Revised Technical Review of Western Power's Proposed Revisions of its Fourth Access Arrangement 2017/18-2021/22

Economic Regulation Authority

Final Report

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Glossary

Acronym	Description
AA3	Third Access Arrangement
AA4	Fourth Access Arrangement
AA5	Fifth Access Arrangement
AAI	Access Arrangement Information
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIP	Asset Investment Planning
AMF	Asset Management Framework
AMI	Advanced Metering Infrastructure
AMS	Asset Management System
ARDS	Rules Engine
ARIMA	Autoregressive Integrated Moving Average
AWOTE	Average Weekly Ordinary Time Earnings
BAU	Business as Usual
BST	Base-Step-Trend top-down OPEX forecasting method
BTP	Business Transformation Program
BUCC	Backup Control Centre
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure

Acronym	Description
CB	Circuit Breaker
CBA	Cost Benefit Analysis
CPI	Consumer Price Index
CRAM	Cost and Revenue Allocation Method
CRM	Customer Relationship Management
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DQM	Distribution Quotation Management
DSLMP	Dedicated Streetlight Metal Poles
DTC	Distribution Transfer Capacity
EGWWS	Energy, Gas, Water and Waste Services
EMS	Energy Management System
EPCC	East Perth Control Centre
ERA	Economic Regulation Authority of Western Australia
ERP	Enterprise Resource Planning
FRZ	Fire Risk Zone
GBA	Geoff Brown & Associates
GEC	General Electric Company
GIS	Geographical Information System
GSL	Guaranteed Service Level
GSM	Gain Sharing Mechanism
GWh	Gigawatt hour
HRIS	Human Resource Information System

Acronym	Description
HV	High Voltage
IAM	Investment Adjustment Mechanism
ICT	Information and Communication Technology
IEEE	Institute of Electrical and Electronics Engineers
IMO	Independent Market Operator
IRR	Internal Rate of Return
IVM	Integrated Vegetation Management
kV	kilo-volt
kW	Kilowatt
LOS	Loss of Supply
LOSEF	Loss of Supply Event Frequency
LSE	Least Squares Estimator
LV	Low Voltage
MED	Major Event Day
MRL	Mean Replacement Life
MPFP	Multilateral Partial Factor Productivity
MTFP	Multilateral Total Factor Productivity
MVA	Megavolt amp
MW	Megawatt
NDP	Network Development Plan
NEM	National Electricity Market
NER	National Electricity Rules
NFIT	New Facilities Investment Test

Acronym	Description
NIEIR	National Institute of Economic and Industry Research
NMP	Network Management Plan
NMS	Network Management System for management of telecommunications network
NPV	Net Present Value
NRMT	Network Risk Management Tool
NSP	Network Service Provider
OEF	Operating Environment Factor
OH HV	Overhead High Voltage
OLS	Ordinary Least Squares
OPEX	Operating Expenditure
POE 10	10% Probability of Exceedance
POE 50	50% Probability of Exceedance
PoW	Program of Work
PPE	Property, Plant and Equipment
PUO	Public Utilities Office
PV	Present Value
RAB	Regulated Asset Base
RBA	Reserve Bank of Australia
REPEX	Replacement Expenditure
RIN	Regulatory Information Notice
SaaS	Software as a Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

Acronym	Description
SCADA	Supervisory Control and Data Acquisition
SFA	Stochastic Frontier Analysis
SMI	System Minutes Interrupted
SOO	Statement of Opportunities
Solar PV	Solar Photovoltaic
SSAM	Service Standard Adjustment Mechanism
SSB	Service Standard Benchmark
SST	Service Standard Target
STPIS	Service Target Performance Incentive Scheme
SUPP	State Underground Power Program
SVC	Static VAR Compensator
SWER	Single-wire earth return
SWIN	South West Interconnected Network
SWIS	South West Interconnected System
The Code	Electricity Networks Access Code 2004
TOU	Time-of-Use tariff
VCR	Value of Customer Reliability
WPI	Wage Price Index

Executive summary

i. Introduction

Western Power has submitted a revision to their initial Access Arrangement proposal (revised AA4 proposal), in response to the Economic Regulations Authority of Western Australia's (ERA) draft decision on Proposed Revisions to the Access Arrangement for the Western Power Network, published by the ERA on May 2nd, 2018. The response sets out Western Power's position regarding the 91 amendments detailed in the ERA's draft decision. The response provided by Western Power needs to be read in conjunction with its initial proposal submitted on October 2nd, 2017.

ii. Scope of GHD's review of the revised AA4 proposal

The ERA has asked GHD to review the revised AA4 capital expenditure proposal and provide the firm's opinion on whether it is reasonably likely to meet the new facilities investment test. Our review has focused on the specific areas of the proposal outlined in the ERA's request dated July 5th, 2018. The specific scope of the review is detailed on in section 2 of this report, however in summary our analysis has looked transmission CAPEX, Distribution CAPEX, including the proposal to implement Advanced Metering and Corporate CAPEX. Our review of Western Power's Revised CAPEX will test whether the expenditure meeting the New Facilities Investment Test (NFIT) and the impact, if any, of the investment on operating expenditure (OPEX).

Our analysis is based on the information provided to GHD from Western Power (via the ERA) and our industry experience and knowledge.

In our analysis of the response GHD has focused on the arguments and supporting documentation supporting Western Power's proposed increase in capital expenditure across Transmission, Distribution and Corporate CAPEX.

iii. GHD Recommendations

Transmission CAPEX

- Growth – Western Power has removed the CAPEX for the proposed CBD substation. However Western Power have reinstated their desire to build a new Picton/ Busselton 132 kV line. GHD is unable to comment on the validity of this proposed investment.
- GHD considers that the allowance of $41 million for customer access work, recommended in its previous report, is reasonable and does not consider Western Power's proposed increase is likely to meet the new facilities investment test.
- Asset Replacement
    - Switchboards – Our recommended CAPEX for AA4 is $60.8 million. This equates to a $6.5 million reduction in CAPEX for this category of spend
    - Power Transformers – GHD recommend that the proposed $52.4 million be accepted
    - Protection Equipment – GHD is of the view that the forecast expenditure allowed for protection equipment in the ERA's draft decision remains appropriate. This equates to a reduction of $21.1 million in CAPEX from Western Power's Revised AA4 proposal for this category of spend
    - SVCs – GHD believes that the West Kalgoorlie project meets the NFIT test and recommends that the proposed $22.2 million CAPEX be accepted

- Transmission Primary Plant – GHD has maintained its initial recommendation on this. This equates to a reduction of $7.1 million in CAPEX for this category of spend
    - Improvement in Service – While we consider the proposed expenditure for AA4 is prudent, we do not believe Western Power has provided sufficient information for an assessment of how the proposed replacement program is to be delivered during AA4. We therefore consider that approval for this expenditure is conditional on this information being provided.
- Compliance
    - Substation Security – Based on our review of the Western Power modelling for substation fencing, GHD considers the AA4 forecast should be based on the replacement of the higher priority fences identified in the risk assessment, and therefore recommend the AA4 forecast be amended to $34.2 million.
    - Physical Security Measures – GHD recommends the proposed provision of $8.3 million be accepted.
    - Asbestos – GHD recommends the proposed provision of $2.5 million be accepted
    - Roofs – GHD recommends the proposed $8.9 million be accepted.

Table 1 shows a summary of recommended Transmission CAPEX for the categories of spend reviewed by GHD.

Table 1 Summary of GHD's Recommended Transmission CAPEX ($ million real, June 2017) direct costs nett of contribution

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Revised Proposal	GHD revised recommendation	Variation between Revised Proposal and GHD recommendation
Growth	240.8	159.4	205.5	159.4	(46.1)[1]
Asset replacement and renewal	245.2	145.9	231.2	197.6	(33.6)
Improvement in service	89.9	89.9	89.9	89.9	0.0
Compliance	155.0	95.3	147.0	136.7	(10.3)
Total	**730.9**	**490.3**	**673.6**	**583.6**	**(90.0)**

Distribution CAPEX – Including the Advanced metering Infrastructure (AMI) program

- Growth – GHD recommends accepting proposal from Western Power.
- Improvement in Service – GHD recommends removing the proposed additional expenditure above the forecast required to execute the Kalbarri microgrid project. This equates to a $3.9 million reduction in Distribution CAPEX.
- Advanced Metering Infrastructure (AMI) – GHD does agree with Western Power that the forecast expenditure on the AMI program, including the deployment of advanced meters and the associated IT and

[1] This amount is made-up of a reduction in growth CAPEX of $26.9 million and $19.2 million for the Picton/ Busselton 132 kV line

communications infrastructure, is reasonably likely to satisfy the requirements of the new facilities investment test and should therefore be included in the forecast capital base.

Table 2 shows the GHD recommended adjustments to distribution CAPEX allowances (direct costs only) for Western Power in AA4.

Table 2 Distribution capex revised forecast expenditures and draft decision direct costs for AA4 ($ million real, June 2017) excluding gifted assets and contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Growth	405.9	417.1	391.4	391.4	0.0
Improvement in Service	94.0	57.7	88.8	84.9	(3.9)
Total	**499.9**	**474.8**	**480.2**	**476.3**	**(3.9)**

Corporate CAPEX

- Depot Optimisation – GHD is concerned that lower priority metro depot optimisation projects within the overall program will not be completed during the AA4 period. The most likely projects to be delayed are the upgrades to [redacted]. GHD recommend that the ERA withhold 50% of the forecast CAPEX for these two projects as GHD believes it is unlikely that both of these projects will be completed during the AA4 period. This would equate to $16.9 million reduction in CAPEX.

  In addition GHD recommends that the savings associated with the depot optimisation and consolidation program not be included as part of the efficiency dividend and be identified separately and that an efficiency dividend of 1% be applied to all operating costs outside of the depots.

- CRM – GHD believes that there is a solid case for the replacement of the existing CRM systems with an integrated group of CRM applications.

  GHD also recommends that the proposed $4.7 million to be spent on the creation of a new CRM system be treated as OPEX. This would result in a reduction in proposed CAPEX of $4.7 million and a corresponding increase in OPEX of the same amount.

Table 3 sets out the GHD recommended expenditures for corporate capex. These revised allowances include our recommended reductions of $16.9 million in the Depot Modernisation program, and $4.7 million shifted from CAPEX to OPEX for the creation of a new CRM system.

Table 3 Corporate capex revised forecast expenditures and draft decision direct costs for AA4 ($ million real, June 2017)

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Business Support					
Corporate real estate	201.1	201.1	201.1	184.2	(16.9)
Fleet CAPEX	46.7	0.0	0.0	0.0	0.0
Fleet lease	30.4	0.0	0.0	0.0	0.0
Property, plant & eqpt	4.2	4.2	4.2	4.2	0.0
Subtotal	*282.4*	*205.3*	*205.3*	*188.4*	*(16.9)*
IT					
Business driven	149.3	134.3	168.7	164.0	(4.7)
Business infrastructure	55.3	55.3	55.3	55.3	0.0
Subtotal	*204.6*	*189.6*	*224.0*	*219.3*	*(4.7)*
Total	**487.1**	**394.9**	**429.3**	**407.7**	**(21.6)**

OPEX

- Depot Optimisation – GHD considers the savings from the Depot Optimisation program should not be included in the planned efficiency dividend. From the information provided our assessment of the Depot Optimisation program, we have estimated the total reduction in OPEX from this program would equate to $10 million over the AA4 period (rather than the $10 million p.a. predicted in the business case). We have estimated the savings would be $2.5 million in 2020/21 and $7.5 million in 2021/22. OPEX in the highlighted years should be reduced by the estimated savings in 2020/21 and 2021/22.
- CRM SaaS (Software as a Service) – GHD considers the costs associated with the implementation of the program should be classified as OPEX. Given the information provided GHD has assumed that the cost of this service will not start to be incurred until 2019/20, will run for three years and be billed at an equal amount (approximately $1.6 million) each year. OPEX should be increased by this amount across each of these years.

Based on GHD's recommendation that costs related to software systems procured using a SaaS should be treated as OPEX rather than CAPEX and our recommendation that the savings associated with the Depot optimisation and consolidation should not be included in the efficiency dividend, we have made the following changes to the Western Power's proposed OPEX for the AA4 period.

Table 4 Impact of GHD Recommendations on AA4 OPEX ($ million real, June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Depot Optimisation Operational Cost savings				(2.5)	(7.5)	(10.0)
CRM SaaS			1.6	1.6	1.5	4.7
GHD OPEX adjustments	**0.0**	**0.0**	**1.6**	**(0.9)**	**(6.0)**	**(5.3)**

iv. GHD CAPEX Recommendations Summary

The net effect of our recommendations is to lower the overall CAPEX (direct costs nett of contributions) for the AA4 period by $115.5 million and decrease in OPEX by $5.3 million.

Table 5 Impact of GHD Recommendations on AA4 CAPEX ($ million real, June 2017) direct costs nett of contributions

Expenditure category	AA4 proposal	GHD initial recommendation	AA4 revised proposal	AA4 Recommended CAPEX	GHD revised recommendation
Total Transmission Network Expenditure	784.1	543.5	755.6		
Transmission Capital Contributions	(53.2)	(53.2)	(53.2)		
Net Transmission Network Expenditure	**730.9**	**490.3**	**673.6**	**583.6**	**(90.0)**
Total Distribution Network Expenditure	2,448.2	2,382.7	2,413.1		
Distribution Capital Contributions	(340.1)	(340.1)	(340.1)		
Distribution Gifted Assets	(400.0)	(400.0)	(400.0)		
Net Distribution network Expenditure	**1,708.10**	**1,642.6**	**1,673.0**	**1,669.1**	**(3.9)**
Corporate	487.1	394.9	429.3	407.7	(21.6)
Total	**2,926.10**	**2,527.8**	**2,775.9**	**2,660.4**	**(115.5)**

Limitations Statement

This report has been prepared by GHD for Economic Regulation Authority and may only be used and relied on by Economic Regulation Authority for the purpose agreed between GHD and the Economic Regulation Authority as set out in the letter of engagement dated 10th July, 2018.

GHD otherwise disclaims responsibility to any person other than Economic Regulation Authority arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

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1. Introduction

Western Power submitted to the Economic Regulation Authority (the ERA) revisions to its Access Arrangement on 2 October 2017. These revisions are to apply from July 2017 until June 2022 (Access Arrangement 4). The Electricity Networks Access Code 2004 (the Code) sets out the requirements for Western Power's Access Arrangement including subsequent revisions.

The ERA has commissioned GHD (our/us/we) to undertake a review of the prudency and efficiency of certain aspects of Western Power's response to the ERA's draft decision. The scope of the request by the ERA is set-out in the Scope section of this report. In our report we will review Western Power Revised AA4 proposal, the additional supporting information provided by Western Power through the ERA and our original analysis

This report contains GHD's (our) review of Western Power's Revised AA4 Proposal, encompassing financial year 2017/18 to financial year 2022/23. Our report comprises the following sections:

Executive Summary

1. Introduction
2. Scope
3. Regulatory framework
4. Transmission CAPEX
5. Distribution CAPEX – Including assessment of the Advance Metering Infrastructure project
6. Corporate CAPEX
7. Impact of GHD's recommendations on OPEX
8. Summary and conclusions

Values found within this report are rounded, including totals in tables, as such some totals may not match due to rounding.

2. Scope

2.1 Scope

The ERA has asked GHD to assist in their review of Western Power's revised AA4 proposal. The assistance required was outlined in an e-mail dated 5 July 2018 and is shown below. The focus of our analysis for this report is on the elements of Western Power's proposal that have materially changed from their initial proposal, or have been revised after the issuing of the ERA's draft decision.

Project Scope

1. Review Western Power's revised AA4 capital expenditure forecasts to advise whether they satisfy the requirements of the new facilities investment test (NFIT).
2. Advise whether the changes to forecast capital expenditure (compared with Western Power's initial proposal) affect any elements of forecast operating expenditure and provide advice on the level of operating expenditure.
3. Assess all of Western Power's revised AA4 capital expenditure forecast. With specific focus on:
    1. Transmission Capital Expenditure:
        - Transmission growth
            - Have the capacity expansion and customer driven expenditure forecasts to reflect the 2017 demand forecasts been properly updated?
            - Does the proposed $19.2 million forecast capital expenditure to proceed with the staged conversion of the Picton South Area network from 66 kV to 132 kV[2] meet the new facilities test?
            - Are all of the projects included in the forecast reasonably likely to proceed in AA4?
            - Assess if Western Power has considered non-network alternatives when developing its growth investment plans?
        - Transmission asset replacement and renewal
            - Has Western Power provided detailed condition analysis to support any replacement or renewal expenditure and is the forecast expenditure reasonable?
            - Has Western Power provided robust information to support costs?
            - Does the market data provided by Western Power provide evidence the costs they are forecasting are efficient?
            - Could expenditure be deferred to future periods?
            - Determine the likelihood the proposed projects will actually be undertaken during AA4 (for example, protection systems[3] and the West Kalgoorlie SVC replacement[4]).
        - Transmission improvement in service - SCADA and communications

[2] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 70 73, paragraph 423 - 438

[3] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 79, paragraph 473

[4] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 83, paragraph 502

- Conclude whether sufficient information has been provided by Western Power to demonstrate the proposed costs are likely to meet the new facilities investment test.
- Determine the likelihood the proposed replacement is reasonably likely to proceed in AA4.
- Review whether Western Power has included any impact on operating expenditure from the investment in SCADA and Comms

– Transmission compliance

- Substation security – Assess Western Power's revised proposal and reasoning for expenditure.

2. Distribution Capital Expenditure:

– Distribution growth

- Determine whether the capacity expansion and customer driven expenditure forecasts have been updated properly to reflect the 2017 demand forecasts.
- Assess the likelihood of the proposed expenditure actually being undertaken within the AA4 period.
- Assess if Western Power has considered non-network alternatives when developing its growth investment plans

– Advanced metering

- Assess Western Power's revised AMI proposal in detail, including testing all of the benefits Western Power has identified to justify its proposal.
- Review Western Power's Radio Frequency (RF) options analysis[5] for completeness and validity
- Assess Western Power's change control for AMI forecast capital expenditure
- Evaluate Western Power's tender process for its AMI IT systems.
- Appraise Western Power's revised forecast metering volumes and related expenditure [6] (including related operating expenditure).
- Provide advice on the technical aspects of the AMI proposal, for example whether the neutral integrity monitoring capability of AMI would assist in mitigating the hazard posed by open-circuit neutral faults as submitted by Energy Safety in its response to the ERA's draft decision. Particular focus should be given to how AMI interacts with other open-circuit neutral fault hazard mitigation solutions.

[5] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 100, paragraph 590

- Improvement in service - SCADA and communications
  - Determine whether Western Power has provided sufficient information to demonstrate the proposed costs are likely to meet the new facilities investment test
  - Determine the likelihood the proposed replacement is reasonably likely to proceed in AA4.
  - Review whether Western Power has included any impact on operating expenditure from the investment in SCADA and Comms.

3. Corporate Capital expenditure –
   - Depot modernisation and relocation of control centre
     - Review evidence provided to demonstrate the first and second limb of the new facilities investment test have been satisfied and that any savings arising from the expenditure have been identified and incorporated in forecast operating and capital expenditure.
     - Assess the likelihood of the proposed projects will actually being undertaken within the AA4 period.
   - CRM software –
     - Review evidence provided that the proposed project meets the first and second limb of the new facilities investment test and that any savings from the proposed new systems have been identified and incorporated in forecast operating and capital expenditure.
     - Assess Western Power's competitive market process for its CRM capital expenditure[6]

2.2 Quality of data

We have relied upon information provided by Western Power for their original AA4 submission and their revised AA4 submission. This includes the materials supplied to support their proposal and answers to subsequent questions raised by the ERA and GHD.

