FINAL DECISION

Jemena distribution determination 2016 to 2020

Overview

May 2016

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au
AER Reference: 57379

Note

This overview forms part of the AER's final decision on Jemena's distribution determination for 2016–20. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – f-factor scheme

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	advanced metering infrastructure
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model

RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

1 Introduction

We, the Australian Energy Regulator (AER), are responsible for the economic regulation of electricity distribution systems in Australia, except for Western Australia.[1]

Jemena is one of five distribution network service providers (distributors) in Victoria and is responsible for providing electricity distribution services in a section north west of Melbourne. We regulate the revenues Jemena and other electricity distributors can recover from their customers.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework governing electricity networks. In regulating Jemena, we are guided by the National Electricity Objective (NEO), as set out in the NEL. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to–

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[2]

We apply incentive regulation in making our decision on a distributor's revenue to promote economic efficiency. Incentive regulation encourages distributors to spend efficiently and to share the benefits of efficiency gains with consumers.

1.1 Structure of overview

This overview provides a summary of our final decision and its constituent components. It is structured as follows:

- Section 1 highlights our process and the transitional arrangements that affect 2016 prices.
- Section 2 provides a summary of our final decision, and highlights where we made significant changes between our preliminary and final decisions.
- Section 3 provides a break-down of our revenue decision into its key components. We determine revenue using the building block approach. This section details the approved amount for each building block component.
- Section 4 sets out our final decision on classification of services, control mechanisms and incentive schemes that will apply to Jemena. These are the decisions we make in addition to the building block revenue determination.
- Section 5 explains our views on the regulatory framework and the NEO.

---

1 The Western Australian Government has signalled its intention to transfer electricity regulation to the AER in the second half of 2016. It is proposed that the first regulatory determination by the AER for Western Power's distribution (and transmission) network would be for a four year regulatory period from 1 July 2018.

2 NEL, s. 7.

- Section 6 outlines both our consultation process in reaching this final decision, and our view of Jemena's consumer engagement undertaken in developing its regulatory proposals.
- Appendix A contains the full list of constituent components for our final decision.
- Appendix B contains a list of stakeholder submissions.

In our attachments to this decision we set out detailed analysis of the constituent components that make up Jemena's revised proposal and our decision on each of them.

1.2 Our process

Jemena submitted its initial regulatory proposal for the 2016–20 regulatory control period in April 2015. We made our preliminary decision on Jemena's proposal in October 2015, which set out the total revenue it can recover from its customers over the 2016–20 regulatory period.

Following our preliminary decision, Jemena submitted its revised proposal in January 2016. We received submissions from stakeholders on our preliminary decisions and the businesses' revised proposals. We published all submissions and revised regulatory proposals on our website.

Our final decision follows extensive consultation (see section 6). We held public forums and workshops and meetings with stakeholders on many elements of our decision. The AER's Consumer Challenge Panel (CCP3) has assisted us by advising us on issues of importance to consumers. We have sought to produce consumer friendly documents, established a consultative group with Victorian consumer representatives and held training sessions with consumers. Table 1 lists the key dates and consultation of the process.

Table 1 Key dates and consultation

Task	Date
Businesses submitted regulatory proposals to AER	30 April 2015
AER released Issues paper	9 June 2015
AER held public forum	22 June 2015
Submissions on regulatory proposals received	13 July 2015
AER preliminary decisions	29 October 2015
AER conference to explain preliminary decisions	17 November 2015
Submissions on preliminary decisions	6 January 2016
Businesses submitted revised regulatory proposals to AER	6 January 2016
Further submissions, including on revised proposals	4 February 2016
AER release of final decisions	End of May 2016

Our preliminary decision for the 2016–20 regulatory control period was the basis used for approving network prices in 2016. As required by the 'transitional arrangements' in the NER, we have revoked the preliminary decision and substitute it with this final decision—which applies to the whole 2016–20 regulatory control period. This decision provides for adjustments over the regulatory control period to account for differences between the amount of revenue we approved for Jemena for 2016 in the preliminary decision and in the final decision.[3]

1.3 Victorian electricity distribution

The electricity industry is divided into four distinct parts, with a specific role for each stage of the supply chain—generation, transmission, distribution and retail.

Electricity distributors, which are the focus of this decision, convert electricity from the transmission network into medium and low voltages and deliver that electricity to homes and businesses across Victoria. Each of Victoria's five distributors serves a different geographic area of Victoria:

- AusNet Services operates in the eastern part of Victoria, including eastern areas of Melbourne
- CitiPower operates in inner urban and CBD parts of Melbourne
- Jemena operates in parts of northern, north-east and north-western areas of Melbourne
- Powercor operates in the western part of Victoria, including some western areas of Melbourne
- United Energy operates in the south-eastern areas of Melbourne.

AusNet Services and Powercor predominantly serve rural and regional Victoria. Jemena, United Energy and CitiPower predominantly serve urban areas.

3 NER, cll. 11.60.4(d) and (e).

2 Summary of final decision

Our final decision is that Jemena can recover $1302.1 million ($ nominal, smoothed) from consumers over the 2016–20 regulatory control period, which began on 1 January 2016. This is a 15.3 per cent reduction from Jemena’s revised proposed revenue allowance of $1538.2 million ($ nominal, smoothed). Our final decision allows Jemena to recover 12.0 per cent more revenue from its customers than we determined in our October 2015 preliminary decision of $1162.7 million ($ nominal, smoothed).

Figure 1 compares our final decision on Jemena's revenue for 2016–20 to its proposed revenue, and to the revenue allowed and recovered during the 2011–15 regulatory period. Jemena's annual revenue increased each year from 2011 to 2015.

This final decision results in relatively stable levels of revenue over 2016–20. The more modest change in revenue over this period reflects reduced pressure on Jemena's underlying costs, including:

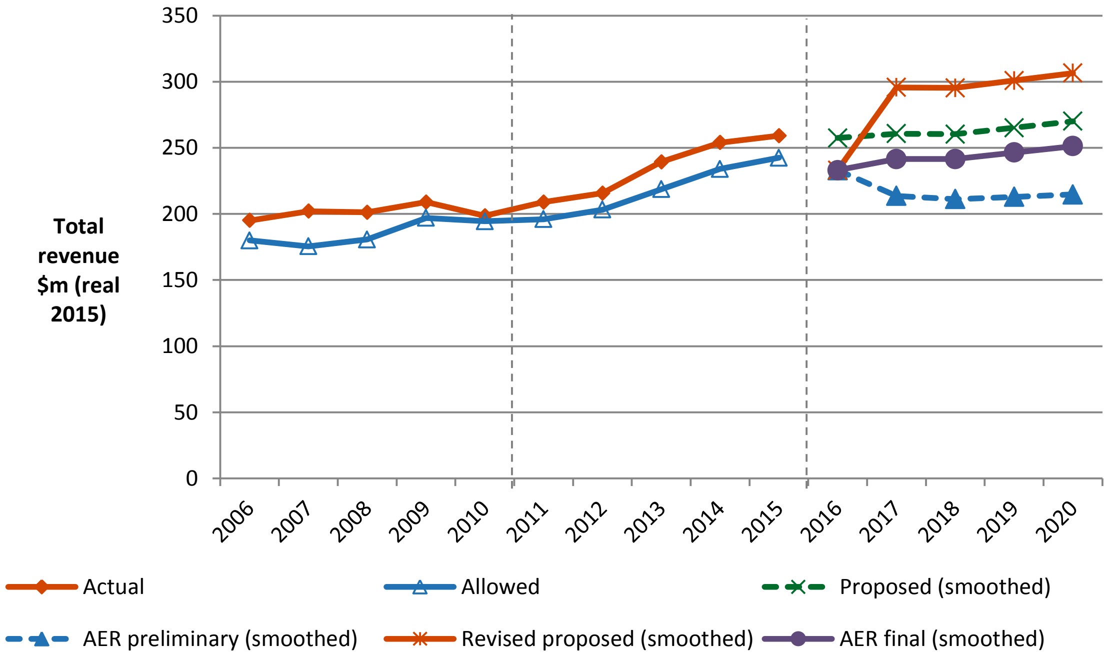
- an improved investment environment compared to 2011–15, which translates to lower financing costs
- lower forecasts of demand growth for electricity in Victoria, which means less pressure on the business to expand the capacity of its network—albeit with some 'pockets' of high growth
- reductions to energy consumers Value of Customer Reliability, which reduces the need to build new infrastructure to meet customers' expectations of reliable electricity.

Total capital expenditure (capex) is forecast to increase compared to capex in the previous period. Although there is less pressure on the business to augment its network to meet peak demand, we expect greater requirements for replacement expenditure compared to the previous period, driven by the need for increased replacement of assets that support network management and operation.

Some advanced metering costs that were allocated to metering services are now allocated to operating expenditure (opex) for standard control services in this final decision. This partly explains the increase in opex between our preliminary and final decisions, and compared to 2011–15.

Our October 2015 preliminary decision was used as the basis for setting network charges in 2016. In this final decision we are approving higher revenues than in the preliminary decision. Network charges over 2017–20 will therefore be somewhat higher in order to capture the difference.

Figure 1 Jemena's past total revenue, proposed total revenue and AER total revenue allowance ($ million, 2015)



Source: AER analysis.

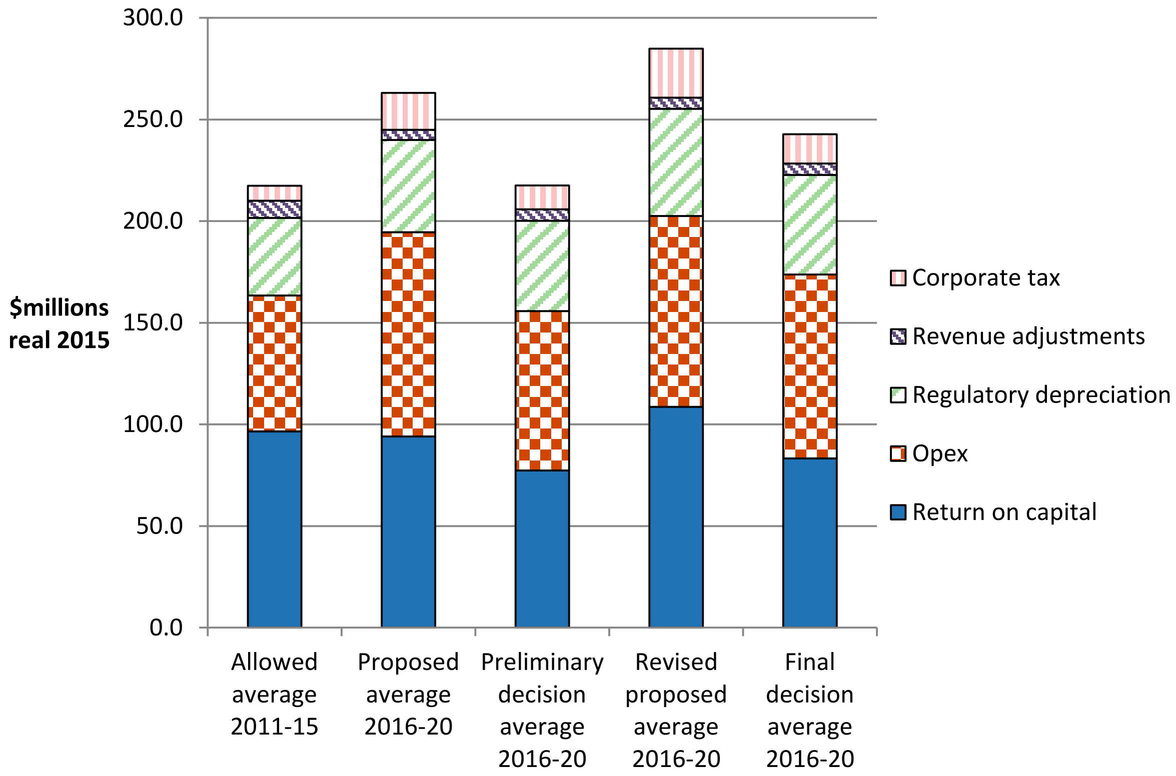
Note: Revenue relates to standard control services only.

2.1 What is driving allowed revenue?

Figure 2 compares the average annual building block revenue from our final decision against that proposed by Jemena for the 2016–20 regulatory control period, as well as the approved average amount for the 2011–15 regulatory control period.

We approve slightly more revenue over 2016–20 than that allowed—and recovered by—Jemena during the previous regulatory period. We have approved significantly less revenue than Jemena sought to recover through both its initial and its revised proposal.

Figure 2 AER's final decision on constituent components of total revenue ($ million, 2015)

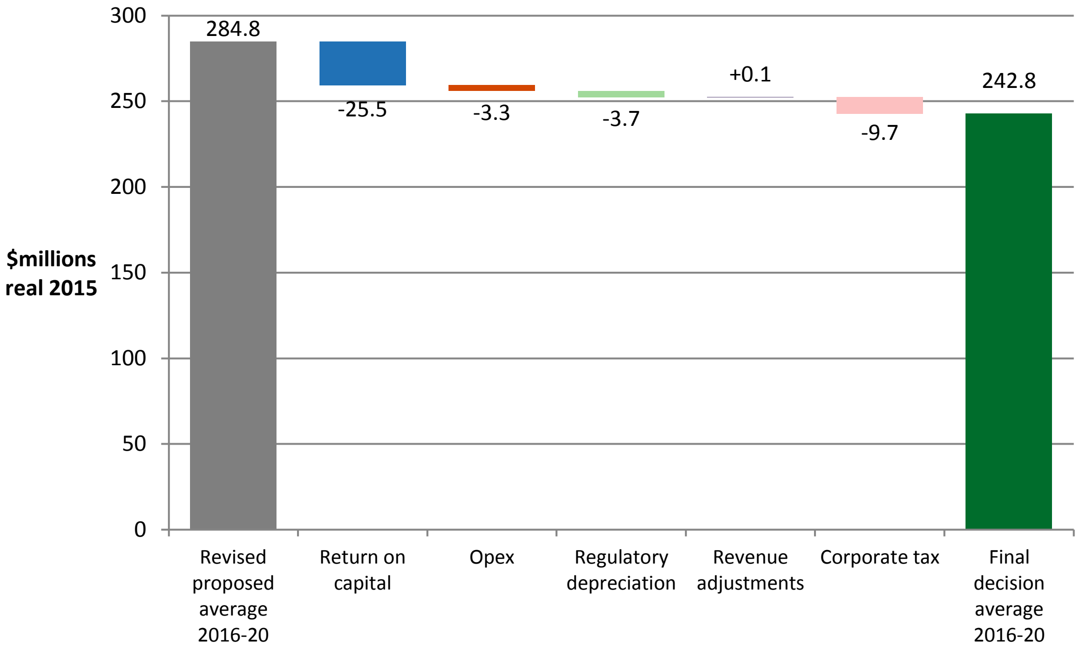


Source: AER analysis.

Note: Components of total revenue relate to standard control services only.

Figure 3 compares our final decision to Jemena's revised proposal, broken down by the various building block components that make up the forecast revenue allowance.

Figure 3 AER's final decision and Jemena's revised proposed annual building block costs ($ million, 2015)



Source: AER analysis.

Note: Building block costs relate to standard control services only.

The allowed rate of return, which feeds into the return on capital building block, is the key difference between our final decision and Jemena's revised proposal (figures 2 and 3 above). The allowed rate of return provides Jemena with revenue to service the interest on its loans and give a return on equity to its shareholders. It is applied to Jemena's asset base to determine the return on capital building block.

Prevailing market conditions for debt and equity heavily influence the rate of return. Financial conditions have changed since our last electricity determination for Jemena in October 2010. Interest rates are lower and financial market conditions are more stable. This means that the cost of debt and the returns required to attract equity are lower.

This is reflected in a lower rate of return in this decision. Our final decision is for a rate of return of 6.37 per cent (for 2016).[4] In comparison, Jemena proposed 8.62 per cent in its revised proposal. The allowed rate of return of 6.37 per cent is also lower than the previous regulatory control period's 10.33 per cent.

