



FINAL DECISION
Energex determination 2015–16
to 2019–20

Attachment 6 – Capital
expenditure

October 2015

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Note

This attachment forms part of the AER's final decision on Energex's 2015–20 distribution determination. 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 mechanism

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
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 distributor
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 distributor
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

Shortened form	Extended form
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

6 Capital expenditure

Capital expenditure (capex) refers to the investment made in the network to provide standard control services. This investment mostly relates to assets with long lives (30-50 years is typical) and these costs are recovered over several regulatory periods. On an annual basis, however, the financing cost and depreciation associated with these assets is recovered (return of and on capital) as part of the building blocks that form part of Energex's total revenue requirement.¹

This attachment sets out our final decision on Energex's total forecast capex. Further detailed analysis is in the following appendices:

- Appendix A - Assessment techniques
- Appendix B - Assessment of capex drivers
- Appendix C - Demand.

6.1 Final decision

We are not satisfied Energex's proposed total forecast capex of \$2889.7 million (\$2014–15) reasonably reflects the capex criteria. This is 52 per cent lower than the AER's allowance for the 2010–15 regulatory control period (\$6039.4 million) and 26 per cent lower than actual capex for the 2010–15 period (\$3921.4 million). We substituted our estimate of Energex's total forecast capex for the 2015–20 regulatory control period. We are satisfied that our substitute estimate of \$2755.4 million (\$2014–15) reasonably reflects the capex criteria. Table 6.1 outlines our final decision.

Table 6.1 Our final decision on Energex's total forecast capex (\$2014–15, million)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Energex's initial proposal	670.3	688.5	629.0	613.3	638.4	3,239.6
AER preliminary decision	498.5	513.6	465.5	446.2	437.8	2,361.5
Energex's revised proposal	604.8	624.8	575.0	546.6	538.5	2,889.7
AER final decision	571.7	588.8	538.9	531.9	524.1	2755.4
Difference (revised proposal and final decision)	-31.1	-36.0	-36.1	-14.7	-14.4	-134.3
Percentage difference (%) (revised proposal and final decision)	-5.5	-5.8	-6.3	-2.7	-2.7	-4.6

¹ NER, cl. 6.4.3(a).

Source: AER, *Preliminary decision, Energex determination 2015–16 to 2019–20, Attachment 6 – Capital expenditure*, April 2015, p. 8; Energex, *Revised regulatory proposal*, July 2015, p. 25; AER analysis.

Note: Numbers may not add up due to rounding.

Table 6.2 summarises our findings and the reasons for our final decision.

These reasons include our responses to stakeholders' submissions on Energex's revised regulatory proposal. In the table we present our reasons by 'capex driver' (for example, augmentation, replacement, and connections). This reflects the way in which we tested Energex's total forecast capex. Our testing used techniques tailored to the different capex drivers, taking into account the best available evidence. Through our techniques, we found Energex's capex forecast was higher than an efficient level, inconsistent with the NER. We are not satisfied that Energex's proposed total forecast capex is consistent with the requirements of the NER.

Our findings on the capex drivers are part of our broader analysis and should not be considered in isolation. Our final decision concerns Energex's total forecast capex for the 2015–20 regulatory control period. We do not approve an amount of forecast expenditure for each capex driver. However we use our findings on the different capex drivers to arrive at an alternative estimate for total capex. We test this total estimate of capex against the requirements of the NER (see section 6.3 for a detailed discussion). We are satisfied that our estimate represents total forecast capex that reasonably reflects the capex criteria.

Table 6.2 Summary of AER reasons and findings

Issue	Reasons and findings
Total capex forecast	<p>Energex proposed a total capex forecast of \$2889.7 million (\$2014–15) in its revised proposal. We are not satisfied this forecast reflects the capex criteria.</p> <p>We are satisfied our substitute estimate of \$2755.4 million (\$2014–15) reasonably reflects the capex criteria. Our substitute estimate is 4.6 per cent lower than Energex's revised proposal (and 15 per cent lower than Energex's initial proposal of \$3239.6 million (\$2014–15)).</p> <p>The reasons for this decision are set out in this table and detailed in the remainder of this attachment.</p>
Forecasting methodology, key assumptions and past capex performance	<p>Energex's forecasting methodology predominately relies upon a bottom up approach. Top down constraints imposed by its governance process are insufficient for us to be able to conclude that the forecasts are prudent and efficient. Bottom up approaches have a tendency to overstate required expenditure as they do not adequately account for inter-relationships and synergies between projects or areas of work.</p>
Augmentation capex	<p>We do not accept Energex's forecast augex of \$472.7 million (\$2014–15) as a reasonable estimate for this category. We consider that \$405.3 million (\$2014–15) is a reasonable estimate for Energex to augment its network and satisfy the capex criteria. In coming to this review, we accept the majority of Energex's revised augex forecast. However, we consider that its proposed capex for its low voltage network, power quality and reliability programs, and to purchase land and easements are overstated.</p>
Customer connections capex	<p>We do not accept Energex's revised proposal for connections capex of \$332.2 million (\$2014–15). We have instead included an amount of \$284.8 million (\$2014–15) in our substitute estimate of forecast capex. This is 85.7 per cent of Energex's revised proposal. In determining our substitute estimate we are not satisfied that part of</p>

Issue	Reasons and findings
	Energex's forecast of commercial project connection activities is justified.
Asset replacement capex (repex)	We accept Energex's forecast repex of \$987.1 million (\$2014–15) as a reasonable estimate for this category which will allow Energex to meet the capex objectives and have included this amount in our alternative estimate.
Non-network capex	<p>We accept Energex's revised non-network capex proposal of \$245.0 million (\$2014–15), excluding overheads. This forecast is consistent with Energex's initial proposal, which we accepted in our preliminary decision as a reasonable estimate of efficient costs required for this category.</p> <p>Energex's forecast non-network capex is 35 per cent lower than actual non-network capex during the 2010–15 regulatory control period. The longer term trends in non-network capex suggest that Energex has forecast capex for this category at historically low levels.</p>
Capitalised overheads	<p>We do not accept Energex's proposed capitalised overheads of \$852.5 million (\$2014–15). We have instead included an amount of \$833.3 million (\$2014–15) for capitalised overheads.</p> <p>We reduced Energex's overheads to reflect the reductions we made to their total capex forecast particularly those components with overheads.</p> <p>However, we also note that 34 per cent of Energex's proposed \$852.5 million (\$2014–15) total capitalised overheads is attributable to information, communications and technology (ICT) services. We do not accept Energex's forecast for ICT services of \$292.5 million (\$2014–15). We have instead included an amount of \$283.4 million (\$2014–15) for ICT services.</p>
Real cost escalators	<p>In respect of real material cost escalators (leading to cost increases above CPI), Energex accepted the AER's application of CPI indexation as a proxy for forecasts of escalation of materials costs in real terms over the 2015–20 regulatory control period. In its revised revenue proposal, Energex commented on the current highly uncertain circumstances in commodities and metals markets. Consistent with our preliminary decision, our approach to real materials cost escalation does not affect the proposed application of labour and construction cost escalators which apply to Energex's forecast capex for standard control services.</p> <p>Energex accepted the AER's use of a simple average of Energex's labour cost forecasts (prepared by PwC) and the AER's forecasts (prepared by Deloitte Access Economics) and considered that this will provide a better basis for the real labour cost escalation forecasts over the 2015–20 regulatory period than sole reliance on the Deloitte Access Economics forecasts.</p>

Source: AER analysis.

We consider that our overall capex forecast addresses the revenue and pricing principles. In particular, we consider that Energex has been provided a reasonable opportunity to recover at least the efficient costs it incurs in:²

- providing direct control network services; and
- complying with its regulatory obligations and requirements.

As set out in appendix B we are satisfied that our overall capex forecast is consistent with the NEO. We consider our decision promotes efficient investment in, and efficient

² NEL, s. 7A.

operation and use of, electricity services for the long term interests of consumers of electricity.

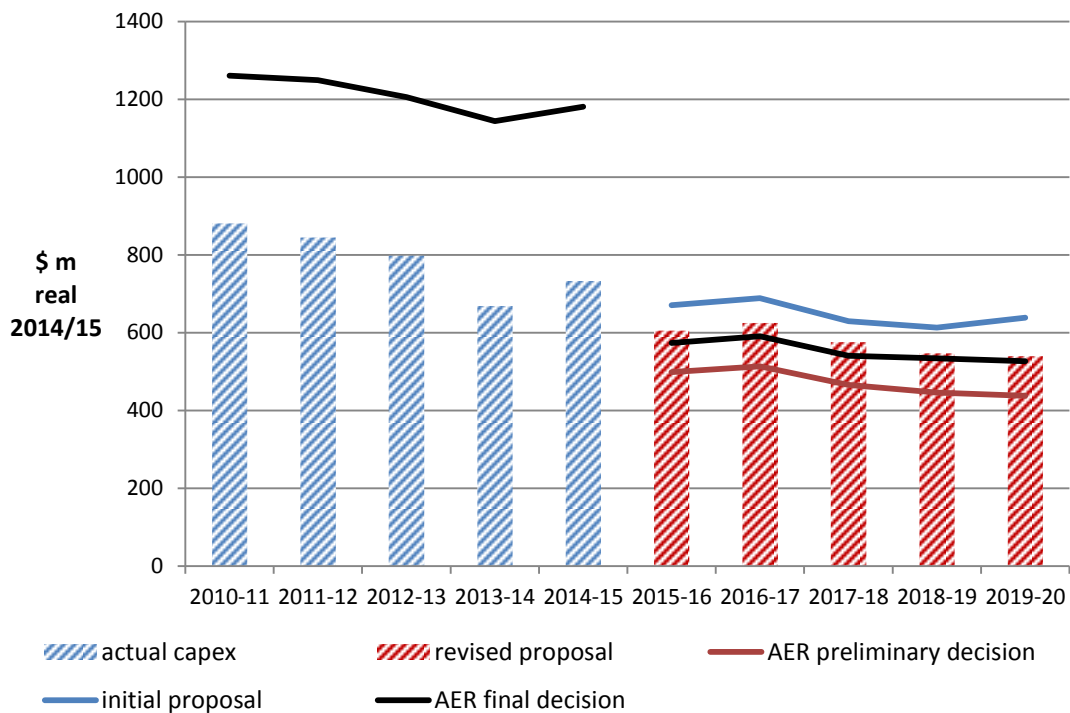
We also consider that overall our capex forecast addresses the capital expenditure objectives.³ In making our final decision, we specifically considered the impact our decision will have on the safety and reliability of Energex's network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in Energex's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

6.2 Energex's revised proposal

Energex's revised proposal was for total forecast capex of \$2889.7 million (\$2014–15) for the 2015–20 regulatory control period. This is 22.4 per cent higher than our preliminary decision and 10.8 percent lower than Energex's initial regulatory proposal.

Figure 6.1 shows the difference between Energex's initial proposal, its revised proposal, and our preliminary decision for the 2015–20 regulatory control period, as well as the actual capex that Energex spent during the 2010–15 regulatory control period.

Figure 6.1 Energex's total actual and forecast capex 2010–2020



Source: AER analysis.

³ NER, cl. 6.5.7(a).

Energex submitted that the reasons for the reduction between its initial proposal and revised proposal are due to:⁴

- an expansion of its options analysis in relation to replacement expenditure recognising comments made by the AER and its consultants
- a revision of its risk profile based on feedback from the AER and customers on the balance between network performance and electricity prices for customers.

6.3 AER's assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, and outlines our assessment techniques. It also explains how we derive an alternative estimate of total forecast capex against which we compare the distributor's total forecast capex. The starting point for our assessment is the information provided by Energex in its revised proposal. At the same time that Energex submitted its proposal, it also submitted its response to our RIN. We also took into account information that Energex provided in response to our information requests, and submissions from other stakeholders.