For any instances where the data provided was either incomplete or in insufficient detail, we have highlighted the issue and applied conservative assumptions in our analysis.

[6] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 114, paragraph 677

3. Regulatory framework

Western Power submitted revisions to its Access Arrangement to the ERA on 2 October 2017. On 2 May 2018 the ERA provided Western Power with their Draft Decision. In response to this draft decision Western Power has made a revised proposal for their fourth Access Arrangement. The Electricity Networks Access Code 2004 (the Code) sets out the requirements for Western Power's Access Arrangement including subsequent revisions. In GHD's Technical Review of Western Power's initial proposal we outlined the regulatory requirements for the Access Arrangement (pp. 24-26) this revised proposal is subject to the same provisions.

However, given the scope of the questions posed by the ERA to GHD we have set-out below the New Facilities Investment Test and the regulatory framework for assessing OPEX.

3.1.1 New Facilities Investment Test

New facilities investment (capital costs) must satisfy the new facilities investment test (NFIT).

Clause 6.52 of the Code states that new facilities investment satisfies the NFIT if:

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

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

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

and

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

(i) either … the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or …

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

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

3.1.2 Alternative non-network solutions

Non-network costs must meet the requirements of section 6.40 or 6.41 of the Code.

We note that Western Power has included one non-network solution option in its AAI which is the proposal to incorporate a battery and generation at Kalbarri in order to improve reliability of the supply to that town. The cost to augment the network to improve reliability is significantly more than the cost of the proposed alternative option. In reviewing this project, it is considered that Western Power has met the requirements of sections 6.41(a) and 6.41(b)(iii) of the Code.

3.2 Regulatory framework for assessing OPEX

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

Section 6.41 deals with the requirements for non-capital solutions (called *alternative option non-capital costs*):

6.41 Where, in order to maximise the net benefit after considering alternative options, a service provider pursues an alternative option in order to provide covered services, the non-capital costs component of approved total costs for a covered network may include non-capital costs incurred in relation to the alternative option if:

(a) the alternative option non-capital costs do not exceed the amount of alternative option non-capital costs that would be incurred by a service provider efficiently minimising costs; and

(b) at least one of the following conditions is satisfied:

(i) the additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs; or

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

(iii) the alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

4. Transmission CAPEX

4.1 Scope

The ERA has asked GHD to review the Western Power's revised fourth Access Arrangement proposal for Transmission CAPEX.

The specific items listed were identified for particular focus:

1. Transmission growth
    - Have the capacity expansion and customer driven expenditure forecasts to reflect the 2017 demand forecasts been properly updated?
    - Does the proposed $19.2 million forecast capital expenditure to proceed with the staged conversion of the Picton South Area network from 66 kV to 132 kV[7] meet the new facilities test?
    - Are all of the projects included in the forecast reasonably likely to proceed in AA4?
    - Assess if Western Power has considered non-network alternatives when developing its growth investment plans?
2. Transmission asset replacement and renewal
    - Has Western Power provided detailed condition analysis to support any replacement or renewal expenditure and is the forecast expenditure reasonable?
    - Has Western Power provided robust information to support costs?
    - Does the market data provided by Western Power provide evidence the costs they are forecasting are efficient?
    - Could expenditure be deferred to future periods?
    - Determine the likelihood the proposed projects will actually be undertaken during AA4 (for example, protection systems[8] and the West Kalgoorlie SVC replacement[9]).
3. Transmission improvement in service - SCADA and communications
    - Conclude whether sufficient information has been provided by Western Power to demonstrate the proposed costs are likely to meet the new facilities investment test.
    - Determine the likelihood the proposed replacement is reasonably likely to proceed in AA4.
    - Review whether Western Power has included any impact on operating expenditure from the investment in SCADA and Comms
4. Transmission compliance
    - Substation security – Assess Western Power's revised proposal and reasoning for expenditure.

[7] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 70 73, paragraph 423 - 438

[8] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 79, paragraph

[9] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 83, paragraph 502

4.2 Overview

On October 17, 2017 and in accordance with the requirements of the Electricity Networks Access Code 2004 (the Code) Western Power submitted its revisions to its access arrangement for the period July 1, 2017 to June 30, 2022. On May 2, 2018 the Economic Regulation Authority (the ERA) issued its draft decision on that submission. This report is GHD's review of Western Power's response with respect to Transmission CAPEX.

Actual expenditure in AA3 was much less than the amounts approved by the ERA in its final AA3 decision. Western Power have forecast amounts of expenditure for AA4 that are, in all cases, greater than the actual AA3 expenditures. The amounts are in $ million real at June 2017 and include overheads but exclude contributed assets.

Table 6 Transmission CAPEX comparison AA3 and AA4 ($ million real, June 2017) excluding gifted assets and capital contributions

Category	AA3 Forecast	AA3 Actual	AA4 Western Power proposal
Growth	1,154.2	517.2*	294.1
Asset replacement and renewal	184.1	186.3	296.2
Improvement in service	84.3	60.3	108.4
Compliance	135.6	111.9	186.9
Corporate	125.8	81.6	167.6
Total	**1,683.8**	**957.2**	**1,050.6**

*includes Midwest transmission line

For the remainder of this report the amounts will exclude overheads and will be in direct $ million real June 2017.

Table 7 Transmission CAPEX forecast direct costs for AA4 ($ million real, June 2017) excluding contributed assets

Category	AA4 Western Power proposal
Growth	240.8
Asset replacement and renewal	245.2
Improvement in service	89.9
Compliance	155.0
Total	**730.9**

Note; that transmission corporate CAPEX has not been reviewed for the purposes of this section of the report. As such the remaining sections of this report will not include reference to the transmission corporate numbers.

Following the ERA's draft decision, Western Power submitted its revised proposed Access Arrangement on 14 June 2018. This submission included revised expenditure forecasts for transmission CAPEX as follows.

Table 8 Transmission CAPEX revised forecast expenditures and draft decision direct costs for AA4 ($ million real, June 2017) excluding contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation#	AA4 Western Power revised proposal (Jun 2018)
Growth	240.8	159.4	205.5
Asset replacement and renewal	245.2	145.9	231.2
Improvement in service	89.9	89.9	89.9
Compliance	155.0	95.3	147.0
Total	**730.9**	**490.3**	**673.6**

Includes contributions of $53.3 million in Growth

4.3 Growth

GHD recommended two projects should be removed; being a new CBD substation ($62.2 million) and a new Picton/ Busselton 132 kV line ($19.2 million). Western Power accepted the removal of the CBD substation from its submission but has retained the view that the Picton/ Busselton line is needed. Any comment on the need for the Picton/ Busselton line is excluded from the scope of this report.

In its revised submission Western Power has sought to increase the amount of customer access work from $41.0 million to $67.9 million excluding contributed assets. This proposed increase has been based on:

- Introduction of the generator interim access (GIA) solution. Three access contracts have been signed to date and there are others under negotiation
- New loads seeking access in the goldfields
- Major lithium projects
- Metronet.

In GHD's opinion any relocation work carried out for Metronet would be fully customer funded and so does not need to be considered. There may be additional connections to meet the power requirements associated with Metronet but these would most likely be connection assets and fully funded by the customer.

Western Power has provided the following table which lists the projects they expect to proceed during AA4. A column has been added on the right with GHD's comments regarding the likely capital contribution considerations.

Table 9 Anticipated AA4 capital growth projects ($ million real, June 2017)

Project	Size (MW)	Est Cost ($M)	Assumed cap con %	Current Scope of Work*	Comments
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Project	Size (MW)	Est Cost ($M)	Assumed cap con %	Current Scope of Work*	Comments
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]

Project	Size (MW)	Est Cost ($M)	Assumed cap con %	Current Scope of Work*	Comments
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]		[redacted]			[redacted]

[redacted]

Western Power contends that a 42% average contribution rate would apply to the projects for which no IWCs have been executed to date. However, GHD analysis of the projects suggests that for the significant projects of Yandin Wind Farm ($22.3 million) and Warradage Wind Farm ($22.3 million) the contributions are likely to be more than 50%; for the Waddi Wind Farm ($2.9 million) and Beros Road Wind Farm ($0.5 million) and the Talison Lithium project in Greenbushes ($8.0 million) the contributions are likely to be close to 100%. The other listed individual projects only account for a further $9.7 million of cost. There is also a further $32.3 million worth of transmission access projects which have not been specifically accounted for. GHD is not able to comment on the capital contribution for these projects without further information.

It is also noted that Western Power believe all listed projects and the unspecified projects will proceed to completion during the AA4 period. There is only 4 years of this access arrangement period remaining and it is difficult to see a scenario where all of these projects could proceed to completion and all of the costs would be incurred in this period.

The introduction of the GIA is significant and there is the possibility of up to eight generators being connected using this facility. Historically, connection rates of new generation have been very low and the SWIS peak load is forecast to decline or at least to remain static into the future. The GIA, as proposed, is an interim step towards a constrained market. It does provide significant opportunity for generators to connect on a constrained basis. One benefit for new entrants is that constrained connection limits any requirement for network reinforcement. This results in a likely lower cost for generators to connect and thus makes connection much more financially attractive.

It is noted that these works are subject to the investment adjustment mechanism and as such any risk of underfunding is ameliorated.

Recommendation

Western Power contends that all the listed projects including those that are unspecified will proceed and be completed within the AA4 period. Based on the information available to us, GHD does not consider this to be at all likely. In addition there is no supporting evidence with respect to $32.3 million of unspecified works. Further, GHD does not accept Western Power's contention that a 42% average rate for capital contributions is applicable for the forecast works.

Consequently GHD recommends that the allowance of $41 million initially proposed by Western Power and reviewed by GHD in its initial report is reasonable and no adjustment is required. The net reduction compares to Western Powers Revised proposal is $26.9 million.

Table 10 Transmission growth capex direct costs for AA4 ($ million real, June 2017) excluding contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation#	AA4 Western Power revised proposal (Jun 2018)	Recommended AA4 allowance
Capacity expansion	199.8	118.4	138.3	118.4*
Customer driven	41.0	41.0	67.9	41.0
Total - Growth	**240.8**	**159.4**	**205.5**	**159.4***

Includes contributions of $53.3 million in Growth

* Excludes consideration of the Picton/Busselton 132 kV line

4.4 Asset replacement and renewal

Asset replacement and renewal is broken into a number of categories as set out in the table below.

Table 11 Transmission asset replacement and renewal CAPEX direct costs for AA4 ($ million real, June 2017) excluding contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)
Switchboards	67.4	37.3	67.4
Power transformers	52.4	31.9	52.4
Protection Equipment	40.3	20.2	40.3
SVC's	36.2	14.6	22.2
Primary Plant	46.8	39.7	46.8
Other	2.2	2.2	2.2
Total - Asset replacement and renewal	**245.2**	**145.9**	**231.3**

4.4.1 Switchboards

The original GHD recommendation was a reduction in the proposed expenditure for switchboard replacement from the Western Power forecast of $67.4 million to $37.3 million. This reduction was based on implied unit rates from the proposed replacements at Hay Street and Milligan Street substations, the amount for reactive replacements and the proposed unit costs for Yorkshire/GEC switchboard replacements.

In their response, Western Power has reiterated:

- There are 137 switchboards across the network, with five in service beyond their nominal asset life
- Replacement-on-failure only will increase percentage of over-age assets from current 4% to 10% by June 2022 and 12% by June 2027
- Switchboards based on a pitch-filled design are known to have catastrophic failure modes. Western Power currently has 17 pitch-filled switchboards in service installed in 11 substations
- Whilst interim work practices and procedures are in place to mitigate the risks, in accordance with their Electricity Network Safety Management System, Western Power plans to replace 11 switchboards and decommission a further five during AA4 and one in AA5
- Staged replacement of four Yorkshire/GEC switchboards that are approaching their nominal asset life and are technically obsolete, with no manufacturer support or spares available
- Estimated cost of replacing a switchboard is approximately $5 million, with the average cost of replacing an obsolete Yorkshire/GEC switchboard being slightly higher
- Reactive replacement allowance based on historic failure rate over past 10 years and existing condition assessments
- Western Power proposes its original forecast of $67.4 million to retained and is expected to satisfy requirements of NFIT

From the Transmission and Distribution Network Management Plan, we note:

- Asset strategy is:
  - Progressively replace/ decommission pitch-filled switchboards and other switchboards at the end of life
  - Identify condition and repair or replace based on condition, prioritised by risk
- Current overall risk is High, driven by High physical impact assessment

In their response, Western Power corrected previous advice regarding the number of switchboards at Hay Street and Milligan Street substations, highlighting that the asset management system records these switchboards by sections. As the switchboards at these two substations comprise two separate sections connected via a bus section, there are actually only two switchboards at each site, and not four as previously suggested. In correcting this, Western Power did not advise if this means the number of switchboards to be replaced is amended from 11 to 7, or if the original 17 pitch-filled switchboards requiring replacement should be amended to 13.

Assuming the number of switchboards has been amended to 7, and using the allocations nominated by Western Power for replacement of Yorkshire/GEC switchboards ($22.7 million), reactive replacement ($9.6 million) and mobile RMU ($2.1 million) from their original forecast of $67.4 million, we have calculated the unit rate per switchboard to be $4.7 million. This is consistent with the approximate $5 million per switchboard stated in their draft response.

We note a recent comparative estimate for an 11 kV switchboard based on market data available to us was $4.1 million, which is a variance of 13% from the Western Power unit rate, and within our nominal test of ±15% for reasonableness. We therefore consider a unit rate of $4.7 million per switchboard to be reasonable.

For the pitch-filled switchboards, we agree that these types of switchboards pose an unacceptable high risk to safety and network reliability and should be replaced, although we note that Western Power has not provided any condition assessment of the switchboards nominated for replacement in AA4.

We accept the Western Power advice regarding the obsolescence of the Yorkshire/GEC switchboards, and the need for their replacement. Western Power has proposed a forecast that supports a staged replacement program during AA4, which replaces four switchboards by 2022/23 and includes preliminary work for a further two switchboard replacement during AA5.

The reactive replacement allowance assumes a failure rate of 1.5 switchboards per 5-year period, based on historic failure rates. Western Power has not advised if this historic failure rate is linked to failures with pitch-filled switchboards, or if the replacement program proposed for AA4 would reduce this failure rate by replacing switchboards that are near end-of-life. Western Power has not justified the proposed $6.4 million unit rate for switchboards, which is approximately 30% higher than the nominated approximate unit rate of $5 million per switchboard for planned replacements.

We have reviewed a comparative estimate for a mobile RMU solution, based on three Ring Main Units to facilitate switchboard replacement and switching capability in the event of an outage due to a switchboard failure. Our comparative estimate is $2.4 million which is within our nominal ±20% test for reasonableness. Therefore we accept the provision of $2.1 million for a mobile substation are reasonable.

Recommendation

GHD accepts the Western Power advice for the qualified replacement volumes at Hay Street and Milligan Street, the need for the replacement of the technically obsolete Yorkshire/GEC switchboards and the prudency of provisions for reactive replacement and mobile RMU solution.

In amending the replacement volumes for pitch-filled switchboards at Hay Street and Milligan Street, we have concluded that the replacement unit cost per switchboard is $4.7 million, which we consider reasonable in comparison to recent market data available to us.

We note that in the Western Power response, the replacement cost for Yorkshire/GEC switchboards is considered to be “slightly more” than a pitch-filled switchboard. Western Power has not provided additional information regarding the unit rate to be used for replacing Yorkshire/GEC units, and so we have adopted the same replacement unit cost as for the pitch-filled switchboards.

We acknowledge that Western Power has used historic failure rates for switchboards to determine an equivalent 1.5 replacements should be provisioned for AA4. Whilst we accept the prudency of the allowance for reactive replacement switchboards, Western Power has not justified the $6.4 million unit rate it states in its response. We do not accept this unit rate to be reasonable, and have adopted the replacement cost of $4.7 million per switchboard as the efficient cost.

Our recommended forecast allowance[10] is $60.8 million for AA4. This equates to a $6.5 million reduction in CAPEX for this category of spend.

[10] Calculated as (7 * 4.7) + (4 * 4.7) + (1.5 * 4.7) + 2.1 = 60.85. Our estimate based on 4 Yorkshire/GEC switchboards completely replaced in AA4, whilst Western Power forecast for staged replacement has costs for preliminary work on two further replacements in AA5 that are equivalent in value to costs to complete the replacement of two switchboards started in AA4.

4.4.2 Power transformers

The original GHD recommendation was a reduction in the proposed expenditure for power transformer replacement from the Western Power forecast of $52.4 million to $31.95 million. At the time of the original GHD review, business cases and condition reports were not available. Using historic replacement volumes during AA3 as a guide, GHD adopted a conservative view of 15% of proposed asset replacements being deferred with maintenance repairs until AA5. In addition, GHD considered a further 30% reduction may be achievable through efficiencies identified during project development and implementation as stated in the Western Power original submission.

In response to the Draft Decision, Western Power advised:

- 90 of the current fleet of 342 power transformers are assessed as being in poor condition
- Optimised plan for AA4 to:
  - refurbish 14 transformers
  - replace 3 transformers
  - decommission 19 transformers
  - install 2 new transformers including network reconfiguration
- Deferring proposed investment will increase risk in network reliability and projected increase in reactive replacement expenditure; as well as reducing forecast benefits through optimised plan

We note that the level of power transformers assessed as being in either Bad or Poor condition is currently 90 transformers, or 27% of the power transformer population.

In their response, Western Power has provided three business cases for post-gate three:

- Replacement of Picton 66/22 kV T3 transformer
- Replacement of two transformers in poor condition at Capel substation with new unit
- Procurement and two new and refurbishment of one existing strategic spare power transformers

Each business case reviews options (including non-network options), current and residual risk, NPV analysis and any site specific operating conditions. In each case, an internal assessment has concluded that the recommended capital investment satisfies the NFIT based on satisfying:

- the efficiency requirements of section 6.52(a) as representing the amount invested by a service provider efficiently minimising costs
- the requirements of section 6.52(b)(iii) for ‘provision of contracted covered services’

We have revisited the asset class strategy, and acknowledge the relatively high percentage of transformers in Bad or Poor condition, and the risk this represents to the reliability of the network. In addition, there are 11 transformers that do not comply with oil containment requirements, and a further 9% of substations that do not comply with statutory physical separation requirements. Both of these groups pose high risks in the event of an unassisted failure. Based on the current risk profile for the transformer population due to asset condition and the compliance issues that are identified in the asset class strategy, the program proposed by Western Power looks reasonable.

Based on the scope of works detailed in the business cases, we have generated comparative estimates for the Picton and Capel transformer replacements. Using market cost data available to GHD, our comparative estimate for the Picton transformer replacement, including substation modifications is $11.1 million which varies by 7% from the business case estimate of $11.9 million, and within our nominal test of ±15% for reasonableness. For the Capel replacement, our comparative estimate is $7.1 million compared with the Western Power business case value of $8.0 million which is a variance of 11%, which is within our nominal range for reasonableness.

Therefore, we accept the Western Power estimates as reasonable.

Recommendation

In developing our original recommendation, we could only assess the information that was provided at the time and Western Power's historical performance. Since we issued our initial assessment we have received additional information that has enabled GHD gain a better appreciation of the proposed expenditure. In our opinion the scope of work proposed by Western Power for power transformer replacement is considered to be consistent with their asset strategy for this asset class, and addresses the risks identified for the power transformers. Based on our comparative estimates for business cases provided, we are satisfied that the costs used by Western Power in generating this forecast reflect market values.

Therefore we recommend that the proposed $52.4 million forecast be accepted.