The impact of the lower rate of return on revenue is offset by other factors to give slightly higher revenues over the 2016–20 regulatory control period compared to the 2011–15 period. The main offsetting factors are increases in operating expenditure and growth in the asset base.

Opex is a key driver of allowed revenue for Jemena (as shown in figure 2). Our benchmarking results show Jemena has been operating relatively efficiently, which gives us

4 For the remaining years of the regulatory control period, we will update the rate of return annually.

confidence to base our opex forecasts on Jemena's actual ('revealed') costs. However, we have increased Jemena's allowance compared to the last regulatory control period.

One reason for the opex increase is step increases in the business' costs for new regulatory obligations imposed on Jemena.

The second is reallocation of a portion of metering costs from alternative to standard control services. The costs of metering services are partly recovered from metering specific charges which are not included in the standard control revenue base we set. In this decision, we have allocated more costs to standard control services, and less to separate meter specific charges. While this increases opex and therefore standard control revenues, it decreases metering revenues. Overall the reallocation has no net impact on the average customer's electricity bill.

When a network business spends money on an asset, the value of that asset is added to its regulatory asset base. Jemena's regulatory asset base is expected to increase by 43.1 per cent in nominal terms over the 2016–20 regulatory control period—from $1186.8 million at 1 January 2016 to $1698.3 million at the end of 2020. Overall forecast capital expenditure of $774.3 million ($ nominal) outweighs an offsetting effect of regulatory depreciation of $262.9 million ($ nominal).[5]

The revenue impact resulting from the higher asset base this regulatory control period compared to the last regulatory control period largely offsets the revenue impact of the lower rate of return.

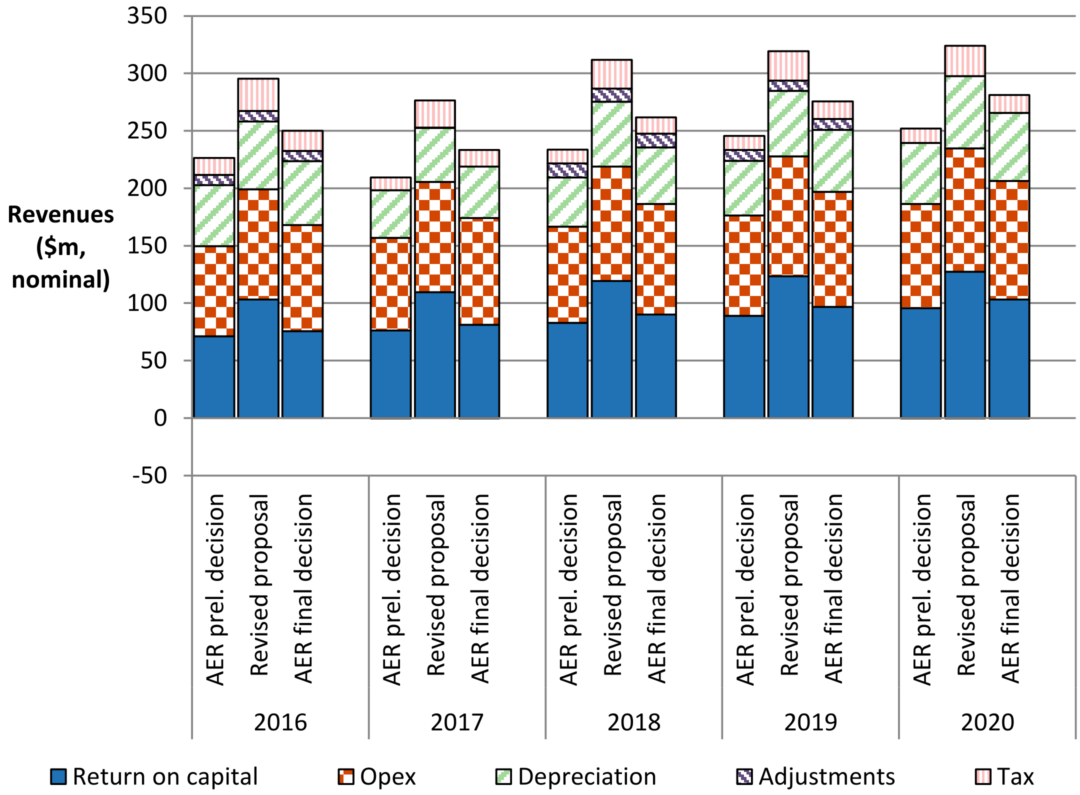
2.2 Key differences between our preliminary and final decisions

While our approved forecast revenue requirement is less than what Jemena proposed, it is higher than our preliminary decision.

Figure 4 compares our final decision on each of the revenue building blocks to our preliminary decision and Jemena's revised proposal.

5 This capex value is inclusive of equity raising costs and after adjusting for the half–WACC to account for the timing assumption in the PTRM.

Figure 4 AER's final decision and Jemena's revised proposal building block components of total revenue – unsmoothed ($ million, nominal)



Source: AER analysis.

Note: Building blocks relate to standard control services only.

A number of aspects of our decision on Jemena's allowable revenue for 2016–20 have changed since our preliminary decision. The key components that have changed include:

- updating the rate of return
- increased capex forecast
- opex step changes
- allocation of metering costs.

This section provides a brief description of these issues.

2.2.1 Updated rate of return data

Our decision on the rate of return has changed from our preliminary decision (from 6.02 per cent to 6.37 per cent), but this is not due to any change in our methodology but rather the use of more current data and averaging periods. This updated data affects both the return on debt and equity components of the rate of return.

Jemena changed its rate of return proposal between its original proposal and its revised proposal. The change increased Jemena's forecast revenue requirement. In its original proposal, Jemena proposed a rate of return of 7.18 per cent, which we did not accept. In its revised proposal, Jemena increased its proposed rate of return to 8.62 per cent.

The higher rate of return in Jemena's revised proposal is largely driven by a change to its approach to estimating the cost of debt. Jemena previously proposed to calculate its return on debt using a hybrid transition which combines a gradual transition of the base rate to a trailing average and a backwards looking debt risk premium (no transition). However, it now proposes an immediate transition to a trailing average (using both a backwards looking base rate and debt risk premium). This approach is more favourable to Jemena in revenue terms than that it originally proposed.

We have retained the approach to cost of debt set out in our rate of return guideline. We have not accepted either the hybrid transition proposed in Jemena's original proposal or the immediate transition to a trailing average proposed in its revised proposal.

2.2.2 Increased capex forecasts

We have increased our capital expenditure forecast from our preliminary decision by $37.2 million. We have accepted Jemena's proposed $27.5 million for its Preston conversion project. Our final decision also includes capex for the Sunbury and Flemington projects as we consider that the new information submitted by Jemena adequately addresses the concerns raised in our preliminary decision.

We have also accepted non-network information and communications technology (ICT) capex for Power of Choice ($25.4 million) and RIN compliance ($2.1 million) as a result of new regulatory obligations.

2.2.3 Additional step changes in opex

Our final decision increases the forecast opex step changes for Jemena from our preliminary decision. Step changes may be triggered by new regulatory obligations, other external drivers or for efficient capex/opex trade-offs.

Of the $27.7 million of step changes proposed by Jemena in its revised proposal, we have accepted $17.1 million. Jemena initially proposed $60.3 million of step changes, of which we accepted $3.2 million in our preliminary decision.

This increased amount largely reflects our decision to accept step changes to cover costs of new regulatory obligations, including:

- the implementation of Power of Choice reforms ($0.9 million).
- the implementation of a new connections charging framework under the National Energy Customer Framework (NECF) ($0.7 million).

Our final decision is to include step changes for the following proposals that were not accepted in our preliminary decision:

- compliance with regulatory information reporting requirements ($5.9 million)
- service inspection and testing program ($5.8 million)
- vegetation management ($2.3 million)
- enclosed substation inspection and rectification ($0.2 million).

We have revised downwards the step change for new tariffs ("new pricing obligations") that we included in our preliminary decision (from $2.5 million to $0.5 million).

2.2.4 Re-allocation of Advanced Metering Infrastructure costs

Our final decision is to allocate 54 per cent of advanced metering infrastructure (AMI) information technology and communications costs to ‘standard control services’ (SCS). This increases the total revenue approved in this decision, but does not affect overall network plus metering charges faced by energy consumers.

This decision means that some costs previously allocated to ‘alternative control services’ (ACS) will now be recovered through SCS. These are costs not of the actual meters themselves (which will be recovered in metering services) but rather costs of shared systems—for example communication and IT systems—that are used in both providing metering services and SCS.

In our preliminary decision, we rejected the allocation of these types of AMI costs to SCS by the businesses. We instead classified these costs under ACS, which meant ongoing AMI costs would be recovered by the businesses through a separate annual metering charge. Section 3.6.2 provides further details on our decision to allocate a portion of AMI costs to SCS.

2.3 Expected impact of decision on residential electricity bills

The annual electricity bill for customers in Jemena’s distribution area will reflect the combined cost of all the electricity supply chain components—wholesale energy generation, transmission, distribution, metering, and retail costs. This decision primarily relates to the distribution charges for SCS, which represent approximately 37 per cent, on average, of the annual electricity bill for these customers. This decision also covers charges for metering services that were previously regulated under a separate Victorian ‘Order in Council’.[6]

We estimate the expected bill impact by varying the distribution and metering charges in accordance with our decision, while holding other components of the bill constant.[7] This approach isolates the effect of our decision on electricity prices, but does not imply that other components will remain unchanged across the regulatory control period.[8]

Based on this approach, we expect that our final decision will result in annual residential electricity bills that are below 2015 levels every year from 2016 to 2020.[9] Estimated 2016 bills have already decreased by 8.5 per cent, reflecting our preliminary decision. For the

6 See section 4.2.2 below.

7 In attachment 1 to this decision, we present equivalent estimates based only on the changes in distribution charges (that is, holding metering charges and all other components constant).

8 It also assumes that actual energy demand will equal the forecast in our final decision. Since Jemena operates under a revenue cap (see section 4.2.1 below), changes in demand will also affect annual electricity bills across the 2016–20 regulatory control period.

9 As set out in the body text, this section presents estimated bill impacts that consider the combined impact of changes in distribution and metering charges (but hold all other bill components constant). Attachment 1 to this decision presents equivalent estimates that isolate the effect of distribution charges (that is, they also hold metering charges constant).

remainder of the regulatory control period from 2017 to 2020, we expect the bill to stay relatively flat, with changes of 0.9 per cent or less each year. By 2020, the expected annual residential electricity bill is still 6.8 per cent below the 2015 level.

We expect that a typical resident in Jemena's distribution area with an annual electricity bill of $1771 ($ nominal) in 2015 will face:

- a decrease of $151 ($ nominal) or 8.5 per cent in 2016
- a decrease of $1 ($ nominal) in 2017
- an increase of between $2–$14 ($ nominal) or 0.1–0.9 per cent from 2018 to 2020.

By comparison, had we accepted Jemena's revised proposal, the expected annual residential electricity bill in 2020 would increase by approximately $39 ($ nominal) or 2.2 per cent above the 2015 level.

Table 2 shows the estimated impact of our final decision on average residential and small business customers' annual electricity bills in Jemena's network area over the 2016–20 regulatory control period, compared with Jemena's revised proposal. As explained above, these bill impact estimates are indicative only, and individual customers' actual bills will depend on their usage patterns and the structure of their chosen retail tariff offering.

Table 2 Estimated impact of final decision on average residential and small business customers' electricity bills in Jemena's network for 2016–20 period ($ nominal)

	2015	2016	2017	2018	2019	2020
AER final decision						
Residential annual bill	1771[a]	1619	1620	1622	1636	1651
Annual change (per cent)[c]		–151 (–8.5%)	1 (0.0%)	2 (0.1%)	14 (0.9%)	14 (0.9%)
Standard control services		–53	46	0	13	12
Metering		–99	–46	2	2	2
Small business annual bill	3771[b]	3560	3613	3615	3644	3672
Annual change (per cent)[c]		–211 (–5.6%)	53 (1.5%)	2 (0.1%)	29 (0.8%)	28 (0.8%)
Standard control services		–112	99	0	27	26
Metering		–99	–46	2	2	2
Jemena revised proposal						
Residential annual bill	1771[a]	1619	1776	1777	1794	1810
Annual change (per cent)[c]		–151 (–8.5%)	156 (9.6%)	1 (0.1%)	17 (0.9%)	16 (0.9%)
Standard control services		–53	192	–1	14	14
Metering		–99	-36	2	2	2

Small business annual bill	3771[b]	3560	3933	3934	3967	3999
Annual change (per cent)[c]		–211 (–5.6%)	373 (10.5%)	1 (0.0%)	33 (0.8%)	32 (0.8%)
Standard control services		–112	409	–2	31	30
Metering		–99	–36	2	2	2

Source: AER analysis; ESC, *Victorian Energy Retailers Comparative Performance Report - Pricing 2014–15*, January 2016, p. XIII; ESC, *Energy Retailers Comparative Performance Report - Pricing 2013–14 -Supplementary Report on Electricity Flexible Prices*, December 2014, p. 3

(a) Based on average of standing offers at June 2015 on Switchon comparison tool (postcode 3047) using annual bill for typical consumption of 4690 kWh per year. We have preserved the 2015 starting bill for comparability with our October 2015 preliminary decision.

(b) Based on average of standing offers at June 2015 on Switchon comparison tool (postcode 3047) using annual bill for typical consumption of 12020 kWh per year. We have preserved the 2015 starting bill for comparability with our October 2015 preliminary decision.

(c) Annual change amounts and percentages are indicative. They are derived by varying 2015 bill amounts in proportion with either total annual regulated revenue (for standard control services) or relevant alternative control services revenue (for metering) divided by forecast demand. Actual bill impacts will vary depending on electricity consumption, tariff class and other variables.

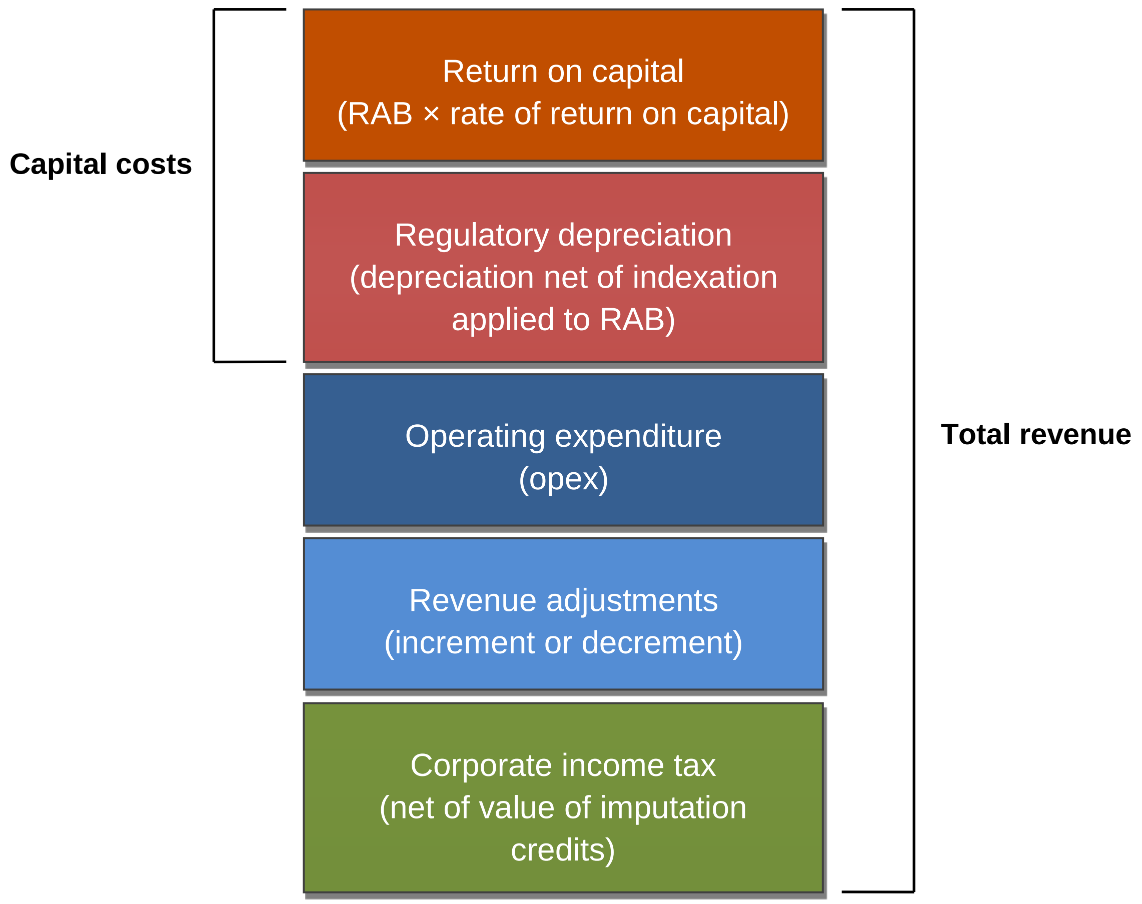
3 Key elements of decision

We use the building block approach to determine Jemena's annual revenue requirement. The building block approach consists of five costs that a business is allowed to recover through its revenue allowance.