Our assessment approach involves the following steps:

- Our starting point for building an alternative estimate is the distributor's revised proposal.⁵ We apply our various assessment techniques, both qualitative and quantitative, to assess the different elements of the distributor's proposal. This analysis informs our view on whether the distributor's proposal reasonably reflects the capex criteria in the NER at the total capex level.⁶ It also provides us with an alternative forecast that we consider meets the criteria. In arriving at our alternative estimate, we weight the various techniques we used in our assessment. We give more weight to techniques we consider are more robust in the particular circumstances of the assessment.
- Having established our alternative estimate of the *total* forecast capex, we can test the distributor's total forecast capex. This includes comparing our alternative estimate total with the distributor's total forecast capex and what the reasons for any differences are. If there is a difference between the two, we may need to exercise our judgement as to what is a reasonable margin of difference.

If we are satisfied the distributor's proposal reasonably reflects the capex criteria in meeting the capex objectives, we will accept it. The capital expenditure objectives (capex objectives) referred to in the capex criteria, are to:⁷

⁴ Energex, *Revised regulatory proposal*, July 2015, pp. 24 & 27.

⁵ AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 7; see also AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, pp. 111 and 112.

⁶ NER, cl. 6.5.7(c).

⁷ NER, cl. 6.5.7(a).

- meet or manage the expected demand for standard control services over the period
- comply with all regulatory obligations or requirements associated with the provision of standard control services
- to the extent that there are no such obligations or requirements, maintain service quality, reliability and security of supply of standard control services and maintain the reliability and security of the distribution system
- maintain the safety of the distribution system through the supply of standard control services.

If we are not satisfied, the NER requires us to put in place a substitute estimate that we are satisfied reasonably reflects the capex criteria.⁸ Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are:⁹

- the efficient costs of achieving the capital expenditure objectives
- the costs that a prudent operator would require to achieve the capital expenditure objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The AEMC noted '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.¹⁰ Importantly, we approve a total capex forecast and not particular categories, projects or programs in the capex forecast. Our review of particular categories or projects informs our assessment of the total capex forecast. The AEMC stated:¹¹

It should be noted here that what the AER approves in this context is expenditure allowances, not projects.

In deciding whether we are satisfied that Energex's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.¹²

In taking the capex factors into account, the AEMC noted:¹³

⁸ NER, cl. 6.12.1(3)(ii).

⁹ NER, cl. 6.5.7(c).

¹⁰ AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 113.

¹¹ AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, November 2012, p. vii.

¹² NER, cl. 6.5.7(e).

¹³ AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 115.

...this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.5 summarises how we took the capex factors into consideration.

More broadly, we note that in exercising our discretion, we take into account the revenue and pricing principles set out in the NEL.¹⁴ In particular, we take into account whether our overall capex forecast provides Energex a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.¹⁵

Expenditure Assessment Guideline

The rule changes the AEMC made in November 2012 required us to make and publish an Expenditure Forecast Assessment Guideline for electricity distribution (Guideline).¹⁶ We released our Guideline in November 2013.¹⁷ The Guideline sets out our proposed general approach to assessing capex (and opex) forecasts. The rule changes also require us to set out our approach to assessing capex in the relevant framework and approach paper. For Energex, our framework and approach paper stated that we would apply the Guideline, including the assessment techniques outlined in it.¹⁸ We may depart from our Guideline approach and if we do so, we need to provide reasons. In this determination, we have not departed from the approach set out in our Guideline.

We note that RIN data form part of a distributor's regulatory proposal.¹⁹ In our Guideline we stated we would "require all the data that facilitate the application of our assessment approach and assessment techniques". We also stated that the RIN we issue in advance of a distributor lodging its regulatory proposal would specify the exact information we require.²⁰ Our Guideline made clear our intention to rely upon RIN data during distribution determinations.

6.3.1 Building an alternative estimate of total forecast capex

The following section sets out the approach we apply to arrive at an alternative estimate of total forecast capex.

¹⁴ NEL, ss. 7A and 16(2).

¹⁵ NEL, s. 7A.

¹⁶ AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 114.

¹⁷ AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013.

¹⁸ AER, *Final Framework and approach for the Victorian Electricity Distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, 119–120.

¹⁹ NER, cl. 6.8.2(c2) and (d).

²⁰ AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 25.

Our starting point for building an alternative estimate is the distributor's revised proposal.²¹ We then considered its performance in the previous regulatory control period to inform our alternative estimate. We also reviewed the proposed forecast methodology and the service provider's reliance on key assumptions that underlie its forecast. Energex has submitted further information on its forecast methodology in its revised proposal and we have addressed this below.

We have maintained in our final decision the use of the specific techniques that we used in our preliminary decision. Many of our techniques encompass the capex factors that we are required to take into account. Further detail on each of these techniques is included in appendix A and appendix B.

Some of these techniques focus on total capex; others focus on high level, standardised sub-categories of capex. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects or programs the distributor should or should not undertake. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve specific projects. Rather, we approve an overall revenue requirement that includes an assessment of what we find to be an efficient total capex forecast.²²

We determine total revenue by reference to our analysis of the proposed capex and the various building blocks. Once we approve total revenue, the distributor is able to prioritise its capex program given its circumstances over the course of the regulatory control period. The distributor may need to undertake projects or programs it did not anticipate during the distribution determination. The distributor may also not require some of the projects or programs it proposed for the regulatory control period. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period in its decision-making.

As we explained in our Guideline:²³

Our assessment techniques may complement each other in terms of the information they provide. This holistic approach gives us the ability to use all of these techniques, and refine them over time. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but we intend to consider the inter-connections between our assessment techniques when determining total capex ... forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques.

²¹ AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 9; AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, pp. 111 and 112.

²² AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. vii.

²³ AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 12.

In arriving at our estimate, we weight the various techniques we used in our assessment. We weight these techniques on a case by case basis using our judgement. Broadly, we give more weight to techniques we consider are more robust in the particular circumstances of the assessment. By relying on a number of techniques, we ensure we consider a wide variety of information and can take a holistic approach to assessing the distributor's capex forecast.

Where our techniques involve the use of a consultant, we consider their reports as one of the inputs to arriving at our final decision on overall capex. Our final decision clearly sets out the extent to which we accept our consultants' findings. Where we apply our consultants' findings, we do so only after carefully reviewing their analysis and conclusions, and evaluating these against outcomes of our other techniques and our examination of Energex's proposal.

We also take into account the various interrelationships between the total forecast capex and other components of a distributor's distribution determination. The other components that directly affect the total forecast capex include:

- forecast opex
- forecast demand
- the service target performance incentive scheme
- the capital expenditure sharing scheme
- real cost escalation
- contingent projects.

We discuss how these components impact the total forecast capex in Table 6.4.

Underlying our approach are two general assumptions:

- The capex criteria relating to a prudent operator and efficient costs are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.²⁴
- Past expenditure was sufficient for the distributor to manage and operate its network in past periods, in a manner that achieved the capex objectives.²⁵

²⁴ AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8 and 9. The Tribunal has previously endorsed this approach: see : Application by Ergon Energy Corporation Limited (Non-system property capital expenditure) (No 4) [2010] ACompT 12; Application by EnergyAustralia and Others [2009] ACompT 8; Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11; Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14; Application by United Energy Distribution Pty Limited [2012] ACompT 1; Re: Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 ; Application by DBNGP (WA).

²⁵ AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

6.3.2 Comparing the distributor's proposal with our alternative estimate

Having established our estimate of the total forecast capex, we can test the distributor's proposed total forecast capex. This includes comparing our alternative estimate of forecast total capex with the distributor's proposal. The distributor's forecast methodology and its key assumptions may explain any differences between our alternative estimate and its proposal.

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:²⁶

The AER could be expected to approach the assessment of a NSP's expenditure (capex or opex) forecast by determining its own forecast of expenditure based on the material before it. Presumably this will never match exactly the amount proposed by the NSP. However there will be a certain margin of difference between the AER's forecast and that of the NSP within which the AER could say that the NSP's forecast is reasonable. What the margin is in a particular case, and therefore what the AER will accept as reasonable, is a matter for the AER exercising its regulatory judgment.

As noted above, we draw on a range of techniques, as well as our assessment of elements that impact upon capex such as demand and real cost escalators.

Our decision on the total forecast capex does not strictly limit a distributor's actual spending. A distributor might spend more on capex than the total forecast capex amount specified in our decision in response to unanticipated expenditure needs.

The regulatory framework has a number of mechanisms to deal with such circumstances. Importantly, a distributor does not bear the full cost where unexpected events lead to an overspend of the approved capex forecast. Rather, the distributor bears 30 per cent of this cost if the expenditure is subsequently found to be prudent and efficient. Further, the pass through provisions provide a means for a distributor to pass on significant unexpected capex to customers, where appropriate.²⁷ Similarly, a distributor may spend less than the capex forecast because they have been more efficient than expected. In this case the distributor will keep on average 30 per cent of this reduction over time.

We set our alternative estimate at the level where the distributor has a reasonable opportunity to recover efficient costs. The regulatory framework allows the distributor to respond to any unanticipated issues that arise during the regulatory control period. In the event that this leads to the approved total revenue underestimating the total capex required, the distributor should have sufficient flexibility to allow it to meet its safety and

²⁶ AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 112.

²⁷ NER, cl. 6.6.

reliability obligations by reallocating its budget. Conversely, if there is an overestimation, the stronger incentives the AEMC put in place in 2012 should result in the distributor only spending what is efficient. As noted, the distributor and consumers share the benefits of the underspend and the costs of an overspend under the regulatory regime.

6.4 Reasons for final decision

We applied the assessment approach set out in section 6.3 to Energex. We are not satisfied Energex's total forecast capex reasonably reflects the capex criteria. We compared Energex's capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. Energex's revised proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6.3 sets out the capex amounts by driver that we included in our alternative estimate of Energex's total forecast capex for the 2015–20 regulatory control period.

Table 6.3 Our assessment of required capex by capex driver 2015–20 (\$2014–15 million)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Augmentation	88.2	95.6	79.9	75.8	65.9	405.3
Connections	54.9	53.9	55.2	58.4	62.4	284.8
Replacement	196.7	210.7	196.7	194.3	188.7	987.1
Non-Network	54.6	56.1	44.3	43.3	46.7	245.0
Capitalised overheads	177.4	172.5	162.8	160.2	160.4	833.3
Materials escalation adjustment	-	-	-	-	-	-
Gross Capex (includes capital contributions)	603.7	624.4	575.4	571.0	564.2	2,938.6
Capital Contributions	30.0	33.2	34.7	36.8	37.6	172.3
Net Capex (excluding capital contributions)	573.7	591.1	540.7	534.1	526.7	2,766.3

Source: AER analysis.

Note: Numbers may not add up due to rounding.

We discuss our assessment of Energex's forecasting methodology, key assumptions and past capex performance in the sections below.

Our assessment of capex drivers is in appendices A and B. These set out the application of our assessment techniques to the capex drivers, and the weighting we gave to particular techniques. We used our reasoning in the appendices to form our alternative estimate.

6.4.1 Key assumptions

The NER requires Energex to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex. Energex must also provide a certification by its Directors that those key assumptions are reasonable.²⁸ Energex's key assumptions are set out in its regulatory proposal.²⁹

We have assessed Energex's key assumptions in the appendices to this capex attachment.