4.4.3 Protection Equipment

The original GHD recommendation was a reduction in the proposed expenditure for the replacement of protection equipment from the Western Power forecast of $40.3 million to $20.2 million. This reduction was related to the AA4 forecast being a step change from AA3. The actual expenditure in AA3 was $5.1 million compared with the AA3 allowance of $10.6 million.

In its response Western Power has maintained their requirement for the original forecast expenditure and has stated it intends to undertake this work.

We do not believe Western Power has provided any additional information to support a change in the ERA's draft decision. It should be noted that protection for transmission lines, transformers and busbars is fully duplicated including the associated communication links. Failure of one protection scheme to clear a fault does not result in the fault not being cleared.

We consider Western Power's program is aggressive and there is not a compelling case to support the rate of works. The existing protection schemes have been reliable to date and there is no suggestion that this reliability will decline in the short to medium term.

Recommendation

GHD has not changed its view on the level of expenditure required as set out in its initial report. This equates to a reduction of $20.1 million in CAPEX for this category of spend.

4.4.4 SVC's

In their response to the Draft Decision, Western Power has highlighted the importance of SVCs to the network to maintain delivery of reliable and quality power to customers. The original submission of $36.2 million related to forecast works at both West Kalgoorlie and Merredin Terminal Substations. For the revised forecast, Western Power has advised that work at the Merredin Terminal Station is not scheduled to commence until 2020/21 and the replacement of this asset has been deferred to the AA5 period. Western Power has developed mitigation strategies to manage and maintain the Merredin SVC during AA4.

To support the revised forecast of $22.2 million, Western Power has detailed the full scope of works planned for the West Kalgoorlie Terminal Station SVC replacement with reference to the business case.

This business case identifies the option considered most prudent to mitigating existing risks associated with two SVCs that have been assessed as being in Bad condition and nearing the end of their nominal replacement life (in-service age of 33 years compared to MRL of 35 years). The network configuration is a 220 kV single line from Muja to West Kalgoorlie, with significant private generation connected to the line at Merredin and at Kalgoorlie. The line operates on an N-0 basis; that is, a loss of the line means load will need to be shed in Kalgoorlie until generation can be bought on line.

The key elements for the West Kalgoorlie SVC replacement are:

- SVCs are assessed in Bad condition and are 33 years old
- Components of the SVCs has obsolete technology that is expensive to maintain
- Units are leaking oil and pose an environmental risk
- Failure of the SVC would result in 60-75 MW reduction of the Eastern Goldfield 155 MW load transfer capacity, causing reliability issues. Any catastrophic failure would represent a major safety risk
- Mitigate the potential for out-of-merit dispatch of West Kalgoorlie generators

We note that the business case investigated five options, with the preferred option being the replacement of the existing SVCs with Static Synchronous Compensators (STATCOMs).[11] There was no viable non-network option available, and the options investigated were based on Do Nothing and other different replacement or refurbish options.

The photographic evidence provided in the Business case highlight the poor condition of the saturated reactor (SR) cooler cores, the large quantity of oil that has leaked from the mesh reactor into unsealed bunds on the floor of the SR building and evidence of an flashover in the saturated reactor.

We accept that the West Kalgoorlie business case has investigated appropriate options, and nominated a preferred option based on the cost effective solution to address and mitigate the network risks.

We have reviewed our original comparative estimate in light of the full scope of work, and accept the nominated costs for the additional plant (shunt reactors) and control devices as reasonable and consistent with market values.

Recommendation

We are of the opinion that this project is likely to meet the requirements of the new facilities investment test and, and recommend the proposed $22.2 million forecast is accepted.

4.4.5 Transmission Primary Plant

The original GHD recommendation was a reduction in the proposed expenditure for the replacement of outdoor circuit breakers from the Western Power forecast of $46.8 million to $39.7 million. This 15% reduction was related to anticipated efficiencies through the business transformation process, and greater efficiency in delivery.

Whilst challenging the proposed efficiency reduction for AA4, Western Power suggested that AA4 unit rates were based on AA3 actual costs that have efficiencies embedded in them. However, we do not consider Western Power has provided any additional information to support a change in our original recommendations.

Recommendation

GHD has not changed its view on the level of expenditure required as set out in its initial report. This equates to a reduction of $7.1 million in CAPEX for this category of spend.

[11] An SVC provides reactive power on a high-voltage electricity transmission network, and can be used for voltage stability. A STATCOM is typically used to support networks with poor power factor and poor voltage regulation, and is often used for voltage stability. However, a STATCOM has better operating characteristics than an SVC, and respond quicker than SVCs.

4.4.6 Summary

A summary of GHD's recommendations for asset replacement and renewal is provided in the following table.

Table 12 GHD recommended expenditures for transmission asset replacement and renewal forecast expenditure direct costs for AA4 ($ million real, June 2017)

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	Recommended AA4 allowances
Switchboards	67.4	37.3	67.4	60.9
Power transformers	52.4	31.9	52.4	52.4
Protection Equipment	40.3	20.2	40.3	20.2
SVC's	36.2	14.6	22.2	22.2
Transmission Primary Plant	46.8	39.7	46.8	39.7
Other	2.2	2.2	2.2	2.2
Total - Asset replacement and renewal	**245.2**	**145.9**	**231.3**	**197.6**

4.5 Improvement in service

GHD's initial report did not recommend any reductions to Western Power's proposed improvement in service expenditure. GHD noted:

- Western Power's SCADA and communications equipment has previously been maintained on a reactive basis and has now reached a point where technical obsolescence, performance and vendor support have become issues,
- GHD believes the past level of expenditure by Western Power has been below industry average and the proposed level of expenditure is more in line with industry benchmark averages.

The ERA is concerned the forecast investment is not supported by sufficient information to demonstrate the proposed costs and are likely to meet the new facilities investment test and evidence that the replacement is reasonably likely to occur in the AA4 period and required Western Power to provide this information.[12]

In their response, Western Power makes the following points:

- Western Power acknowledges that GHD and the ERA have accepted the need to upgrade the SCADA and communications facilities,
- Western Power will use a mix of internal and external resourcing to undertake the works. The intention is to use internal resources for design and commissioning, and external resources to carry out installation works,
- They have evaluated the market and have external delivery vendors in place.
- [redacted]
- Western Power has sought to improve the efficiency of delivery through grouping projects by location and utilising joint planning teams.

[12] ERA draft decision pp.91-92

In addition, Western Power has provided work planning reports for transmission and distribution SCADA and communications equipment. Our review of these documents suggest that these work planning reports detail the options investigated, the nature of the work to be done (similar to a business case) and details of the preferred option.

For the transmission SCADA, we note that in [redacted], Western Power highlights the risk as medium that a lack of skilled resources may compromise the on-time completion of the project, and that the program requires close co-ordination with the site owner and system outage requirements. The mitigation strategy requires a review of available resources and the project schedule. The Works Planning Report documents a summary of the meetings and the key decisions made up to 16 January 2015.

However, other than highlighting the mitigation strategy for the identified resource risk and documenting the activities of the Joint Planning Team, we do not believe these reports detail the deliverability of the transmission SCADA program in AA4, including considerations such as:

- What timelines are in place for the delivery of the programs
- How projects are grouped by location
- How the work is to be delivered - mix of internal/external resources
- Internal and external skills resourcing assessment
- How tenders are to be issued/assessed
- What efficiency opportunities in delivery have been identified
- The nature of progress reporting including current work status

Recommendation

We remain satisfied that the proposed expenditure for AA4 is prudent, as it addresses the replacement of assets that are technically obsolete and important to the efficient operation of the network.

However, we do not consider Western Power has provided sufficient information for an assessment of how the proposed replacement program is to be delivered during AA4. We therefore agree with the ERA that approval for this expenditure is conditional on this information being provided.

Table 13 Transmission improvement in service CAPEX direct costs for AA4 ($ million real, June 2017) excluding contributed assets

Category	AA4 Western Power proposal (Oct 2017)	AA4 Western Power revised proposal (Jun 2018)	Recommended AA4 allowances
Improvement in service	89.9	89.9	89.9

4.6 Compliance

Western Power's compliance expenditure is broken into a number of categories as set out in the table below.

Table 14 Transmission compliance CAPEX direct costs for AA4 ($ million real, June 2017) excluding contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)
Poles and towers	60.0	60.0	60.0
Cross arm replacement	4.8	4.8	4.8
Substation security	72.1	12.4	64.1
Transformers	12.7	12.7	12.7
Protection	2.3	2.3	2.3
Cables	3.0	3.0	3.0
Total - Compliance	**155.0**	**95.3**	**147.0**

The original GHD recommendation was a reduction in the proposed expenditure for substation security compliance issues from the Western Power forecast of $72.1 million to $12.4 million. This reduction was related to the AA4 forecast relying upon the provisions of the National Guidelines published by the Australia-New Zealand Counter-Terrorism Committee which GHD did not accept as sufficient justification for the proposed forecast. GHD proposed an alternate allowance of $12.4 million based on AA3 expenditure.

In their response to the Draft Decision, Western Power has provided risk assessment models for substation fences and roofs to support their proposed forecasts. This is a departure from the approach used for previous regulatory periods, as expenditure ahead of AA3 was not planned in a similar way.

4.6.1 Substation security

Western Power has advised that the fencing program commenced in 2015/16 with detailed analysis of each fence underpinning the schedule.

In response to the Draft Decision, Western Power provided a risk assessed approach in identifying substation fences for replacement, based on an assessment of the fence field condition, the criticality of the substation based on its configuration, and the perceived threat to the substation considering its locality, visibility and historic known security incidents. The Western Power nominated asset life for substation fencing is 25 years, which is consistent with the asset life for fences adopted by other electricity transmission utilities. Our review notes that as at 30 June 2016, 90% of the substation fencing population is at or under this 25-year threshold, with 53% of the population between 23 and 25 years old.

Western Power has generated a "risk score" based on a weighted average of the condition, criticality and threat assessments, and then allocated these scores a Priority ranking based on a risk score scale they have developed. In the model we received from Western Power, these priority rankings appear to have been manually categorised. We believe a number of the higher risk items have been inadvertently incorrectly categorised – the model provided lists 13 x Priority 5 and 15 x Priority 4 assets, whilst assigning Priority rankings using the 5-level table provided in the Western Power model results in 4 x Priority 5 and 24 x Priority 4 fences.

The program proposed by Western Power for AA4 is summarised in Table 15, and includes the provision of additional security measures on the building at the Hay Street substation.

Table 15 Western Power proposed AA4 annual forecasts ($ million real, June 2017)

Financial Year	No. of fences	Forecast ($M)
2017/18	2	10.52
2018/19	9	8.80
2019/20	12	11.67
2020/21	8	8.59
2021/22	7*	4.48
Total	**38***	**44.06**

* Includes new security measures on Hay Street substation building

Figure 1 shows the revised Priority ratings for substation fences by the assessed condition of the fence.

Figure 1 Risk priority for substation fences by assessed condition

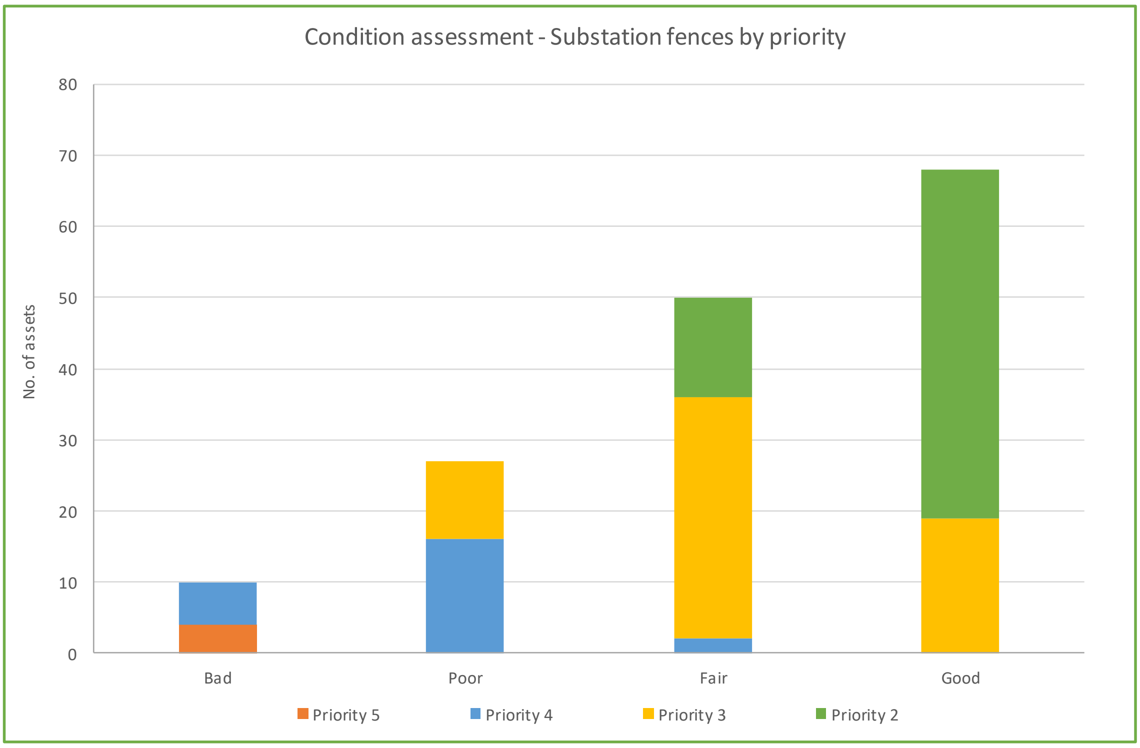
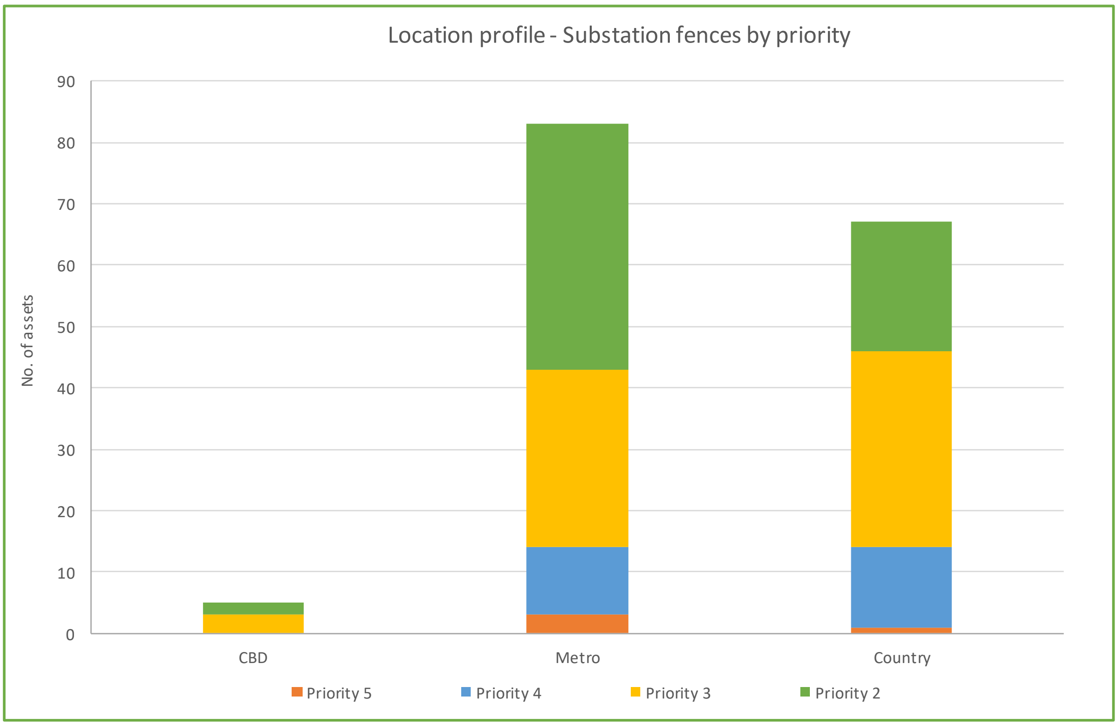


Figure 2 shows the Priority ratings for substation fences by physical location.

Figure 2 Risk priority for substation fences by location



From these graphs, we note the higher priority fences for replacement are in Metro and Country areas, and that some of the fences assessed as Poor are Priority 3 risks, due to lower rankings for criticality and/or threat factors.

The AA4 schedule[13] provided by Western Power includes new security measures for 14 substations (including the [redacted]) with fences categorised as Priority 3, totalling $9.9 million. We agree that the AA4 program proposed by Western Power addresses 17 fences with the highest risk scores, and 22 of the 28 Priority 5 & Priority 4 category fences.

It is not immediately apparent to us why Western Power has listed 16[14] substations with fences categorised as Priority 3 in the AA4 program, whilst there remains six Priority 4 fences not scheduled for replacement prior to 2021/22. Most of these unscheduled Priority 4 fences are assessed as being in Poor condition.

We agree with the proposed replacement program for 2017/18 and 2018/19, as these focus on the fences with the highest risk scores. However, we note Western Power has suggested in the substation security asset strategy and in response to the ERA that investment is informed by risk assessment outcomes including consideration of asset condition inspections. Therefore, we do not accept that Priority 3 fences are scheduled for investment in the latter years of AA4 whilst Priority 4 fences, typically in Poor condition, are not planned to be replaced.

Recommendation

Based on our review of the Western Power modelling for substation fencing, we consider the AA4 forecast should be based on the replacement of the higher priority fences identified in the risk assessment, and therefore recommend the AA4 forecast be amended to $34.2 million for AA4.[15]

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[13] [redacted] notes that "*high risk areas with fencing that has reached end of Mean Replacement Life (25 years) or on failure will be replaced with a new Weld Mesh standard*." In a response to the ERA dated 14 August 2018, Western Power advised that weld mesh is proposed for all fence replacements during AA4.

[14] [redacted]

[15] Calculated as [proposed $44.1 million] - [$9.9 million for proposed Priority 3 security expenditure] = $34.2 million

4.6.2 Physical security measures

Western Power has adopted a “Deter-Detect-Delay-Respond-Recover strategy” for physical security. In addition to the fencing expenditure within the Deter element, Western Power is proposing investment in the Detect element through real-time vision, surveillance monitoring and keys and locks management programs.

The physical security measure category relates to risks posed by intruders who may bypass the perimeter security fencing. This includes automated security systems, CCTV, high security doors, locks, grills, electronic access controls and an improved key and lock system.

Western Power has advised that this category is split into:

- Security systems
- Physical access controls
- Key & locks management program

Western Power has advised in their response that $8.3 million has been forecast for physical security measures, with supporting reports highlighting an anticipated reduction in security guards supervising CCTV due to analytic systems, and improved and more convenient security access for staff due the proposed physical access measures.

With regards to physical security measures:

- We understand the general security systems detect people who have bypassed perimeter fencing. This appears to be significant particularly where fencing requires improvement and will not be attended to for some time.
- The physical access control system has two phases:
  - Role-specific access which is intended to provide a consistent and standard role-specific access which should increase security for all personnel.
  - A self-service system for employees and contractors to self-manage access outside the normal designated locations.
- The third is a key management project that has been made a requirement due to Western Power’s key patents expiring during AA4, requiring replacement and upgrade - this presents an opportunity for Western Power to review the need for mechanical keys and the possible adoption of more efficient, secure and cost-effective options.

The split of the Western Power proposed physical security expenditure is shown in Table 16.

Table 16 Western Power AA4 physical security forecast ($ million real, June 2017)

Category	AA4 forecast ($ M)
Security systems	0.85
Physical access controls	0.45
Key & locks management program	7.00
Total	**8.30**

Security systems

The security system investment relates to the automation of monitoring of CCTV footage, which should improve the control the security guards have, and provide for more efficient camera control. The introduction of this automation reduces the monitoring time and allows Western Power to retain the current number of security guards to supervise the current and new locations. In the absence of this automation, Western Power has estimated that they would require an additional 4 FTEs per year to monitor the new locations. The estimated cost for these additional FTEs is approximately $400,000 per annum. Based on this, the forecast cost of $0.85 million in AA4 will have a 2-year ROI.