The building block costs are illustrated in figure 5 and include:

1. a return on the regulatory asset base (RAB) (return on capital)
2. depreciation of the RAB (return of capital)
3. forecast opex
4. revenue increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
5. the estimated cost of corporate income tax.

Figure 5 The building block approach for determining total revenue



The building block costs are comprised of key elements that we determine through our assessment processes. For example, the size of the RAB—and therefore the revenue generated from the return on capital and return of capital building blocks—is directly affected by our assessment of capex.

This section summarises our decisions on key elements of the building blocks, including:

- RAB (section 3.1)
- rate of return (section 3.2)
- imputation credits (section 3.3)
- depreciation allowance (section 3.4)
- efficient level of capex (section 3.5)
- efficient level of opex (section 3.6)
- forecast level of corporate income tax (section 3.7)

Incentive mechanisms are covered in section 4.3.

Table 3 shows our decision on Jemena's revenues including the building block components.

Table 3 AER's decision on Jemena's revenues ($ million, nominal)

	2016	2017	2018	2019	2020	Total
Return on capital	75.7	81.4	90.2	96.8	103.2	447.4
Regulatory depreciation	55.5	44.9	49.3	53.8	59.3	262.9
Operating expenditure	92.5	92.8	96.1	100.3	103.2	485.0
Revenue adjustments[a]	8.9	–0.3	12.0	9.5	–0.1	30.1
Net tax allowance	17.6	14.3	14.2	15.1	15.5	76.8
Annual revenue requirement (unsmoothed)	**250.3**	**233.2**	**261.9**	**275.6**	**281.1**	**1302.1**
Annual expected revenue (smoothed)	**238.5**	**252.8**	**258.8**	**270.1**	**281.9**	**1302.1**
X factor[b]	n/a[c]	–3.60%	–0.02%	–2.02%	–2.00%	n/a

Source: AER analysis.

(a) Revenue adjustments include efficiency benefit sharing scheme carry-overs, forecast DMIA, 2010 S-factor scheme close out and shared asset adjustments.

(b) The X factors from 2017 to 2020 will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue

(c) In our preliminary decision, we determined the expected revenue and associated X factor for 2016. In this final decision to update the 2016 revenue for our assessment of efficient costs, we maintained the preliminary decision expected revenue and determined X factors for the final four years of the 2016–20 regulatory control period. This is to adjust the total expected revenue requirement for the remaining four years in the 2016–20 regulatory control period for the difference between the preliminary decision revenue and our final decision on efficient costs for 2016. Expected revenue in 2016 is around 9.0 per cent lower than approved revenue in 2015 in real terms, or 6.9 per cent lower in nominal terms.

3.1 Regulatory asset base

The regulatory asset base (RAB) is the value of the assets owned by Jemena to provide distribution network services. We use the RAB to determine the return on capital and depreciation allowance (return of capital) building blocks.

We make a decision on the opening value of Jemena's RAB as at 1 January 2016. We then roll forward the forecast RAB over the 2016–20 regulatory control period.[10]

Our decision is to set Jemena’s opening RAB at $1186.8 million ($ nominal), as at 1 January 2016. This is 1.0 per cent ($11.7 million) lower than Jemena's revised proposal of $1198.5 million ($ nominal). Our final decision is almost equal (just $0.2 million lower) to our preliminary decision value for Jemena's opening RAB of $1187.0 million ($ nominal).

There are two key factors affecting the opening RAB value in this decision. First, we updated the 2015 capex estimate with a more recent estimate provided by Jemena. Second, we have accepted Jemena's revised proposal to use an all-lagged approach for CPI indexation in the RAB roll forward. This approach is consistent with the past treatment of the Victorian service providers' RAB by the Essential Services Commission of Victoria. Our decision to accept Jemena's revised approach reflects our view that, to the extent possible, consistency is desirable, and our assessment of the strengths and weaknesses of possible alternative indexation approaches (specifically, partially-lagged and all-lagged approaches). Attachment 2 sets out further details of our reasoning for accepting an all-lagged approach.

Determining the opening value of the RAB

To determine the opening RAB as at 1 January 2016, we roll forward the RAB using actual capex incurred over the 2011–15 regulatory control period to determine a closing RAB value as at 31 December 2015. This roll forward includes an adjustment at the end of 2011–15 to account for the difference between actual 2010 capex and the estimate approved at the 2011–15 determination.[11]

Tables 4 sets out our decision on the roll forward of Jemena's RAB for the 2011–15 regulatory control period.

Table 4 AER's decision on Jemena’s RAB for 2011–15 regulatory control period ($ million, nominal)

	2011	2012	2013	2014	2015[a]
Opening RAB	764.2	861.3	954.8	1033.2	1115.6
Capital expenditure[b]	122.0	117.2	121.9	128.7	137.1
Inflation indexation on opening RAB	21.3	30.3	19.1	22.3	25.7
Less: straight-line depreciation	46.2	54.0	62.6	68.7	71.8
Closing RAB	861.3	954.8	1033.2	1115.6	1206.6
Difference between estimated and actual 2010 capex					–12.1
Return on difference for 2010 capex					–7.7
Closing RAB as at 31 December 2015					**1186.8**

10 NER, cll. 6.5.1 and S6.2.

11 The end of period adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2011–15 determination.

Source: AER analysis.
(a) Based on estimated 2015 capex, including an updated estimate provided after the submission of Jemena's revised proposal.
(b) Net of disposals and capital contributions, and adjusted for CPI.

Rolling forward the RAB over 2016–20

Once we have determined the opening RAB as at 1 January 2016, we roll forward that RAB over 2016–20 with forecast capex, inflation and depreciation to arrive at a forecast value for the RAB at the end of the regulatory period. Table 5 sets out our forecast RAB for Jemena in 2016–20.

Table 5 AER's decision on Jemena’s RAB for 2016–20 regulatory control period ($ million, nominal)

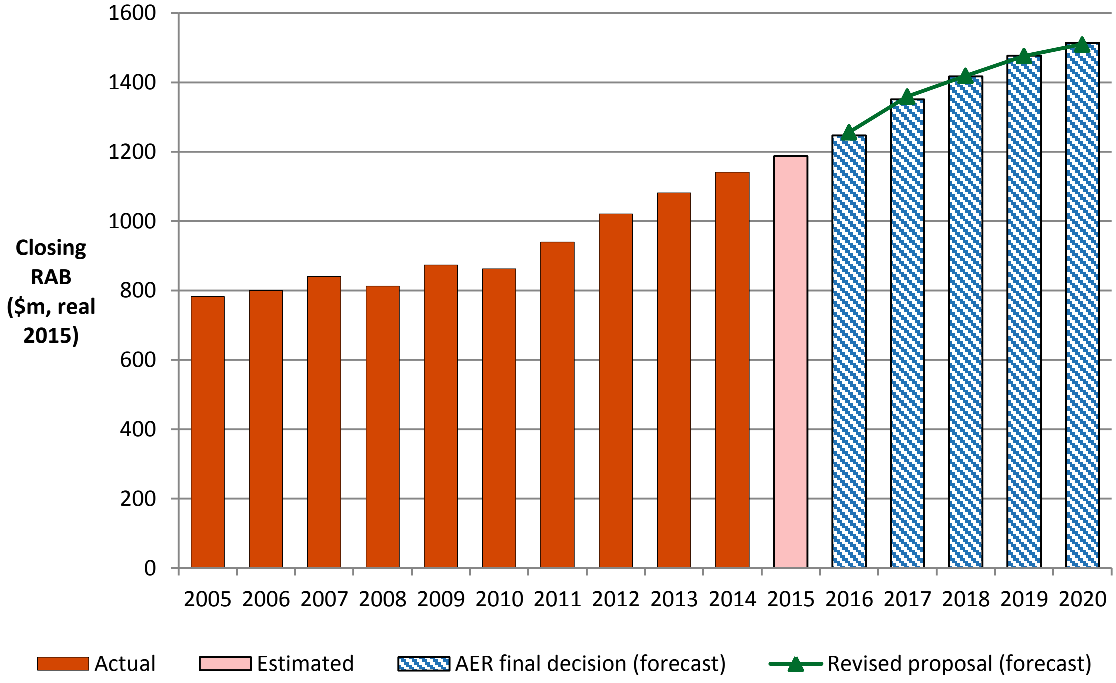
	2016	2017	2018	2019	2020
Opening RAB	1186.8	1277.1	1415.6	1519.1	1619.5
Capital expenditure[b]	145.8	183.4	152.9	154.2	138.1
Inflation indexation on opening RAB	27.6	29.7	32.9	35.3	37.6
Less: straight-line depreciation	83.1	74.5	82.2	89.1	96.9
Closing RAB	1277.1	1415.6	1519.1	1619.5	1698.3

Source: AER analysis.
(a) Net of forecast disposals and capital contributions. Inclusive of equity raising costs and the half-WACC to account for the timing assumption in the PTRM.

We determine a forecast closing RAB value as at 31 December 2020 of $1698.3 million ($ nominal). This is $4.5 million (or 0.3 per cent) higher than the amount of $1693.7 million ($ nominal) Jemena proposed.[12] Our decision on the forecast closing RAB reflects the amended opening RAB as at 1 January 2016, and our decisions on expected inflation (attachment 3) and forecast depreciation (attachment 5). Figure 6 compares our final decision on Jemena's forecast RAB to Jemena's revised proposal and actual RAB in real dollar terms.

12 The higher closing RAB is the result of the higher expected inflation rate (attachment 3) that impacts on the indexation of the RAB, and amendments to some of Jemena's standard asset lives leading to lower forecast straight-line depreciation removed from the RAB (attachment 5).

Figure 6 Jemena's actual RAB, revised proposed forecast RAB and AER final decision forecast RAB ($ million, 2015)



Source: AER analysis.

Details of our decision on the value of the RAB are set out in attachment 2.

3.2 Rate of return (return on capital)

The allowed rate of return provides a network service provider (NSP) a return on capital to service the interest on its loans and give a return on equity to investors.[13] The return on capital building block is calculated as a product of the rate of return and the value of the RAB. The rate of return is discussed in attachment 3.

We are satisfied that the allowed rate of return of 6.37 per cent (nominal vanilla) we determined contributes to the achievement of the NEO, and achieves the allowed rate of return objective set out in the NER.[14] That is, we are satisfied that this allowed rate of return is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to Jemena in providing standard control services.[15]

This allowed rate of return will apply to Jemena for the 2016 regulatory year. A different rate of return will apply to Jemena in each remaining regulatory year of the 2016–20 regulatory control period. This is because we will update the return on debt component of the rate of

13 The term network service provider relates to service providers that provide gas and electricity transmission and distribution services.
14 NER, cl. 6.5.2(b).
15 NER, cl. 6.5.2(c).

return each year to partially reflect prevailing debt market conditions in each year. We discuss this annual update further below.

In its initial and revised proposals, Jemena proposed that we depart from the rate of return guideline (the Guideline) and our preliminary decision on the allowed rate of return for Jemena. Jemena provided further information in support of its revised proposal, which included a change in methodology to the calculation of return on debt. The Australian Competition Tribunal (the Tribunal) also recently reviewed several aspects of our approach to estimating the rate of return that have been contested by Jemena as part of this revenue determination process. While it upheld a number of these, it found error in other aspects of our approach and remitted these matters back to us. On 24 March 2016, we applied to the Federal Court for judicial review of these aspects of the Tribunal's decision.

With respect to the current decision before us, we have considered the information provided by Jemena as well as submissions from stakeholders. However, we are not satisfied that a change in our approach would produce an allowed rate of return that better achieves the allowed rate of return objective. Our reasons are highlighted below and explained in further detail in attachment 3 to this final decision.

Advice from CCP, and submissions by the Consumer Utilities Advocacy Centre, Victorian Energy Consumer and User Alliance, Victorian Government, Energy Retailers Association of Australia and Origin Energy indicated that the Victorian distributors' proposals should not depart from the Guideline, and that their proposed rates of return are excessive given the current investment environment.[16] For example, VECUA stated:

> The distributors' WACC proposals are excessive and are based on major unjustified departures from the AER's Rate of Return Guideline—a guideline that was developed through extensive consultation over a 12 month period with a broad range of stakeholders, including the Victorian distributors.
>
> By contrast, the Victorian distributors' proposed departures have not been submitted to any rigorous analysis or stakeholder consultation. Most of the information used by the Victorian distributors to support their departures was already considered by the AER during the development of the rate of return guideline.[17]

We agree with the following aspects of Jemena's revised rate of return proposal:

- adopting a weighted average of the return on equity and return on debt (WACC) determined on a nominal vanilla basis (as required by the rules)
- adopting a 60 per cent gearing ratio

16 Consumer Challenge Panel – Sub panel 3, Response to AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period, 25 February 2016 (received by AER on 11 March 2016), pp. 75–114; Consumer Utilities Advocacy Centre, Re: Victorian electricity distribution pricing review (EDPR), 2016 to 2020, 13 July 2015; Victorian Energy Consumer and User Alliance, Submission to the AER, Victorian Distribution Networks' 2016–20 Revenue Proposals, July 2015; Victorian Government, Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016–20, 12 February 2016, p. 1; Energy Retailers Association of Australia, Re: Issues paper – Victorian electricity distribution pricing review 2016-2020, 13 July 2015; Origin Energy, Re: Submission to AER Preliminary Decision Victorian Networks, 6 January 2016, p. 3; Origin, Re: Victorian Networks Revised Proposals, 4 February 2016, p. 2.

17 Victorian Energy Consumer and User Alliance, Submission to the AER, Victorian Distribution Networks' 2016–20 Revenue Proposals, July 2015, p. 3.

- adopting a 10 year term for the return on debt
- estimating the return on debt by reference to a third party data series
- estimating the risk free rate using nominal Commonwealth government securities averaged over 20 business days as close as practical to the commencement of the regulatory control period.

However, we are not satisfied that Jemena's proposed (indicative) 8.62 per cent rate of return for the 2016 regulatory year has been determined such that it achieves the allowed rate of return objective.[18]

Our allowed rate of return is a weighted average of our return on equity and return on debt estimates (WACC) determined on a nominal vanilla basis that is consistent with our estimate of the value of imputation credits.[19] Also, in arriving at our decision we have taken into account the revenue and pricing principles (RPPs) set out in the NEL and are also satisfied that our decision will or is likely to contribute to the achievement of the National Electricity Objective (NEO).[20] Our rate of return and Jemena's proposed rate of return are set out in Table 6.