6.4.2 Forecasting methodology

The NER requires Energex to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.³⁰ Energex must include this information in its regulatory proposal.³¹ The main points of Energex's forecasting methodology are set out in its regulatory proposal.³²

In our preliminary decision we identified two aspects of Energex's forecasting methodology which indicate that its methodology is not a sufficient basis on which to conclude that its proposed total forecast capex reasonably reflects the capex criteria. These were:³³

- Energex's forecasting methodology generally applies a bottom–up build (or bottom–up assessment) to estimate the forecast expenditure for all its capex categories
- Energex's cost–benefit evaluation of each of its capital projects or programs reveals that its underlying risk assessment is excessively conservative.

Energex did not respond to our concerns regarding its top–down/bottom–up builds in its revised proposal. Energex did however note in its revised proposal that it has revised its risk profile based on feedback from the AER and its customers on the balance between network performance and electricity prices. Energex submitted that this revised program appropriately balances customer outcomes with its risk profile, safety and legislative obligations and network performance objectives.³⁴

EMCa assessed Energex's risk management procedures as part of its review on the revised capex program. EMCa noted that, whilst Energex refers to changes in its risk appetite, it has not provided evidence of the changes to risk of the revised program.

²⁸ NER, cl. S6.1.1.1(2), (4) and (5).

²⁹ Energex, *Regulatory proposal*, October 2014, p. 108.

³⁰ NER, cl. 6.8.1A and 11.60.3(c).

³¹ NER, cl. S6.1.1(2).

³² Energex, *Regulatory proposal*, October 2014, p. 106.

³³ AER, *Preliminary decision, Energex determination 2015–16 to 2019–20, Attachment 6 – Capital expenditure*, April 2015, pp. 20–24.

³⁴ Energex, *Revised regulatory proposal*, July 2015, p. 24.

Energex has also not explained the impact on the level of risk across its portfolio to confirm that it has achieved an optimal portfolio.³⁵

EMCa considered that the review process undertaken by Energex in its revised proposal confirmed the existence of a conservative risk assessment leading to an over-estimation of expenditure. As compared to its initial proposal, Energex appears to have taken prudent steps to review its forecast to reduce the over-estimation of expenditure. However from the information provided, EMCa could not confirm that this over-estimation of expenditure (resulting from the conservative risk assessment) had been completely removed.³⁶

The CCP also raised concerns with Energex's capex forecasting methodologies. In its submission, the CCP noted that Energex's capex forecasts have an insufficient regard to top-down considerations. The CCP submitted that bottom-up assessments have a tendency to overstate expenditure requirements, as they do not adequately account for interrelationships and synergies between projects or areas of work. The CCP also noted that Energex's capex forecasts are based on risk-averse and overly conservative risk assessments resulting in overstated costs.³⁷

We agree with the concerns raised by both EMCa and the CCP. We consider that the information provided in Energex's revised proposal did not address the concerns set out in our preliminary decision. Hence, the concerns we raised in our preliminary decision also hold for this final decision. We discuss issues with Energex's forecasting methodology in more detail in the appendices to this attachment.

6.4.3 Interaction with the STPIS

We consider that our approved capex forecast is consistent with the setting of targets under the STPIS. Particularly, we consider that the capex allowance should not be set such that there is an expectation that it would lead to Energex systemically under or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow Energex to maintain performance at the targets set under the STPIS. As such it is appropriate to apply the STPIS as set out in attachment 11.

In making our final decision, we have specifically considered the impact our decision will have on the safety and reliability of Energex's network. We consider our substitute estimate is sufficient for Energex to maintain the safety, service quality and reliability of its network consistent with its regulatory obligations. In any event, our provision of a total capex forecast does not constrain a service provider's actual spending – either as a cap or as a requirement that the forecast be spent on specific projects or activities. It is conceivable that a service provider might wish to expend particular capex differently or in excess of the total capex forecast set out in our decision. However such additional

³⁵ EMCa, *Review of proposed capex in Energex's revised regulatory proposal*, August 2015, pp. 5–6.

³⁶ EMCa, *Review of proposed capex in Energex's revised regulatory proposal*, August 2015, p. 6.

³⁷ Consumer Challenge Panel (CCP 2), *Submission - AER preliminary 2015–20 revenue determinations, Energex and Ergon Energy revised revenue proposals*, 3 September 2015, pp. 16–17.

expenditure is not included in our assessment of expenditure forecasts as it is not required to meet the capex objectives. We consider the STPIS is the appropriate mechanism to provide distributors with the incentive to improve reliability performance where such improvements reflect value to the energy customer.

6.4.4 Energex's capex performance

We have looked at a number of historical metrics of Energex's capex performance against that of other distributors in the NEM. We also compare Energex's proposed forecast capex allowance against historical trends. These metrics are largely based on outputs of the annual benchmarking report and other analysis undertaken using data provided by the distributors for the annual benchmarking report. The report includes Energex's relative partial and multilateral total factor productivity (MTFP) performance, capex per customer and maximum demand, and Energex's historic capex trend.

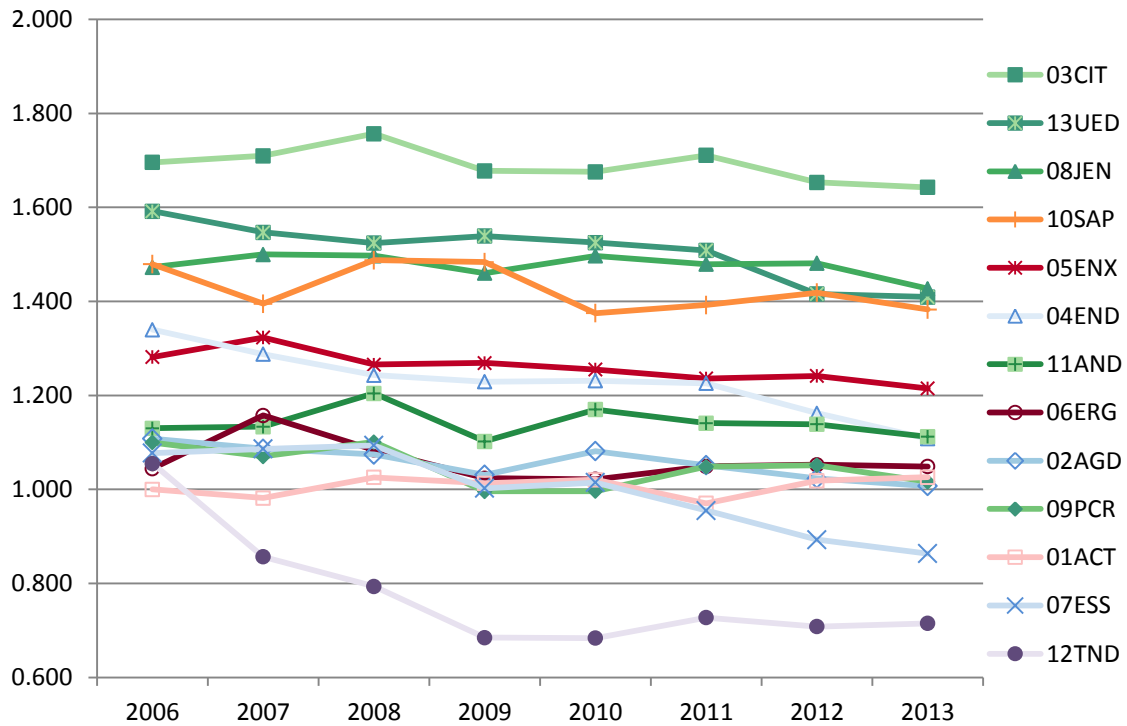
We note that the NER sets out that we must have regard to our annual benchmarking report.³⁸ This section explains how we have taken it into account. We consider this high level benchmarking at the overall capex level is suitable to gain an overall understanding of Energex's proposal in a broader context. We have not relied on our high level benchmarking metrics other than to gain a high level insight into Energex's proposal. We have not used this analysis deterministically in our capex assessment, which differs from our approach in the opex assessment.

Partial factor productivity of capital and multilateral total factor productivity

Figure 6.2 shows a measure of partial factor productivity of capital taken from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. Energex falls in the middle of the range on this assessment, falling behind some of the Victorian and South Australian distributors.

³⁸ NER, cl. 6.5.7(e).

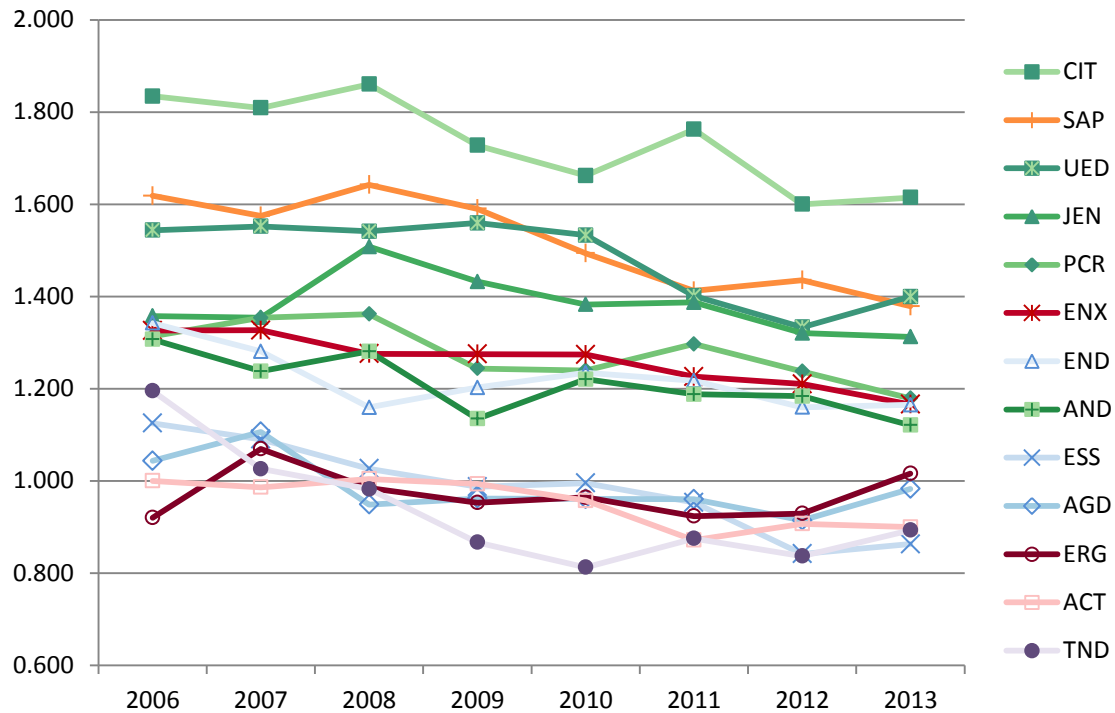
Figure 6.2 Partial factor productivity of capital (transformers, overhead and underground lines)



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 33.

Figure 6.3 shows that Energex ranks similarly on MTFP. MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length). Across all of these measures, Energex outperformed the NSW and ACT distributors; however the majority of the Victorian and South Australian distributors outperformed Energex.

Figure 6.3 Multilateral total factor productivity



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 31.