Physical access controls

There are two initiatives as part of the forecast $0.45 million for physical access controls in AA4:

- To replace the current practice of manually allocating appropriate access permissions for each team member, Western Power proposes to automate this allocation based on an individual's designated role in the organisation, and their associated physical access requirements. This will involve an integration between the HR system and an access control system.
- As a follow-on to the initiative for automated access permissions for Western Power employees, a self-service system that allows employees to log a security access request for a specific business need requiring access to an area outside of their access permissions allocated to their organisational role.

We agree with Western Power that the automatic linking of physical access permissions will ensure that these permissions are allocated on a consistent and transparent basis. With the implementation of this initiative, all employees will be familiar with any constraints on their physical access permissions. We accept the proposed self-service arrangement that allows for application for special access due to a specific business need beyond their normal access permissions is a reasonable extension.

Western Power has not justified its contention that these initiatives "increase security safety for all personnel", but we accept that these programs should improve the overall co-ordination of physical access permissions across the organisation, and better control which employees can gain access to particular areas based on the need of their role within Western Power.

We are of the opinion that the proposed expenditure is prudent in improving the management of employee, contractor and visitor access permissions, and recommend the proposed allowance of $0.45 million be accepted.

Key & locks management program

Western Power currently relies upon mechanical keys as the primary means of prevent unauthorised access to substations and major primary equipment such as ring main units and pole-top switches. This includes gate, substation and equipment keys for approximately [redacted]. The 12-year patents on these keys is due to expire during AA4, [redacted]

[redacted].

The forecast expenditure of $7.0 million will replace the existing keys and locks with a combination of restricted locks and electronic access controlled locks, managed by electronic key safes. The criticality of each site will be considered when introducing a new system to ensure it is sufficient for the site risk.

We accept the critical nature of the keys and locks as the first line of protection against unauthorised access, and the prudency of the Western Power proposal for AA4 to replace and upgrade this system. We recommend that the proposed $7.0 million be accepted for this program.

Deliverability

In their internal document detailing the physical security strategy[16], Western Power has defined the delivery strategy, including the sourcing of security systems and resourcing of security services and a delivery schedule for the activities during AA4. The schedule highlights tasks that are pre-requisites to others.

We are satisfied that Western Power has considered the key areas for collaboration across the business and the preferred delivery strategies using both internal and external resources, with the projects and initiatives consolidated and managed within programs and delivered as part of an overall Property and Fleet enabled portfolio of work.

We believe Western Power has an executable program of works for the delivery of the key initiatives of the physical security measures program, and the nominated works should be completed during AA4.

Recommendation

We recommend that the proposed AA4 expenditure forecast of $8.3 million be accepted.

4.6.3 Asbestos

Western Power has nominated a provision of $2.5 million for AA4 to deal with asbestos. We would expect that Western Power has a register of known asbestos risks, but given the age and nature of the Western Power network, we assume that it is possible planned work at a substation may discover an asbestos risk that was not previously known.

We note that there is little reference to asbestos control in the review of proposed expenditure for AA3.

Western Power advised that asbestos at transmission sites is inspected an annual basis. Current major asbestos removal project include decommissioning of Shenton Park and Herdsman Parade transmission substations. In addition, the AA4 plan includes the removal of 41 instances of asbestos that have been identified as medium risk across 31 substations. The building condition survey has identified asbestos that requires remediation work, which were previously not identified under visual inspection.

Given the proposed escalated work volumes of replacement work in substation buildings and grounds, we consider it prudent and important to include an allowance in the AA4 forecast to manage the asbestos risk.

We recommend the proposed provision of $2.5 million be accepted.

4.6.4 Roofs

Western Power provided a risk based assessment of roofs, albeit not as complete as that provided for fences. Whilst the model reports a condition assessment of the roofs, there is no calculation of a risk score to support the allocation of a Priority rating. Instead, a Priority rating appears to have been manually assigned.

Figure 3 the current age profile for substation roofs. It should be noted that the nominal Mean Replacement Life for a roof, adopted by Western Power, is 50 years.

[16] EDM#44569863

Figure 3 Substation roof population age profile

Approximately 43% of the substation building roofs are over-age (in-service age > 50 years).

In the absence of a risk score, we have reviewed the population based on the assigned priority assignment for each condition assessment.

Figure 4 Substation roof assessments by priority

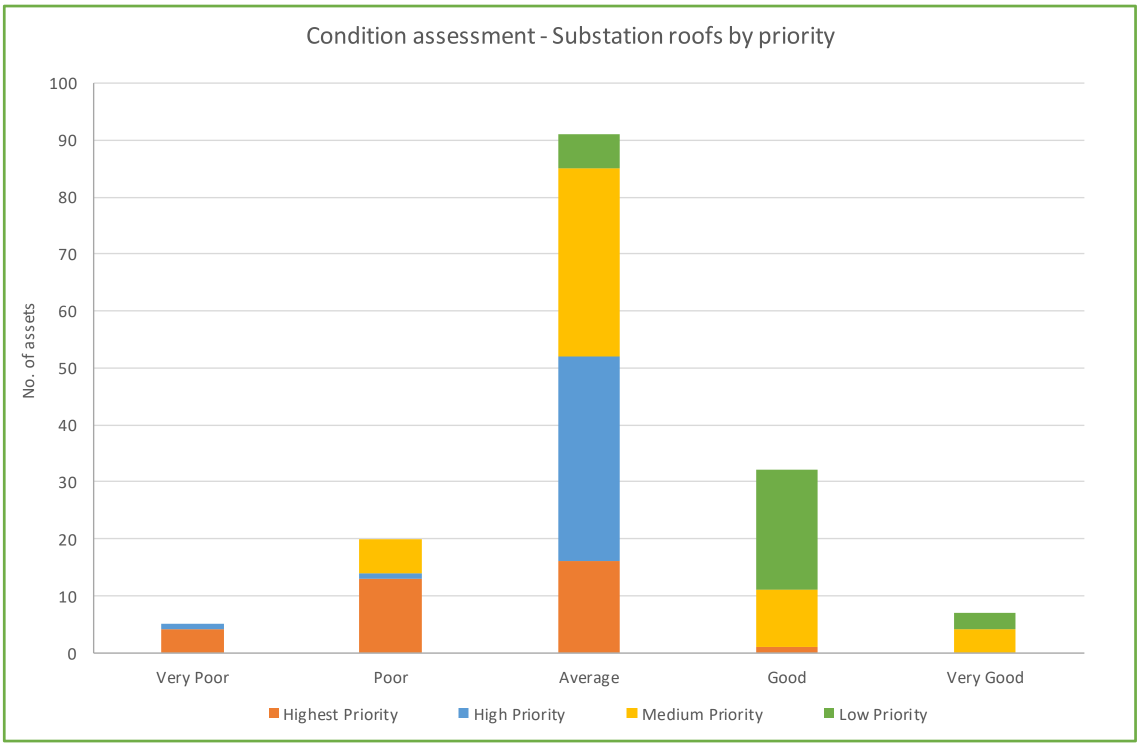


Figure 4 suggests that the roofs that have been identified as being in Very Poor condition (5 in total) are classified as 4 Highest Priority and 1 High Priority, and for those in Poor condition, there are 13 that are considered Highest Priority, 1 High Priority and a further 6 that are only Medium Priority.

It also shows that there are 16 considered Highest Priority and 36 High Priority roofs that are in Average condition. The replacement program proposed by Western Power calls for 4 roofs to be replaced annually for the next 10 years.

In their model, Western Power has specifically identified six roofs for immediate replacement.

Table 17 Substation roofs for immediate replacement in AA4

#	Substation	Assessed condition	Criticality ranking*	Age (years)
1	[redacted]	Average	[redacted]	56
2	[redacted]	Average	[redacted]	55
3	[redacted]	Average	[redacted]	51
4	[redacted]	Poor	[redacted]	40
5	[redacted]	Average	[redacted]	53
6	[redacted]	Very Poor	[redacted]	61

* [redacted]

In each case, a structural engineering report was completed in May 2018. From these examples, Western Power is not relying solely on the assessed condition for a roof from the structural engineers before proceeding with replacement. Most are over-age (with the exception of [redacted] which is assessed as being in Poor condition), but all are considered critical locations, which appears to be one of the primary drivers. To support this, we compared nominated work priority against criticality (consequence) in the following chart and the associated table.

Figure 5 Substation roof consequences by priority

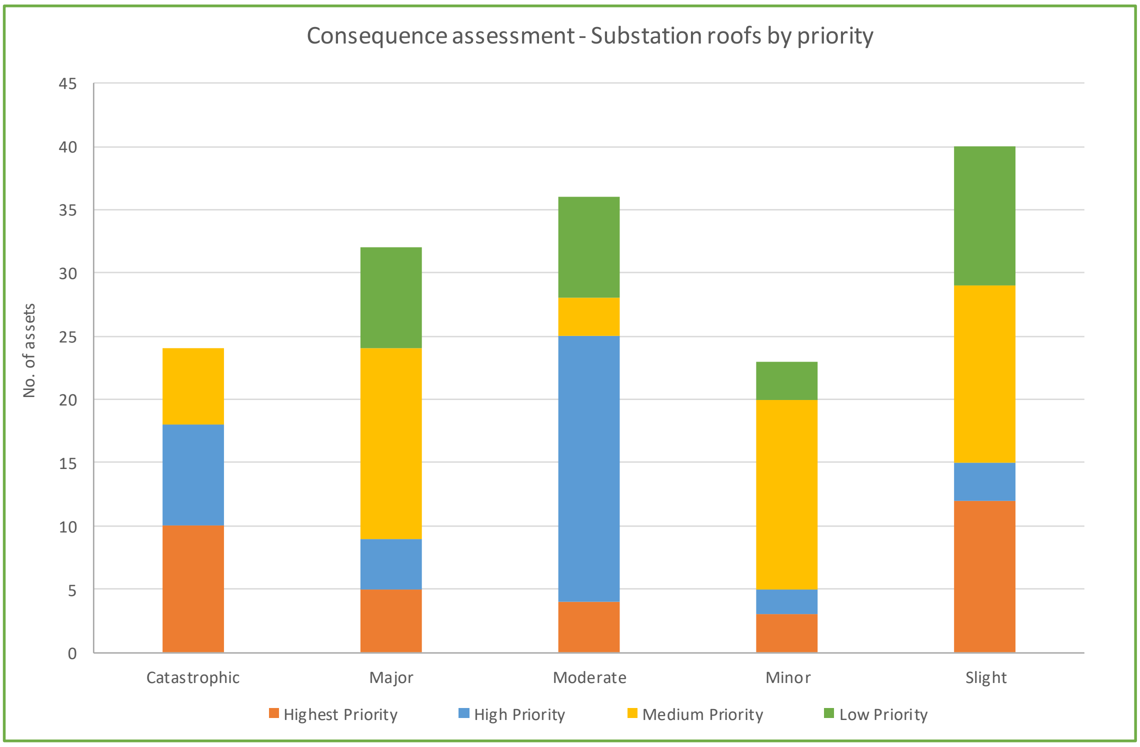


Table 18 Substation roof consequences by priority

Consequence	Highest Priority	High Priority	Medium Priority	Low Priority	Total	% of Population
Catastrophic	10	8	6	-	24	15%
Major	5	4	15	8	32	21%
Moderate	4	21	3	8	36	23%
Minor	3	2	15	3	23	15%
Slight	12	3	14	11	40	26%
Total	**34**	**38**	**53**	**30**	**155**	**100%**

The six substations that have been listed in Table 17 are in the shaded area of Table 18 – ones with the highest priority, and either Catastrophic or Major criticality ranking. Western Power has suggested that 4 roofs will be replaced per year. The red shaded area in Table 18 totals 23.

Recommendation

We have relied upon the condition assessments for roofs provided by Western Power, albeit that we have some reservations as to whether these assessments are conservative.

The incomplete risk assessment for roofs provided by Western Power did not have risk scores and associated Priority levels based on condition, criticality and threat criteria. Whilst Western Power has identified field condition and substation criticality (based on configuration) for each substation roof, we were advised Western Power has manually categorised the Priority levels for roofs using a 4-step classification (Highest/High/Medium/Low) instead of the 5-step classification (5-1) used for fences, confirming a slightly different approach in determining the priority replacement order for roofs compared to fences. At present, structural engineering reviews are being used to prioritise roof replacements.

We consider the analysis of the roofs based on the Western Power priority classification vs condition (refer Figure 4) and classification vs consequence (refer Figure 5) suggests that the progress proposed by Western Power for AA4 of 4 roofs per year is the minimum necessary to address the current and future risk profiles. The current population has 23 roofs that are classified Highest or High Priority for roofs with catastrophic consequences of failure, and 5 with Highest Priority for roofs with a major failure consequence. Western Power has identified 6 roofs with Highest Priority that are designated as requiring immediate replacement, with which we agree as these are part of the 23 roofs we have identified as the most likely requiring prompt attention.

We therefore recommend that the proposed $8.9 million allowance for roof replacement be accepted.

4.6.5 Summary

Table 19 shows a summary of our review of the proposed substation security forecast.

Table 19 GHD recommended expenditures for substation security direct costs for AA4 ($ million real, June 2017)

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	Western Power revised proposal (Jun 2018)	GHD revised recommendation
Substation fencing and security systems	72.1	12.5	44.4	34.2
Physical security systems			8.3	8.3
Building and ground works - asbestos			2.5	2.5
Building and ground works - roofing			8.9	8.9
Total - Substation security	**72.1**	**12.5**	**64.1**	**53.9**

The forecast expenditure for AA4 represents a significant step change on historic spending on the maintenance of substation buildings and grounds. The age profile as at 30 June 2016 for substation fencing has a large proportion of the asset population[17] currently at or near the nominal asset life for fences adopted by Western Power. Similarly, there is currently 43% of the substation roofs at or in excess of the nominal asset life of 50 years. The field condition assessments for both fences and roofs suggest that a majority percentage of these asset populations are in average condition or worse. Our high-level analysis suggests that Western Power will require similar efforts as proposed for AA4 in later regulatory periods (AA5 and AA6) to address the backlog.

Given this, we believe Western Power should report progress on the replacement of fences and roofs, and the residual risk for the substation buildings and grounds assets (fences and roofs), so as to demonstrate a steady progress across the regulatory period in addressing the identified high risk assets.

Table 20 shows the total recommended expenditures for Compliance for AA4.

17 [redacted]

Table 20 GHD recommended expenditures for transmission compliance forecast expenditure direct costs for AA4 ($ million real, June 2017)

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	GHD revised recommended allowances
Poles and towers	60.0	60.0	60.0	60.0
Cross arm replacement	4.8	4.8	4.8	4.8
Substation security	72.1	12.4	64.1	53.9
Transformers	12.7	12.7	12.7	12.7
Protection	2.3	2.3	2.3	2.3
Cables	3.0	3.0	3.0	3.0
Total - Compliance	**155.0**	**95.3**	**147.0**	**136.7**

4.7 Summary of Recommendations

The following table sets out the GHD recommended expenditures for transmission capex. This is in response to Western Power's response to the ERA draft decision.

Table 21 Transmission capex revised forecast expenditures and draft decision direct costs for AA4 ($ million real, June 2017) excluding contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Growth	240.8	159.4	205.5	159.4	(46.1)[18]
Asset replacement and renewal	245.2	145.8	231.2	197.6	(33.6)
Improvement in service	89.9	89.9	89.9	89.9	0.0
Compliance	155.0	95.3	147.0	136.7	(10.3)
Total	**730.9**	**490.3**	**673.6**	**583.6**	**(90.0)**

18 This amount is made-up of a reduction in growth CAPEX of $26.9 million and $19.2 million for the Picton/ Busselton 132 kV line

5. Distribution CAPEX

5.1 Scope

The ERA has asked GHD to provide advice on whether Western Power's revised Distribution CAPEX proposal is reasonably likely to meet the new facilities investment test. In our analysis we have looked at the variations to our initial recommendations, and commented on the changes. Note; we have treated the Advanced Metering Infrastructure (AMI) and associated CAPEX (including related SCADA and Comms spend) separately from the other changes in proposed Distribution CAPEX. The ERA identified some specific areas of focus;

4. Distribution Capital Expenditure:

   – Distribution growth

     - Determine whether the capacity expansion and customer driven expenditure forecasts have been updated properly to reflect the 2017 demand forecasts.
     - Assess the likelihood of the proposed expenditure actually being undertaken within the AA4 period.
     - Assess if Western Power has considered non-network alternatives when developing its growth investment plans

   – Advanced metering

     - Assess Western Power's revised AMI proposal in detail, including testing all of the benefits Western Power has identified to justify its proposal.
     - Review Western Power's Radio Frequency (RF) options analysis[19] for completeness and validity
     - Assess Western Power's change control for AMI forecast capital expenditure[20].
     - Evaluate Western Power's tender process for its AMI IT systems.
     - Appraise Western Power's revised forecast metering volumes and related expenditure (including related operating expenditure).
     - Provide advice on the technical aspects of the AMI proposal, for example whether the neutral integrity monitoring capability of AMI would assist in mitigating the hazard posed by open-circuit neutral faults as submitted by Energy Safety in its response to the ERA's draft decision. Particular focus should be given to how AMI interacts with other open-circuit neutral fault hazard mitigation solutions.

   – Improvement in service - SCADA and communications

     - Determine whether Western Power has provided sufficient information to demonstrate the proposed costs are likely to meet the new facilities investment test
     - Determine the likelihood the proposed replacement is reasonably likely to proceed in AA4.
     - Review whether Western Power has included any impact on operating expenditure from the investment in SCADA and Comms.