Table 6 Final decision on Jemena's rate of return (% nominal)

	AER previous decision (2011–15)	Jemena revised proposal (2016)	AER final decision (2016)	Allowed return over 2016–20 regulatory period
Return on equity (nominal post–tax)	10.85	9.89	7.5	Constant (7.5%)
Return on debt (nominal pre–tax)	9.99	7.77	5.62	Updated annually
Gearing	60	60	60	Constant (60%)
Nominal vanilla WACC	10.33	8.62	6.37	Updated annually for return on debt
Expected inflation	2.57	2.19	2.32	Constant (2.32 %)

Source: AER analysis; Jemena, 2016 to 2020 electricity distribution price review regulatory proposal: Revocation and substitution submission, 6 January 2016; AER, Jemena Electricity Networks (Victoria) Ltd distribution determination 2011–2015: Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited (No 2) [2012] ACompT 8, September 2012, p. 30.

Our return on equity estimate is 7.5 per cent. Consistent with the Guideline, the return on equity remains constant over the regulatory control period. Our return on equity point estimate and the parameter inputs are set out in Table 7. Jemena proposed departing from the approach in the Guideline. We are not satisfied that doing so would result in an outcome

18 Jemena, 2016 to 2020 electricity distribution price review regulatory proposal: Revocation and substitution submission, 6 January 2016, p. 26.

19 NER, cl. 6.5.2(d)(1) and (2).

20 NEL, s.16.

that better achieves the allowed rate of return objective.[21] We do not agree with Jemena that our method applied in the preliminary decision will result in a return on equity which is inconsistent with the allowed rate of return objective.[22] Our return on equity preliminary decision and this final decision is largely consistent with the views in the Guideline.

Table 7 Final decision on Jemena's return on equity (nominal)

	AER previous decision (2011–15)	Jemena revised proposal (2016–20)	AER final decision (2016–20)
Nominal risk free rate (return on equity only)	5.65%	2.75%*	2.93%**
Equity risk premium	5.20%	7.19%	4.55%
MRP	6.50%	7.90%	6.50%
Equity beta	0.8	0.91	0.7
Nominal post–tax return on equity	10.85%	9.89%	7.5%

Source: AER analysis; Jemena, Revocation and substitution submission Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016; AER, Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015, October 2010.

* Calculated with a placeholder averaging period of 20 business days to 30 September 2015.

** Calculated with an averaging period of 20 business days up to 11 December 2015 agreed upon in advance of its commencement.

Our return on debt estimate for the 2016 regulatory year is 5.62 per cent. This estimate will change each year as we partially update the return on debt to reflect prevailing interest rates over Jemena's debt averaging period in each year. Our return on debt estimate for future regulatory years will be determined in accordance with the methodology and formulae we have specified in this decision. As a result of updating the return on debt each year, the overall rate of return and consequently Jemena's revenue will also be updated.

Consistent with our preliminary decision, we agree there should be a transition from the on-the-day approach to the trailing averaging approach. However, we disagree with the hybrid form of transition proposed in Jemena's (initial) regulatory proposal. In its revised proposal, Jemena departed from its initial position to apply a transition to the trailing averaging approach. It now proposes to not apply a transition (that is, to immediately move to a trailing average approach). We also disagree with Jemena on this approach.

Consistent with our preliminary decision, we apply a transition to both the base rate and debt risk premium components of the return on debt as per the Guideline.

Our final decision on the return on debt approach is to:

- estimate an on-the-day rate (that is, based on prevailing market conditions) in the first regulatory year (2016) of the 2016–20 regulatory control period, and

21 NER, cl. 6.2.8(c)

22 Jemena, 2016 to 2020 electricity distribution price review regulatory proposal: Revocation and substitution submission, 6 January 2016, pp. 31, 34.

- gradually transition this rate into a trailing average approach (that is, a moving historical average) over 10 years.[23]

3.3 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[24] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore valuable to investors and are a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

However, the estimation of the return on equity does not take imputation credits into account.[25] Therefore, an adjustment for the value of imputation credits is required. This adjustment could take the form of a decrease in the estimated return on equity itself. An alternative but equivalent form of adjustment, which is employed under the NER, is via the revenue granted to a service provider to cover its expected tax liability. Specifically, the NER require that the estimated cost of corporate income tax be determined in accordance with a formula that reduces the estimated cost of corporate tax by the 'value of imputation credits' (represented by the Greek letter, γ, 'gamma').[26] This form of adjustment recognises that it is the payment of corporate tax which is the source of the imputation credit return to investors.

We adopt a value of imputation credits of 0.4 for this decision, based on our conceptual approach and a wide range of relevant evidence. Estimating the value of imputation credits is a complex and imprecise task, and as such, requires the use of regulatory judgement. There is no consensus among experts on the appropriate value or estimation techniques to use. Conceptually, the value of imputation credits must be between 0 and 1, and the range of expert views on the value of imputation credits is almost this wide.

We do not accept Jemena's proposed value of imputation credits of 0.25.[27] We assessed its reasoning in its revised proposal, and respond in detail in attachment 4. After Jemena submitted its revised proposal, a number of service providers made late submissions.[28]

---

23 This final decision determines the return on debt methodology for the 2016–20 regulatory control period. This period covers the first five years of the 10 year transition period. This decision also sets out our intended return on debt methodology for the remaining five years. However, we do not have the power to determine in this decision the return on debt methodology for those years. Under the NER, the return on debt methodology must be determined in future decisions that relate to that period.

24 Income Tax Assessment Act 1997, parts 3–6.

25 While the return on equity is not reduced to take into account the value of imputation credits, we note our estimate of the MRP does consider the value we use for imputation credits to ensure it reflects the value to investors in the domestic Australian market inclusive of credits.

26 NER, cll. 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3.

27 JEN, Revised regulatory proposal: Attachment 6-1—Rate of return, gamma, forecast inflation, and debt and equity raising costs, January 2016, pp. 85–105.

28 United Energy, Submission on AER preliminary determination - Submission on gamma, 26 April 2016; CitiPower/Powercor, Submission on implications of recent Australian Competition Tribunal Decision, 18 April 2016; ActewAGL, Implication of recent Tribunal decisions for final decision and updates to the allowed rate of return and forecast inflation estimate, 12 May 2016.

These late submissions asked us to take into account a range of issues identified in the recent Australian Competition Tribunal (the Tribunal) decisions for ActewAGL Distribution, Ausgrid, Endeavour Energy, Essential Energy and Jemena Gas Networks.[29] We have considered these submissions as fully as possible in the limited time permitted, and we set out our response in attachment 4. We also sought expert advice from Dr Martin Lally (Lally), in response to the issues raised in these submissions.[30]

In light of the above, in coming to a value of imputation credits of 0.4:

- We adopt a conceptual approach consistent with the Officer framework, which we consider best promotes the objectives and requirements of the NER. We consider this conceptual approach allows for the value of imputation credits to be estimated on a consistent basis with the allowed rate of return and allowed revenues under the post-tax framework in the NER.[31]
- We use the widely accepted approach of estimating the value of imputation credits as the product of two sub-parameters: the 'distribution rate' and the 'utilisation rate'. We use a wide range of relevant evidence to estimate these parameters, having regard to expert advice on each source of relevant evidence.
- Overall, the evidence suggests a range of estimates for the value of imputation credits might be reasonable. With regard to the merits of the evidence before us, we choose a value of imputation credits of 0.4 from within a range of 0.3 to 0.5.
- Lally's latest advice recommended a value of imputation credits of at least 0.5. This is higher than the estimate of 0.4 we adopt in this decision. We maintain our approach and final estimate because we consider it meets the requirements of the NER, taking into account the importance of regulatory certainty and predictability.

We elaborate on our reasons for this decision in attachment 4.

3.4 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital) (box 1). We are required to decide whether to approve the depreciation schedules submitted by Jemena.[32] In doing so, we make a determination on the indexation of the RAB and depreciation building blocks for Jemena's 2016−20 regulatory control period.

29 For example, see Australian Competition Tribunal, Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, 26 February 2016, para 1(c).

30 Lally, Gamma and the ACT Decision, May 2016.

31 In finance, the consistency principle requires that the definition of the cash flows in the numerator of a net present value (NPV) calculation must match the definition of the discount rate (or rate of return / cost of capital) in the denominator of the calculation (see Peirson, Brown, Easton, Howard, Pinder, Business Finance, McGraw-Hill, Ed. 10, 2009, p. 427). By maintaining this consistency principle, we provide a benchmark efficient entity with an ex ante total return (inclusive of the value of imputation credits) commensurate with the efficient financing costs of a benchmark efficient entity

32 NER, cl. 6.12.1(8).

Box 1: What is depreciation?

Regulated service providers invest in large sunk assets to provide electricity distribution services to customers. While some of the cost of such assets may be recovered from customers upfront, a greater proportion is recovered over time. A depreciation charge is used for this purpose. This is particularly important for long-lived assets, since it spreads the cost across the current and future customers who benefit from the use of the asset.

Depreciation reflects the use of an asset each year and accounts for its loss of value due to wear and tear over its useful life.[33] Some assets, such as land, are not depreciated as they have an unlimited useful life.[34]

For assets that do depreciate, there are several methods that can be employed to calculate the annual depreciation amount. Under a 'straight-line approach', the asset is reduced by a constant amount each period. That is, the asset value is depreciated evenly over its useful life. Alternatively, under a 'diminishing value approach', a constant percentage is applied to the asset value to work out the annual depreciation amount.[35] Applying a constant percentage leads to a reducing annual depreciation amount over time as the asset value declines.

Our decision is to determine a regulatory depreciation allowance of $262.9 million ($ nominal) for Jemena.[36] This amount represents a decrease of $19.7 million or 7.0 per cent from the $282.5 million ($ nominal) Jemena proposed for the 2016–20 regulatory control period.[37] It represents an increase of $25.2 million or 10.6 per cent from the $237.7 million ($ nominal) in our preliminary decision.

Our final decision implements straight-line depreciation using the year-by-year tracking approach, which is the same approach used in Jemena's revised proposal and our preliminary decision. Straight-line depreciation is often implemented using an approach known as weighted average remaining life (WARL). The key difference is that WARL makes one depreciation calculation for all assets in an asset class, but year-by-year tracking performs multiple depreciation calculations within each asset class, disaggregating assets by year of expenditure. Both these approaches ensure that the initial capital investment is recovered (in real terms) over the lives of the assets, without over or under recovery.

The use of WARL remains our preferred approach because it meets the requirements of the NER and avoids the additional complexity inherent in year-by-year tracking. However, because year-by-year tracking also meets the requirements of the NER, we must accept Jemena's revised proposal to use this approach. The transition to year-by-year tracking

33 NER, cl. 6.5.5(b)

34 For example, see Australian Accounting Standards Board, *AASB 116, Property, plant and equipment*, December 2015, paragraph 58.

35 For example, an asset with 10 year life could have a depreciation percentage of 10 per cent (i.e. 1/10) applied to the remaining asset value each year. This percentage may also have a multiple applied. For example, tax law may allow the 10 per cent to be doubled to 20 per cent for certain assets. The higher the multiple applied, the greater the decrease in the value of the asset early in its life due to faster depreciation.

36 These figures reflect the regulatory depreciation building block allowance, which is calculated as straight-line depreciation less the indexation adjustment on the RAB. The straight-line depreciation figures are presented in the second row of table 8 below.

37 Jemena, *Revised regulatory proposal*, January 2016, Attachment 05-02 (PTRM).

produces a slight increase in the regulatory depreciation allowance for the 2016–20 regulatory control period, as a by-product of discontinuing the aggregation that previously occurred.

We accept Jemena's proposed asset classes, its straight-line depreciation method, and its method to determine the standard asset lives used to calculate the regulatory depreciation allowance.[38] The adoption of year-by-year tracking means it is no longer necessary to explicitly calculate remaining asset lives as at 1 January 2016.

We have made determinations on other components of Jemena's proposal that also affect the forecast regulatory depreciation allowance—for example, expected inflation (attachment 3) and the opening RAB value (attachment 2).[39]

Table 8 sets out our decision on Jemena’s depreciation allowance for 2016–20.

Table 8 AER's decision on Jemena’s depreciation allowance for 2016−20 regulatory control period ($ million, nominal)

	2016	2017	2018	2019	2020	Total
Straight-line depreciation	83.1	74.5	82.2	89.1	96.9	425.9
Less: inflation indexation on opening RAB	27.6	29.7	32.9	35.3	37.6	163.0
Regulatory depreciation	**55.5**	**44.9**	**49.3**	**53.8**	**59.3**	**262.9**

Source: AER analysis.

3.5 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of network services. The return on and return of forecast capex for standard control services are two of the building blocks we use to determine a service provider's total revenue requirement.

We estimate total capex of $709.3 million ($2015) for Jemena’s 2016−20 regulatory control period—which consistent with Jemena’s revised proposal. We are satisfied Jemena’s total forecast capex reasonably reflects the capex criteria. Our decision represents an increase of $37.2 million (or 5.5 per cent) from our preliminary decision. Table 9 shows our decision compared to Jemena’s forecast.

Table 9 AER decision on total net capex ($ million 2015)

	2016	2017	2018	2019	2020	Total
Jemena's revised proposal	138.1	172.0	140.1	138.2	120.9	709.3
AER decision	138.1	172.0	140.1	138.2	120.9	709.3

38 The standard asset lives are used to depreciate forecast capex. While we accept Jemena's method to determine its standard asset lives, we identified a number of input errors impacting the standard asset lives of the 'Subtransmission' and 'Distribution system assets' asset classes that were corrected in our final decision.

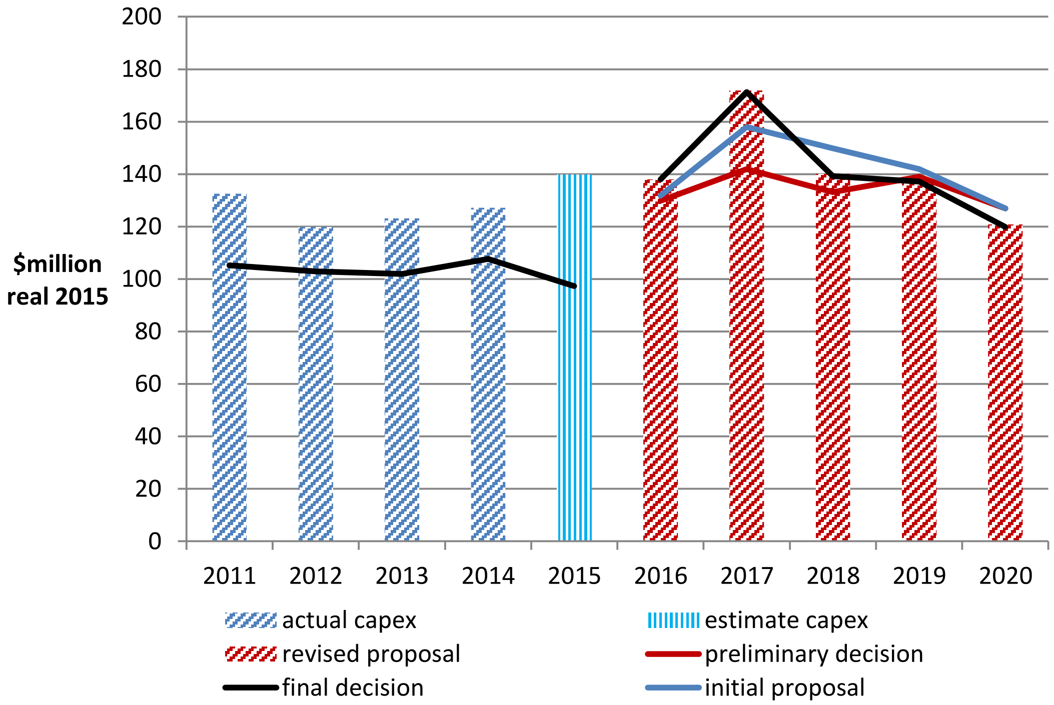
39 NER, cl. 6.5.5(a)(1).