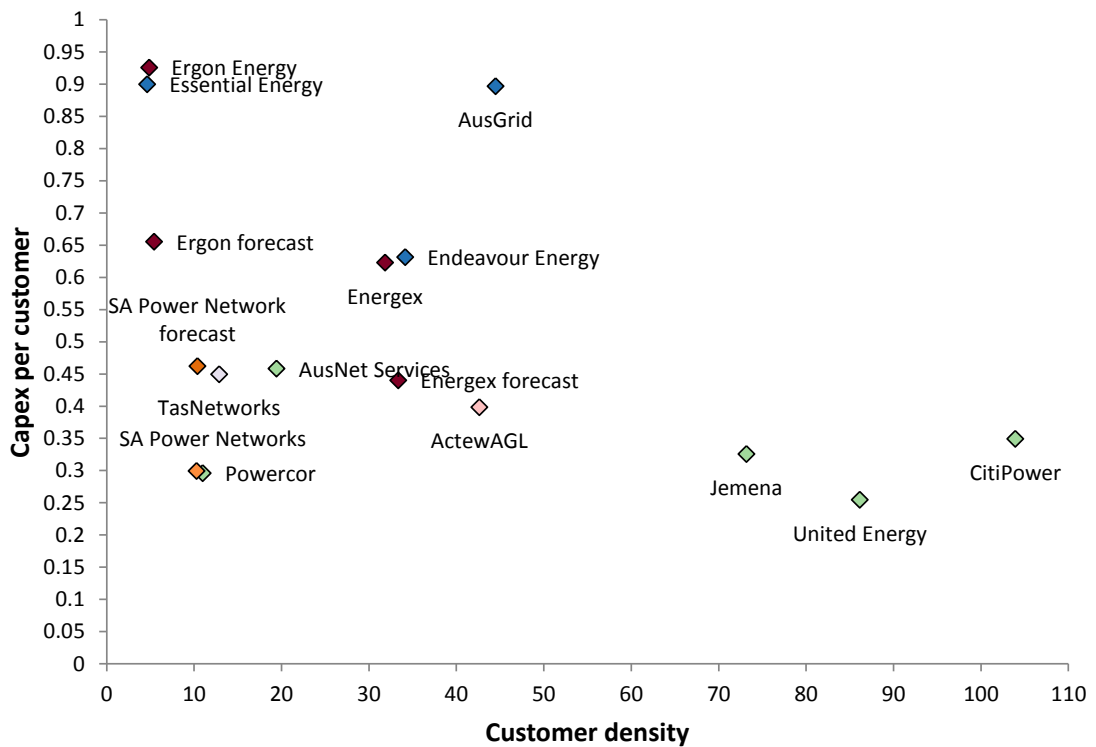
Relative capex efficiency metrics

Figure 6.4 and Figure 6.5 show capex per customer and per maximum demand, against customer density. Unless otherwise indicated as a forecast, the figures represent the five year average of each distributor's actual capex for the years 2008–2012. For the QLD and SA distributors we have also included the businesses' proposed capex for the 2015–20 regulatory control period. We have considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

For completeness Figure 6.4 and 6.5 also include Ergon Energy and SA Power Networks' proposed capex for the 2015–20 regulatory control period. However we do not use comparisons of Energex's total forecast capex with the total forecast capex of these distributors as inputs to our assessment. We consider it is appropriate to compare Energex's forecast only with actual capex. This is because actual capex consists of 'revealed costs' and would have occurred under the incentives of the regulatory regime.

Figure 6.4 shows that Energex had relatively high capex per customer for the 2008–2012 period when compared to its peers. Energex's capex per customer will decrease for the 2015–20 regulatory control period based on their proposed forecast capex. This reduction brings Energex's capex per customer to a similar level as the Victorian and South Australian distributors.

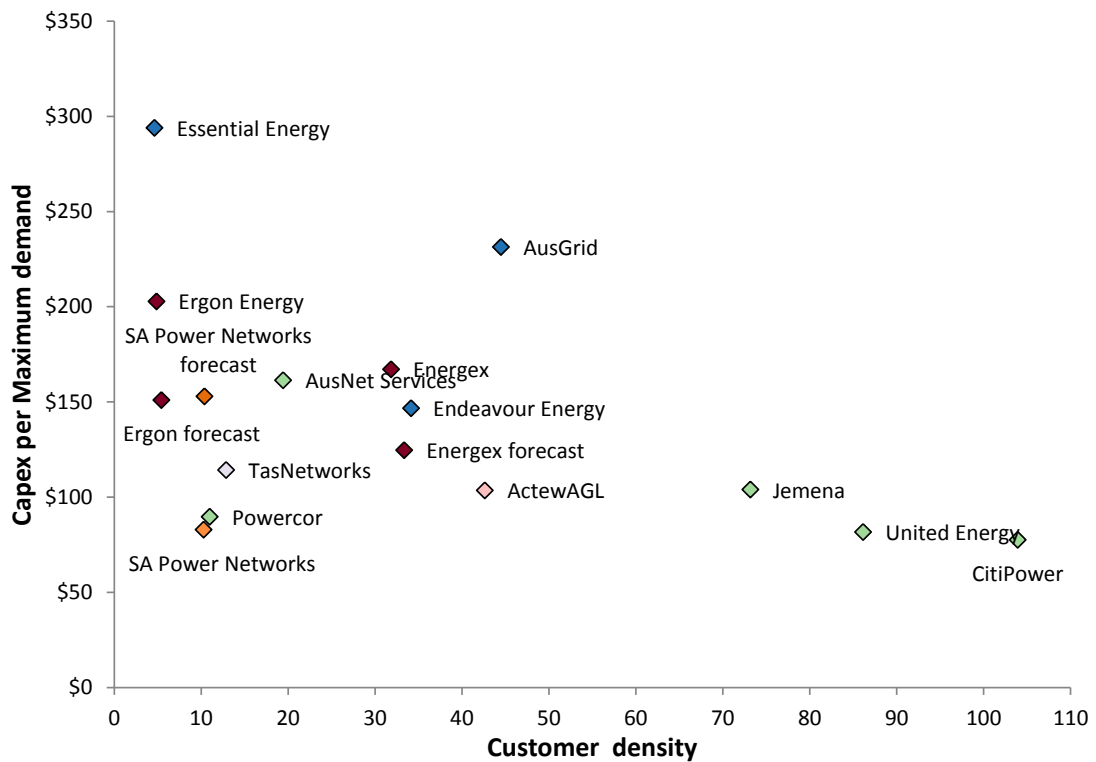
Figure 6.4 Capex per customer (000s, \$2013–14), against customer density



Source: AER analysis.

Figure 6.5 shows that Energex's capex per maximum demand for the 2008–2012 period was relatively high, but significantly lower than some NSW distributors. Capex per maximum demand is forecast to reduce for Energex in the next period.

Figure 6.5 Capex per maximum demand (000s, \$2013–14), against customer density



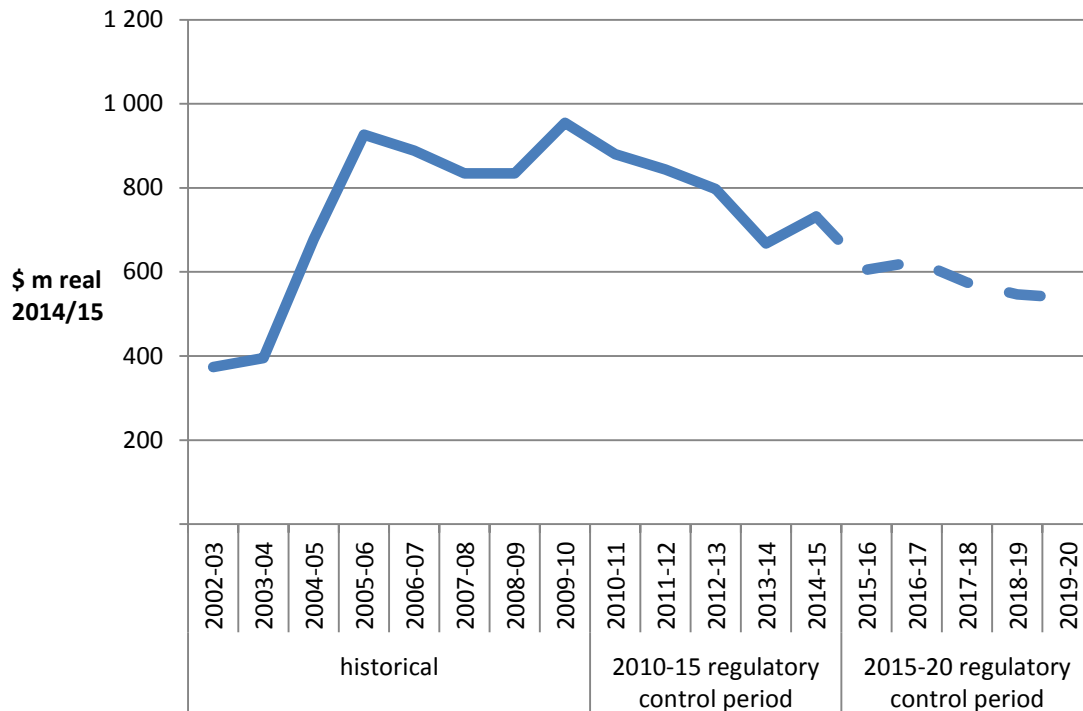
Source: AER analysis

Energex’s historic capex trends

We compared Energex’s capex proposal for the 2015–20 regulatory control period against the long term historical trend in capex levels.

Figure 6.6 shows actual historic capex and proposed capex between 2002 and 2020. This figure shows that while Energex’s average proposed capex for the 2015–20 regulatory control period is lower than the previous regulatory control period, it is still a substantial increase over the early 2000’s.

Figure 6.6 Energex total capex – historical and forecast 2002–2020



Source: AER analysis.

Submissions received by the AER note that the Queensland distributors significantly increased capex expenditure post 2005. This was due to flatter demand prior to 2005 as well as a change in jurisdictional standards in 2006 which drove investment in the networks. Submissions from interested parties suggest that we should have regard to the level of capex in 2000 to 2005 when considering proposed capex for the 2015–20 regulatory control period. Many stakeholders consider this a more like for like comparison.³⁹

In considering an approved level of capex we have not only considered past capex trends, rather we have used a range of methods available to us to assess the businesses proposals. We discuss these methods in further detail in the appendices to this attachment.

³⁹ Consumer Challenge Panel (CCP 2), *Submission - AER preliminary 2015–20 revenue determinations, Energex and Ergon Energy revised revenue proposals*, 3 September 2015, p. 16; EUAA, *Submission to AER draft determination and Energex's revised revenue proposal for the 2015 to 2020 regulatory period*, 24 July 2015, p. 5; QCOSS, *Response to the AER preliminary decision for Queensland distributors 2015–2020*, July 2015, p. 5; Total Environment Centre, *Submission to the AER on the preliminary decisions on the QLD DB's regulatory proposals 2015–20*, July 2015, p. 5.

6.4.5 Interrelationships

There are a number of interrelationships between Energex’s total forecast capex for the 2015–20 regulatory control period and other components of its distribution determination (see Table 6.4). We considered these interrelationships in coming to our final decision on total forecast capex.

Table 6.4 Interrelationships between total forecast capex and other components

Other component	Interrelationships with total forecast capex
Total forecast opex	<p>There are elements of Energex’s total forecast opex that are specifically related to its total forecast capex. These include the forecast labour price growth that we included in our opex forecast in attachment 7. This is because the price of labour affects both total forecast capex and total forecast opex.</p> <p>More generally, we note our total opex forecast will provide Energex with sufficient opex to maintain the reliability of its network. Although we do not approve opex on specific categories of opex such as maintenance, the total opex we approve will in part influence the repex Energex needs to spend during the 2015–20 regulatory control period.</p>
Forecast demand	<p>Forecast demand is related to Energex’s total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.</p>
Capital Expenditure Sharing Scheme (CESS)	<p>The CESS is related to Energex’s total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, and that it reasonably reflects the capex criteria. As we note in the capex criteria table below, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudence of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from Energex’s regulatory asset base. In particular, the CESS will ensure that Energex bears at least 30 per cent of any overspend against the capex allowance. Similarly, if Energex can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, Energex risks having to bear the entire overspend.</p>
Service Target Performance Incentive Scheme (STPIS)	<p>The STPIS is interrelated to Energex’s total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the 2015–20 regulatory control period. This is because such expenditure should be offset by rewards provided through the application of the STPIS.</p> <p>Further, the forecast capex should be sufficient to allow Energex to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to Energex systematically under or over performing against its targets.</p>
Contingent project	<p>A contingent project is interrelated to Energex’s total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of Energex’s total forecast capex for the 2015–20 regulatory control period.</p> <p>We did not identify any contingent projects for Energex during the 2015–20 regulatory control period.</p>

Source: AER analysis.