[19] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 100, paragraph 590

[20] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 96, paragraph 572 - 575

5.2 Distribution Growth

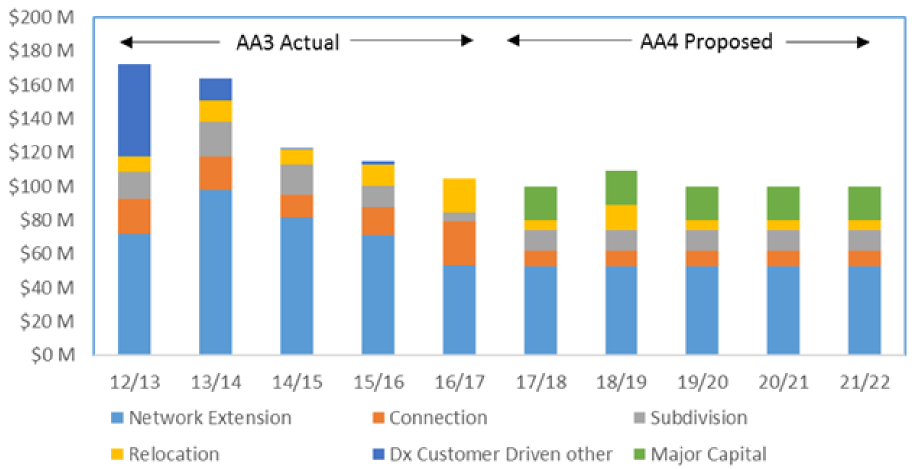
In their original proposal Western Power was forecasting a spend of $406 million over the AA4 period as outlined in the table below;

Table 22 AA4 proposed distribution growth capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Proposed capacity expansion	36.2	34.7	28.3	26.6	30.7	156.5
Proposed customer driven	49.9	49.9	49.9	49.9	49.9	249.4
Total Initial AA4 proposal	**86.1**	**84.6**	**78.2**	**76.5**	**80.6**	**405.9**
Revised capacity expansion	36.1	34.7	28.2	20.5	22.5	142.0
Revised customer driven	49.9	49.9	49.9	49.9	49.9	249.4
Total Revised Proposal	**86.0**	**84.5**	**78.1**	**70.4**	**72.4**	**391.4**
Difference between Proposal and Revision	**(0.1)**	**(0.1)**	**(0.1)**	**(5.1)**	**(8.2)**	**(14.5)**

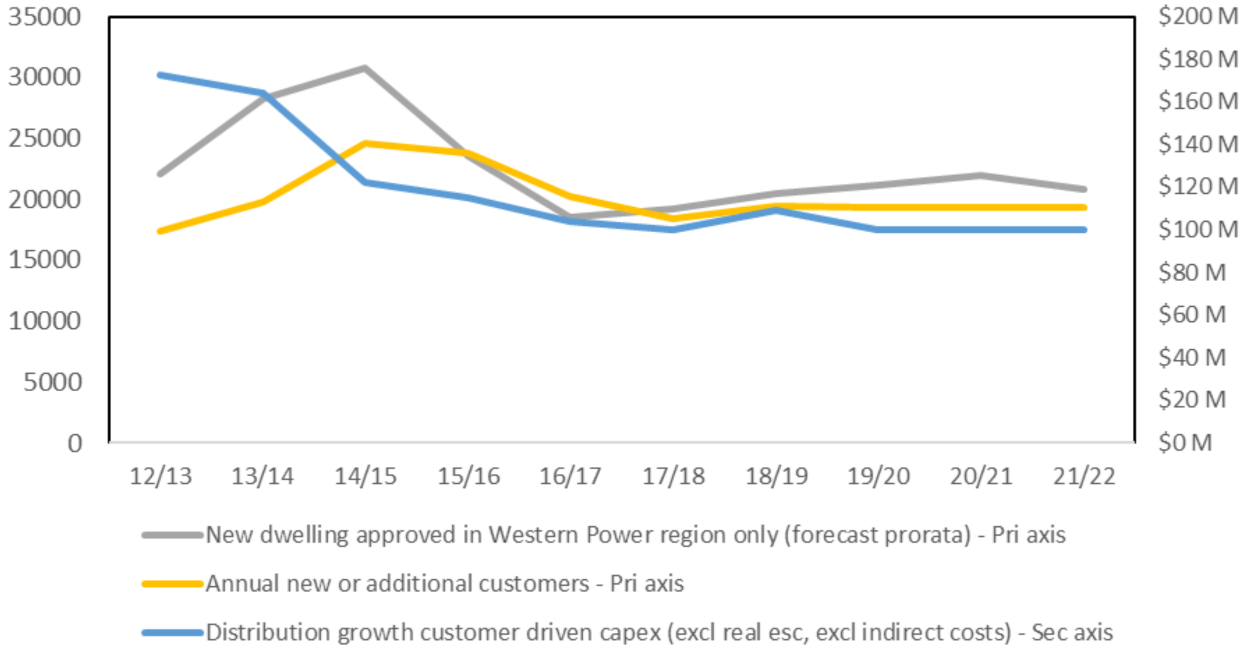
In GHD's review of Western Power's initial AA4 proposal of Distribution Growth CAPEX spend, due to the nature of this type of spend and high-level detail from Western Power to support their estimate, we compared forecast spend with historic spend within the AA3 period and against HIA forecasts and other key drivers of likely spend.

Figure 6 Distribution growth customer driven CAPEX ($ million direct costs at 30 Jun 2017)



In our initial report we also examined the historical and forecast trends of CAPEX against the HIA dwelling growth and customer growth. The correlation or trend pattern match is as expected. This correlation is shown in the following diagram.

Figure 7 Correlation of CAPEX with dwelling and customer growth



GHD also received explanations from Western Power on how their Business Transformation Program was expected to be able to further drive down the cost of executing these small scale projects on an on-going basis.

In our Technical Report on Western Power's initial AA4 proposal we accepted that the proposed level of Distribution spend was reasonable.

Western Power in their Revised AA4 proposal have reviewed their growth-related distribution CAPEX forecasts in light of the 2017 demand forecasts. This review has indicated that the differences between 2016 and 2017 demand forecasts are immaterial and as a result Western Power has made no change to its forecast growth related CAPEX, with the exception of the removal of the distribution related expenditure on the CBD (Milligan Street) substation. This equates to a reduction in forecast spend of $14.5 million.

Given GHD's initial analysis and the lack of change in forecast spend we accept the revised proposed level of expenditure.

5.3 Distribution Improvement in Service

In Western Power's initial AA4 proposal they proposed spending $13.2 million on improving distribution reliability, the largest project in this spend and the only project detailed was the proposal to create a microgrid for the town of Kalbarri. The value of this project was proposed to be $7.9 million. GHD in its technical report on Western Power's initial proposal concluded that the Kalbarri microgrid project passed the NFIT test and accepted the proposed expenditure. In addition, Western Power's initial AA4 proposal included $5.6 million for targeted reliability-driven automation and $0.5 million for R&D projects.

In Western Power's revised proposal, the proposed distribution reliability expenditure has been reduced from $13.2 million to $11.9 million, and reduced targeted reliability-driven automation and R&D pilot projects to zero.

Table 23 Western Power's revised allowances for Distribution Improvement in Service for AA4 ($ million real, June 2017)

Distribution capex amendments	WP AA4 proposal (Oct 2017)	WP revised AA4 proposal (Jun 2018)	Summary
Distribution reliability other	13.1	11.9	Western Power has not made this amendment, and submits further information to support inclusion of a revised amount of capex in the AA4 forecast RAB
Targeted reliability-driven automation	5.6	0.0	Western Power accepts this amendment
RD pilot projects	0.5	0.0	Western Power accepts this amendment
Corporate – advanced meters (AMI)	25.1	27.1	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB

In their revised proposal Western Power has explained that the additional spend is focused on similar edge of grid reliability issues that are impacting the ability of Western Power to meet customer expectations. Western Power in their proposal suggest that the resulting benefit from this additional amount is subjective improvement rather than a demonstrable and measureable benefit.

In our original report we detailed our support for the allowance of $7.9 million in this distribution CAPEX sub-category. This is consistent with Kalbarri microgrid project estimate as stated in paragraph 629 in Western Power's AAI document. This is also consistent with our assessment provided in Section 10.5.1 in our review report.

Western Power's response in Section 6.3.5.1 in its revised proposal mentions that the additional amount is for investment in projects targeting similar edge-of-grid reliability issues and/or to improve customer experience. However, GHD notes that the scope of works for such investment remains largely undefined. Therefore, GHD recommends removing the proposed additional amount above the Kalbarri microgrid project estimate of $7.9 million for this distribution capex sub-category.

Recommendation

That all distribution improvement in customer service spend above that required for the Kalbarri microgrid project ($7.9 million) be removed. This equates to $3.9 million reduction in Distribution CAPEX.

5.4 Advanced Metering Infrastructure (AMI) Revised Submission

GHD considers that the installation of modern electronic devices with enhanced capabilities for new properties and for replacing faulty old meters is consistent with good electricity industry practice, and therefore, is consistent with the new facilities investment test.

GHD also considers that the installation of modern electronic devices with enhanced capabilities for new properties and for replacing faulty old meters is consistent with good electricity industry practice, and therefore, is consistent with the new facilities investment test.

Furthermore, this position is supported in the National Electricity Market (NEM), as from 1 December 2017, these types of smart meters must be deployed by retailers (Queensland, NSW, South Australia and ACTEW) where new and replacement meters are required or where energy businesses and consumers are seeking access to advanced metering services. Note: Victoria is exempt as smart meters have already been installed to all consumers in this state.

The following key factors for the AMI business case are relevant to be justified with sufficient quality of analysis and data to support a positive NPV business case;

1. An appropriate Base Case definition
2. The incremental costs to provide and install AMI meters
3. The incremental costs of the AMI communication and information management systems
4. The cost savings and benefits from AMI Metering and Infrastructure

5.4.1 Determining the Base Case (BAU)

With respect to BAU, Western Power's initial business case (BC) and cost benefit analysis (CBA), approved by the Board in December 2016, assumed the costs of new and replacement meters to be the current basic meter standard. The incremental costs being the additional costs to install meters to the advanced metering standard as well as the associated communications infrastructure and IT system costs to facilitate remote acquisition of metering data.

Western Power revised the business case (Change Control or CC) which went to the Board for approval in February 2018 (CC CBA). Western Power in Section 4 of "Attachment 6.3 Advanced Metering Infrastructure (AMI) Revised Information 14 June 2018" provided details on the changes in the revised business case. The Base Case in the revised business case included the costs of new and replacement meters being the current basic meter standard for single phase meters and the AMI standard for three phase meters which are currently being installed in AA3.

5.4.2 The incremental costs to provide and install AMI meters

Western Power states that the Base Case (BAU metering) in the BC CBA model had a significantly higher incremental meter cost of [redacted] per meter and assumed that meters deployed would be on a constant 60:40 single phase meter to three phase meter ratio. All of the incremental costs for meters were applied to both single phase and three phase meters in the BC CBA, based on the increase in costs of single phase basic meters to single phase AMI capable meters (approximately [redacted] per meter) and the NICs (approximately [redacted] per meter). Western Power is already deploying three phase AMI capable meters as BAU.

However; in the updated model the calculated incremental cost above BAU metering activity is on average [redacted] *per meter*.

Western Power has indicated that the revised cost benefit analysis has reduced the incremental costs of the meter rollout due to the following:

- AMI meter prices have been revised using pricing from a competitive tender process for advanced meters and communication infrastructure
- The incremental costs should not have been applied to three phase meters
- A review of forecasted single phase and three phase meters resulted in a reduction in the ratio of single phase to three phase meters.

This resulted in a major reduction in the incremental costs required to implement the AMI. Table 4.1 on Page 9, "Section 4 of Attachment 6.3 Advanced Metering Infrastructure (AMI) Revised Information 14 June 2018" provided a summary of the costs, benefits and resulting NPV of the initial BC CBA model position and the updated CC CBA model.

Table 24 Table 4.1: Cost Benefit Analysis NPV Comparison ($ million real, June 2017)

Cost Benefit Analysis NPV	Business Case CBA	Change Control CBA
Benefits	362.4	235.9
Incremental Costs	(271.0)	(167.3)
TOTAL NPV	**91.5**	**68.6**

The movement down in costs is attributable to:

- revised SCADA & Communications and IT capital expenditure following the competitive tender process for both meters and communications infrastructure and assets
- **$101.2 million** reduction in incremental meter cost

The difference between the BC CBA incremental meter cost of [redacted] per meter and the CC CBA of [redacted] per meter is [redacted] per meter. Based on the rollout volumes of approximately 1.1 million meters and the ratio mix of single phase meters to three phase meters, this represents a significant reduction to incremental costs. Accordingly, this reduced the NPV for incremental metering costs from $153.5 million to $52.3 million – a cost reduction of $101.2 million in NPV terms.

The respective incremental meter costs of [redacted] per meter and [redacted] per meter are direct inputs to the cost benefit analysis models. While Western Power provided copies of the respective cost benefit analysis for review, GHD was initially unable to verify the validity of the data that determined these input values, such as the meter costs, installation costs and the ratio of single to three phase meters. Following requests by the ERA, and subsequent additional information provided by Western Power (ERA060) and (ERA064), the following analysis allowed for more detailed analysis of the underlying cost changes from the original business case (BC) to the updated business case (CC).

Table 25 Causes of increases in BAU costs ($ real, June 2017)

Cause	Analysis of NPV Impact	Percent
Increase in BAU installed 1Ph Meter Costs	$ 20,553,315	20%
Correction to mix of 1ph to 3 ph and 3ph meter costs	$ 46,759,926	46%
“other Meter Comms Cost Install”	$ 33,886,759	33%
TOTAL	**$101,200,000**	

Western Power was asked in ERA064 to provide an explanation for the “other Meter Comms Cost Install” which above is estimated to represent $33.9 million in the NPV BAU costs. Western Power’s response as follows:

- In the BAU scenario, the installation and replacement of modems and antennas are necessary to provide communications for non-residential customer meters requiring remote access.
- For the AMI scenario, the installation and replacement of NIC cards into retrofittable AMI capable meters is estimated to be required for the operation of the communication network to operate more efficiently. Western Power is not forecasting a retrofitting program, these volumes are estimated to be required for the operation of the communications network.

This raises further questions regarding the validity of these above costs in the BAU costs. Particularly why are NIC cards required to be fitted into existing AMI capable meter in the BAU case?

GHD considers, without sufficient reason being provided, that these cost items will require further justification in a new facilities investment test. The sensitivity analysis of the cost and benefits provided by Western Power and reviewed by GHD in Section 5.4.4 indicates that the NPV for CC CBA case would still be positive even if $33.9 million of costs is removed from the BAU costs.

5.4.3 Incremental costs of the AMI communication and information management systems

In the "Revised AA4 proposal Response to the ERA's draft decision 14 June 2018" P100 Western Power states the following;

> 588. *The AA4 proposal included $25.1 million of forecast investment in SCADA and communications systems associated with the installation of advanced metering infrastructure (AMI). The AMI-related SCADA and communications investment is required to install a radio frequency (RF) mesh two-way communications network, leveraging Western Power's existing fibre backbone where possible.*
>
> 589. *The RF mesh network is the communications backbone of the AMI program and is the element that enables data transfer between the meters installed at customers' premises and the IT systems controlled by Western Power. The RF mesh network was used in Western Power's Perth Solar Cities smart meter trial and is proven technology.*

GHD considers that Western Power has demonstrated that the RF mesh network technology is the most cost efficient for providing a communication backbone for the over 1,000,000 volume of meters.

Western Power's revised AMI capex proposal was presented in Table 5.4 under Advanced metering infrastructure – SCADA and communications on page 103.

Table 26 Table 5.4: Revised AA4 proposal on AMI capital expenditure ($ million real, June 2017)

AMI capex components	WP AA4 proposal	GHD recommendation	WP revised AA4 proposal	Summary
Metering (gross capex)	137.3	105.7	130.7	Western Power has revised its metering forecast to reflect metering replacement volumes proposed by GHD
Capital contributions	14.3	14.3	14.3	
Metering (net of capital contributions)	123.0	91.4	116.4	
Metering volumes	355,493	273,493	331,925	Western Power has revised its metering forecast to reflect metering replacement volumes proposed by GHD
SCADA and communications (AMI RF mesh communications network)	(25.1)	-	(27.1)	Western has revised its AMI-related communications forecast to reflect the February 2018 AMI change control, and submits further information to demonstrate this expenditure is reasonably expected to satisfy the NFIT.
IT (AMI IT systems – HUB, Silver Spring UIQ and AM deployment tool))	(15.0)	-	(34.4)	Western has revised its AMI-related IT forecast to reflect the February 2018 AMI change control, and submits further information to demonstrate this expenditure is reasonably expected to satisfy the NFIT.

AMI capex components	WP AA4 proposal	GHD recommendation	WP revised AA4 proposal	Summary
Total AMI (gross capex)	**177.4**	**105.7**	**192.3**	
Total AMI (net of capital contributions)	**163.1**	**91.4**	**178.0**	

On Page 103, Western Power provided an explanation of the increase in SCADA and communication costs as follows:

608. *The variation to the AMI SCADA and communications forecast is **$2.0 million**. This cost estimate increase is a result of the detailed design and competitive tendering process undertaken in 2017, which has refined the actual cost of the RF mesh network.*

609. *We submit that the revised **$27.1 million** capex forecast for the RF mesh solution is a critical part of the overall AMI solution and is fundamental to the AMI program delivering the proposed benefits and a positive net present value (NPV).*

On Page 111 Western Power provided an explanation of the increase in AMI IT costs as follows:

655. *The AMI-related IT expenditure is required to deliver upgrades to three key IT systems that are necessary to enable Western Power to store, analyse and use the data collected from advanced meters and provide advanced metering services. These key IT systems are:*

- *Network Management System (NMS) – this is the head-end system that communicates with the installed meters, capturing and storing metering data for interpretation and analysis*
- *the advanced meter deployment tool, which is the interface that enables deployment and field servicing of the 331,925 advanced meters being installed*
- *upgrades to the Metering Business System (MBS) which will enable advanced metering data to be processed for customer billing,*

656. *The IT upgrades to MBS, NMS and the advanced meter deployment tool are critical to the AMI program and are a prerequisite for the program delivering the expected benefits to customers and Western Power.*

657. *Western Power undertook a detailed design and competitive tender process during 2017. This led to an increase in forecast IT expenditure from **$15.0 million** to **$34.4 million**. This increase also reflects a scope increase to include a route optimisation tool which will support the ongoing optimisation of meter reading routes to enable better management of metering deployment costs.*

GHD recommends accepting the change in AMI IT forecast costs of **$34.4 million** and SCADA and communication costs of **$27.1 million** as these costs are based on competitive pricing and reasonable revised scope requirements for the project.

5.4.4 The cost savings and benefits from AMI Metering and Infrastructure

Western Power's "Attachment 6.3 Advanced Metering Infrastructure (AMI) Revised Information 14 June 2018" Page 5 provides a comparison between the original and revised business cases and with GHD's view of benefits [CONFIDENTIAL];

26. *A comparison of the benefits between BC CBA, Restated BC CBA, CC CBA and GHD's view is provided in Table 3.1 below. A summary of the full list of benefits included in the cost benefit analysis is provided in Appendix A of this report.*

Table 27 Table 3.1: AMI Benefits

Benefit Category $ million	Business Case CBA	Restated BC CBA	Change Control CBA	GHD View
Deferred augmentation - time of use network tariffs	28.1	46.1	42.1	18.0
Deferred augmentation – Power Factor correction	20.7	34.0	7.6	10.0
Overhead Service Condition Monitoring	78.6	80.2	14.7	53.6
Admin Support - Call Centre	10.3	16.7	13.8	5.1
Reduced technical losses	39.5	41.1	9.0	26.0
Avoidance of SCADA/Comms costs plus incremental revenue	14.1	22.6	18.4	0.0
Other benefits	171.1	130.5	130.3	
Total	**362.4**	**371.2**	**235.9**	

Western Power updated the original BC CBA model. A significant and appropriate impact of this change was to allocate indirect costs and contingencies associated with avoided network cost benefits to individual benefit items rather than being added as a total benefit. This assumes that direct avoided costs will also result in accompanying overhead cost reduction which is reasonable. Item 25 in the Western Power's attachment provided a summary of the changes as follows.

> *25. In order to undertake an appropriate comparison between the BC CBA, CC CBA and GHD view of the benefits Western Power has also provided a Restated BC CBA position (Restated BC CBA). Modelling adjustments made to the Restated BC CBA model were undertaken to correct some inconsistencies within the BC CBA with regard to inflation and discount rates and to appropriately allocate indirect costs and contingencies across many categories in place of a separate line item for indirect costs and contingencies.*

GHD provides the following view on the above individual benefit items that depart significantly from GHD's review of the BC CBA.

Deferred augmentation - time of use network tariffs ($42.1 million)

The savings attributed to this benefits is the largest of all benefit items in the CC CBA. Western Power has based the benefit on a sliding take-up of TOU tariffs from 25% to 100% in the last year of the 15 year modelling period. The recognition of benefits were delayed until year five in the model. Western Power's model also adjusts downwards the benefits associated from a 100% take-up of TOU, and other related input assumptions, by 50% to allow for the risk of less than a 100% take-up of TOU at the end of the 15 year modelling period. Western Power also includes a 25% factor for customers who respond to reducing peak demand.