Difference	0.0	0.0	0.0	0.0	0.0	0.0
Percentage difference (%)	0.0	0.0	0.0	0.0	0.0	0.0

Source: AER analysis.
Note: Numbers may not add up due to rounding.
Note: The figures above do not include equity raising costs. For our assessment of equity raising costs, see attachment 3.

Figure 7 shows our capex decision compared to Jemena's proposal, its past allowances and past actual expenditure.

Figure 7 Jemena total actual and forecast capex 2011–2020



The key points of our capex decision for Jemena are:[40]

- We accept Jemena's revised replacement expenditure (repex) forecast, although we have included the Preston upgrade project as augmentation expenditure (augex). After this re-categorisation, our alternative estimate of total capex includes $228.1 million ($2015) for repex.
- We have included a forecast of augex of $132 million ($2015). We accept Jemena's revised forecast of $104.6, and have also included additional capex to upgrade its Preston network.
    - We have accepted Jemena's proposed $27.5 million for its Preston conversion project. While the information presented with the initial proposal was insufficient to justify the inclusion of the project, the new information and cost benefit analyses submitted with the revised proposal support its inclusion in the final decision. While

40 We obtained Jemena's proposed capex figures from its RIN. Our assessment used information from information subsequently provided by Jemena.

    the categorisation has no impact on our total capex decision, we recognise that this project is driven by asset condition but will also upgrade the network and so we have included it as augex.

  - This augex decision reflects a softening of demand for electricity in Victoria, which means less pressure on the business to expand the capacity of its network—albeit with some 'pockets' of high growth, such as the Northern and North-Western corridors of Jemena's network.[41]
  - Reductions to energy consumers' Value of Customer Reliability also reduce the need to build new infrastructure to meet customers' expectations of reliable electricity.[42]

- We have included the amount Jemena forecast for connections capex of $172.1 million ($2015) in our capex decision. Our preliminary decision accepted Jemena's proposed gross connection capex. However, we considered that the Melbourne airport expansion was better characterised as augmentation and we included it in this category in our preliminary decision.
  - In its revised proposal Jemena accepted our preliminary decision for gross connections capex. Jemena also reassessed the scope of the Melbourne Airport precinct project and re-categorised all components of this expenditure as connections capex. Jemena now forecasts that the funding for the Melbourne Airport precinct project will come through an upfront customer contribution and future customer-specific tariffs and will therefore not be funded by all customers.
  - We assessed Jemena's supporting material regarding the Melbourne Airport expansion and we are satisfied that Jemena has demonstrated that the amount it has forecast represents connections capex and reasonably reflects the capex criteria.
- We have accepted Jemena's revised proposal of $153.2 million ($2015) for customer contributions capex forecast. Jemena in its revised proposal notes that the increased forecasts is based on:
  - including $29.9 million of customer contributions associated with special capital works relating to relocating assets which was categorised as repex but not included in the preliminary decision
  - updates to the customer mix in its revised proposal on the basis of its updated customer number forecasts
  - including the Melbourne Airport precinct project as connections capex that was previously augex

41 Maximum demand for electricity is a key driver of the level of investment required in a regulatory period. Developments in the Australian and Victorian electricity markets in recent years have influenced electricity consumption patterns and led to a softening of maximum demand. These include household installations of photo-voltaic (PV) cells, changing customer behaviours and the increased focus on energy efficiency. This means that Jemena is likely to be under less pressure to expand its network than in previous regulatory periods to meet the needs of additional customers or any increased demand from existing customers.

42 In planning network augmentation, the Victorian businesses apply a measure of customers' willingness to pay, in dollar terms, for the reliable supply of electricity—known as the Value of Customer Reliability (VCR). This allows the businesses to compare the economic cost to customers from network outages against the cost of augmenting the network. This is a commonly used assessment and reflects good industry practice.

    - changes arising from the transition from Guideline 14 to NER chapter 5A.
    - We examined each of the above changes to its proposal in turn and we are satisfied that the forecast is a realistic expectation of the customer contributions Jemena will receive over the 2016–20 regulatory control period.
- We accepted Jemena's estimate of non-network capex of $161.7 million ($2015) and have included it in our alternative estimate of capex.

The detailed reasons for our final decision on Jemena's capex are set out in attachment 6 of this decision.

3.6 Operating expenditure

Operating expenditure (opex) is the costs of running an electricity distribution network and maintaining its assets. It includes labour and other non-capital costs.

We are not satisfied Jemena's forecast opex of $470.9 million ($2015) over the 2016–20 regulatory control period reasonably reflects the opex criteria. We have determined an alternative estimate of total opex of $452.3 million ($2015).

We have increased our opex forecast by $62.2 ($2015) million from our preliminary decision. The difference between our preliminary and final decisions largely reflects a decision to allow a proportion of smart metering costs to be allocated to SCS from ACS, as well as the inclusion of six additional step changes.

Attachment 7 sets out our detailed reasons for our decision on Jemena's total forecast opex. We compare our estimate with Jemena's proposal in table 10.

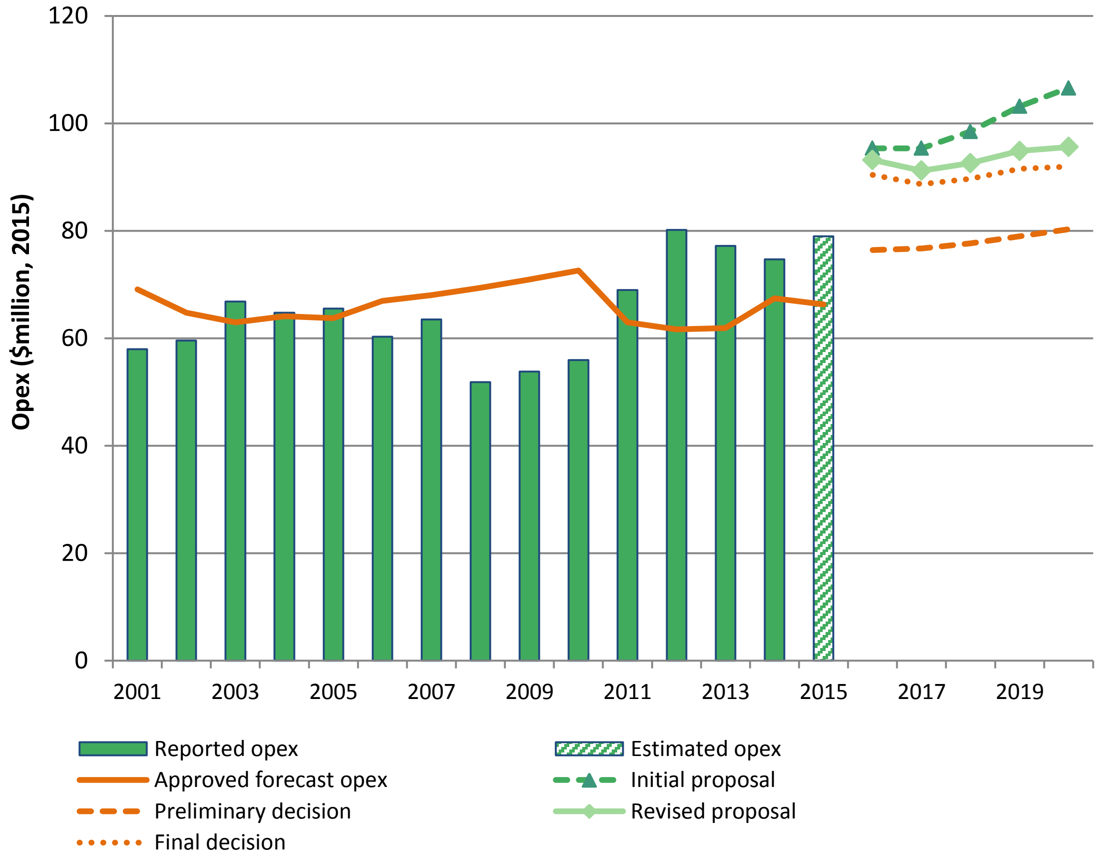
Table 10 AER decision on total opex ($ million, 2015)

Year ending 30 June	2016	2017	2018	2019	2020	Total
Jemena proposal	95.4	95.4	98.5	103.2	106.6	499.0
AER preliminary decision	76.4	76.7	77.7	79.0	80.3	390.1
Jemena revised proposal	93.8	91.8	93.3	95.6	96.4	470.9
AER decision	90.4	88.7	89.7	91.5	92.0	452.3
Difference	–3.4	–3.2	–3.6	–4.1	–4.4	–18.6

Source: AER analysis.
Noted: Includes debt raising costs. Excludes DMIA.

Figure 8 shows our decision compared to Jemena's proposal, its past allowances and past actual expenditure.

Figure 8 AER decision compared to Jemena's past and proposed opex ($ million, 2015)[43]



Source: AER analysis

Note: standard control services

3.6.1 The components of our estimate of opex

We have used Jemena's actual opex for 2014 as the basis for forecasting total opex. Based on our benchmarking results we find that Jemena has been operating relatively efficiently—such that we can use Jemena's 2014 opex as a basis for assessing overall forecasts going forward. This is referred to as the revealed cost approach.

However, as discussed below we have included an adjustment to reflect the change in service classification for some advanced metering infrastructure (AMI) opex from alternative control services to standard control services. The impact of this reallocation is revenue neutral, for the reasons discussed in the section below.

To this base level of opex, we have applied a forecast annual rate of change that accounts for the forecast change in opex due to price, output and productivity growth over the regulatory control period. Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than Jemena's estimate over the forecast period.

43

Jemena used the forecast price change we determined in our preliminary decision in its revised regulatory proposal. However, it did not update its forecast of labour price growth to account for changes in economic conditions since we published our preliminary decision. Our preliminary decision used an average of the WPI growth rates forecast by Deloitte Access Economics (DAE) prepared in June 2015 and BIS Shrapnel prepared in November 2014. Our updated forecast uses an average of forecasts from DAE prepared in February 2016 and CIE prepared in November 2015.

Jemena forecast higher output growth due to a higher forecast growth in customer numbers. Jemena forecast future customer numbers using a projection of population growth in local government areas. We used historical growth in customer numbers to forecast future growth. Also, Jemena did not ratchet its maximum demand forecast.[44]

Jemena identified a number of cost drivers that it considers will require increased opex over the forecast period. We refer to these cost drivers as possible ‘step changes’. Step changes may be for cost drivers such as new, changed or removed regulatory obligations, or efficient capex/opex trade-offs. We typically compensate a network business for step changes only if efficient base year opex, and the rate of change in opex of an efficient service provider, do not already compensate the business for the proposed costs.[45]

Jemena proposed $27.7 million for step changes in its revised proposal, of which we have accepted $17.1 million. We have included step changes in our final decision opex forecast for the following proposals:

- service testing and inspection program
- enclosed substation inspection and rectification
- vegetation management
- demand management opex/capex trade-off
- new tariff implementation
- new RIN reporting requirements
- power of choice
- adoption of chapter 5A.

The majority of these step changes relate to the costs of complying with new or changed regulatory obligations.

3.6.2 Advanced metering infrastructure

Victorian energy consumers have made a substantial investment in advanced metering infrastructure (AMI)—also known as 'smart meters'. Smart meters can record electricity usage every 30 minutes and give customers access to accurate real-time information about their electricity consumption. The rollout of AMI required an upgrade of the network as well as metering replacement.

44 Ratcheted maximum demand is the highest value of maximum demand observed up to the year in question.

45 AER, Expenditure Forecast Assessment Guideline, November 2013, p. 24.

The costs for the installation and operation of the smart meters were previously regulated under an 'Order in Council'. This meant cost recovery for these services was separate to the network charges derived from our revenue determination processes.

The smart meter rollout is now largely completed so the Victorian distributors have entered a 'business-as-usual' phase. The capex component for metering will fall in 2016–20, although opex is still required to maintain the metering infrastructure.

As part of this decision, we considered how certain AMI costs should be allocated between standard control services (SCS) and alternative control services (ACS).

A portion of these costs (54 per cent) have been allocated to SCS because some of the IT systems, for example, customer information and billing systems, support network services.[46] This is a departure from our preliminary decision, which allocated 100 per cent of AMI costs to ACS. This decision increases Jemena's opex allowance by $44.7 million (10 per cent) from the amount included in our preliminary decision but leads to a similar reduction in Jemena's opex allowance for metering.

Further details on our allocation of AMI costs are provided in box 2 and attachment 7.

Box 2: Allocation of smart metering costs to standard control services

Standard control services are services that are central to electricity supply and therefore relied on by most (if not all) customers, such as building and maintaining the shared distribution network.

Alternative control services are customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor.

The two types of services are treated differently in a regulatory context. We regulate standard control services by determining prices or an overall cap on the amount of revenue that may be earned. The costs associated with these services are shared by all customers via their regular electricity bill. We regulate alternative control services by setting service specific prices to enable the distributor to recover the efficient cost of each service from customers using that service.

The Victorian distribution businesses allocated a significant amount of opex for smart metering or 'AMI' under standard control services in their regulatory proposals for 2016–20.

Our preliminary decision rejected the allocation of AMI costs to standard control services. Instead, we allocated 100 per cent of these costs to alternative control services. We noted that until we issue a new distribution ring fencing guideline that sets out how metering costs should be treated, we considered all costs formerly regulated under the AMI Order in Council should be allocated to alternative control services. We considered this approach would also assist in promoting transparency around trends in AMI and standard control expenditure.

The businesses opposed our preliminary decision to allocate all AMI costs to alternative control services. In support of their position, the businesses highlighted that a number of the IT systems rolled out as part of the AMI service would be needed even if the businesses did not provide a metering service. The businesses expressed the view that the forthcoming ring fencing guideline was not relevant to our decision on the appropriate allocation of AMI costs as part of these determinations. Such a delay, the businesses argued, may also create distortions in the market for metering services,

46 The remaining 46 per cent will be recovered through annual metering charges.

which will soon be opened up to competition.

The Victorian Government submitted that a portion of AMI costs should be allocated back to standard control services rather than alternative control services. The Consumer Challenge Panel (CCP) and Vector, on the other hand, agreed with our preliminary decision.

We have reviewed the businesses' revised proposals and supplementary information provided. EMCa provided us with analysis and advice that we considered in arriving at our final decision.[47] EMCa advised that costs should be directly attributed (to distribution network SCS or metering ACS) only where the relevant systems are solely used to provide that service or where use for the other services can be considered immaterial as defined by Australian accounting standards. Where costs are shared and material, it recommended the costs be allocated on a causal basis. We agree with this approach and have implemented it in reaching our final decision.

For instance, customer information systems and network billing systems are allocated solely to SCS because these systems are solely used to support SCS. On the other hand, all communications costs are allocated to metering ACS on the basis that these systems were primarily put in place to support the remote collection of metering data.

3.7 Corporate income tax

The NER requires us to make a decision on the estimated cost of corporate income tax for Jemena's 2016–20 regulatory control period.[48] The estimated cost of corporate income tax contributes to our revenue decision. It enables Jemena to recover the costs associated with the estimated corporate income tax payable during the regulatory control period.

As shown by Table 11, our decision on the estimated cost of corporate income tax is $76.8 million ($ nominal) for Jemena over the 2016–20 regulatory control period. This amount represents a decrease of $52.0 million or 40.4 per cent from the $128.8 million ($ nominal) in Jemena's revised proposal.[49] Our decision represents an increase of $13.8 million (or 21.9 per cent) from the $62.9 million estimated cost of corporate income tax in our preliminary decision.

Table 11 AER's decision on Jemena's cost of corporate income tax allowance for 2016–20 regulatory control period ($ million, nominal)

	2016	2017	2018	2019	2020	Total
Tax payable	29.4	23.9	23.6	25.2	25.9	127.9
Less: value of imputation credits	11.7	9.5	9.5	10.1	10.4	51.2
Corporate income tax allowance	**17.6**	**14.3**	**14.2**	**15.1**	**15.5**	**76.8**

Source: AER analysis.