6.4.6 Consideration of the capex factors

As we discussed in section 6.3, we took the capex factors into consideration when assessing Energex's total capex forecast.⁴⁰ Table 6.5 summarises how we have taken into account the capex factors.

Table 6.5 AER consideration of the capex factors

Capex factor	AER consideration
The most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient distributor over the relevant regulatory control period	We had regard to our most recent benchmarking report in assessing Energex's proposed total forecast capex and in determining our alternative estimate for the 2015–20 regulatory control period. This can be seen in the metrics we used in our assessment of Energex's capex performance.
The actual and expected capex of Energex during any preceding regulatory control periods	<p>We had regard to Energex's actual and expected capex during the 2010–2015 and preceding regulatory control periods in assessing its proposed total forecast.</p> <p>This can be seen in our assessment of Energex's capex performance. It can also be seen in our assessment of the forecast capex associated with each of the capex drivers that underlie Energex's total forecast capex.</p> <p>In these cases we have applied trend analysis which is reasonably likely to be recurrent in nature (e.g. non-network related capex).</p>
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by Energex in the course of its engagement with electricity consumers	<p>We had regard to the extent to which Energex's proposed total forecast capex includes expenditure to address consumer concerns that Energex identified. Energex has undertaken engagement with its customers and presented high level findings regarding its customer preferences. These findings suggest that consumers value lower prices and reliable networks.</p> <p>On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Energex's proposed total forecast capex includes capex that addresses the concerns of its consumers that it has identified.</p>
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing Energex's proposed real cost escalation factors.
The substitution possibilities between operating and capital expenditure	We had regard to the substitution possibilities between opex and capex. We considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion about the interrelationships between Energex's total forecast capex and total forecast opex in Table 6.4 above.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to Energex	We had regard to whether Energex's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between Energex's total forecast capex and the application of the CESS and the STPIS in Table 6.4 above.

⁴⁰ NER, cl. 6.5.7(c), (d) and (e).

Capex factor	AER consideration
The extent to which the capex forecast is referable to arrangements with a person other than the distributor that do not reflect arm's length terms	We had regard to whether any part of Energex's proposed total forecast capex or our alternative estimate is referable to arrangements with a person other than Energex that do not reflect arm's length terms. We considered the arrangements between Energex and its related party SPARQ regarding the provision of ICT services and do not have evidence to indicate that this does not reflect arm's length terms.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We had regard to whether any amount of Energex's proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriately be included as a contingent project.
The extent to which Energex has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which Energex made provision for efficient and prudent non-network alternatives as part of our assessment. In particular, we considered this within our review of Energex's augex proposal.
Any other factor the AER considers relevant and which the AER has notified Energex in writing, prior to the submission of its revised regulatory proposal, is a capex factor	We did not identify any other capex factor that we consider relevant.

Source: AER analysis.

A Assessment techniques

This appendix describes the assessment approaches we applied in assessing Energex's proposed forecast capex. Appendix B sets out in greater detail the extent to which we relied on each of the assessment techniques.

The assessment techniques that we apply in capex are necessarily different from those we apply in the assessment of opex. This is reflective of differences in the nature of the expenditure we are assessing. As such, we use some assessment techniques in our capex assessment that are not suitable for assessing opex and vice versa. We set this out in our expenditure assessment guideline, where we stated:⁴¹

Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes. For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across distributors) when forming a view on forecast unit costs.

Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements.

Below we set out the assessment techniques we used to assess Energex's capex.

A.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. The NER requires us to consider the annual benchmarking report as it is one of the capex factors.⁴² Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.⁴³ It allows us to compare the performance of a distributor against its own past performance, and the performance of other distributors. Economic benchmarking helps us to assess whether a distributor's capex forecast represents efficient costs.⁴⁴ As the AEMC stated, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.⁴⁵

A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and overall capex efficiency. In general, these measures calculate a distributor's efficiency

⁴¹ AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 8.

⁴² NER, cl. 6.5.7(e)(4).

⁴³ AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines*, November 2013.

⁴⁴ NER, cl. 6.5.7(c).

⁴⁵ AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 25.

with consideration given to its inputs, outputs and its operating environment. We considered each distributor's operating environment in so far as there are factors outside of a distributor's control that affect its ability to convert inputs into outputs.⁴⁶ Once such exogenous factors are taken into account, we expect distributors to operate at similar levels of efficiency. One example of an exogenous factor we took into account is customer density. For more on how we derived these measures, see our annual benchmarking report.⁴⁷

In addition to the measures in the annual benchmarking report, we considered how distributors performed on a number of overall capex metrics, including capex per customer, and capex per maximum demand. We calculated these economic benchmarks using actual data from the previous regulatory control period.

The results from economic benchmarking give an indication of the relative efficiency of each of the distributors, and how this has changed over time.

A.2 Trend analysis

We considered past trends in actual and forecast capex as this is one of the capex factors under the NER.⁴⁸

Trend analysis involves comparing a distributor's forecast capex and work volumes against historical levels. Where forecast capex and volumes are materially different to historical levels, we seek to understand the reasons for these differences. In doing so, we consider the reasons the distributor provides in its proposal, as well as changes in the circumstances of the distributor.

In considering whether the total forecast capex reasonably reflects the capex criteria, we need to consider whether the forecast will allow the distributor to meet expected demand, and comply with relevant regulatory obligations.⁴⁹ Demand and regulatory obligations (specifically, service standards) are key drivers of capex. More onerous standards will increase capex, as will growth in maximum demand. Conversely, reduced service obligations or a decline in demand will likely cause a reduction in the amount of capex the distributor requires.

Maximum demand is a key driver of augmentation or demand driven expenditure. Augmentation often needs to occur prior to demand growth being realised. Hence, forecast rather than actual demand is relevant when a business is deciding the augmentation projects it will require in an upcoming regulatory control period. To the extent actual demand differs from forecast, however, a business should reassess the need for the projects. Growth in a business' network will also drive connections related

⁴⁶ AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.

⁴⁷ AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014.

⁴⁸ NER, cl. 6.5.7(e)(5).

⁴⁹ NER, cl. 6.5.7(a)(3).

capex. For these reasons it is important to consider how trends in capex (in particular, augex and connections) compare with trends in demand (and customer numbers).

For service standards, there is generally a lag between when capex is undertaken (or not) and when the service improves (or declines). This is important when considering the expected impact of an increase or decrease in capex on service levels. It is also relevant to consider when service standards have changed and how this has affected the distributor's capex requirements.

We looked at trends in capex across a range of levels including at the total capex level, and the category level (such as growth related capex, and repex) as relevant. We also compared these with trends in demand and changes in service standards over time.

A.3 Category analysis

Expenditure category analysis allows us to compare expenditure across NSPs, and over time, for various levels of capex. The comparisons we perform include:

- overall costs within each category of capex
- unit costs, across a range of activities
- volumes, across a range of activities
- asset lives, across a range of asset classes which we use in assessing repex.

Using standardised reporting templates, we collected data on augex, repex, connections, non-network capex, overheads and demand forecasts for all distributors in the NEM. The use of standardised category data allows us to make direct comparisons across distributors. Standardised category data also allows us to identify and scrutinise different operating and environmental factors that affect the amount and cost of works performed by distributors, and how these factors may change over time.

A.4 Predictive modelling

Predictive modelling uses statistical analysis to determine the expected efficient costs over the regulatory control period associated with the demand for electricity services for different categories of works. We have two predictive models:

- the repex model
- the augex model (used in a qualitative sense).

The use of the repex and augex models is directly relevant to assessing whether a distributor's capex forecast reasonably reflects the capex criteria.⁵⁰ The models draw on actual capex the distributor incurred during the preceding regulatory control period. This past capex is a factor that we must take into account.⁵¹

⁵⁰ NER, cl. 6.5.7(c).

⁵¹ NER, cl. 6.5.7(e)(5).

The repex model is a high-level probability based model that forecasts asset replacement capex (repex) for various asset categories based on their condition (using age as a proxy), and unit costs. If we consider a distributor's proposed repex does not conform to the capex criteria, we use the repex model (in combination with other techniques where appropriate) to generate a substitute forecast.

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.⁵² The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the distributor over a given period.⁵³ In this way, the augex model accounts for the main internal drivers of augex that may differ between distributors, namely peak demand growth and its impact on asset utilisation. We can use the augex model to identify general trends in asset utilisation over time as well as to identify outliers in a distributor's augex forecast.⁵⁴

For our decision we have relied on input data for the augex model to review forecast utilisation of individual zone substations to assess whether augmentation may be necessary to alleviate capacity constraints. We use this analysis both as a starting point for our further detailed evaluation, and as a cross-check on our overall augex estimate. We have not otherwise used the augex model in our assessment of Energex's augex forecast.

A.5 Engineering review

We drew on engineering and other technical expertise within the AER to assist with our review of Energex's capex proposal.⁵⁵ We also relied on the technical review of our consultant, EMCa, to assist with our review of Energex's capex proposal. This involved reviewing Energex's processes, and specific projects and programs of work.

Appendix B discusses in detail our consideration of these reviews in our assessment of Energex's capex forecast.

⁵² Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

⁵³ For more information, see: AER, *Guidance document: AER augmentation model handbook*, November 2013.

⁵⁴ AER, *Meeting summary – distributor replacement and augmentation capex*, *Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution)*, 8 March 2013, p. 1.

⁵⁵ AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 86.

B Assessment of capex drivers

We present our detailed analysis of the sub-categories of Energex's forecast capex for the 2015–20 regulatory control period in this appendix. These sub-categories reflect the drivers of forecast capex over the 2015–20 regulatory control period. These drivers are augex, customer connections capex, repex, reliability improvement capex, capitalised overheads and non-network capex.

As we discuss in the capex attachment, we are not satisfied that Energex's proposed total forecast capex reasonably reflects the capex criteria. In this appendix we set out further analysis in support of this view. This further analysis also explains the basis for our alternative estimate of Energex's total forecast capex that we are satisfied reasonably reflects the capex criteria. In coming to our views and our alternative estimate we have applied the assessment techniques that we discuss in appendix A.

This appendix sets out our findings and views on each sub-category of capex. The structure of this appendix is:

- Section B.1 Alternative estimate
- Section B.2 AER findings and estimates for augmentation expenditure
- Section B.3 AER findings and estimates for customer connections capex, including capital contributions
- Section B.4 AER findings and estimates for replacement expenditure
- Section B.5 AER findings and estimates for capitalised overheads
- Section B.6 AER findings and estimates for non–network capex.

In each of these sections, we examine sub-categories of capex which we include in our alternative estimate. For each such sub-category, we explain why we are satisfied the amount of capex that we include in our alternative estimate reasonably reflects the capex criteria.

B.1 Alternative estimate

Having examined Energex's proposal, we formed a view on our alternative estimate of the capex required to reasonably reflect the capex criteria. Our alternative estimate is based on our assessment techniques, explained in section 6.3 and appendix A. Our weighting of each of these techniques, and our response to Energex's submissions on the weighting that should be given to particular techniques, is set out under the capex drivers in appendix B.

We are satisfied that our alternative estimate reasonably reflects the capex criteria.

B.2 AER findings and estimates for augmentation expenditure

Augex is driven by a service provider's need to build or augment its network. The main driver of augex is maximum demand and its effect on network utilisation. It can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements. Our assessment of augex seeks to establish the prudent and efficient expenditure that Energex will require to build or augment its network in response to these drivers.