GHD previously used a benchmark to other advanced metering roll outs to arrive at a value of $18 million. GHD reviewed the input data used in the model and the assumptions above and as a result now considers the projected savings to be reasonable based on current end use consumer consumption patterns. It is difficult though to assess the impact to the calculated benefits due to increased distributed generation, battery storage and electric vehicles that are likely to be installed in the network over the next 15 years. The AMI communication network will however provide benefits towards managing and planning the network to adapt to these changes.

Overhead Service Condition (OHSC) Monitoring ($14.7 million)

AMI is the proposed solution for OHSC monitoring. The benefit is calculated based on avoided field opex and deferral of capex replacement of service mains with potential safety defects. Western Power has reduced the benefit considerably from the value in the BC CBA. The original BC CBA was based on completely avoiding the need to replace faulty service mains rather than deferral of replacement until the new condition monitoring method would identify defective service mains. GHD considers the change valid and had not identified the incorrect analysis in the original business case.

Avoidance of SCADA/Comms costs plus incremental revenue ($18.4 million)

GHD notes Western Power's reasons for the included benefits as follows and considers the assessment is reasonable (Page 106 Attachment 6.3);

635. *GHD considers benefits arising from unregulated revenue should not be included in the AMI business case. We agree with this view and accordingly have not included any benefits arising from potential unregulated revenue streams.*

636. *The benefits assumed by Western Power have been derived from the avoided costs associated with SCADA and communications equipment related to the covered network (approximately 57 per cent of the benefit) and potential incremental regulated revenue to be derived from third party access to the communications infrastructure (approximately 43 per cent of the benefit).*

Appendix A1 to Western Power's Attachment 6.3 provided a summary of all of the changes in Table A1.1 [CONFIDENTIAL] and reproduced below.

Table 28 Table A.1.1: Reconciling Initial AA4 Submission / Business Case and Change Control benefits

Benefit Category NPV $M	Bus Case CBA	Restated Bus Case CBA	Change Control CBA	Impact	Explanation of movement	Justification of benefits
Deferred augmentation - time of use network tariffs	28.1	46.1	42.1	(4.0)	Impact of deferred start to AMI rollout to Sept 2018	Sliding take-up of TOU tariffs from 25% to 100% in the last year of the 15 year modelling period. Recognition of benefits delayed until year five of the model.
Avoided cost of network reconfiguration	25.2	21.7	0	(21.7)	Benefit removed	
Deferred augmentation – Power Factor correction	20.7	34.0	7.6	(26.4)	Change in approach to benefit calculation	Power factor correction now reflects deferred network augmentation from use of batteries to improve grid utilisation and information from downstream AMI meters.
Power Quality	2.5	4.1	6.9	2.8	Revised forecast of BAU power quality investigations	Based on forecast number of power quality investigations, hours per investigation and avoided level of investigations.

Benefit Category NPV $M	Bus Case CBA	Restated Bus Case CBA	Change Control CBA	Impact	Explanation of movement	Justification of benefits
Overhead Service Condition Monitoring (OHSC)	78.6	80.2	14.7	(65.5)	Reduction in volumes and capex now deferred rather than avoided	AMI is the proposed solution for change in OHSC monitoring. Benefit is based on avoided field opex and deferral of capex replacement. Volumes based on target pre-2010 wedge clamp connections - population (circa 130,000 meters). Benefit is aligned to the approx one third of the connections monitoring which overlap with AMI deployed meters.
Admin Support (Call Centre)	10.3	16.7	13.8	(2.9)	Impact of deferred start to AMI rollout to Sept 2018	Reduced call volumes relating to customer notified faults and the time (average 10 min) to resolve the call at hourly rate. Benefits based on overseas studies.
Client Outage Compensation	0.5	0.8	0.5	(0.3)	Removed indirect cost allocation from payment	Based on international studies benefit assumes a 2% reduction in customers eligible for outage compensation payments.
Scheduled meter reads	15.9	25.9	18.7	(7.2)	Impact of deferred start to AMI rollout to Sept 2018	Benefit calculated as difference between a standard read cost and AMI at 6 reads per year. Annual inefficiency factor of 4% to reflect impact of increase in AMI meters on planned reads.
Special reads	9.5	15.5	27.7	12.2	Impact of deferred start to AMI rollout to Sept 2018 plus avoided cost for interval read for 30,000 meters over AA4	Based on pricing of interval reads associated with 30,000 meters over AA4. Pricing reflects obtaining interval data on cycle and off cycle and meter reconfigure costs. Benefit of BAU special reads set at 19% of installed AMI meters at per read saving of $10.
De-energisation	2.8	4.6	3.8	(0.8)	Impact of deferred start to AMI rollout to Sept 2018	Benefit based on 1.9% of AMI installed meters at a net saving of $30 per service.
Re-energisation	2.8	4.6	3.8	(0.8)	Impact of deferred start to AMI rollout to Sept 2018	Benefit based on 1.9% of AMI installed meters at a net saving of $30 per service.

Benefit Category NPV $M	Bus Case CBA	Restated Bus Case CBA	Change Control CBA	Impact	Explanation of movement	Justification of benefits
Reconfigure costs	2.3	3.7	3.0	(0.7)	Impact of deferred start to AMI rollout to Sept 2018	Benefit based on 1.5% of AMI installed meters at a net saving of $30 per service.
Billing Systems Savings	8.3	13.3	11.8	(1.5)	Impact of deferred start to AMI rollout to Sept 2018	Current ICT incurs $3.3 million opex and $1.0 million capex annual billing spend. The proposed AMI billing solution will reduce opex to $2.88 million and capex to $0.5 million.
Reduced energy theft	17.2	17.9	35.2	17.3	Changed calculation to reflect benefit that accrues to retailer	Savings based on energy demand, with a reduced theft rate from 0.75% to 0.385% at a tariff rate of 15.5 c/kwh. (Delta between residential tariff 26.5 c/kwh and network tariff 11 c/kwh) and rollout of advanced meters.
Avoidance of SCADA/Comms costs plus incremental revenue	14.1	22.6	18.4	(4.2)	Impact of deferred start to AMI rollout to Sept 2018	$0.6 million of incremental revenue will be made from 3rd party access to comms infrastructure. Annual savings on planned spend to 2032 have been identified (capex $0.51 million and opex $0.45 million).
Reduced technical losses	39.5	41.1	9.0	(32.1)	Reduced the technical loss % and applied at STEM energy price not network price	Savings based on energy demand, loss factor moving from 4.3% to 4.03%, and a STEM energy price of 6 c/kwh.
Avoidance of unnecessary attendance	1.3	1.6	1.7	0.1	Impact of deferred start to AMI rollout to Sept 2018	Savings based on average volume of unnecessary callouts, time taken to resolve the callout, crew hourly rate and advanced meter impact.
Faster fault detection	11.2	11.6	11.9	0.3	Reduction in value of customer reliability offset by an increase in energy intensity per customer	Savings based on annual fault call volumes, number of customers impacted, time saved by advanced meters notification of a fault and % of advanced meter rollout. Time saved is converted to MWhs using customer energy intensity and converted to $ using value of customer reliability.

Benefit Category NPV $M	Bus Case CBA	Restated Bus Case CBA	Change Control CBA	Impact	Explanation of movement	Justification of benefits
Nested fault identification	5.0	5.2	5.3	0.1	Reduction in value of customer reliability offset by an increase in energy intensity per customer	Savings based on faults requiring a revisit, number of customers impacted, additional time lost before power restore and % of advanced meter rollout. The time saved is converted to MWhs using customer energy intensity and converted to $ using value of customer reliability.
Indirect Costs	29.8	0	0	0	Allocated back to line items and rate reduced	
Contingency	36.8	0	0	0	Allocated back to line items and rate reduced	
TOTAL	**362.4**	**371.2**	**235.9**	**(135.3)**		

In development of the Change Control an internal and external review of the CC CBA benefits was undertaken by Western Power based on updated information. As a result of the review, the NPV of total benefits underpinning the CC CBA decreased by $135.3 million to $235.9 million (from $371.2 million per the Restated BC CBA).

The reductions in individual AMI benefit items in the revised business case is less than GHD's view in some areas and greater in other areas. The net effect is a more reasonable position for assessed total benefits compared with the original business case.

The revised benefits are commensurate with other international AMI business case cost benefit analysis that GHD reviewed previously. In comparison with the benefits types included in Western Power's cost benefit analysis, these business cases were around $110 million less than Western Power's original business case. As above, the NPV of total benefits underpinning the CC CBA decreased by $135.3 million to $235.9 million (from $371.2 million per the Restated BC CBA).

Western Power also provided the following summary of a sensitivity analysis on Page 107;

637. *In addition to undertaking a detailed internal sensitivity analysis on Western Power's estimated benefits, if Western Power were to apply GHD's more conservative assumptions the program would still be in a net positive position. Sensitivity analysis demonstrating this has also been provided to the ERA.*

638. *Western Power considers that the cost benefit analysis and related sensitivity analysis supporting the approved change control position, demonstrate a positive net benefit for the AMI program under all scenarios tested.*

639. *Accordingly, Western Power considers that the forecast expenditure on the AMI program, including the deployment of advanced meters and the associated IT and communications infrastructure, is reasonably expected to meet the requirements of the new facilities investment test and should therefore be included in the forecast capital base.*

640. From a model sensitivity perspective, if Western Power were to apply GHD's more conservative assumptions the program would still be in a net positive position. Sensitivity analysis demonstrating this has also been provided at Attachment 6.3.

Details of the cost benefit sensitivity analysis was provided in Attachment 6.3 and was reviewed by GHD. This indicated, amongst other sensitivity tests, that for the NPV to become negative the following movements in costs or benefits would need to occur;

- an unfavourable movement in Total Gross Benefits of 30%
- an unfavourable movement in Total Costs of 40%

GHD has some concern with the increase in BAU metering costs of $101.2 million from the BC CBA to the CC CBA. This amount represents a 37.4% increase in the BAU metering costs. GHD's further analysis of the breakdown of this change in incremental costs identified an expenditure of $33.9 million, referred to as "other Meter Comms Cost Install", which GHD cannot confirm as being a valid BAU cost. The remainder of the change is considered valid.

The NPV calculated by Western Power in the CC CBA was $68.6 million. An increase in the BAU NPV costs of $33.9 million would reduce the NPV to $34.7 million. Furthermore almost all of the value determined for Deferred augmentation - time of use network tariffs ($42.1 million) would have to be discounted for the NPV to revert to a negative outcome.

Further potential benefit side for the business case should be considered in GHD's view. Western Power indicates, in Attachment 6.3, that they have not included a financial value for the range of benefits that can accrue to other users of the covered network (i.e. generators and retailers) in their CC CBA model. Accordingly, Western Power has not undertaken any detailed review of these benefits but notes the review undertaken by GHD included a comparative of other utilities that had included these benefit types, in particular Amaren Illinois and BC Hydro.

Western Power used these comparisons by adopting a conservative view of 50% which indicated a further $160 million could be added to the CC CBA NPV for these other value benefits.

Western Power also noted the Deloitte review into the Victorian advanced meter rollout program and similarly applied a conservative view to remove 50% of the benefit considered to be generation only benefits which suggested $70 million of additional net benefits could be included for generation benefits in the Western Power's CC CBA NPV.

GHD's review of Western Power's sensitivity analysis provides confidence that the installation of the AMI communications network, related IT systems and other incremental costs will meet a new facilities investment test.

5.4.5 Responses to ERA's Draft Decision

GHD has noted the following responses from stakeholders and summarises respective views in regard to the AMI proposal.

Horizon Power

Horizon Power is very supportive of the deployment of Advanced Metering in the SWIS based on the experience with a rollout in the NWIS and remote areas. GHD notes that the costs of meter reading in the NWIS would be significantly higher, avoided travel costs higher for servicing needs and avoided network and demand management benefits would be much higher. On the other hand Western Power will benefit from greater scale of deployment.

Synergy

Synergy's submission commented on the draft decision that the ERA needs to address outcomes that will meet the Access Code objective of promoting the economically efficient investment in, and operation and *use of, networks and services of networks in WA in order to promote competition in markets upstream and downstream of the network.*

Synergy supports efficient advanced meter infrastructure deployment provided such investment meets the requirements of users and passes the new facilities investment test (NFIT).

Synergy, recognising the importance of interval energy data to customer choice and affordability, supports in principle WP's AMI deployment under AA4 subject to it passing NFIT. Therefore, it is important to ensure the proposed AMI is the right solution at the right price. Consequently, Synergy requires the ERA to ensure these services are provided efficiently and meet the requirements of the Access Code particularly, in relation to the NFIT and (alternative options) regulatory test.

As mentioned above distributors, generators, retailers and customers recognise the operational, cost, affordability and choice benefits an AMI solution can provided. However, in the context of investment such a solution must be both:

- Efficient; and
- Supported by reference services based on user requirements to ensure customers receive the benefit of the AMI investment.

One of the main concerns users have expressed is there is no clear mechanism under AA4 for network benefits to be delivered through to the end customer. Therefore, it is also important to recognise that reference services based on user requirements not only provide for innovative retail offerings but also ensure network benefits are delivered to the end customer. This outcome cannot be achieved by unbundling metering services alone.

Government of Western Australia – Department of Treasury

The Department of Treasury states;

Advanced metering infrastructure is a fundamental enabling technology to facilitate the development of smarter electricity networks. However, for the benefits of advanced meters to be fully realised, a communications network linking the meters to the data management systems is essential. Consequently, Western Power should be allowed to recover efficient costs of the communication infrastructure as part of its approved expenditure allowance for the deployment of the advanced meters.

Vector Limited

2. In Vector's view, the Authority must not approve Western Power's proposed advanced metering project unless and until Western Power has complied with the Regulatory Test in Chapter 9 of the *Electricity Networks Access Code 2004* (WA) (the Access Code). The Regulatory Test requires a detailed consideration of alternative options, which we consider should include an assessment of third party ownership of meters and third party metering services provision to Western Power.

11. Vector has had the opportunity to review Synergy's public submission in relation to price control and agrees with Synergy that Western Power must, in respect of its $177 million advanced meter project, comply with the requirements of the Regulatory Test under Chapter 9 of the Access Code.[2]

Western Australia Major Energy Users (WAMEU)

WAMEU addresses the proposed advanced metering program and points out that the experience in Victoria where a roll out of advanced meters was mandated to be carried out by the networks, consumers have seen little value from the program. While theory implies that advanced metering should be beneficial to consumers (see table 30 in the GHD report), there is scant evidence from Victoria that consumers have received sufficient benefit to offset the costs involved. WAMEU considers that the ERA needs to carry out deeper investigations to demonstrate that there is a benefit to consumers to offset the considerable cost of the allowed AMI capex program. WAMEU notes there is considerable capex devoted to “improvement is service”.

WAMEU raises two key points:

- The improvement in service must deliver a demonstrable benefit to consumers, yet there is no evidence provided that this delivers any quantifiable benefit to them that they value or have a “willingness to pay” for.
- The service standards are already at levels that consumers consider delivers acceptable electricity supplies and there is little appetite for higher prices, even if service standards improve.

On this basis WAMEU considers that greater investigation into whether the increased costs involved to provide this improved service match the generally expressed views of consumers that current prices are already too high and that they do not want to pay more for higher standards

5.4.6 Specific Requirements for ERA review

The ERA requested responses to specific requirements which the following draws on the previous review of the costs and benefits identified by Western Power for the Advanced Metering Infrastructure investment:

- Assess Western Power’s revised AMI proposal in detail, including testing all of the benefits Western Power has identified to justify its proposal.

  GHD has reviewed the revised proposal including testing the benefits and review of Western Power’s sensitivity analysis and considers the forecast expenditure on the AMI program, including the deployment of advanced meters and the associated IT and communications infrastructure, is reasonably likely to satisfy the requirements of the new facilities investment test.

- Review Western Power’s Radio Frequency (RF) options analysis [4] for completeness and validity

  GHD has reviewed Western Power’s analysis of AMI communication systems and agree that RF mesh technology is the best option for a large scale AMI network. Western Power considered the following technology options:

  - RF mesh
  - Point-to-Point (P2P) Public cellular (mobile phone coms – LTE/3G and LTE Cat M1
  - Power line communications (PLC)
  - Satellite
  - Low Power Wide Area Network (LoRA)
  - Digital Mobile Radio (DMR)

  RF mesh is a mature and proven product that has been deployed as the preferred communications solution in the majority of AMI rollouts in Australia and overseas. Western Power has also proven experience in using the technology on previous AMI pilot projects. Security features are incorporated into the RF mesh communication interfaces to prevent unauthorised to access to customer data or hacking of the wireless network.

  For the large scale AMI implementation, the RF mesh option is the most cost effective solution.

- Assess Western Power's change control for AMI forecast capital expenditure [5].

  The change control covered approval for expenditure for the first 5 five years of the 15 years program which included the following changes from the original business case for AMI expenditure:

  - An increase in the approved schedule and expenditure from 3 years to 5 years to align with the AA4 period.
  - An increase in the approved value by $115.2 million from $144.5 million to $259.7 million, with $84 million of that increase related to meters required for the additional two years.
  - Inclusion of an additional $31.2 million for a route optimisation tool, program management activities and operating expenditure.

  These changes are appropriate and mainly relate to the increase in 2 years for approved expenditure to align with the AA4 period. The prime objective of the change control document (Attachment 6.3 A.2 AMI Change Control – December 2017) mainly related to this additional expenditure.

  With respect to the revised business case for the costs and benefits over the 15 year program only summary statements were provided in the change control document which indicated increases in costs, reductions in benefits and that the investment remained justified with a reduction in the original business case NPV from $91.5 million to $68.6 million. However the support documentation shows that significant changes occurred to both costs and benefits compared to the original business case.

  GHD has had some concerns with individual cost and benefit changes in the CC CBA, however we are satisfied that the program will result in a positive NPV and that the forecast expenditure for AA4 is appropriate.

- Evaluate Western Power's tender process for its AMI IT systems.

  Western Power conducted two competitive market engagements for contracts to cover the period to June 2021 for the supply of:

  - Communications infrastructure, including Network Management System (NMS), Network Interface Cards (NICs) and associated communication assets.
  - Advanced capable meters.

  A RFT was issued to the market in April 2017 to eight potential vendors for the communications infrastructure, with responses received from four Tenderers. Two vendors were shortlisted to proceed to detailed presentations and clarifications, and were provided an opportunity to update pricing prior to the selection of the final preferred supplier.

  A RFT was also issued to service providers through a competitive process to deliver the Information Technology components of the AMI solution. Western Power's Board reviewed and approved selected service providers in April 2018.

  An external legal firm and probity auditor were engaged throughout the processes and external advisors attended the shortlist presentations to provide technical advice on the product offerings. :

  The revised Change Control business case included updated costs based on pricing for the communication network, IT technology solutions and meters from the competitive tendering processes.

GHD considers Western Power has conducted an appropriate tender process for its AMI IT systems.

- Appraise Western Power's revised forecast metering volumes and related expenditure [6] (including related operating expenditure).

  GHD has appraised the revised forecast metering volumes and related Capex and Opex expenditures for the AMI communication and IT systems and consider the metering volumes and expenditure is consistent with GHD's review of the revised business case (CC CBA).

- Provide advice on the technical aspects of the AMI proposal, for example whether the neutral integrity monitoring capability of AMI would assist in mitigating the hazard posed by open-circuit neutral faults as submitted by Energy Safety in its response to the ERA's draft decision. Particular focus should be given to how AMI interacts with other open-circuit neutral fault hazard mitigation solutions.

  GHD considers the technological considerations in the cost and benefit line items in the CC CBA are relevant and Western Power has been more robust in the analysis of respective items compared to the original business case (BC CBA).

  AMI is the proposed solution for a change in Overhead Service Condition Monitoring (OHSC). The benefit is based on avoided field inspection of service conductors and the deferral of service main replacements due to an otherwise more risk conservative replacement strategy. Volumes based on target pre-2010 wedge clamp connections - population (circa 130,000 meters) which have been the main concern for damage to neutral conductors.