Our decision reflects our amendments to some of Jemena's proposed inputs for forecasting the cost of corporate income tax such as the opening tax asset base and the remaining tax asset lives. It also reflects our decision on the value of imputation credits—gamma—

47 EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016.
48 NER, cl. 6.4.3(a)(4).
49 Jemena, *Revised regulatory proposal*, January 2016, Attachment 05–02 (PTRM).

(attachment 4). Changes to the building block costs also affect revenues, which in turn impacts the tax calculation. The changes affecting revenues are discussed in attachment 1.

Details of our decision on the corporate income tax allowance are set out in attachment 8.

4 Service classification, control mechanisms and incentive schemes

This section explains our approach to service classification (section 4.1), the forms of regulation to apply (section 4.2) and incentive schemes to promote efficiency (section 4.3).

4.1 Classification of services

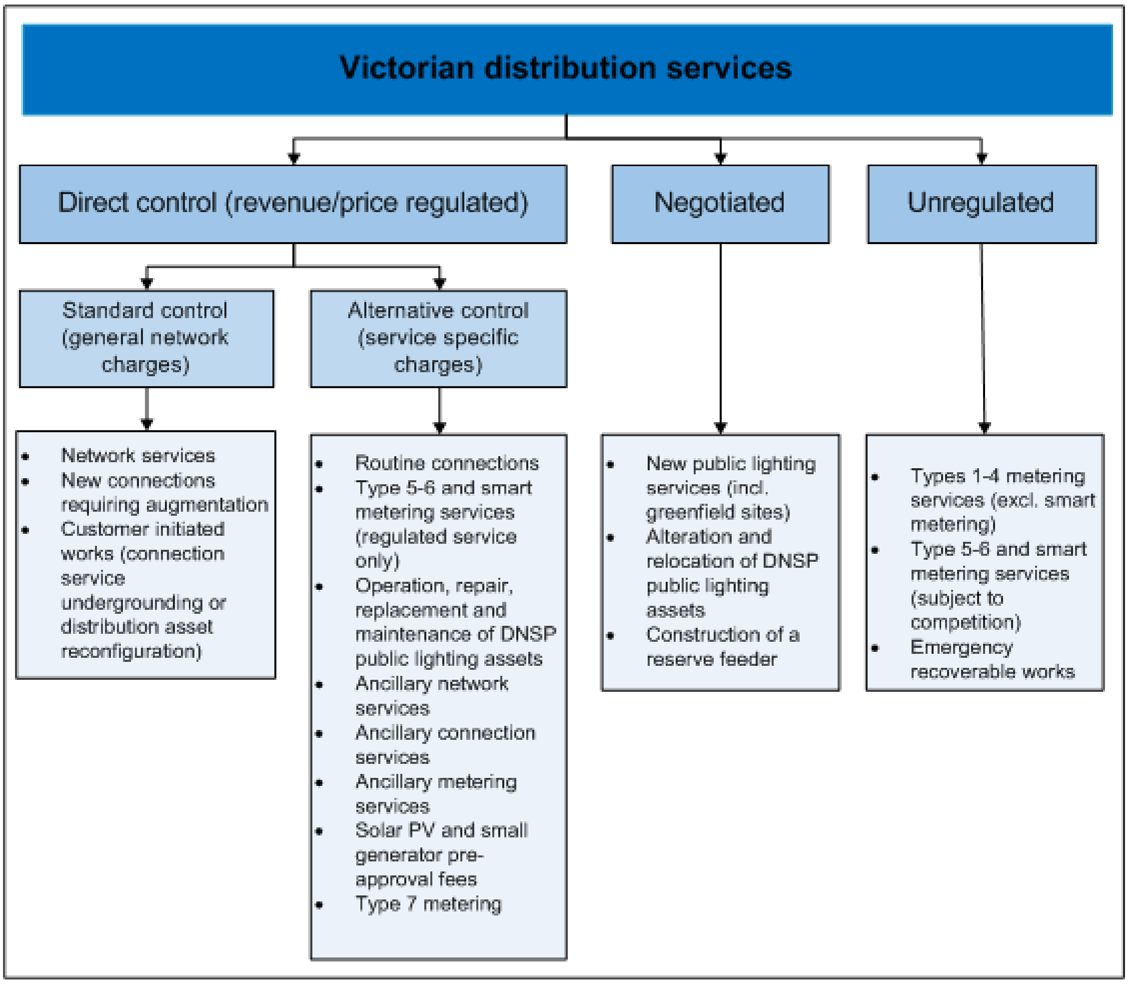
Service classification is inherently linked to the type of economic regulation, if any, to apply to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our decision on service classification reflects our assessment of a number of factors, including existing and potential competition to supply these services.

Services are classified as either 'direct control', 'negotiated' or 'unregulated' services.

- Direct control services are services where we directly control prices by setting a revenue cap or the prices a distributor may charge. These services can be further split by 'standard control' and 'alternative control' services. Our decision on the forms of regulation to apply to standard control and alternative control services is outlined in the following section.
  - Standard control services are services that are central to electricity supply and therefore relied on by most (if not all) customers.
  - Alternative control services are customer specific or customer requested services.
- Negotiated services are services that require a less prescriptive regulatory approach because the relevant parties have sufficient market power to negotiate the provision of those services. Distributors and customers are able to negotiate prices, and we are available to arbitrate if necessary.
- Unregulated services are services that are not distribution services, or services that are contestable and therefore do not need to be regulated. We have no role in regulating these services.

Figure 9 summarises our decision on service classification for Jemena for the 2016–20 regulatory control period.

Figure 9 AER decision on 2016–20 service classifications for Jemena



4.2 Regulatory control mechanisms

This section sets out our decision on the type of regulation to apply to standard control services (section 4.2.1) and alternative control services (section 4.2.2).

4.2.1 Standard control services

We have decided Jemena will be subject to a 'revenue cap' form of control for standard control services over the next regulatory control period. This decision is consistent with our final framework and approach (F&A).[50]

The control mechanism, which describes how the revenues will vary from year to year, is discussed in attachments 14 and 16. The control mechanism for standard control services is described in mathematical terms and reflects all possible adjustments that might be made to the revenue cap.

50 The F&A is the first step in our determination of a business' allowable revenue. The F&A determines, amongst other things, which services we will regulate and the broad nature of the regulatory arrangements. AER, Final framework and approach for the Victorian Electricity Distributors – Regulatory control period commencing 1 January 2016, October 2014.

4.2.2 Alternative control services

Alternative control services (ACS) do not form part of a business' revenue cap. Rather, the prices of these services are generally set individually.

Our decision for services other than metering is that the form of control mechanism to apply will be price caps. We have decided a revenue cap will operate for metering services during the 2016–20 regulatory control period. This decision is consistent with our F&A. As per past regulatory practice, Jemena must demonstrate compliance with the control mechanism through an annual pricing proposal.

We have set charges for fee based and quoted services that reflect the costs incurred by Jemena to provide these services. Jemena only earns revenues on these activities where they are specifically requested by individual customers. Further details on our decision on alternative control services are in attachment 16.

The charges for public lighting have been set on the same basis as the 2011–15 regulatory control period. That is with Jemena operating, maintaining and replacing luminaires it owns on behalf of municipal councils in its distribution area. It does this in accordance with both our decision and the Public Lighting Code. There has been an increase in charges as a result of higher opex, mostly associated with the growth in labour costs.

The AMI rollout that commenced in 2009 under an Order in Council (the Order) is now largely completed. In the 2016–20 regulatory control period, metering in Victoria is entering a 'business-as-usual' phase.

For metering services, we have set charges that recover the efficient opex and capex associated with the ongoing provision of meters to customers from 2016. This means that we regulate metering services under the NEL and NER, subject to certain modifications set out in the Order. Those modifications contain the requirement for us to set meter restoration and exit fees. None of the businesses proposed meter restoration fees. We have set exit fees in this decision—see attachment 16.

The completion of the AMI roll out means that Jemena needs less revenue to provide metering services. Our final decision on the approved revenue requirement results in a decrease in metering charges.

As discussed in section 2.2.4, we have allocated 46 per cent of AMI costs to ACS for IT and communications costs partly incurred in providing AMI services.

4.3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. The incentive schemes that will apply to Jemena are:

- efficiency benefit sharing scheme (EBSS)
- capital expenditure sharing scheme (CESS)
- service target performance incentive scheme (STPIS)
- demand management incentive scheme (DMIS)

- f-factor scheme.

Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced with the incentives under our STPIS. This encourages businesses to make efficient decisions on when and what type of expenditure to incur, and meet service reliability targets.

4.3.1 Efficiency benefit sharing scheme

The EBSS provides an incentive for service providers to pursue efficiency improvements in opex.

As opex is largely recurrent and predictable, opex in one period is often a good indicator of opex in the next period.[51] Where a service provider is relatively efficient, we use the actual opex it incurred in a chosen base year of the regulatory control period to forecast opex for the next regulatory control period. We call this the 'revealed cost approach'.

However, using a network business' past information to set future targets can reduce the incentives of the business to reduce its costs—since the business knows that any cut in its expenditure will decrease its revenue allowance in the future.

To encourage a business to become more efficient it is allowed to keep any difference between its approved forecast and its actual opex during a regulatory control period. This is supplemented by the EBSS which allows the distributor to retain efficiency savings and losses for a longer period of time. In this way, the EBSS can provide businesses with an additional reward for reductions in opex and additional penalties for increases in opex.

Under the EBSS, a business gets to keep the benefits of any efficiency gains for a full five year period, but after that all the gains are passed on to consumers in the form of lower network charges. Efficiency gains made in year 1 or 2 of the regulatory period benefit the business as much as efficiency gains made in year 4 or 5. This ensures the business faces a continuous incentive to pursue efficiency gains over the regulatory control period. The EBSS also discourages a service provider from inflating its base year opex in order to receive a higher opex allowance in the following regulatory control period.[52]

Our final decision for the EBSS carryover amounts from the application of the EBSS in the 2011–15 regulatory control period is outlined in table 12. It is consistent with our preliminary decision which Jemena accepted in its revised proposal (updated for the most recent CPI).[53]

Table 12 AER's decision on Jemena's EBSS carryover amounts ($ million, 2015)

	2016	2017	2018	2019	2020	Total

51 Step changes provide for increases where this is not the case.

52 These concepts are explained more fully in the explanatory statement to the EBSS, AER, Efficiency benefit sharing scheme for electricity network service providers - explanatory statement, November 2013.

53 Jemena, Revised regulatory proposal, Attachment 3-1 Incentive Schemes, January 2016, p. 7.

Jemena proposal	5.3	0.0	10.5	7.2	0.0	23.0
AER preliminary decision	5.0	–0.1	11.3	8.8	0.0	24.9
Jemena revised proposal	5.3	0.3	10.9	8.3	0.0	24.8
AER final decision	**5.1**	**–0.1**	**11.4**	**8.8**	**0.0**	**25.1**

Note: The small difference between Jemena's revised carryover amount and our preliminary decision is due to the way it adjusted forecast and actual opex for inflation. The increase in the final decision reflects the most recent CPI.

Our decision is to apply version two of the EBSS to Jemena in the 2016–20 regulatory control period.[54] This decision is consistent with our preliminary decision. Our decision on the EBSS is outlined in attachment 9.

4.3.2 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides an incentive for service providers to pursue efficiency improvements in capex. Similar to the EBSS, the CESS provides a network service provider with the same reward for an efficiency saving and same penalty for an efficiency loss regardless of which year they make the saving or loss.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

Our decision is to apply version one of the CESS, as set out the Capital expenditure incentives guideline, to Jemena in the 2016–20 regulatory control period. We have not accepted Jemena's proposed exclusion of reliability improvement expenditure from the CESS. This decision is consistent with our preliminary decision. Attachment 10 sets out our reasons for our decision on CESS.

4.3.3 Service target performance incentive scheme (STPIS)

The service target performance incentive scheme (STPIS) is intended to balance a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to distributors to maintain and improve service performance where customers are willing to pay for these improvements.

Distributors can only retain their rewards for sustained and continuous improvements to the reliability of supply for customers. Once improvements are made, the benchmark performance targets will be tightened in future years.

Our decision is to apply the service standards component (the s-factor) of our national STPIS to Jemena for the 2016–20 regulatory control period. This decision is consistent with

54 AER, Efficiency benefit sharing scheme for electricity network service providers, November 2013.

our final F&A and our preliminary decision. We will not apply the guaranteed service level component to Jemena as the existing Victorian jurisdictional arrangements will continue to apply.[55] Our decision is to set revenue at risk for Jemena at the range ± 5.0 per cent.

In setting the STPIS performance targets, we have considered both completed and planned reliability improvements expected to materially affect network reliability performance. By setting the performance targets in such a way, any incentive a distributor may have to reduce the capex at the expense of target service levels should be curtailed by the STPIS financial penalties.

Attachment 11 sets out our decision on Jemena's service component parameter values.

4.3.4 Demand management incentive scheme

The demand management incentive scheme (DMIS) includes a demand management innovation allowance (DMIA). The DMIA is a capped allowance for distributors to investigate and conduct broad based and/or peak demand management projects.

Our decision is to continue Part A of the DMIS for Jemena in the 2016–20 regulatory control period (that is, the DMIA component). We will not apply Part B of the DMIS to Jemena for the 2016–2020 regulatory control period because we have decided to apply a revenue cap form of control. This is consistent with our proposed approach in our final F&A paper[56] and our preliminary decision.

Jemena proposed that a DMIA of $5.6 million was necessary to deliver their planned initiatives. However, we do not consider that it is appropriate to provide for expenditure beyond the capped allowance, in advance of consultation on a new DMIS and DMIA. Consistent with our preliminary decision, the current innovation allowance amount of $0.2 million ($2015) per annum (or $1 million over the period) will continue in the 2016–20 regulatory control period.

Attachment 12 sets out our decision on Jemena's DMIS.

4.3.5 f-factor scheme

The f-factor is an incentive scheme to reduce the risk of fire starts due to electricity infrastructure and the risk of loss or damage caused by such fire starts. The f-factor scheme is prescribed by the *f-factor scheme order 2011* (the Order) issued under the National Electricity (Victoria) Act 2005. The Order confers functions and powers on the AER to implement the f-factor.

As explained in the F&A paper, the Victorian Government advised that it intended to review the f-factor scheme in 2015 to determine how the incentive has performed in delivering efficient improvements to power line bushfire safety. As a new scheme has not been made as yet by the Victorian Government, we will retain the current incentive framework for the

55 AER, Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016, 24 October 2014, pp. 96–97.

56 AER, Final Framework and Approach for the Victorian Electricity Distributors, October 2014, p. 114.

purpose of this decision to set the target based on a five year historical average and an incentive rate of $25 000 per fire start. We will amend this scheme as appropriate to reflect any changes legislated by the Victorian Government following the review.

Attachment 18 sets out our decision on the f-factor scheme.

5 Understanding the NEO

The NEO is the central feature of the regulatory framework. The NEO is to:

> promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.[57]

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NEO.[58] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[59]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.[60] We have also considered the quality and reliability of services provided to consumers. For example, opex allowances have been set so Jemena may meet existing and new regulatory requirements. Repex allowances take into account the age and condition of assets. We have allowed sufficient augex and connections capex to cater for expected areas of growth. Our capex allowance is based on a contemporary estimate of the value of customer reliability. And the STPIS encourages maintenance, and indeed improvement of, service quality.

The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[61] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would.

For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[62] This could have significant longer term pricing implications for those consumers who continue to use network services.

Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the

---

57 NEL, s. 7.

58 Hansard, SA House of Assembly, 9 February 2005, pp. 1451–1460.
Hansard, SA House of Assembly, 27 September 2007, pp. 963–972.
Hansard, SA House of Assembly, 26 September 2013, pp. 7171–7176.

