaining (higher cost to serve customers) can revert to new connections, replacements, upgrades and retailer requests, as well as on attended disconnection/reconnections (which are often due to a change in tenant or property owner which can avoid challenges of ideological opposition to AMI by a customer, dogs, obstructed access etc.)

Ultimately, Engevity is concerned that Western Power's proposed mass roll out model for the AMI program is unlikely to efficiently minimise the cost of the AMI implementation. The mass roll out model has previously been proven to be problematic in Victoria, with the Auditor General noting in 2015 (as the program was nearing completion) that:

"By the end of 2015, ***Victoria's electricity consumers will have paid an estimated $2.239 billion*** *(nominal dollars undiscounted)* ***for metering services****, including the rollout and connection of smart meters. The net position of the program has changed significantly since its inception, and* ***there is now expected to be a substantially increased net cost to consumers over the life of the program****…*

…In contrast, ***while a few benefits have accrued to consumers, benefits realisation is behind schedule and most benefits are yet to be realised****…*

*…****There is a risk that the AMI program's most recent 2011 estimate of a net cost of $319 million*** *(in present value terms at 2008 in 2011 dollars)* ***to consumers may worsen*** *as costs are projected to increase and benefits remain decidedly uncertain"* [718]

Over the course of delivery the cost of AMI installations rose substantially, and productivity rates declined due to:

1. Greater volumes of more complex installations were encountered that had initially been skipped, or the installation abandoned due to customer hostility, dogs or discovery of issues with the customers switchboard/wiring.
2. The remaining installation addresses were less localised resulting in greater travel time between installation sites.

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[718] Victorian Auditor General, *Realizing the Benefits of Smart Meters,* September 2015, pp. x-xi (emphasis added)

3. Resourcing became an issue as individual installation technicians on ‘per installation’ remuneration arrangements moved to more lucrative contracts due to the productivity decline at the later stages or the roll out. In some cases this left the main contractor unable to obtain the staff needed to fulfil the contract.

Whilst several other factors also contributed, the challenge of reaching near universal coverage of AMI was hindered by much greater customer resistance, complexity and co-ordination effort to deliver the final 10-15% of installations than the earlier stages of the program. Engevity has not seen these issues addressed in the business case documentation.

Recommendation

Given the findings of our review of the AMI program for AA5, Engevity recommends:

1. The accelerated component of the scope is delivered in AA6, as originally envisioned on the basis that the available benefits do not justify the additional cost.
2. The 10% contingency that is applied by Western Power to metering hardware and IT costs in the financial analysis is removed.

The impact of this recommendation on the recommended AA5 CAPEX allowance is shown in graph and detailed in the table below.

Figure 8–31: Meter Replacement 2007-2027 - Total CAPEX ($real June 2022) incl OH and esc