  Remote monitoring of currents flowing through AMI meters allows broken neutrals to be detected providing early detection significantly reducing risk of shocks and potential fatalities to the public and consumers. The remote monitoring capability was developed and benefits proven by distribution utilities in Victoria. Detection of a service main open circuit neutral is only possible though when an AMI meter is installed at that particular premises.

  Once the full rollout of meters after 15 years is near complete the full benefits of reduced risks to electric shocks will be obtained. Western Power has reduced the benefits from deferring the replacement of service main replacement but indicated they have not valued the reduced risks to the public. GHD considers that the reduced risk could be valued in the business case and hence would increase the value provided to this benefit.

5.4.7 Conclusions and Recommendations

- The incremental metering costs from BAU in the original business case was [redacted] per meter and this has been changed to [redacted] per meter in the updated business case analysis (CC CBA). While Western Power has provided copies of the respective cost benefit analysis for review, GHD was initially unable to verify the validity of reasons for the changes to these input values, such as the meter costs, installation costs and the ratio of single to three phase meters. The increase in BAU costs resulted in a reduction of **$101.2 million** in NPV terms in the business case, a very significant change.

- GHD was able to breakdown these additional BAU costs with additional information provided by Western Power. This increase consisted of;

  - An increase in total installed costs for BAU 1Ph meters (representing 20% of the NPV cost reduction). GHD considers this increase an appropriate change.

  - A correction to the mix of 1Ph to 3Ph meters and removal of additional costs for 3Ph meters which are already to the AMI standard (representing 46% of the NPV cost reduction). GHD considers this increase an appropriate change.
  - An addition of $33.9 million for “other Meter Comms Cost install” (representing 33% of the NPV cost reduction). GHD considers, without sufficient reason being provided, that these cost items will require further justification in a new facilities investment test. Sensitivity analysis of cost and benefits indicates that the NPV in the CC CBA case would still be positive even if $33.9 million of costs is removed from the BAU costs.
- The reductions in individual AMI benefit items in the revised business case is less than GHD’s view in some areas and greater in other areas. The net effect is a more reasonable position for assessed total benefits compared with the original business case. The reasons provided for Western Power’s revised benefits with the more robust analysis conducted in each case provides a reasonable degree of confidence in the assessed benefits. GHD also considers the revised benefits are commensurate with other international AMI business case cost benefit analysis compared to the benefits types included in Western Power’s cost benefit analysis.
- Western Power has not included potential benefits from the generation and retailer supply chain benefits, however based on the sensitivity analysis undertaken and giving consideration to these additional potential benefits, Western Power considers that the approved Change Control position for AMI remains NPV positive under all scenarios tested. Western Power did consider GHD’s information in assessing potential other supply chain benefits which suggested these benefits would provide an NPV benefits in the order of $160 million. This counterbalances concerns over the cost reduction of $101.2 million in incremental meter costs with respect to the NPV of the business case.
- GHD considers that Western Power has demonstrated that the RF mesh network technology is the most cost efficient for providing a communication backbone for the over 1,000,000 volume of meters in the AMI rollout.
- GHD recommends accepting the change in AMI IT forecast costs of $34.4 million as these costs are based on competitive pricing and revised scope requirements for the project.
- GHD does agree with Western Power that the forecast expenditure on the AMI program, including the deployment of advanced meters and the associated IT and communications infrastructure, is reasonably likely to satisfy the requirements of the new facilities investment test and should therefore be included in the forecast capital base.

5.5 Master Station and operating systems

The level of expenditure on Master Station and other SCADA and Comms operating systems hasn’t been changed in the revised proposal. In our initial report GHD concluded that the program proposed for AA4 was reasonable and we believe that our original conclusion remain valid.

With regards to deliverability of the distribution SCADA program, similar issues to the delivery of the transmission SCADA program with regards to the information provided (refer section 0). In the Works Planning Report and business case provided for the distribution SCADA program, Western Power has detailed the works required, and identified the key issues for deliverability and included overall comments on the delivery of the program with regards to resource availability, without providing details on the program timeline, resource engagement and management, and any efficiencies identified by the Joint Planning Team.

5.6 Summary of Recommendations

The following table sets out the GHD recommended adjustments to expenditures for distribution capex. This is in response to Western Power's response to the ERA draft decision.

Table 29 Distribution capex revised forecast expenditures and draft decision direct costs for AA4 ($ million real, June 2017) excluding gifted assets and contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Growth	405.9	417.1	391.4	391.4	0.0
Improvement in Service	94.0	57.7	88.8	84.9	(3.9)
Total	**499.9**	**474.8**	**480.2**	**476.3**	**(3.9)**

6. Corporate CAPEX

The focus of Western Power's response to the draft decision on corporate CAPEX expenditure was on three specific programs;

- Fleet
- Advanced metering
- CRM software

GHD recommended Western Power's proposal to move fleet assets into the RAB should be rejected. In its revised proposal, Western Power has removed fleet assets from the RAB. For the other two categories it has revised its proposals and provides some additional detail to support their re-submission of this spend. Table 30 shows a summary of Western Power's submission.

Table 30 Revised AA4 proposal on corporate direct cost capital expenditure ($ million real, June 2017)

Corporate capex amendment	WP AA4 proposal	GHD recommendation	WP revised AA4 proposal	Summary
Fleet adjustment	77.2	0.0	0.0	Western Power removed fleet assets from the RAB
Advanced metering infrastructure	15.0	0.0	34.4	Western Power has increased its proposed expenditure and submitted further information to support inclusion of this capex in the AA4 forecast RAB
CRM software	24.0	0.0	24.0	Western Power has maintained its initial forecast, and submits further information to support inclusion of this capex in the AA4 forecast RAB

6.1 Scope

The ERA specifically asked GHD to look at the following questions in our review of Western Power's response to the ERA's draft decision.

1. Depot modernisation and relocation of control centre
    a. Review evidence provided to demonstrate the first and second limb of the new facilities investment test have been satisfied and that any savings arising from the expenditure have been identified and incorporated in forecast operating and capital expenditure.
    b. Assess the likelihood of the proposed projects will actually being undertaken within the AA4 period.
2. CRM software –
    a. Review evidence provided that the proposed project meets the first and second limb of the new facilities investment test and that any savings from the proposed new systems have been identified and incorporated in forecast operating and capital expenditure.

b. Assess Western Power's competitive market process for its CRM capital expenditure[21];

The new facilities investment test (NFIT) is defined in clause 6.52 of the code and states;

New facilities investment satisfies the NFIT if:

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

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

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

and

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

(i) *either … the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or …*

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

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

Our review the response and additional information provided has focused on whether the proposed expenditure meets this test and also addresses the other questions raised by the ERA.

The validity of the spend on IT infrastructure to support the roll-out of the AMI project will be addressed in our discussion on the merits of the project in section 5.4.

6.2 Depot Modernisation and Relocation of Controls Centre

Western Power is intending to carry out an extensive Depot Modernisation program during the AA4 period. With this initiative Western Power intends to reduce the number of [redacted]

[redacted] The remaining regional depots will be addressed during the next Access Arrangement period. The CAPEX cost of these projects in the AA4 period is shown in the following table.

[21] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 114, paragraph 677

Table 31 Depot Optimisation and Consolidation Program

Project	Project description	Expected completion	Project Budget ($ M)
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]		[redacted] [redacted]
[redacted]	[redacted]		[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]		[redacted] [redacted]
	[redacted]		[redacted]

In GHD's report on Western Power's initial application, the firm concluded that the amount budgeted to be spent during the AA4 period appeared reasonable. In section 12.2.1.2 of our report we detail our rationale for accepting the forecast level of spend. Our comfort with the estimated total was based on the use of outside experts to estimate the level of spend for each project. In the current response the approach used to estimate the total for the overall program is the same, therefore GHD has not changed its opinion that the overall estimate for the program of work is reasonable. However, GHD is concerned that the amount estimated to be spent in the AA4 period may be too high.

In our review to the additional data provided by Western Power, it is clear that the level of resources and management time required to complete all the projects within AA4 period could be challenging. In our review of the Depot Optimisation and Consolidation Plan – PMP 2018, the complexity of the overall program is clearly demonstrated. A copy of the program timeline is captured below, see Figure 8. The PMP already describes how two elements of the program, [redacted]. Using the PMP document GHD created a staffing matrix that highlighted the challenge faced by Western Power to adequately staff these projects, see Figure 9. We are particularly concerned by the plan to work on both the [redacted] projects while also completing the transition and de-commissioning of multiple depots to move to the new large [redacted] projects have already been delayed, however based on the plan in the PMP both projects are scheduled to be re-start while the [redacted] project is being executed. While both these projects are smaller and less complex the [redacted] project they will take considerable resources to complete successfully.

An example of the challenges that can be encountered during construction related projects can be seen from the construction of the new Vasse depot. The project is following all its governance processes and procedures, however it is currently forecast to be completed three months late and require an increase in the project's budget of $1.44 million. This illustrates the challenges that will be faced during the overall optimisation program.

In the current plan there are several elements of the project that are mission critical or appear to have an ambitious timeline. Any delays in these elements of the project could lead to the overall plan not being met. The most critical date to manage is the date of completion and handover of the new [redacted]. While the constructor is ultimately responsible for the delivery of the project on-time and on budget, hitting the practical completion date of 8 May 2020 is vital for the rest of the project to be completed as planned. The transition of the [redacted] start almost immediately after practical completion. Given that the site is expected to incorporate new ways of working and other substantial changes in practices it is GHD's belief that the plan to start transition of [redacted] during the handover of the site would be impractical. [redacted] While GHD believes that all sites will be transferred to the [redacted] facility during AA4, we believe that the timing will be different from planned and we recommend that Western Power model the potential impact of delays to the transition program. Pushing the transition too quickly could also threaten the capture of expected benefits as planned improvements in process efficiency are lost in the scramble to meet project deadlines.

As a flow-on from the execution of the complex [redacted] project, GHD is concerned that other lower priority metro projects within the program will not be completed during the AA4 period. The most likely projects to be delayed are the upgrades to [redacted]. We do not have a breakdown of spend on these projects across the AA4 period, therefore at this stage we are unable to identify the impact delays would have on the timing of CAPEX requirements. However, we recommend that the ERA withhold 50% of the forecast CAPEX for these two projects as GHD believes it is unlikely that both of these projects will be completed during the AA4 period. This would equate to $16.9 million reduction in CAPEX.

Figure 8 [redacted]

[redacted]

Figure 9 [redacted]

[redacted]

The second part of the NFIT test asks that projects;

> *either … the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or …*
>
> *(ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies higher reference tariffs; or*
>
> *(iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.*

The overall project is anticipated to yield a positive NPV, generated by reducing overall CAPEX and a reduction in operating costs. Western Power states in its response that it has included a $1.1 million savings in the 2016/17 efficient base year and additional savings from the consolidation are included in the $12 million in recurrent step change in indirect costs. These estimates are supported by the PMP (p. 39) where Western Power estimate that the recurrent savings from the program will be $10 million p.a. in 2022 and the capital spend avoided would be a net $60 million. Given these savings it would appear that overall program would appear to have satisfied point (ii) of the second part of the NFIT test.

However, GHD is not convinced by Western Power's description in its response of how the savings from the optimisation program have been incorporated in its OPEX forecast. None of the new depots are currently in operation yet so it is difficult to see how $1.1 million of the savings would have been included in the efficient base year. In addition the step change is a constant $5 million each year of the AA4 period, however the savings from this program will only be captured once the new/ refurbished depots are open and the old depots closed in the latter half of the AA4 period. Confusingly, Western Power in its response (paragraph

280 through 283) has made it clear that while they expect these savings will be achieved, they have not separately identified the savings within their overall proposal. Rather Western Power make the argument that the savings from the depot optimisation program make up a part of the efficient base and the step change savings.

From our analysis, if the savings from this program are included as part of the efficiency dividend in 2022 the savings from this program alone would make up over 60% of the cumulative efficiency dividend forecast for that year. Or put another way the rest of the organisation would only need to find a recurrent efficiency dividend of $4 million over the four years prior to 2022.

Western Power argues that separating the forecast savings would require them to create a bottom up estimate of their costs. This argument is not strong. The point of an efficiency dividend is that management cannot yet articulate how it will achieve a savings target, however it commits to identifying how it will achieve a saving during the intervening period. In this case Western Power already knows that the depot optimisation will create savings of approximately $10 million p.a. If this is the case then Western Power management is only tasked with finding an additional $1 million of recurring savings each year. That equates to an efficiency saving target of approximately 0.3% - 0.5% of OPEX costs not associated with the depots. This level of efficiency dividend is below what would be expected from an organisation like Western Power and considerably below what the organisation has been able to achieve in the AA3 period.

Recommendation

GHD recommendations that the savings associated with the depot optimisation and consolidation program not be included as part of the efficiency dividend and be identified separately and that an efficiency dividend of 1% be applied to all operating costs outside of the depots.

6.3 CRM Software

In our initial assessment GHD agreed that there is *"… a requirement for a new and comprehensive system"*[22]. However, we could not draw a conclusion on whether the level of proposed expenditure was warranted given that the information provided in the original proposal described the need for the change but contained limited information on how the forecast spend was derived.

In the revised proposal Western Power has reiterated the requested CAPEX for the installation of a new CRM system. In this response Western Power has explained that they are not proposing a singular software package; rather they have outlined a program of work required to completely update the systems supporting how Western Power interacts with all its customers. In the revised proposal they have broken down the proposed expenditure as shown in the following table.

[22] Page 178, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018

Table 32 Western Power split of proposed CRM capital spend ($ million real, June 2017)

Customer service and engagement component	Detail – Functional	Cost	Total cost
CRM system	CRM core	5.1	16.0
	Customer service improvements	4.3	
	Access solutions and queuing process (to replace SalesForce)	1.5	
	Customer data warehouse, data model and GIS	5.1	
Customer management components of Customer funded work process (DQM)			3.8
Customer data analytics			2.0
Metering data portal			1.9
Total			**23.7**

In the revised proposal Western Power describes the key elements of the different categories of spend outlined in the table and makes a sound argument as to why these systems will be of benefit to Western Power in meeting the needs of its customers more effectively. The core rationale includes:

a. Replacement of the 20 year old Distribution Quotation Management system (DQM) which is no longer fit for purpose. The new systems would upgrade the external customer funded design and construction process and provide an on-line platform for customers to initiate work and facilitate automatic updates

b. Enhanced customer analytics enabled by having access to a full-suite of customer information

c. Facilitate the development of a metering portal

d. Reduce the number of bespoke solutions currently being run including;

    i. Oracle CC&B (NetCIS)

    ii. DQM

    iii. Salesforce

    iv. Consultation Manager

    v. Western Power Outage App

e. Reduced capital operational expenditure on legacy systems

Western Power has not provided details of the likely benefits and efficiencies that will be delivered by the implementation of the new systems. However, in GHD's opinion, the removal of multiple antiquated bespoke systems and replacement with an integrated CRM solution should enhance the customer experience potentially increasing revenues particularly by facilitating the development of the metering portal. In addition the integrated solution should assist with outage management and other customer activities that should enhance safety. As a result GHD believes that the investment in the CRM program is likely to meet the second part of the NFIT test.

However, our primary concern with the original proposal still applies to the revised proposal. In our previous report we stated that *"…following our internal discussions with our IT specialists, including staff with extensive experience in CRM systems, we believe the forecast CAPEX allowance for a new CRM system is* *excessive. We are of the opinion there are a number of different potential solutions that could work well for Western Power, including a number of Software as a Service (SaaS) products that could materially reduce the CAPEX required to implement a new CRM."*[23]

In their revised proposal Western Power has stated that it has run a competitive tendering process to select a provider of the CRM system. In this review GHD has reviewed both the:

a. CRM sourcing Strategy (EDM#34124976)

b. CRM EOI Shortlisting Memo (EDM#34124976)

However, while this process appears to have enabled Western Power to select a well-qualified and cost effective CRM product, it only addresses a small fraction of the overall spend, $4.72 million out of a total proposed spend of $23.7 million. Western Power has not provided a business case or other support to justify this level of spend or the other planned expenditure in the overall CRM program, or a rational for the overall level of estimated spend, nor the amount of CAPEX that would be avoided by installing these systems.[24]

At this stage GHD cannot provide an opinion on whether the proposed investment in a revised CRM program meets the first stage of the NFIT test.

Another question also remains from the explanation provided by Western Power. In response to the suggestion by GHD that there could be SaaS solutions that would require less capital than historical systems that sit on Western Power's systems (or hosted systems), Western Power stated:

We can confirm that the CRM solution we propose is based on a Software as a Service implementation approach, and that SaaS products have been selected through the tender process[25]*.*

Given that SaaS applications by their nature do not reside on Western Power servers (or servers owned and managed by others for Western Powers exclusive use), the relationship between Western Power and the vendors is one of a service user and service provider. Therefore, it is challenging for us to see how the cost of these applications can be classified as assets which come under the regulated asset base. Western Power has procured a service not an asset.

GHD therefore recommends that the proposed $4.7 million to be spent on the creation of a new CRM system be treated as OPEX. This would result in a reduction in proposed CAPEX of $4.7 million and a corresponding increase in OPEX of the same amount.

No detailed breakdown was available to us as to whether the other proposed spend will also be acquired on a SaaS basis and cannot comment on whether this proposed spend should be treated as OPEX or CAPEX.

Western Power also noted in their proposal that they have selected an IT program delivery partner. GHD reviewed the process and it appeared to be a valid procurement process and enabled Western Power to select a strong a capable partner to help them execute the different elements of their IT program successfully. At this stage, however, we are not sure how this award would impact the CRM program as the winning CRM bidder is partnered with an alternative vendor.

[23] Page 178, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018

[24] Western Power has advised that at the time of this report the CRM project is currently in the design and plan phase with the business case still under development

[25] Revised AA4 proposal – Response to the ERAs draft decision, Western Power, July 2018

Conclusions and Recommendations

- In conclusion GHD believes that there is a solid case for the replacement of the existing “CRM” systems with an integrated group of CRM applications. However, we cannot provide an opinion on whether the proposed level of investment proposed meets the NFIT test as the information is not yet available.
- GHD recommends that the proposed $4.7 million to be spent on the creation of a new CRM system be treated as OPEX. This would result in a reduction in proposed CAPEX of $4.7 million and a corresponding increase in OPEX of the same amount.

6.4 Advanced Metering Infrastructure (AMI) IT systems

GHD has reviewed the merits of this spend in its review of the entire AMI project in section 5.4 of this report. It is GHD’s conclusion based on the information provided and the competitive tendering process that the revised forecast capital spend is reasonable.

6.5 Summary of Recommendations

Table 33 sets out the GHD recommended expenditures for corporate capex. These revised allowances include our recommended reductions of $16.9 million in the Depot Modernisation program, and $4.7 million shifted from CAPEX to OPEX for the creation of a new CRM system.

Table 33 Corporate capex revised forecast expenditures and draft decision direct costs for AA4 ($ million real, June 2017)

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Business Support					
Corporate real estate	201.1	201.1	201.1	184.2	(16.9)
Fleet CAPEX	46.7	0.0	0.0	0.0	0.0
Fleet lease	30.4	0.0	0.0	0.0	0.0
Property, plant & eqpt	4.2	4.2	4.2	4.2	0.0
Subtotal	*282.4*	*205.3*	*205.3*	*188.4*	*(16.9)*
IT					
Business driven	149.3	134.3	168.7	164.0	(4.7)
Business infrastructure	55.3	55.3	55.3	55.3	0.0
Subtotal	*204.6*	*189.6*	*224.0*	*219.3*	*(4.7)*
Total	**487.1**	**394.9**	**429.3**	**407.7**	**(21.6)**

7. Forecast OPEX

7.1 Revised AA4 OPEX proposal

The ERA has not asked GHD to review the proposed revision made by Western Power, however they have asked GHD to identify the impact on OPEX of our recommendations from our review of transmission, distribution and corporate CAPEX.