59 Hansard, SA House of Assembly, 26 September 2013, p. 7173.

60 Hansard, SA House of Assembly, 9 February 2005, p. 1452.

61 Re Michael: Ex parte Epic Energy [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, p. 50.

62 NEL, s. 7A(7).

network than is sustainable. This could create longer term problems in the network[63] and could have adverse consequences for safety, security and reliability of the network.

The NEL also includes the revenue and pricing principles (RPP),[64] which support the NEO. As the NEL requires,[65] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> - providing direct control network services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
> - the efficient provision of electricity network services; and
> - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
>
> - in any previous—
> - as the case requires, distribution determination or transmission determination; or
> - determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
> - in the Rules.
>
> A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.
>
> Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

Consistent with Energy Ministers' views, we set revenue allowances to balance all elements of the NEO and consider each of the RPPs.[66] For example:

---

63 NEL, s. 7A(6).

64 NEL, s. 7A.

65 NEL, s. 16(2).

66 Hansard, SA House of Assembly, 27 September 2007 pp. 965. Hansard, SA House of Assembly, 26 September 2013, p. 7173.

- In determining forecast opex and capex that reasonably reflects the opex and capex criteria, we take into account the revenue and pricing principle that we should provide Jemena with a reasonable opportunity to recover at least efficient costs. (Refer to capex attachment 6 and opex attachment 7).
- We take into account the economic costs and risks of the potential for under and over investment by a network service provider in our assessment of Jemena's forecast capital expenditure and operating expenditure proposals. (Refer to capex attachment 6 and opex attachment 7).
- We consider the economic costs and risks of the potential for under and over utilisation of Jemena's distribution system in our demand forecasting and augmentation determinations (Refer to capex attachment 6).
- Our application of the EBSS, CESS, STPIS and DMIS in this determination provide Jemena with effective incentives which we consider will promote economic efficiency with respect to the direct control services that Jemena provides throughout the regulatory control period. (Refer to attachments 9, 10, 11 and 12).
- We have determined Jemena's opening RAB taking into account the RAB adopted in the previous distribution determination. (Refer to attachment 2, regulatory asset base).
- The allowed rate of return objective reflects the revenue and pricing principle in s.7A(5). We have determined a rate of return that we consider will provide Jemena with a return commensurate with the regulatory and commercial risks involved in providing direct control services. (Refer to attachment 3, rate of return).
- Our financing determinations provide the distributor with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital. (Refer to attachment 3, rate of return).

In some cases, our approach to a particular component (or part thereof) results in an outcome towards the end of the range of options that may be favourable to the businesses, for example, our choice of equity beta. While it can be difficult to quantify the exact revenue impact of these individual decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model.

We take into account the RPPs when exercising discretion about an appropriate estimate. This requires a recognition that for the long term interests of consumers, the risk of under compensation for, or underinvestment by, a service provider may be less desirable than the risk of overcompensation or overinvestment. However, the AER is also conscious of the risk of introducing an inherent bias towards higher amounts where estimates throughout the different components of the determination are each set too conservatively.[67] The legislative

67 AEMC, Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006, p. 52.

framework recognises the complexity of this task by providing the AER with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.[68]

5.1 Achieving the NEO to the greatest degree

A distribution determination is a complex decision and must be considered as such. In most instances, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. For example, chapter 6 of the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. There is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several plausible point estimates.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. Where this is the case, our role is to make an overall decision that we are satisfied contributes to the achievement of the NEO to the greatest degree.[69]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives each of which would result in an overall decision that contributes to the achievement of the NEO, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree. This is our role under the NEO.

In coming to this final decision we have considered Jemena's initial and revised regulatory proposal. We have examined each of the building block components of the revised proposal and the incentive mechanisms that would apply across the next regulatory control period. We have considered the submissions we received in regard to Jemena's initial and revised proposal and our preliminary decision. We have conducted our own analysis and engaged expert consultants to help us better understand if and how Jemena's revised proposal contributes to the achievement the NEO. We have also considered how our constituent decisions relate to each other, the impact that particular constituent decisions have on other constituent components of our decision, and have described these interrelationships in this final decision. We have undertaken an extensive and consultative regulatory review process to ensure we have canvassed stakeholder issues and made as much of this information

68 NEL, s. 88.
AEMC, Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, p. 8.

69 NEL, s. 16(1)(d).

publicly available as practicable. We have had regard to and weighed up all the information assembled before us in making this final decision.

Therefore, we are satisfied that among the options before us our final decision on Jemena's distribution determination for the 2016–20 regulatory control period contributes to the achieving the NEO to the greatest degree.

5.1.1 Interrelationships between constituent components

Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[70] Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the distributor has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the distributor's approach to managing its network. The distributor's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6).

We have considered interrelationships, including those above, in our analysis of the constituent components of our final decision. These considerations are explored in the relevant attachments.

70 SCER, Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper, 6 June 2013, p. 6.

6 Consultation

Stakeholder participation is important to informed decision making under the NEL and NER. It allows us to take a range of views into account when considering how a proposal or decision contributes to the NEO. Effective consultation and engagement provide confidence in our processes and are good regulatory practice.

We have undertaken extensive consultation in developing this final decision (section 6.1). We have also taken into account the network businesses' consultation with their customers (section 6.2).

6.1 Our consultation process

In developing this final decision, we have considered views presented to us by all stakeholders. We also received advice from expert consultants and our CCP.

The NER sets out a process for both consultation on our decisions and publication of information that will inform those decisions. Under the transitional rules for this decision, we must:

- publish the regulatory proposals and any supporting material
- invite written submissions on the regulatory proposals
- hold a public forum on the regulatory proposals
- publish a preliminary determination and reasoning
- invite written submissions on the revocation and substitution of the preliminary determination
- publish a final determination and reasoning.

In developing this final decision, in addition to the above steps, we:

- published an issues paper
- published a consumer guide on this process and our assessment approach
- allowed for further submissions by stakeholders on the distribution businesses' revised proposals
- allowed for further submission by stakeholders on submissions made to the preliminary decisions
- sought advice from the CCP on both the preliminary and final decisions
- held meetings with the Victorian consultative group, which includes Victorian consumer representatives, among others
- held training sessions on the building block model for members of the Victorian consultative group and other stakeholders
- held a workshop on demand management with members of the Victorian consultative group and the distribution businesses
- held a workshop on demand forecasts with AEMO and the distribution businesses

- held meetings with the distribution businesses on various elements of their regulatory proposals
- sought further information from the distribution businesses about the regulatory proposals when questions arose, including through information requests.

This process builds on consultation we undertook with a broad range of stakeholders as part of the Better Regulation program. Following changes to the NER in 2012, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[71]

This gives us confidence the approaches set out in our various guidelines, which we have applied in this decision, will result in outcomes that will or are likely to contribute to the achievement of the NEO to the greatest degree. Our Better Regulation guidelines are available on our website[72] and include:

- Expenditure forecast assessment guideline
- Expenditure incentives guideline
- Rate of return guideline
- Consumer engagement guideline for network service providers
- Shared assets guideline
- Confidentiality guideline.

The guidelines provide businesses, investors and consumers predictability and transparency of our approach to regulation under the new rules.

6.2 Consumer engagement

Recent changes to the NER provide further support for consumer involvement in the regulatory process, and enable us to engage more productively with energy consumers and businesses.[73] Chapter 6 of the NER was amended to, among other things, require:

- distributors to submit an overview with their regulatory proposal which describes how they have engaged with consumers and sought to address any relevant concerns identified by that engagement[74]
- the AER to publish an issues paper after receiving the distributor's regulatory proposal.[75] The purpose of the issues paper is to assist consumer representative groups to focus on the key preliminary issues on which they should engage and comment[76]

71 AER, Overview of the Better Regulation reform package, April 2014, pp. 4 and 7–13.

72 www.aer.gov.au/Better-regulation-reform-program

73 AEMC, Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012.

74 NER, cl. 6.8.2(c1)(2).

75 NER, cl. 6.9.3(b).

76 AEMC, Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule

- the AER, when determining capex and opex allowances, to have regard to the extent to which the forecast includes expenditure to address the concerns of consumers as identified by the distributor in the course of its engagement with the consumers.[77]

Our Better Regulation Consumer engagement guideline sets out our expectations of how the network businesses should engage with their customers. We expect the network businesses to demonstrate a commitment to ongoing and genuine consumer engagement on issues relevant to consumers. We want to see businesses being more accountable to their consumers.[78] We understand the businesses may need some time to develop and implement robust and comprehensive engagement strategies and approaches.[79]

More specifically, the guideline sets out our expectations that the network businesses should develop consumer engagement approaches and strategies that address best practice principles.[80] We identify four components of best practice for consumer engagement. Each component is underpinned by four principles that are expected to characterise company interactions with consumers.

The four components of best practice are:

1. Priorities—we expect the businesses to identify consumer cohorts and their relevant views, outline their engagement objectives, and discuss how to achieve those objectives
2. Delivery—we expect the businesses to address priorities through ‘robust and thorough’ consumer engagement
3. Results—we expect the businesses to articulate the outcomes from their engagement processes and how success has been measured
4. Evaluation and review—we expect the businesses to evaluate and review the effectiveness of their engagement processes

Four principles support each of these components of best practice:

- Clear, accurate and timely communication—we expect the businesses to provide information to consumers that is clear, accurate, relevant and timely, recognising the different communication needs and wants of consumers
- Accessible and inclusive—we expect the businesses to recognise, understand and involve consumers early and throughout the expenditure process
- Transparent—we expect the businesses to clearly identify and explain the role of consumers in the engagement process, and to consult with consumers on information and feedback processes
- Measurable—we expect the businesses to measure the success, or otherwise, of their engagement activities[81]

2012.

77 NER, cll. 6.5.6(e)(5A) and 6.5.7(e)(5A).

78 AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 5.

79 AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 12.

80 AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 5.

81 AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 7.

As set out in the guideline, we monitor consumer engagement activities through the CCP and our ongoing engagement with stakeholders. We may publicly comment in our decisions on any shortcomings that we identify from an expenditure proposal that reflect weaknesses in consumer engagement.[82]

In its most recent advice to us, the CCP stated there is a need for the AER to address the extent to which the businesses are following our consumer engagement guideline, carrying out consumer engagement effectively and appropriately, and drawing substantiated conclusions from their consumer engagement activities.[83]

We have considered the material presented in Jemena's regulatory proposal (section 6.2.1), and stakeholder views presented to us in submissions (section 6.2.2) to form a view of its progress in implementing improved engagement strategies and approaches (section 6.2.3). We have not undertaken a substantive review of Jemena's consumer engagement approaches and strategies against the above best practice principles as part of this process.

6.2.1 Jemena's consumer engagement activities

Jemena undertook its own engagement with consumers in developing its regulatory proposal. This involved identifying the following five groups among its diverse customer and stakeholder base, and selecting the best way to engage with each group:

- the Jemena Customer Council (meetings)
- residential and business customers (via forums and focus groups)
- broader community (via online surveys and community relations)
- large customers and local governments (via interviews, workshops and meetings)
- retailers, consumer advocates, other stakeholders (workshops and meetings).[84]

Jemena sought feedback from these customer groups on these specific issues:

- the safety and service levels Jemena currently provides, and whether Jemena should invest more to increase the quality of its services across its network, or reduce costs by lowering this quality
- Jemena's proposed investments to manage expected changes in its network and the energy market, as new customers join the network and new technologies become available
- Jemena's proposed changes to the structure of its network prices, intended to help customers make more informed decisions about the way they use the network, to lower network costs, and to help customers save money in the long run
- what Jemena can do to help the most vulnerable customers.[85]

---

82 AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 12.

83 Consumer Challenge Panel – Sub panel 3, Response to AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period, 25 February 2016, pp. 7–8.

84 Jemena, Regulatory proposal, April 2015, p. 31; Jemena, Attachment 01-03 Continuing engagement with our customers, January 2016, p. 4.

Jemena reported that the findings of its consumer engagement process indicated that its customers:

- want to be informed to make their own energy decisions and that they prioritise reliability and safety
- consider existing reliability levels are appropriate, although large commercial or industrial customers require specific service differentiation
- want the business to continually improve service efficiency to keep prices low
- are concerned some are struggling to pay for their energy services and require support.[86]

Jemena stated that it took account of its customers' feedback in its decision making for its initial and revised proposals.[87] Jemena stated that its 2016 Plan included the following responses to customer feedback:

- Maintaining current safety and service levels—expenditure will be targeted to ensure demand from new growth areas (such as Craigieburn and Sunbury, Victoria) and ageing assets (such as the oldest pole structures) in well-established areas do not compromise service levels.[88]
- Reducing average network prices—Jemena's initial proposal included an 8.2 per cent decrease in average network prices over the five-year period (excluding the impact of inflation). This means the distribution network component of annual electricity bills of typical residential customers will fall over the five-year period, offsetting the impact of inflation.[89]
- Updating price components to encourage informed energy decision making—Jemena has introduced a new 'maximum demand charge'. This new charge means that over the next 5 years, how much the customer pays for using the network will depend on how and when the customer uses the network.[90]
- Providing assistance to vulnerable customers struggling to pay energy bills—Jemena will partner with a No Loan Interest Scheme to help these customers to replace inefficient appliances, trial 500 in-home energy displays, and provide targeted information about their energy usage and bills.[91]

In its revised regulatory proposal, Jemena stated that it was informed by further consultation with its customers and stakeholders to confirm their priorities and preferences for the 2016 regulatory period. Jemena stated that its engagement helped it develop a revised proposal

---

85 Jemena, Jemena's 2016 Plan: Consumer Overview, April 2015, pp. 6–7.

86 Jemena, Regulatory proposal, Attachment 4–1 Our customer, stakeholder and community engagement, April 2015, p. 44.

87 Jemena, Regulatory proposal, April 2015, p. 33; Jemena, 2016-20 Electricity Distribution Price Review Regulatory Proposal Revocation and substitution submission 1 January 2016 – 31 December 2020, 6 January 2016, p. xi (Jemena, Revised Regulatory Proposal, 6 January 2016).

88 Jemena, Jemena's 2016 Plan: Consumer Overview, April 2015, p. 10, 13.

89 Jemena, Jemena's 2016 Plan: Consumer Overview, April 2015, p. 16.

90 Jemena, Jemena's 2016 Plan: Consumer Overview, April 2015, p. 18.

91 Jemena, Regulatory proposal, April 2015, p. 33.

that responds to the changing energy market and its customers' interests in terms of service levels, costs, prices and tariff structures.[92]

In reviewing Jemena's revised proposal, we note that Jemena listed several meetings, forums and workshops with its various customer groups subsequent to its April 2015 proposal. Jemena submitted that the findings of its further consumer engagement showed support for its demand management activities, assistance to vulnerable customers, price path structure, and continuing engagement.

6.2.2 Stakeholder submissions

Victorian Energy Consumer and User Alliance (VECUA) recognise that consumer engagement is a new space for distributors. VECUA provided some perspectives to assist us in our assessment of the distributors' claims, and to assist the distributors to improve their ongoing consumer engagement efforts.[93]

Specifically, VECUA submitted that the distributors need to have consumers more involved in their decision-making regarding options and preferred solutions, to provide consumers with more detailed information, and to better enable consumers to challenge the distributors through their participation. VECUA noted that a deeper level of consumer participation will result in revenue proposals that better reflect consumers' long term interests.[94]

VECUA considered that Jemena made positive and genuine efforts to extensively engage with residential consumer advocates.[95] Similarly, Consumer Utilities Advocacy Centre (CUAC) submitted that Jemena's consumer engagement was meaningful and genuine.[96]

CUAC submitted that Jemena's engagement process has shown good evidence of engaging with a wide range of stakeholders and reflecting their needs in its plans. CUAC considered Jemena's engagement is more often at the 'consult' or 'inform' levels than the 'involvement' level.[97]

The Ethnic Communities' Council of NSW (ECC) considers one of the major criticisms of the process of consumer consultation and engagement by network businesses (with the exception of Jemena) is that it has been, and continues to be, largely a process of one-way information transfer:

92 Jemena, Revised Regulatory Proposal, 6 January 2016, p. xi.

93 Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals, 13 July 2015, p. 49.