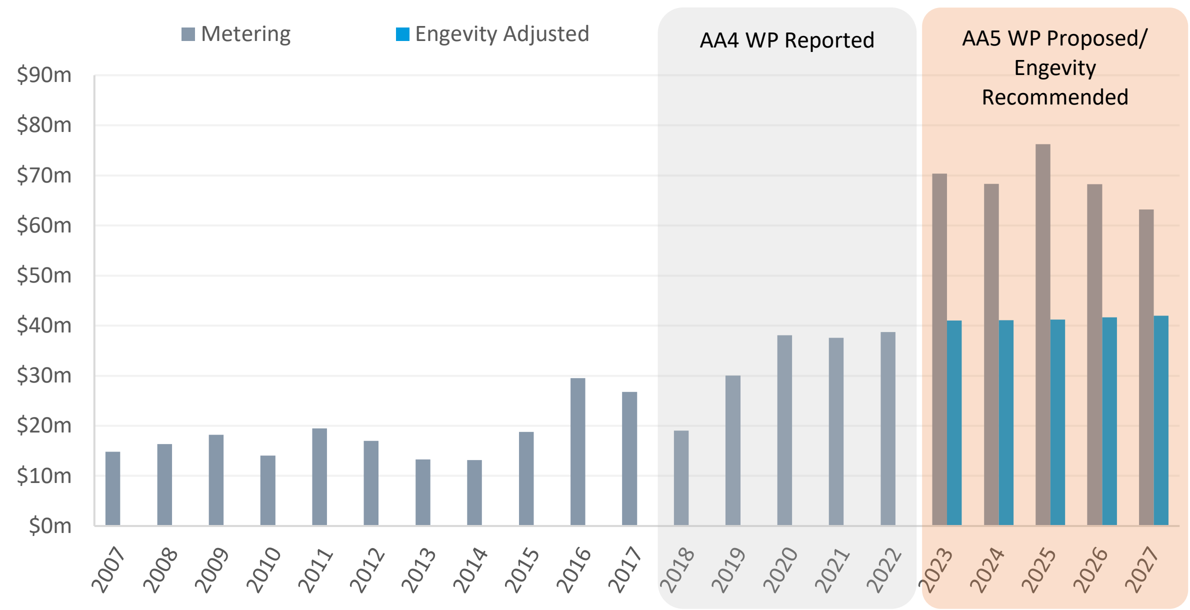

Table 8–31: AA5 Expenditure and Scale – Advanced Metering Infrastructure ($m real at 30 June 2022)

AMI	Proposed Expenditure					
	Yr1	**Yr2**	**Yr3**	**Yr4**	**Yr5**	**Total**
Western Power Proposed Total CAPEX [719]	*61.67*	*61.814*	*62.026*	*62.632*	*63.189*	***311.33***
Western Power Proposed Direct CAPEX [720]	51.5	51.5	51.5	51.5	51.5	**257.51**
Adjustment 1 – remove acceleration[721]	-16.35	-16.35	-16.35	-16.35	-16.35	**-78.88**
Adjustment 2 – Remove Meter and ICT CAPEX contingency @ 8.2% of AA5 cost for AMI2 BAU[722]	-3.47	-3.23	-3.75	-4.23	-3.93	**-18.61**
Engevity Recommended Direct CAPEX	31.68	31.92	31.4	30.92	31.22	**157.14**
Adjustment 3 - Add back to OPEX Total OPEX	0.37	0.75	1.16	1.58	2.03	**5.89**

Source: Western Power CAPEX Model, AMI Financial Analysis spreadsheet and Engevity Analysis

719 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs' Sheet Row 16

720 Western Power, *AAI – Attachment 8.10 Capital Expenditure Model*, 'CAPEX Calcs' Sheet Row 16

721 Proportional adjustment based on Western Powers Reported $115.6m incremental CAPEX for acceleration and the $377.4m total cost reported for the accelerated program. (i.e. $115.6m / $377.4m = 30.6%)

722 Western Power, *AA5ENG22.07 – AMI Financial Analysis model 2021v6 (CCONFIDENTIAL),* 'SC7 AMI BAU' Sheet, Sum of contingency rows / AMI2 BAU Total for the years 2023-2027 = 8.2% total contingency component in the BAU program. 8.2% x cost of BAU program gives the adjustment amount.

Attachment 9: Appendices

9.1 Scope of works

The Contractor is required to provide technical advice to assist the ERA with its assessment of Western Power's actual capital expenditure for AA4 and proposed capital and operating expenditure for AA5. The Contractor is required to consider Western Power's proposed revised access arrangement, access arrangement information, access arrangement supporting information and any supplementary information provided by Western Power to the ERA after making its access arrangement submission. The Contractor must also consider any relevant matters raised in stakeholder submissions to the ERA's public consultations.

9.1.1 Governance Review

a. The Contractor is required to review the quality and efficacy of the systems and processes used by Western Power to manage its capital and operational expenditures. This would allow the ERA to determine the extent to which Western Power's governance arrangements can be relied on to determine whether Western Power's access arrangement forward work program and forecasts of capital and operating expenditure are prudent.

b. The scope of works includes both Western Power's management of expenditure during the current access arrangement period and the processes it has used to prepare its capital and operating expenditure forecasts.

c. The review should include consideration of:

   i. integration and consistency of procedures and policies across projects;

   ii. the adequacy of internal control structures or specific internal controls, to ensure due regard for effectiveness and efficiency;

   iii. the extent to which activities have been effective in achieving organisational objectives;

   iv. whether projects take place on a timely basis with minimum network disruption and at least cost;

   v. the effectiveness of internal audit processes;

   vi. past practices relating to planning future work programs and strategies;

   vii. the independent review of Western Power's Asset Management Plan regularly conducted at the request of the ERA; and

   viii. long term network development strategies.