In our review we have identified two recommendations that impact OPEX. Specifically;

1. The savings from the Depot Optimisation of approximately 10 million should be identified separately and not be included in the proposed 1% efficiency dividend.
2. The procurement of a new CRM capability for $4.7 million over three years using a SaaS model should not be treated as CAPEX. Rather it should be treated as OPEX.

The arguments GHD has made for each of the recommendations is made above in sections 6.2 and 6.3 respectively.

The impact of these savings per year is difficult to estimate as details were not available as to when Western Power expect to generate the savings from the Depot Optimisation program or when they expect to have the new CRM operational.

7.2 Depot Optimisation

From our assessment of the Depot Optimisation program we would anticipate that the savings would not eventuate until the later years of the AA4 period. GHD has therefore assumed that savings would start to occur in 20/21 and accelerate in 21/22. Western Power has estimated that the savings from the program would be $10 million p.a.

However, from our analysis GHD is concerned whether Western Power will meet its milestones for the program as a result we have estimated the savings would equate to $10 million over the AA4 period and would be $2.5 million in 2020/21 and $7.5 million in 2021/2022.

7.3 CRM SaaS

Western Power has provided the GHD with a copy of its CRM Shortlisting Memo that details the procurement process that it has followed to select a vendor for its CRM program. In that memo the cost of the preferred vendors service for three years is $4.7 million.

Given that a vendor has not yet been formally chosen, GHD has assumed that the cost of this service will not start to be incurred until 2019/20 and will run for three years and be billed at an equal amount (approximately $1.6 million) each year.

7.4 OPEX adjustments

Table 34 shows the two recommendations noted above on overall annual OPEX forecast for AA4.

Table 34 Recommended adjustments to AA4 OPEX ($ million real, June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Depot Optimisation Operational Cost savings				(2.5)	(7.5)	(10.0)
CRM SaaS			1.6	1.6	1.5	4.7
GHD OPEX adjustments	**0.0**	**0.0**	**1.6**	**(0.9)**	**(6.0)**	**(5.3)**

8. Summary and conclusions

The following summarises the conclusions and recommendations from GHD's analysis of the Western Power revised AA4 proposal.

8.1 Transmission CAPEX

8.1.1 Growth

Western Power contends that all the listed projects including those that are unspecified will proceed and be completed within the AA4 period. Based on the information available to us, GHD does not consider this to be likely. In addition there is no supporting evidence with respect to $32.3 million of unspecified works. Further, GHD does not accept Western Power's contention that a 42% average rate for capital contributions is applicable for the forecast works.

Consequently GHD recommends that the allowance of $41 million for customer access works as stated in the ERA's draft report is reasonable and no adjustment is required from the draft decision. The net reduction on Western Power's revised proposal is $26.9 million.

8.1.2 Asset Replacement and Renewal

8.1.2.1 Switches

GHD accepts the Western Power advice for the qualified replacement volumes at Hay Street and Milligan Street, the need for the replacement of the technically obsolete Yorkshire/GEC switchboards and the prudency of provisions for reactive replacement and mobile RMU solution.

In amending the replacement volumes for pitch-filled switchboards at Hay Street and Milligan Street, we have concluded that the replacement unit cost per switchboard is $4.7 million, which we consider reasonable in comparison to recent market data available to us.

We note that in the Western Power response, the replacement cost for Yorkshire/GEC switchboards is considered to be "slightly more" than a pitch-filled switchboard. Western Power has not provided additional information regarding the unit rate to be used for replacing Yorkshire/GEC units, and so we have adopted the same replacement unit cost as for the pitch-filled switchboards.

We acknowledge that Western Power has used historic failure rates for switchboards to determine an equivalent 1.5 replacements should be provisioned for AA4. Whilst we accept the prudency of the allowance for reactive replacement switchboards, Western Power has not justified the $6.4 million unit rate it states in its response. We do not accept this unit rate to be reasonable, and have adopted the replacement cost of $4.7 million per switchboard as the efficient cost.

Our recommended forecast allowance[26] is $60.8 million for AA4. This equates to a $6.5 million reduction in CAPEX for this category of spend.

[26] Calculated as (7 * 4.7) + (4 * 4.7) + (1.5 * 4.7) + 2.1 = 60.85. Our estimate based on 4 Yorkshire/GEC switchboards completely replaced in AA4, whilst Western Power forecast for staged replacement has costs for preliminary work on two further replacements in AA5 that are equivalent in value to costs to complete the replacement of two switchboards started in AA4.

8.1.2.2 Power Transformers

The scope of work proposed by Western Power for power transformer replacement is considered to be consistent with their asset strategy for this asset class, and addressing the risks identified for the power transformers. Based on our comparative estimates for business cases provided, we are satisfied that the costs used by Western Power in generating this forecast reflect market values.

Therefore we recommend that the proposed $52.4 million forecast be accepted.

8.1.2.3 Protection Equipment

Western Power's program is aggressive and there is not a compelling case to support the rate of works. The existing protection schemes have been reliable to date and there is no suggestion that this reliability will decline in the short to medium term.

GHD is of the view that the forecast expenditure allowed for protection equipment in the ERA's draft decision remains appropriate. This equates to a reduction of $21.1 million in CAPEX from Western Power's revised AA4 proposal for this category of spend.

8.1.2.4 SVCs

GHD accept that the West Kalgoorlie business case has investigated appropriate options, and nominated a preferred option based on the cost effective solution to address and mitigate the network risks.

We have reviewed our original comparative estimate in light of the full scope of work, and accept the nominated costs for the additional plant (shunt reactors) and control devices as reasonable and consistent with market values.

Therefore GHD is of the opinion that this project is likely to meet the requirements of the new facilities investment test and, and recommend the proposed $22.2 million forecast is accepted

8.1.2.5 Transmission Primary Plant

Whilst challenging the proposed efficiency reduction for AA4, Western Power suggested that AA4 unit rates were based on AA3 actual costs that have efficiencies embedded in them. However, we do not consider Western Power has provided any additional information to support a change in our original recommendations.

GHD recommends the forecast expenditure allowed in the ERA's Draft Decision remains appropriate. This equates to a reduction of $7.1 million in CAPEX for this category of spend.

8.1.3 Improvement in Service

GHD remain satisfied that the proposed expenditure for AA4 is prudent, as it addresses the replacement of assets that are technically obsolete and important to the efficient operation of the network.

However, we do not consider Western Power has provided sufficient information for an assessment of how the proposed replacement program is to be delivered during AA4. We therefore agree with the ERA that approval for this expenditure is conditional on this information being provided.

8.1.4 Compliance

8.1.4.1 Substation Security

GHD notes that Western Power has used a risk-based approach in prioritising fence replacements for AA4, using a weighted combination of condition, criticality and threat assessments. This generated a risk score and associated Priority allocation for each fence. As a large proportion of the fence population is beyond or near the nominal asset life for fencing, and the fences with the higher priorities (4 and 5) are generally also part of the older population, we agree with Western Power that the initial focus in the replacement program should be on the fences classified as Priority 4 and Priority 5. We note that some work on Priority 3 fences has been included in the revised AA4 proposal which we do not consider prudent when there are Priority 4 and Priority 5 fences that have not been included in the AA4 program.

Therefore, based on our review of the Western Power modelling for substation fencing, we consider the AA4 forecast should be based on the replacement of the higher priority fences identified in the risk assessment, and therefore recommend the AA4 forecast be amended to $34.2 million for AA4.

8.1.4.2 Physical Security Measures

Given the expenditure for the replacements of keys is prudent, due to the expiry of protective patents, we recommend that the proposed expenditure of $8.3 million be accepted.

8.1.4.3 Asbestos

However, given the proposed escalated work volumes at replacement work in substation buildings and grounds, we consider it prudent and important to include an allowance in the AA4 forecast to manage the asbestos risk.

We recommend the proposed provision of $2.5 million be accepted.

8.1.4.4 Roofs

The condition data available from Western Power suggests that the overall general condition of substation building roofs is poor. Western Power has used a risk based approach in assessing roofs that is similar but not consistent with that used for fences, but which has identified the roofs considered to pose the highest risk to the network. We agree with the Western Power proposal to replace 4 roofs per year during AA4, as we have concluded from the risk model provided by Western Power that this replacement rate should be the minimum rate to address the aging and higher risk roofs.

In summary, we recommend the proposed $8.9 million for roof replacement in AA4 be accepted.

8.1.5 Summary of Transmission CAPEX

Table 35 shows the GHD recommended transmission CAPEX allowances (direct costs only) for Western Power in AA4.

Table 35 Recommended transmission CAPEX forecast allowances for AA4 ($ million real, June 2017) excluding contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Growth	240.8	159.4	205.5	159.4	(46.1)[27]
Asset replacement and renewal	245.2	145.8	231.2	197.6	(33.6)
Improvement in service	89.9	89.9	89.9	89.9	0.0
Compliance	155.0	95.3	147.0	136.7	(10.3)
Total	**730.9**	**490.3**	**673.6**	**583.6**	**(90.0)**

[27] This amount is made-up of a reduction in growth CAPEX of $26.9 million and $19.2 million for the Picton/ Busselton 132 kV line

8.2 Distribution CAPEX

8.2.1 Distribution Growth

Given GHD's initial analysis, and the lack of change in forecast spend we accept the revised proposed level of expenditure.

8.2.2 Distribution Improvement in Service

Western Power's response in its revised proposal mentions that the additional amount it is proposing to spend is for investment in projects targeting similar edge-of-grid reliability issues as the Kalbarri micro grid and/or to improve customer experience. However, GHD notes that the scope of works for such investment remains largely undefined. Also Western Power has not been able to provide any definitive, demonstrable or measurable description of benefits it aims to achieve by investing in such projects. Therefore, GHD recommends removing the proposed additional amount above the Kalbarri microgrid project estimate of $7.9 million for this distribution CAPEX sub-category. This equates to $3.9 million reduction in Distribution CAPEX.

8.2.3 Advanced Metering Infrastructure (AMI)

The respective incremental meter costs of $145 per meter and $61 per meter are direct inputs to the cost benefit analysis models. While Western Power provided copies of the respective cost benefit analysis for review, GHD was initially unable to verify the validity of the data that determined these input values, such as the meter costs, installation costs and the ratio of single to three phase meters. Following requests by the ERA, and subsequent additional information provided by Western Power (ERA060) and (ERA064), the following analysis allowed for more detailed analysis of the underlying cost changes from the original business case (BC) to the updated business case (CC).

Table 36 Causes of increases in BAU costs ($million real, June 2017)

Cause	Analysis of NPV Impact	Percent
Increase in BAU installed 1Ph Meter Costs	$ 20,553,315	20%
Correction to mix of 1ph to 3 ph and 3ph meter costs	$ 46,759,926	46%
"other Meter Comms Cost Install"	$ 33,886,759	33%
TOTAL	**$101,200,000**	

Western Power was asked in ERA064 to provide an explanation for the "other Meter Comms Cost Install" which above is estimated to represent $33.9 million in the NPV BAU costs. Western Power's response as follows:

- In the BAU scenario, the installation and replacement of modems and antennas are necessary to provide communications for non-residential customer meters requiring remote access.
- For the AMI scenario, the installation and replacement of NIC cards into retrofittable AMI capable meters is estimated to be required for the operation of the communication network to operate more efficiently. Western Power is not forecasting a retrofitting program, these volumes are estimated to be required for the operation of the communications network.

GHD considers, without sufficient reason being provided, that these cost items will require further justification in a new facilities investment test. The sensitivity analysis of the cost and benefits provided by Western

Power and reviewed by GHD in Section 5.4.4 indicates that the NPV for CC CBA case would still be positive even if $33.9 million of costs is removed from the BAU costs.

The incremental metering costs from BAU in the original business case was $145 per meter and this has been changed to $61 per meter in the updated business case analysis (CC CBA). While Western Power has provided copies of the respective cost benefit analysis for review, GHD was initially unable to verify the validity of reasons for the changes to these input values, such as the meter costs, installation costs and the ratio of single to three phase meters. The increase in BAU costs resulted in a reduction of $101.2 million in NPV terms in the business case, a very significant change.

GHD was able to breakdown these additional BAU costs with additional information provided by Western Power. This increase consisted of;

- An increase in total installed costs for BAU 1Ph meters (representing 20% of the NPV cost reduction). GHD considers this increase an appropriate change.
- A correction to the mix of 1Ph to 3Ph meters and removal of additional costs for 3Ph meters which are already to the AMI standard (representing 46% of the NPV cost reduction). GHD considers this increase an appropriate change.
- An addition of $33.9 million for "other Meter Comms Cost install" (representing 33% of the NPV cost reduction). GHD considers, without sufficient reason being provided, that these cost items will require further justification in a new facilities investment test. Sensitivity analysis of cost and benefits indicates that the NPV in the CC CBA case would still be positive even if $33.9 million of costs is removed from the BAU costs.

The reductions in individual AMI benefit items in the revised business case is less than GHD's view in some areas and greater in other areas. The net effect is a more reasonable position for assessed total benefits compared with the original business case. The reasons provided for Western Power's revised benefits with the more robust analysis conducted in each case provides a reasonable degree of confidence in the assessed benefits. GHD also considers the revised benefits are commensurate with other international AMI business case cost benefit analysis compared to the benefits types included in Western Power's cost benefit analysis.

Western Power has not included potential benefits from the generation and retailer supply chain benefits, however based on the sensitivity analysis undertaken and giving consideration to these additional potential benefits, Western Power considers that the approved Change Control position for AMI remains NPV positive under all scenarios tested. Western Power did consider GHD's information in assessing potential other supply chain benefits which suggested these benefits would provide an NPV benefits in the order of $160 million. This counterbalances concerns over the cost reduction of $101.2 million in incremental meter costs with respect to the NPV of the business case.

GHD considers that Western Power has demonstrated that the RF mesh network technology is the most cost efficient for providing a communication backbone for the over 1,000,000 volume of meters in the AMI rollout.

GHD recommends accepting the change in AMI IT forecast costs of $34.4 million as these costs are based on competitive pricing and revised scope requirements for the project.

GHD does agree with Western Power that the forecast expenditure on the AMI program, including the deployment of advanced meters and the associated IT and communications infrastructure, is reasonably likely to satisfy the requirements of the new facilities investment test and should therefore be included in the forecast capital base.

8.2.4 Summary of Distribution CAPEX

Table 37 shows the GHD recommended adjustments to distribution CAPEX allowances (direct costs only) for Western Power in AA4.

Table 37 Distribution capex revised forecast expenditures and draft decision direct costs for AA4 ($ million real, June 2017) excluding gifted assets and contributed assets

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Growth	405.9	417.1	391.4	391.4	0.0
Improvement in Service	94.0	57.7	88.8	84.9	(3.9)
Total	**499.9**	**474.8**	**480.2**	**476.3**	**(3.9)**

8.3 Corporate CAPEX

8.3.1 Depot Modernisation and Relocation of Control Centre

GHD is concerned that other lower priority metro projects within the program will not be completed during the AA4 period. The most likely projects to be delayed are the upgrades to [redacted]. We do not have a breakdown of spend on these projects across the AA4 period, therefore at this stage we are unable to identify the impact delays would have on the timing of CAPEX requirements, however we recommend that the ERA withhold 50% of the forecast CAPEX for these two projects as GHD believes it is unlikely that both of these projects will be completed during the AA4 period. This would equate to $16.9 million reduction in CAPEX.

GHD recommendations that the savings associated with the depot optimisation and consolidation program not be included as part of the efficiency dividend and be identified separately and that an efficiency dividend of 1% be applied to all operating costs outside of the depots.

8.3.2 CRM

GHD believes that there is a solid case for the replacement of the existing “CRM” systems with an integrated group of CRM applications, although we cannot provide an opinion on whether the proposed level of investment proposed meets the NFIT test.

GHD also recommends that the proposed $4.7 million to be spent on the creation of a new CRM system be treated as OPEX. This would result in a reduction in proposed CAPEX of $4.7 million and a corresponding increase in OPEX of the same amount.

8.3.3 Summary of Corporate CAPEX

Table 38 shows the GHD recommended corporate CAPEX allowances (direct costs only) for Western Power in AA4.

Table 38 Recommended corporate CAPEX forecast allowances for AA4 ($ million real, June 2017)

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Business Support					
Corporate real estate	201.1	201.1	201.1	184.2	(16.9)
Fleet CAPEX	46.7	0.0	0.0	0.0	0.0
Fleet lease	30.4	0.0	0.0	0.0	0.0
Property, plant & eqpt	4.2	4.2	4.2	4.2	0.0
Subtotal	*282.4*	*205.3*	*205.3*	*188.4*	*(16.9)*
IT					
Business driven	149.3	134.3	168.7	164.0	(4.7)
Business infrastructure	55.3	55.3	55.3	55.3	0.0
Subtotal	*204.6*	*189.6*	*224.0*	*219.3*	*(4.7)*
Total	**487.1**	**394.9**	**429.3**	**407.7**	**(21.6)**

8.4 Summary of recommended CAPEX

Table 39 shows the recommended adjustments to Western Power's revised proposed CAPEX (direct costs only) during the AA4 period, totalling a reduction of $115.5 million.

Table 39 Recommended amendments to revised Western Power AA4 CAPEX forecast ($ million real, June 2017)

Category	AA4 Western Power proposal (Oct 2017)	GHD initial recommendation	AA4 Western Power revised proposal (Jun 2018)	AA4 GHD recommended allowances	Variation - AA4 Revised Proposal to AA4 GHD recommended
Transmission network	730.9	490.3	673.6	583.6	(90.0)
Distribution network	499.9	474.8	480.2	476.3	(3.9)
Corporate	487.1	394.9	429.3	407.7	(21.6)
Total	**1,717.9**	**1,360.0**	**1,583.1**	**1,467.6**	**(115.5)**

8.5 OPEX

8.5.1 Depot Optimisation

From our assessment of the Depot Optimisation program we have estimated the savings from this program would equate to $10 million over the AA4 period and would be $2.5 million in 2020/21 and $7.5 million in 2021/22. OPEX should be reduced by these amounts in 2020/21 and 2021/22.

8.5.2 CRM SaaS

GHD believed the costs associated with this program should be classified as OPEX. Based on the information provided to GHD, we have assumed that the cost of this service will not start to be incurred until

2019/20 and will run for three years and be billed at an equal amount (1.6 million) each year. OPEX should be increased by this amount across each of these years.

8.5.3 Summary of OPEX adjustments

Table 40 shows the two recommendations noted above on overall annual OPEX forecast for AA4.

Table 40 Recommended adjustments to AA4 OPEX ($ million real, June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Depot Optimisation Operational Cost savings				(2.5)	(7.5)	(10.0)
CRM SaaS			1.6	1.6	1.5	4.7
GHD OPEX adjustments	**0.0**	**0.0**	**1.6**	**(0.9)**	**(6.0)**	**(5.3)**

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https://projects.ghd.com/oc/Advisory/techadvisorreviewwpa/Delivery/Documents/Deliverables/Final/Revised TR of WPs Proposed Revisions to its AA4 v2.1 20180919 Final.docx

Rev.No.	Author	Reviewer		Approved for Issue		
		Name	Signature	Name	Signature	Date
Preliminary draft	GHD	Nick Reynolds Jeff Butler		Stephen Hinchliffe		06/08/2018
Final	GHD	Nick Reynolds Jeff Butler		Stephen Hinchliffe		12/09/2018
Final (updated)	GHD	Nick Reynolds Jeff Butler		Stephen Hinchliffe		19/09/2018

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