94 Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals, 13 July 2015, p. 51.

95 Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals, 13 July 2015, p. 50.

96 Consumer Utilities Advocacy Centre, RE Victorian electricity distribution pricing review (EDPR), 2016 to 2020, 13 July 2015, pp.3–4.

97 Consumer Utilities Advocacy Centre, RE Victorian electricity distribution pricing review (EDPR), 2016 to 2020, 13 July 2015.

> There is little indication or transparency of how, if at all, such consultation and communication has been used to shape the networks' initial proposals and their subsequent revised proposals.[98]

Further, the ECC submits that detailed information on the methodologies employed by networks to consult with consumers is not easily found, nor is information about the spread and diversity of consumers engaged and consulted, and by what means, especially those with a first language other than English.[99]

The ECC provides some perspectives to assist us and the distributors to engage with culturally and linguistically diverse energy consumers.[100] Similarly, the Ethnic Communities' Council of Victoria submitted that Victorian distribution businesses should engage more with culturally and linguistically diverse consumers—particularly those who may be disadvantaged by 'price-based mechanisms' to balance quality and service with operational costs.[101]

Origin raises concerns about the ability of stakeholders to engage with the material submitted by the Victorian electricity distributors in their initial and revised proposals:

> The Victorian DNSPs have collectively submitted over 70,000 pages of material to address matters raised in the AER's preliminary decision. This is in addition to the vast quantity of information submitted in their substantive regulatory proposals.
>
> We recognise the importance for regulated [distributors] to present robust and accurate regulatory submissions to support their proposed expenditure and revenue allowances. However, we are concerned that the quantity of information, not just in this process, but in all recent network reviews, makes it increasingly challenging for stakeholders to meaningfully contribute to the regulatory debate.[102]

In its most recent advice, CCP raised concerns about whether the network businesses consulted with their customers on significant changes in their position particularly on the cost of debt in the revised proposals, which would have a significant impact on network charges:

> … the [return on debt] proposals, and the impact of these proposals on the price paths, represent a substantial change from the pricing proposals that the DNSPs' put to their customers as part of their original customer engagement programs. CCP3 is not aware whether this new approach has been canvassed by the DNSPs with their consumers and whether the DNSPs have established a consensus with their customers that this increase (well above market rates) is in the consumers' long-term interests.[103]

98 Ethnic Communities' Council of NSW, Submission concerning the Victorian Distribution Networks Revised Revenue Proposal 2016-20 Submissions to AER January 2016, 4 February 2016, p. 3.

99 Ethnic Communities' Council of NSW, Submission concerning the Victorian Distribution Networks Revised Revenue Proposal 2016-20 Submissions to AER January 2016, 4 February 2016, p. 3.

100 Ethnic Communities' Council of NSW, Submission concerning the Victorian Distribution Networks Revised Revenue Proposal 2016-20 Submissions to AER January 2016, 4 February 2016, pp. 4–5.

101 Ethnic Communities' Council of Victoria, Submission to the Australian Energy Regulator Victoria Electricity Pricing Review, 15 July 2015, p. 6.

102 Origin, Re: Victorian Networks Revised Proposals, 4 February 2016, p. 1.

103 Consumer Challenge Panel – Sub panel 3, Overview: Response to AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period, 22 February 2016, p. 35.

CCP raised other more general concerns that may apply to the Victorian distribution businesses' consumer engagement activities. For example, CCP notes: information provided and questions to consumers in workshops, focus groups and surveys are potentially open to bias;[104] the full context of an issue is not always provided;[105] and the selection of attendees at the various consumer engagement activities can lead to bias.[106] VECUA raised similar concerns.[107]

As part of this process, CCP observed consumer engagement activities undertaken by some of the businesses only.[108] CCP noted that its concerns do not necessarily apply to each Victorian distributor and does not cite specific examples.[109]

6.2.3 Our view of Jemena's consumer engagement

Overall, we consider Jemena has taken important steps to engage with its customers. Stakeholder comments that Jemena's consumer engagement was meaningful and genuine are encouraging.

VECUA and the CCP indicated there are further opportunities for Jemena to improve the way it objectively seeks consumer feedback in developing its regulatory proposals.[110] Further, the ECC indicates Jemena could be more transparent in the way it reports its consumer engagement activities and how they affected its initial and revised regulatory proposals.[111] We expect Jemena to consider these submissions in developing its consumer engagement program going forward.

Jemena consulted with its customer council in developing its revised proposal, and included a consumer overview with its revised proposal—unlike the other Victorian electricity distributors. However, we are concerned that Jemena did not engage with its customers on the change in position particularly on cost of debt between the initial and revised proposals (discussed in section 3.2).

Also, Jemena's consumer overview is potentially unclear in explaining its proposed approach to calculating the cost of debt. Jemena stated:

104 Consumer Challenge Panel – Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, p. 6.

105 Consumer Challenge Panel - Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, pp. 6–7.

106 Consumer Challenge Panel - Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, pp. 7–8.

107 Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals, 13 July 2015, pp. 51–53.

108 Consumer Challenge Panel - Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, p. 5.

109 Consumer Challenge Panel - Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, p. 5.

110 Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals, 13 July 2015, pp. 49–53; Consumer Challenge Panel – Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, pp. 4–9.

111 Ethnic Communities' Council of NSW, Submission concerning the Victorian Distribution Networks Revised Revenue Proposal 2016-20 Submissions to AER January 2016, 4 February 2016, p. 3.

> You told us you want to know where your money goes, so we're going to be more transparent about our costs over the 5-year period, and how much revenue we need to earn to recover those costs.[112]
>
> …
>
> … our funding costs for the period are lower than for the current period. Like home interest rates, the costs of funding our past and forecast capital costs vary with economic and financial market conditions. When we submitted our current plan 5 years ago, our rates of 'borrowing' were high due to the unusual conditions in financial markets at that time (the global financial crisis). Since then, conditions have improved and our costs have come down.[113]

Jemena's change in position on the cost of debt—for which it proposed an immediate implementation of a 10 year trailing average with no transition—incorporates the higher financing costs experienced at the time of the global financial crisis. This would lead to a wealth transfer to Jemena. Indeed, Jemena's proposed cost of debt is higher than its initial proposal, which did not incorporate historical rates over the last 10 years.

We expect the businesses to involve consumers throughout the process, and to provide information to consumers that is clear, accurate, relevant and timely.[114] Although explaining rate of return concepts is inherently difficult, this does not mean the business should avoid engaging on this aspect of the regulatory proposal—especially when it has decided to change its approach from its initial proposal and where this would have a significant effect on network charges.

112 Jemena, Submission on its 2016 Plan: 2016–20, Consumer Overview, January 2016, p. 17.
113 Jemena, Submission on its 2016 Plan: 2016–20, Consumer Overview, January 2016, p. 18.
114 AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 7.

A Constituent decisions and revocation of preliminary decision

In November 2012, the AEMC introduced major changes to the economic regulation of electricity distributors under chapter 6 of the National Electricity Rules. To allow consumers to receive the benefit of the new rules, the AEMC made transitional rules under chapter 11 of the NER. Those rules required the AER to make a preliminary distribution determination for each of the Victorian distributors prior to the commencement of the 2016–20 regulatory control period.

The AER made its preliminary decision for Jemena for the 2016–20 regulatory control period in October 2015. That distribution determination formed the basis for approving network prices for Jemena for 2016.

At the same time as we made the preliminary decision, we invited submissions on the revocation and substitution of that distribution determination.

As required by the transitional rules,[115] we now revoke the preliminary decision and substitute it with this new distribution determination. This new distribution determination (referred to as our final decision) takes effect at the date it is made and applies in respect of the 2016–20 regulatory control period.

The final decision provides for adjustments over the regulatory control period to account for differences between the revenue that we approved for Jemena, in the preliminary and final decisions, for the 2016 regulatory year.[116]

Our final distribution determination is predicated on the following decisions (constituent decisions):[117]

Constituent decision

In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to Jemena for the 2016–20 regulatory control period (listed by service group):

- Standard control services include network services, connection services requiring augmentation, customer initiated works (connection service undergrounding or distribution asset reconfiguration)
- Alternative control services include routine connections, type 5–6 and smart metering services (regulated service only), operation, repair, replacement and maintenance of public lighting assets, ancillary network services, ancillary connection services, ancillary metering services, solar PV and small generator pre-approval fees, type 7 metering
- Negotiated distribution services include new public lighting services (incl. greenfield sites), alteration and relocation of DNSP public lighting assets, construction of a reserve feeder
- Unregulated services include type 1 to 4 metering services (excl. smart metering), type 5–6 and

115 NER, cl. 11.60.4.

116 NER, cl. 11.60.4(d) and (e).

117 NER, cl. 6.12.1.

smart metering services (subject to competition), emergency recoverable works.

Attachment 13 of the final decision discusses classification of services.

In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in Jemena's building block proposal. Our final decision on Jemena's annual revenue requirement for each year of the 2016–20 regulatory control period is set out in attachment 1 of the final decision.

In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Jemena's proposal that the regulatory control period will commence on 1 January 2016. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Jemena's proposal that the length of the regulatory control period will be five years from 1 January 2016 to 31 December 2020.

In accordance with clause 6.12.1(3)(i) and acting in accordance with clause 6.5.7(c), the AER accepts Jemena's proposed total forecast capital expenditure of $709.3 million ($2015). This is discussed in attachment 6 of the final decision.

In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept Jemena's proposed total forecast operating expenditure inclusive of debt raising costs and exclusive of DMIA of $470.9 million ($2015). Our substitute estimate of Jemena's total forecast opex for the 2016–20 regulatory control period is $452.3 million ($2015). This is discussed in attachment 7 of the final decision.

In accordance with clause 6.12.1(4A)(i) the AER determines that there are no contingent projects for the purposes of the distribution determination.

Jemena did not include any proposed contingent projects in its regulatory proposal for the 2016–20 regulatory control period. Therefore,

- in accordance with clause 6.12.1(4A)(ii), the AER has not made an assessment of whether the capital expenditure proposed in the context of each contingent project reflects the capital expenditure criteria and factors
- in accordance with clause 6.12.1(4A)(iii), the AER does not specify any trigger events in relation to contingent projects
- in accordance with clause 6.12.1(4A)(iv), the AER does not determine that any proposed contingent project is not a contingent project.

In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the first regulatory year of the regulatory control period in accordance with clause 6.5.2 is not to accept Jemena's proposal of 8.62 per cent. Our decision on the allowed rate of return for the first regulatory year of the regulatory control period is 6.37 per cent as set out in table 3.1 of attachment 3 of the final decision. This rate of return will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.

In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in attachment 3 (appendix I) of the final decision.

In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in attachment 4 of the final decision.

In accordance with clause 6.12.1(6) the AER's decision on Jemena's regulatory asset base as at 1 January 2016 in accordance with clause 6.5.1 and schedule 6.2 is $1186.8 million ($ nominal). This is set out in attachment 2 of the final decision

In accordance with clause 6.12.1(7) the AER does not accept Jemena's proposed corporate income tax of $128.8 million ($ nominal). Our decision on Jemena's corporate income tax is $76.8 million ($ nominal). This is set out in attachment 8 of the final decision.

In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by Jemena. This is set out in attachment 5 of the final decision.

In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply:

- In accordance with clause 6.12.1(9) of the NER, the AER's decision is to apply version two of the EBSS to Jemena in the 2016–20 regulatory control period. This is set out in attachment 9 of the final decision.
- In accordance with clause 6.12.1(9) of the NER, we will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to Jemena in the 2016–20 regulatory control period. CESS is discussed in attachment 10 of the final decision.
- In accordance with clause 6.12.1(9) of the NER, we will apply our Service Target Performance Incentive Scheme (STPIS) to Jemena for the 2016–20 regulatory control period.
    - We will apply the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) reliability of supply parameters, and momentary average interruption frequency index (MAIFI). We will also apply the customer service telephone answering parameter. We will not apply a guaranteed service level scheme as Jemena must comply with its existing Victorian jurisdictional guaranteed service level scheme.
    - A beta of 2.5 will be used to calculate the major event day boundary.
    - Our decision on the SAIDI and SAIFI incentive rates and performance targets to apply to Jemena for the 2016–20 regulatory control period are set out in tables 11.1 and 11.2 of attachment 11 of the final decision.
    - Our decision on the customer service incentive rate and performance target are set out in sections 11.1.2 and 11.1.3 of attachment 11 of the final decision.
    - The revenue at risk for Jemena will be capped at ±5.0 per cent. Within this there will be a cap of ±0.5 per cent on the telephone answering parameter for performance.

Note: The meaning for year "t" under the price control formula for this determination is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.

- In accordance with Division 4 of Part 3 to the National Electricity (Victoria) Act 2005 and the NER, the AER will make a final adjustment to close out the ESCV's s-factor scheme for the 2006–10 regulatory control period by including the adjustment amount shown in attachment 11 in the 'revenue adjustments' row of the post-tax revenue model.
- The AER has determined to continue Part A of the Demand Management Innovation Scheme (DMIS) for Jemena in the 2016–20 regulatory control period (that is, the DMIA component). DMIS

is discussed in attachment 12 of the final decision.

In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.

In accordance with clause 6.12.1(11) the AER's decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Jemena for any given regulatory year is the total annual revenue calculated using the formula in attachment 14 plus any adjustment required to move the DUoS under/over account to zero. This is discussed at attachment 14 in the final decision.

In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control services is to apply price caps for all services other than metering, for which a revenue cap will apply. This is discussed in attachment 16 in the final decision.

In accordance with clause 6.12.1(13), to demonstrate compliance with its distribution determination, the AER's decision is Jemena must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 14 in the final decision.

In accordance with clause 6.12.1(14) the AER's decision is that the additional pass through events set out in attachment 15, Table 15–1 will apply to Jemena for the 2016–20 regulatory control period.

In accordance with clause 6.12.1(15) the AER's decision is to approve Jemena's proposed negotiating framework. The negotiating framework that is to apply to Jemena is set out at attachment 17 of the final decision.

In accordance with clause 6.12.1(16) the AER's decision is to apply the negotiated distribution services criteria published in May 2015 to Jemena. This is set out is at attachment 17 of the final decision.

In accordance with clause 6.12.1(17) the AER's decision on the procedures for assigning retail customers to tariff classes for Jemena is set out at attachment 14 of the final decision.

In accordance with clause 6.12.1(18) the AER's decision on depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of Jemena's regulatory control period (1 January 2021). This is discussed in attachment 2 of the final decision.

In accordance with clause 6.12.1(19) the AER's decision on how Jemena is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The method to account for the under and over recovery of designated pricing proposal charges is discussed in attachment 14 of the final decision.

In accordance with clause 6.12.1(20) the AER's decision is we require Jemena to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 14 of the final decision.

In accordance with section 16C of the National Electricity (Victoria) Act 2005, the NEL, the NER and the Victorian F-Factor Scheme Order In Council 2011, we will apply the f-factor scheme based on an incentive rate of $25,000 per fire start higher/lower than the f-factor target as set out in attachment 18 of the final decision.

B List of stakeholder submissions

Submission from	Date received
ActewAGL Distribution	4 February 2016
AGL	8 January 2016 *
AusNet Services	4 February 2016
CitiPower	4 February 2016
Consumer Challenge Panel subpanel 3	25 February 2016 *
Eastern Alliance for Greenhouse Action	6 January 2016
Ethnic Communities' Council of NSW	20 January 2016
Jemena	4 February 2016
Origin Energy	6 January 2016; 4 February 2016
Powercor	4 February 2016
RESPAresearch	1 December 2015
Street Light Group of Councils	6 January 2016
United Energy	4 February 2016
Vector Ltd	21 December 2015
Victorian Energy Consumer and User Alliance (VECUA)	6 January 2016
Victorian Government	14 January 2016 *
Victorian Government	29 January 2016
Victorian Government	12 February 2016 *

* These submissions were received after the consultation period ended.