9.1.2 Review of forecast capital expenditure and operating expenditure for AA5

a. The Contractor must provide advice to assist the ERA to determine whether Western Power's forecast capital expenditure and operating expenditure only includes expenditure that would be incurred by a service provider efficiently minimising costs as required under section 6.40 and section 6.52 of the Access Code.

b. If the Contractor identifies forecast expenditure that is not consistent with the requirements of section 6.40 or 6.52, it should set out details of the inconsistencies it has identified and its advice on the level of expenditure that would be consistent with the requirements of section 6.40 or 6.52.

c. To enable this assessment, the Contractor is required to evaluate the following items in relation to the capital and operating expenditure forecasts and underlying assumptions in Western Power's access arrangement proposal:

   i. Current operational and service level performance in comparison with industry standards;

ii. Forecast changes to operational and service level performance including any justifications and the likelihood of achievability;

iii. The methodology used to develop demand forecasts and how/if this was independently assessed, including:

› the key drivers behind the demand forecasts;

› how the demand forecast has been used to develop operating expenditure and capital expenditure forecasts;

› providing information and analysis on any trends inherent in the demand profile;

iv. The key factors driving expenditure;

v. Benchmarking costs against other service providers, including utilising the Australian Energy Regulator's benchmarking methodology and data;

vi. The methods, including models, used to estimate expenditure including the process for prioritising expenditure against other potential expenditure;

vii. The process adopted for policy formulation and the refinement, if any, of earlier policies to suit the next period;

viii. The cost estimation process and level of unit costs for network augmentation, asset replacement and operating expenditure;

ix. The process to account for cost estimation risk in both the option selection process and once a project has been selected, including a benchmark comparison to determine if the level is acceptable;

x. The appropriateness and consistency with prior periods of its capitalisation policy and recommend changes if necessary;

xi. An assessment of overhead costs including the appropriateness of the cost categories Western Power includes and how overhead costs are apportioned (if at all) over other operating expenditure categories as well as reviewing benchmark comparisons with other service providers;

xii. The interaction between capital expenditure and operating expenditure and whether the forecasts are based on an optimal mix;

xiii. The extent to which future efficiencies/savings have been factored into Western Power's proposed expenditure and whether these are reasonable or, if not, recommend alternatives;

xiv. Assess the reasonableness of the methodology and level of any escalation factors proposed by Western Power in its expenditure forecasts and propose alternatives if necessary;

xv. The reasonableness of procurement practices and processes;

xvi. Western Power's ability to deliver its proposed capital expenditure program; and

xvii. Identification of any matters that, in the opinion of the Contractor, may warrant further investigation by the ERA and/or explanation from Western Power.

d. In addition, the review of operating expenditure should include:

i. An assessment of the efficient level of base operating expenditure, including a review of the most recent actual operating expenditure and benchmark comparisons with other service providers;

ii. An assessment of the forecasts, considering historical and industry benchmark data;

iii. An assessment of whether Western Power has adequately substantiated and justified any forecast increases in costs;

iv. An assessment of whether any operational changes due to new or amended regulatory requirements are adequately supported;

v. An assessment of Western Power's forecast operational and service level performance resulting from its forecast operating expenditure;

vi. An assessment of Western Power's forecast operating expenditure resulting from capital expenditure programs; and

vii. An assessment of whether Western Power has incorporated a sufficient level of future efficiencies in its forecasts.

e. In addition, the review of maintenance expenditure should include:

i. An assessment of the impact on the level and balance of maintenance costs (i.e. between preventative routine, preventative condition, corrective deferred, and corrective emergency) as a result of any changes in maintenance or replacement programs either of a capital expenditure or operating expenditure nature;

ii. An assessment of whether Western Power's maintenance procedures are best practice; and

iii. An assessment of whether Western Power has adopted optimal solutions.

f. In addition, the review of capital expenditure should include:

i. An assessment of Western Power's forecasts, considering historical and industry benchmark data;

ii. An assessment of the reasonableness of any assumptions made by Western Power in its calculations;

iii. An assessment of the adequacy and reliability of asset information Western Power has based its forecasts on; and

iv. A detailed review of specific projects and programs:

› The Contractor will need to select a number of projects and programs for a more detailed review. The Contractor will be required to recommend a sample to the ERA for approval before commencing its detailed review.