B.2.1 Position

Our estimate of required augex for Energex for the 2015–20 regulatory control period is \$403.7 million (\$2014–15). We accept that a large proportion of Energex's revised augex forecast reasonably reflects the capex criteria. However, we consider that Energex's proposed capex for some of its individual augmentation programs is overstated (as set out in Table). We are satisfied that our estimate of required augex, when combined with the rest of our capex decision, reasonably reflects the capex criteria and will enable Energex to achieve the capex objectives, including those relating to complying with its regulatory obligations and maintenance of the quality, reliability and security of its network.

Table compares forecasts across the decision making process between the initial proposal and our final decision.

Table B.1 Energex augex forecasts comparisons (\$2014–15 million, excluding overheads)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Initial augex forecast	117.5	126.7	109.2	84.8	74.4	512.7
AER preliminary decision	92.6	103.6	87.9	65.3	56.4	405.5
Revised Proposal	108.5	116.5	100.7	77.3	68	471.0
AER final forecast	88.0	95.3	79.6	75.3	65.6	403.7

Source: AER analysis, Energex revised regulatory proposal.

Similar to its initial proposal, Energex's revised proposal augex forecast is comprised of demand-related capex (for its distribution, sub-transmission and low voltage networks), reliability, quality of supply, and land and easements. Our final decision on these components, and the reasons for our decision, are set out in section B.2.4

Table sets out our alternative estimate for each year of the 2015–20 regulatory control period.

Table B.2 AER's alternative estimate of augex (\$2014–2015 million, excluding overheads)

	2015–16	2016–7	2017–18	2018–19	2019–20	Total
Energex revised proposal	108.5	116.5	100.7	77.3	68.0	471.0
Reduction in low voltage augex	-14.2	-14.1	-14.2	10.3	10.3	-22.0
Reduction in quality of supply augex	-2.4	-2.0	-2.0	-4.4	-4.4	-15.2
Reduction in reliability augex	-2.2	-1.5	-1.5	-1.6	-1.6	-8.4
Reduction in land and easements augex	-1.7	-3.6	-3.6	-6.3	-6.7	-21.7
AER alternative estimate	88.0	95.3	79.6	75.3	65.6	403.7
Difference	-18.9%	-18.2%	-21.0%	-2.6%	-3.5%	-14.3%

Source AER analysis.

Note The annualised augex in this table differs from our capex model. Energex's revised proposal and our alternative estimate is based on the bottom-up build of the individual components of Energex's forecast, based on costing information provided by Energex in its regulatory proposal and in response to an information request. The augex estimate in our capex model is based on applying the annual percentage to each year of Energex's augex forecast as contained in its revised proposal capex model. Numbers may not add up due to rounding.

B.2.2 Revised proposal

Energex's revised proposal is \$471 million (\$2014–15). Table shows Energex's augex cost drivers and their contribution to Energex's overall revised augex forecast.

Table B.3 Energex's proposed augex (\$2014–15 million, excluding overheads)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Growth and compliance	87.8	98.4	82.5	49.9	40.4	359.0
Power quality	6.3	5.3	5.3	11.8	11.8	40.5
Reliability	11.1	7.5	7.5	7.9	7.9	41.8
Land and easements	3.3	5.4	5.5	7.7	7.8	29.6
Total augex revised proposal	108.5	116.5	100.7	77.3	68.0	471.0

Source: Energex revised regulatory proposal.

Note: Capex includes Energex's proposed 'on-costs' allocated in accordance with Energex's response to AER EGX 068.

Energex's revised augex forecast is 8 per cent lower than its initial proposal. In developing its revised forecast, Energex stated that it reviewed its augmentation programs in light of the preliminary decision, including the network risk profile, safety

implications and customer impact associated with a revised program.⁵⁶ Energex's revised proposal:

- accepts our preliminary decision on the sub-transmission and 11kV augex components of its growth and compliance capex forecast
- retains its original forecast for the low voltage program which also forms part of its growth and compliance category, and provides further information about the fuse retrofit component of this program
- reduces its forecast capex to comply with its jurisdictional reliability obligations based on a review of the scope and cost of the program
- retains its original forecast for monitoring and managing power quality issues
- reduces its forecast 'on-costs' and provided further information about this capex.

Energex's revised proposal and reasoning for these elements is set out in more detail in section B.2.5.

B.2.3 AER approach

In our preliminary decision on Energex's augex forecast, we examined the proposal in four parts.

First, we considered the proposed forecast in the context of past expenditure, demand and current network utilisation. We concluded that utilisation of Energex's network had fallen over the period between 2009–10 and 2013–14, but this was to be expected following the change to the standards that Energex was required to plan and build its network to meet. We further noted that the fall in utilisation had been exacerbated by declining peak demand over the previous period.⁵⁷

Second, we examined the governance processes and forecasting methodologies that underpinned Energex's forecast, which was assisted by a technical review undertaken by our independent consultants, Energy Market Consulting Associates (EMCa). We concluded that the framework and methodology applied by Energex is consistent with industry standards.⁵⁸ However, we also noted the findings of EMCa that Energex's risk assessment approach meant that the augex forecast is overstated.⁵⁹

Third, to quantify the impact of any identified biases, we had regard to the technical review of a sample of projects undertaken by EMCa.⁶⁰ We removed the impact of the identified overestimation bias evident in the following categories:

⁵⁶ Energex, *Revised Regulatory Proposal*, July 2015, p. 39

⁵⁷ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 43.

⁵⁸ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 47.

⁵⁹ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 50.

⁶⁰ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, pp. 41 and 51-61; EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 March 2015, pp. 41-66.

- Growth and compliance capex — 10 per cent adjustment to reflect our conclusion that the forecast is biased upwards from low risk consequence projects being included and the potential for the deferral of projects in the front-end loaded forecast.⁶¹
- Power quality — 37.5 per cent adjustment to reflect our conclusion that the scope of the proposed capex is likely overstated because the level of network monitoring is above the level of power quality monitoring present at most network operators, and appropriate cost benefit and risk analysis has not been conducted by Energex.⁶²
- Reliability — 65 per cent adjustment to reflect our conclusion that the scope of the proposed capex to address low reliability feeders is likely overstated.⁶³

We also reviewed proposed capex for land and easements and on-costs:

- We accepted Energex's proposed augex for land and easements because it likely reflects a realistic expectation of demand in the 2020–25 period. However, we stated that our final decision will take into account AEMO's connection point forecasts for 2020–25 (to be published by July 2015) and other information so that it reflects the most up to date information.⁶⁴
- We did not accept the additional on-costs because it was not clear based on the information provided by Energex whether the underlying driver of the capex is augmentation, or how it has been calculated.⁶⁵

For our final decision on Energex's augex proposal, we adopt the same assessment approach as for our preliminary decision. Where we have relied upon analysis and reasoning previously provided in our preliminary decision, we will state so in the relevant sections.

We received submissions from the Consumer Challenge Panel, the Queensland Council of Social Service (QCOSS) and the Alliance of Electricity Consumers on our preliminary decision and Energex's revised proposal. We consider these submissions in the relevant sections of this final decision.

The remainder of this chapter is structured as follows:

- Section B.2.4 responds to the submission from the CCP on our use of trend analysis.
- Section B.2.5 sets out our final decision on Energex's augex drivers and projects, including our responses to Energex's revised proposal submission. We are assisted by further technical analysis from our independent consultants, EMCA.

⁶¹ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 51 and 52-55.

⁶² AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 51 and 56-57.

⁶³ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 51 and 57-61.

⁶⁴ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, pp. 61-62.

⁶⁵ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, pp. 62-63.

B.2.4 Trend analysis

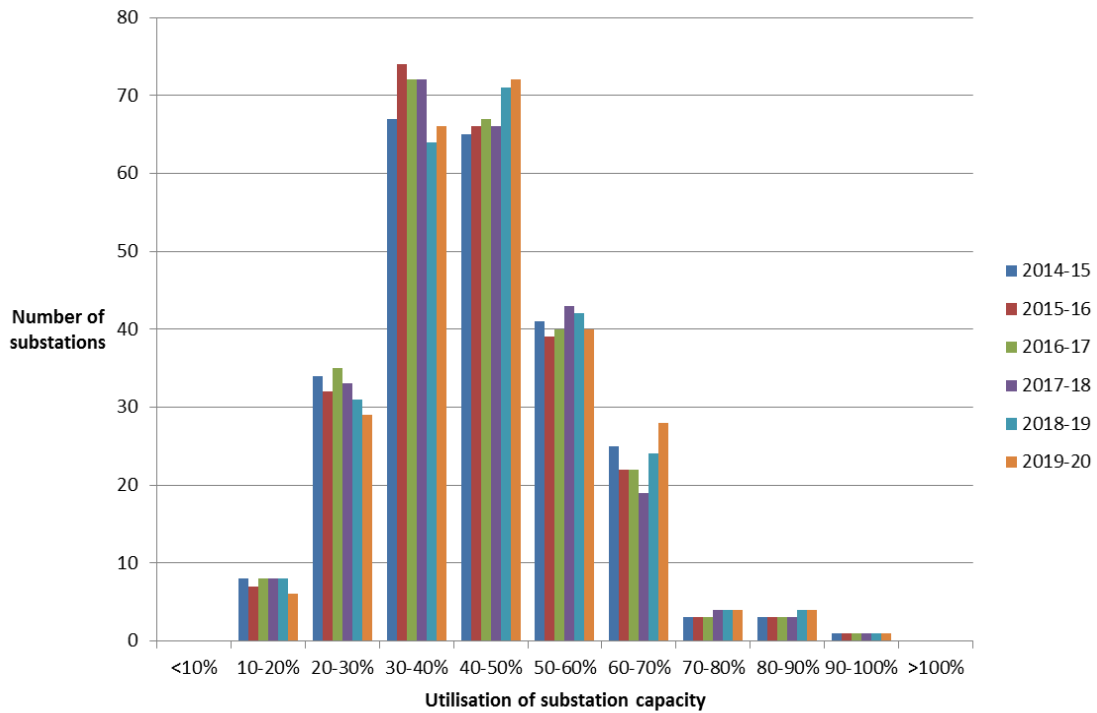
For our preliminary decision, the starting point for our analysis was reviewing the trends in Energex's augex, maximum demand and network utilisation as these are the key drivers of network augmentation.⁶⁶ This provided us with an initial sense of whether Energex's augex forecast is reasonably required to meet forecast demand and alleviate forecast capacity constraints.

On the basis of our review we observed that:

- Energex's proposed demand-driven augex was 64 per cent lower than the 2010–15 regulatory period.
- Energex's overall network utilisation had significantly decreased between 2010 and 2014, which was consistent with a decrease in demand and significant network investment over this period. Declining network utilisation historically supported lower levels of augex than in previous periods, which was consistent with Energex's proposal.
- Energex's forecast network utilisation at each zone substation shows that the majority of Energex's substations are not forecast to be highly utilised over the 2015–20 period. While a small number of zone substations are forecast to operate at between 80 and 90 per cent of capacity in 2020, it was not clear that this supported the overall level of augex Energex proposed. This is evident in Figure below, which shows that Energex expects that the vast majority of its zone substations will operate below 70 per cent of its capacity by 2020 (in the absence of augmentation).

⁶⁶ See AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, pp. 42-46.

Figure B.1 Zone substation forecast utilisation 2014–15 to 2019–20 (without additional augmentation)



Source: AER analysis; augex model, Energex reset RIN.

Notes: Utilisation is the ratio of maximum demand and the thermal rating of each feeder for the specified years. Forecast utilisation in this figure is based on forecast weather corrected 50 per cent POE maximum demand at each substation and existing capacity without additional augmentation over 2015–20.

We have maintained these views from our trend analysis for this final decision.

Energex did not directly respond to our observations about its network utilisation in its revised proposal. However, Energex accepted our preliminary decision on its sub-transmission and distribution network augex.⁶⁷ Energex also stated in its revised proposal:

The growth-related program was based on the 2014 post-summer maximum demand forecast. Energex has reviewed the growth related projects and programs based on the latest demand forecast and resulting network risk. Energex is not proposing to increase its growth-related expenditure and has accepted the AER’s reductions to its subtransmission and 11 kV augmentation programs. Energex will instead manage the increase in network risk associated with the higher demand forecast.⁶⁸

⁶⁷ Energex, *Revised Regulatory Proposal*, July 2015, pp. 39-40.

⁶⁸ Energex, *Revised Regulatory Proposal*, July 2015, pp. 39-40.

The Consumer Challenge Panel's submission to our preliminary decision and Energex's revised proposal raised some concerns with our augex allowance (and the use of trend analysis in particular). The CCP submitted that:

- We accepted maximum demand forecasts that were not supported by AEMO's most recent forecasts. The CCP submitted that AEMO's 2015 connection point forecasts do not support Energex's proposed levels of augmentation.⁶⁹
- We gave inadequate scrutiny of any 'pockets of demand growth' and insufficient demonstration of associated local capacity constraints. It submitted that augex needs to be justified based on sound evidence of localised demand growth together with detailed demonstration of genuine local capacity constraints.⁷⁰
- We gave insufficient consideration to Energex's excess capacity and declining system utilisation. While the CCP stated that we acknowledged trends in excess capacity, it submitted that we did not quantify the impacts of excess capacity or demonstrate that it has been appropriately considered in the augex assessment.⁷¹ It submitted that system utilisation is much more material to the determination of efficient augex needs than our preliminary decision determined.⁷²
- We gave insufficient consideration to capital efficiency and the prudence/efficiency of the proposed augex spend.
- We were over-reliant on trend analysis rather than on efficient costs.

We agree with the CCP that network utilisation is an important factor to consider in reviewing augmentation requirements over time. This is because network utilisation is the fundamental driver of network augmentation due to demand growth. Network utilisation is the measure of installed network capacity that is in use (or is forecast to be in use).

As a starting point, we review average utilisation rates in order for us, as well as stakeholders, to gain a broader understanding of trends over time particularly against aggregated augex trends. Similar to the CCP, we observed that there was declining system utilisation over the recent period. However, in terms of determining a level of augex for the 2015–20 period, it is also necessary to consider future demand and forecast network utilisation over this period, including localised demand growth and capacity.

For this assessment we looked at forecast network utilisation at the zone substation level which gave us an indication of whether there were forecast localised capacity constraints over the 2015–20 period. This is shown in Figure , which shows that only a few zone substations are expected to be highly utilised by the end of the 2015–20 regulatory control period. While this suggests that some augmentation may be justified

⁶⁹ CCP, *Submission to preliminary decision and revised proposal*, September 2015, p. 22.

⁷⁰ CCP, *Submission to preliminary decision and revised proposal*, September 2015, p. 22.

⁷¹ CCP, *Submission to preliminary decision and revised proposal*, September 2015, p. 24.

⁷² CCP, *Submission to preliminary decision and revised proposal*, September 2015, p. 25.

to alleviate forecast capacity constraints, it may not support the amount of capex originally proposed by Energex to alleviate capacity constraints.

In some cases, this information may inform our estimate of augex. However, for our preliminary decision, our observations were primarily used to inform us and direct us to more detailed economic and engineering reviews of Energex's augex forecast.

We disagree with the CCP that we gave insufficient consideration to the prudence and efficiency of Energex's proposed augex. Our detailed assessment of the prudence and efficiency of Energex's augex forecast was based on our detailed economic and engineering review of the proposal. We were informed by the findings and recommendations from engineering consultants EMCa, which are set out in our preliminary decision. For our final decision, we have considered all new information provided by Energex in its revised proposal and other material before us, and formed a view on the prudence and efficiency of its revised proposal. This is considered in section B.2.5 below.

Finally, all of our analysis of network utilisation trends was based on Energex's forecasts of maximum demand at the system and local levels. As set out in appendix C, we are satisfied that Energex's forecasts of maximum demand reflect a realistic expectation of demand over the 2015–20 period. Our reasons, including responding to points raised in the CCP's submission, are provided in appendix C.

B.2.5 Driver analysis

This section sets out our assessment of whether each component of Energex's augex forecast reasonably reflects the capex criteria. We then determine an alternative estimate for each augex component.

As discussed in section B.2.3, our decision is based on identified forecasting biases within Energex's bottom-up project estimates, and then quantifying these impacts. To quantify the impact of the forecasting biases, we have had regard to the findings of our preliminary decision (as well material taken into account in reaching that decision), Energex's revised proposal, supporting documentation and submissions on this material, and a further review of Energex's revised proposal (including a further review conducted by our independent consultants, EMCa).

Table B.4 sets out our final decision on each component of Energex's augex proposal and the overall augex forecast.

Table B.4 AER alternative augex forecast (\$2014–15 million, excluding overheads)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Growth and compliance	73.6	84.2	68.3	60.2	50.7	337.0
Quality of supply	3.9	3.3	3.3	7.4	7.4	25.3
Reliability	8.9	6.0	6.0	6.3	6.3	33.4
Land and easements	1.6	1.8	1.9	1.4	1.1	7.9
Total augex alternative estimate	88.0	95.3	79.6	75.3	65.6	403.7

Source: AER analysis.

Our final decision reflects the following positions:

- We include \$337 million of Energex’s proposed \$359.0 million (\$2014–15, including on-costs) growth and compliance augex in our alternative estimate. Energex’s revised proposal for sub-transmission, distribution and demand management augex is consistent with our preliminary decision.
- We include \$136.6 million of Energex’s proposed 158.6 million (\$2014–15, including on-costs) for low voltage augex (which is also contained within its growth and compliance forecast in our alternative estimate. After including on-costs (as discussed below), this amount is consistent with our preliminary decision and follows an EMCa review of new information submitted by Energex and a bottom-up review of the proposed projects.
- We include \$24 million of Energex’s proposed \$38.5 million (\$2014–15, including on-costs) for power quality augex in our alternative estimate. Based on our review of Energex’s revised proposal, we consider that the case for implementing its power quality program has not been justified. While Energex has provided new evidence to support the expected increase in solar PV penetration on its network, we are not satisfied that this supports investment in network monitoring of voltage levels. Our included capex will allow Energex to remediate existing and forecast supply voltage issues on its network.
- We include \$31.8 million of Energex’s proposed \$39.8 million (\$2014–15, including on-costs) for reliability augex in our alternative estimate. Based on our review of Energex’s revised proposal, we consider there is further scope for Energex to reduce its reliability augex program while still meeting the requirements set out under its obligations to improve worst performing feeders under its Distribution Authority.
- We include \$7.9 million of Energex’s proposed \$29.7 million (\$2014–15, including on-costs) for land and easements capex in our alternative estimate. While we provisionally accepted Energex’s proposed amount for land and easements capex in our preliminary decision, this was to be reviewed further in this final decision, based on updated forecasts for maximum demand. Energex’s recent maximum demand forecasts (as calculated at the connection point level) reveal that it

forecasts less demand in the regions where it proposed to purchase land for future infrastructure. In all instances, we found that infrastructure may not be needed for between 5 and 10 years, which supports deferring the purchase of land and some easements. This results in a reduction of 73 per cent.

- We have allocated Energex’s proposed on-costs to each augex sub-category, using an allocation provided by Energex. We have not separately assessed on-costs in this final decision. Energex allocates on-costs to projects and/or services on the basis of the value of material or labour charged to each service. It follows that where we have accepted Energex’s forecast, we have included all of the on-costs for that category. Where we have made adjustments, these adjustments have applied equally to the associated on-costs.

The following sections set out Energex’s revised proposed capex for each cost driver, EMCa’s assessment and findings (where relevant), and our conclusions.

Note that our preliminary decision discussed our findings on Energex’s forecasting methodology. This final decision does not repeat this discussion and we maintain our findings on these aspects as set out in the preliminary decision.⁷³ Where Energex or others have responded to or addressed any concerns we raised in our preliminary decision, we consider it this in this section.

Growth and compliance augex

Table sets out the components and drivers of Energex’s revised growth and compliance augex for the 2015–20 regulatory control period.

Table B.5 Energex revised growth and compliance forecast (\$2014–15 million, excluding overheads)

Category	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Sub-transmission augmentation	29.2	38.1	21.2	12.4	3.9	104.8
11kv Distribution augmentation	16.8	18.2	19.2	18.4	17.6	90.2
Low voltage augmentation projects	40.8	40.9	40.9	17.9	18.0	158.6
Demand management	1.0	1.2	1.2	1.2	1.0	5.5
Total	87.8	98.4	82.5	49.9	40.4	359.0

Source: Energex revised proposal; Energex response to AER EGX 068.

Note: Capex includes Energex’s proposed ‘on-costs’ allocated in accordance with Energex’s response to AER EGX 068.

The following sections set out our consideration of those components.

⁷³ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, pp. 46-49.

Sub-transmission and distribution augex

In its original regulatory proposal, Energex proposed:

- \$113.1 million (\$2014–15) to augment its sub-transmission network. The augmentation program consisted of 90 projects to service customer growth, comply with security standards and to undertake joint planning projects with Powerlink.
- \$97 million (\$2014–15) to augment the 11kV network to service customer and demand growth.

In our preliminary decision we noted that the sub-transmission forecast was heavily front-loaded with 85 per cent of proposed expenditure occurring in the first three years of the 2015–20 period.⁷⁴ EMCa observed that the timing of individual sub-transmission projects is likely to change, including a level of deferral beyond the 2015–20 period.

In regard to distribution augex, EMCa reviewed the two largest projects for which Energex had provided project assessment reports. EMCa found that one of these projects (11kV overhead fault limit correction) could be deferred and that the other (Deception Bay project) was justified.

EMCa concluded that Energex's forecast growth and compliance augex requirements (of which sub-transmission and distribution are components) are overestimated in the order of 5 to 15 per cent.⁷⁵ In light of the EMCa analysis, in our preliminary decision we applied a 10 per cent reduction to the total growth and compliance augex forecast.⁷⁶ This reduced sub-transmission augex to \$102 million and distribution to \$87 million (excluding on-costs that we assessed separately in our preliminary decision).

In its revised proposal, Energex noted that it had “subsequently reviewed its augmentation programs including the network risk profile, safety implications and customer impact associated with a revised program.”⁷⁷ Energex’s capex included with its revised proposal for sub-transmission and distribution augex is consistent with the amount we provided in our preliminary decision.

A key driver of Energex’s proposed augex for sub-transmission and distribution (and other augex programs such as upgrading pole transformers) is forecast maximum demand growth. As set out in Appendix C, we consider that Energex’s demand forecasts submitted in its original proposal likely reflect a realistic expectation of demand. Energex’s augex in its revised proposal is based on these demand forecasts.

Energex slightly increased its system-level maximum demand forecast between its original and revised proposals. However, Energex submitted that it did not propose any increases in growth-related capex from this increase in demand forecasts and “will

⁷⁴ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 53.

⁷⁵ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 March 2015, pp. 47-52, 63.

⁷⁶ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 51 and 52-55.

⁷⁷ Energex, *Revised Regulatory Proposal*, July 2015, p. 39.

manage the associated increase in network risk while meeting its legislative supply obligations.”⁷⁸ This means that adopting Energex’s demand forecasts in its revised proposal will not impact on the augex we include in our alternative estimate of capex.