› The Contractor will need to assess whether Western Power has provided adequate information and documents to support claims that the new facilities investment undertaken satisfies the requirements of the new facilities investment test (as specified in the Access Code and ERA guidelines); and

› For each project, the Contractor will be required to:

A. Assess the adequacy of the information and documents provided from a technical perspective, considering the requirements of the new facilities investment test;

B. Provide advice on whether the costs do not exceed the amount that would be invested by a service provider efficiently minimising costs and, if necessary, provide advice on a revised amount;

C. Provide advice on whether the amount claimed by Western Power to satisfy the new facilities investment test is reasonable and, if not, provide advice on a revised amount; and

D. Assess whether Western Power has used reasonable timeframes for project commissioning dates and construction timetables.

9.1.3 Review of actual capital expenditure for the AA4 period

a. The ERA must determine the opening capital base for AA5. The Contractor is required to provide advice to assist the ERA to determine whether actual capital expenditure for the AA4 period meets the new facilities investment test and, therefore, can be added to the opening capital base.

b. The Contractor must provide a recommendation on the amount of AA4 capital expenditure that should be added to the capital base. In making its recommendation, the Contractor should undertake a review of total expenditure and a more detailed review of a sample of projects and programs. The Contractor will be required to recommend a sample to the ERA for approval before commencing its detailed review.

c. The Contractor will be required to:

   i. Assess the adequacy of the information and documents provided from a technical perspective, considering the requirements of the new facilities investment test;

   ii. Assess the variance, if any, between the actual new facilities investment undertaken and what was originally forecast and report on the validity of the explanations and/or reasons given by Western Power for any variances;

   iii. Assess whether the costs do not exceed the amount that would be invested by a service provider efficiently minimising costs and, if necessary, propose a revised amount; and

   iv. Assess whether the amount claimed by Western Power to satisfy the new facilities investment is reasonable and, if not, propose a revised amount.

d. The detailed review of a sample of projects should also include assessing the overall efficiency of the project or program by:

   i. Assessing if Western Power fully identified and considered all viable options and selected the best option;

   ii. An assessment of the technical aspects of the project or program;

   iii. Assessing the consistency of unit rates of construction with historical unit rates for the covered network and unit rates of similar works in other networks, considering trends in productivity improvements and underlying costs; and

   iv. Assessing whether the procedures of construction planning, contracting and cost control are consistent with minimising costs.

9.1.4 Review of other expenditure

e. In addition to the expenditure above, the Contractor must review and assess the following expenditure that has specific provisions set out in the Access Code:

   i. The recovery of advanced metering communications infrastructure expenditure as set out in sections 6.5F to 6.5J of the Access Code.

   ii. Access reform costs as set out in sections 6.81 to 6.83 of the Access Code. This includes the costs of development and provision of network constraint information to AEMO and the preparation of the initial whole of system plan.

9.1.5 Asset lives

The Contractor is required to review the asset lives proposed by Western Power and recommend reasonable economic lives for these assets.

9.2 General requirements

a. It will be the responsibility of the Contractor to ensure that all required work is undertaken within the timeframes required by the ERA to meet the various timing requirements specified in the Access Code. The Contractor will be provided with specific timings and assistance from the ERA in coordinating information requests as appropriate throughout the contract term.

b. The Contractor will be required to update the ERA on progress and issues on a regular basis to ensure the work is progressing as expected and allow scope for early discussion of issues as required. Minimum communication requirements include:

   i. Attend an inception meeting either face to face, via video conferencing or by phone on commencement of the task/s.

   ii. Attend review meetings either face to face, via video conferencing or by phone following each review/deliverable.

   iii. Brief the ERA on particular matters, as requested.

   iv. Liaise directly with other consultants appointed by the ERA to undertake tasks in relation to the access arrangement review. Such consultants may include technical, economic/financial advisors, legal professionals and media advisors.

   v. Participate in meetings with the ERA, Western Power and/or other interested parties in relation to the proposed revisions.

c. The Contractor should have regard to industry best practice, applicable legislation, precedent relevant to regulated energy infrastructure in Australia and elsewhere, and the objectives of the Access Code.

d. The Contractor must also ensure that it captures and confirms any commercial discussions and decisions in writing.