Accordingly, we are satisfied that Energex’s estimates of sub-transmission and 11kV distribution augex reasonably reflect the capex criteria (for the reasons set out above and in our preliminary decision) and we do not revisit this issue further in this document. We have provided an allowance of \$104.8 million (\$2014–15) for sub-transmission expenditure and \$90.2 million (\$2014–15) for 11kV distribution works, including on-costs.

Low voltage programs

Energex has not revised its original \$158.6 million (\$2014–15) forecast capex to augment its low voltage network in response to our preliminary decision. The components of this forecast are set out in Table . Energex has submitted further information in support of its program to retrofit its low voltage transformers with protection. However, it has not submitted new or additional information on the remaining components of the low voltage program.

Table B.6 Energex’s forecast low voltage program (\$2014–15 million, excluding overheads)

Category	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Uprating pole mounted transformer	4.0	4.0	4.0	4.0	4.0	20.0
Uprating pad mounted transformer	0.7	0.7	0.7	0.7	0.7	3.7
Retrofit transformers with LV protection	24.6	24.6	24.7	0.0	0.0	73.9
11kV wildlife proofing	0.1	0.1	0.1	0.1	0.1	0.6
Bushfire and flood mitigation	2.0	2.0	2.0	2.0	2.0	10.0
Neutral integrity monitoring	1.1	1.1	1.1	2.8	2.8	8.8
11kV & LV augmentation & minor works	8.2	8.4	8.3	8.3	8.3	41.6
Total low voltage Program	40.8	40.9	40.9	17.9	18.0	158.6

Source: Energex revised proposal; Energex response to AER EGX 068.

Note: Capex includes Energex’s proposed ‘on-costs’ allocated in accordance with Energex’s response to AER EGX 068.

In this final decision we do not accept Energex’s forecast for low voltage works. This is consistent with our preliminary decision where we rejected Energex’s initial forecast,

⁷⁸ Energex, *Revised Regulatory Proposal*, July 2015, p. 22.

having regard to the technical review undertaken by EMCa. Their review concluded that the programs had not been subject to appropriate risk assessment, adequate governance and top-down challenge to establish the optimal level of risk.⁷⁹ In addition, EMCa observed that the proposed accelerated low voltage fuse retrofit program had not been adequately justified.⁸⁰ EMCa concluded that the forecast for growth and compliance augex (of which these low voltage programs are a component) was overestimated in the order of 5 to 15 per cent.⁸¹ We accepted this advice in our preliminary decision and substituted a forecast of \$136.6 million (\$2014–15) for low voltage programs (as part of our alternative forecast for growth and compliance capex).

Our final decision maintains our preliminary view that a forecast of \$136.6 (\$2014–15) million for low voltage programs reasonably reflects the capex criteria (noting that this figure now includes on-costs that were excluded in the preliminary decision). In coming to our decision we engaged EMCa to undertake a review of the new material submitted by Energex and provide advice on whether the material caused it to revise its advice on the prudence and efficiency of the forecast. The results of their review are discussed further below in our consideration of the low-voltage fuse retrofit program.

We then undertook our own bottom-up review of the individual programs that comprise Energex's low voltage capex proposal, drawing on engineering and other technical expertise within the AER. This was based on a review of all material submitted by Energex, including the original proposal and the revised proposal in support of the low voltage programs.⁸² From this review we determined those programs with costs that were either overestimated or did not meet the capex criteria. The components of the low voltage program are discussed in detail in the following sections.

Our findings from our bottom-up review, summarised in Table B.7, resulted in a forecast estimate of \$133.4 million (\$2014–15, including on-costs), which is within the range recommended by EMCa and is largely consistent with our preliminary decision (after allowing for on-costs). While we found that a number of the components are forecast on a sound basis, there are others that are overestimated or not required over the 2015–20 period. We consider that this lends considerable support to the reductions recommended by EMCa on Energex's revised proposal. We have therefore maintained our preliminary decision forecast of \$136.6 million (\$2014–15, including on-costs).

It is important to note that our overall capex decision does not approve or reject funding for individual projects. Rather, as set out in our Expenditure Forecast Assessment Guideline, we conduct technical project reviews to help us assess the efficient overall capex required for network augmentation, in conjunction with other

⁷⁹ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, pp. 54-55.

⁸⁰ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 55.

⁸¹ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 55.

⁸² A large proportion of supporting material is included within Energex's report, *Network Asset Management Program – Distribution Augmentation 2015-2020*.

techniques such as trend analysis. For this particular decision, we have used technical analysis as a cross-check against the sampling approach undertaken by EMCa. Indeed, this final decision adopts a forecast for growth and compliance augex that is consistent with our preliminary decision (after on-costs are added), which is slightly higher than the results of our bottom-up analysis outlined in the next section. Within the overall capex and revenue allowance we provide in this final decision, it is up to Energex to allocate its capital and operating budget to meet its obligations (including as circumstances change over time).

Table B.7 AER’s bottom-up review of low voltage programs forecast (\$2014–15 million, excluding overheads)

Category	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Uprate pole transformer	4.0	4.0	4.0	4.0	4.0	20.0
Uprate Padmount transformer	0.7	0.7	0.7	0.7	0.7	3.7
Retrofit transformers with LV protection	14.8	14.8	14.8	14.8	14.8	73.9
11kV wildlife proofing	0.1	0.1	0.1	0.1	0.1	0.6
Bushfire and flood mitigation	0.0	0.0	0.0	0.0	0.0	0.0
Neutral integrity monitoring	0.0	0.0	0.0	0.0	0.0	0.0
11kV & LV augmentation & minor works	7.0	7.0	7.0	7.0	7.0	35.2
Total LV Program	26.7	26.7	26.7	26.7	26.6	133.4

Source: AER analysis.

Note: Includes scaled 'on-costs' allocated in accordance with Energex’s response to AER EGX 068.

Project review: uprating of pole and pad mounted transformers

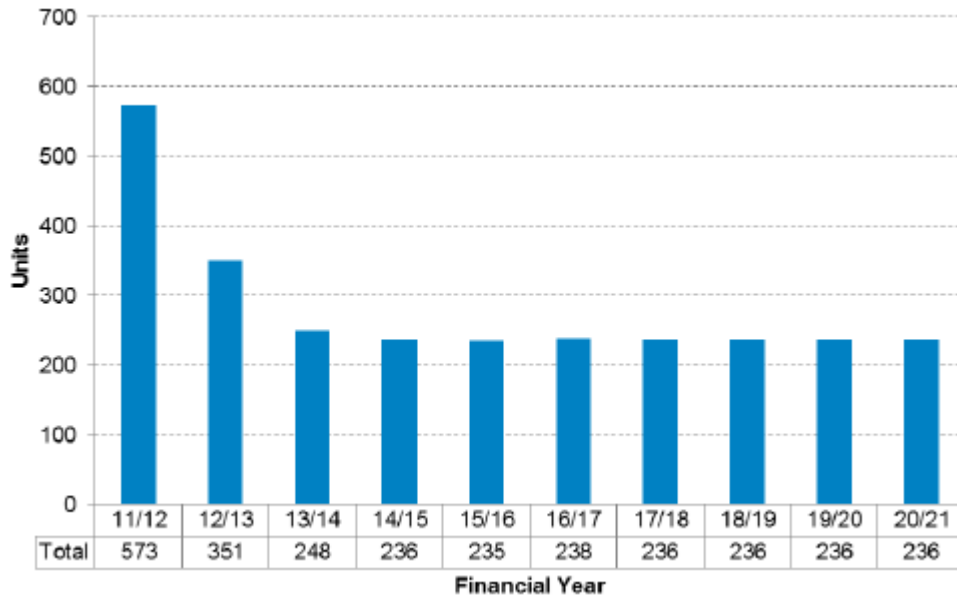
The uprating of pole and pad mounted transformers are two proactive programs to increase the capacity of transformers within the network that have or are likely to exceed acceptable load limits causing problems in the distribution network.⁸³

To assess the prudence and efficiency of these forecasts we have had regard to the trends in volume of transformers uprated since 2011–12. In both cases the trend has shown a steep decline since 2011–12 and Energex forecasts it to stabilise at the volumes observed in 2013–14 and to be flat across the forecast period. Figure provides the pole transformer example of this trend. This appears to be consistent with the low demand growth that is forecast. Accordingly, we consider that Energex’s

⁸³ Energex, *Network Asset Management Program- Distribution Augmentation 2015-2020*, p. 8.

forecasts for these categories are a reasonable reflection of the expenditure required and reflect the capex criteria.

Figure B.2 Annual pole transformer up-rates



Source: Energex Network Asset Management Program – Distribution Augmentation 2015-2020.

Project review: retrofit low voltage fuses

This project retrofits low voltage fuses into pole mounted transformers across the Energex network. The fuses operate to stop current flowing in the event that there is a failure in the low voltage network. For example, if a car knocks over a power pole, the fuse would ‘rupture’ and disconnect the power to the fallen wires.

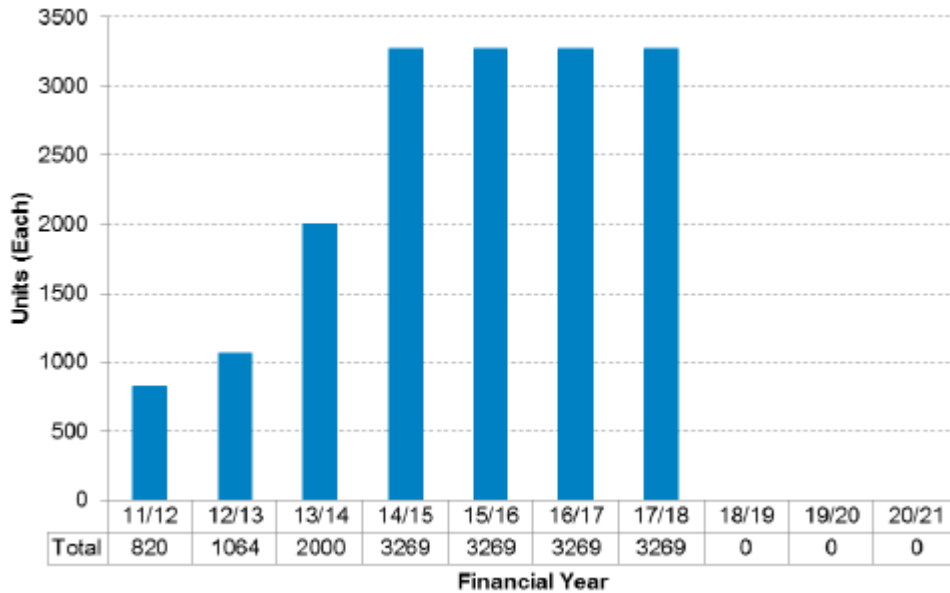
In 2006, the Energy Networks Association (ENA) issued new guidelines for the design of low voltage protection systems. This program of work stems from Energex’s own review (completed in 2008) that compared their systems to those contained in the ENA’s guideline. It found that it was not installing fuses on all pole mounted transformers and that a program to retrofit fuses to all transformers (20,000) should be undertaken. This program commenced in 2010 with an initial rate of 400 fuses per annum being retrofitted.⁸⁴

In 2012–13 a further review was undertaken by Energex that suggested that the retrofit program should be completed within a “reasonable” timeframe. In practice, Energex took this to mean that they should complete the work within 10 years of the ENA guideline publication. As shown in figure B.3, this led to a ramp-up of volumes. By the

⁸⁴ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.6, p. 5.

end of 2013–14, Energex had retrofitted around one quarter of the pole mounted transformer population.⁸⁵

Figure B.3 Low Voltage Fuse Retrofits to Pole Transformers per annum



Source: Energex Network Asset Management Program – Distribution Augmentation 2015-2020.

In Energex’s initial regulatory proposal it forecast completing the retrofitting program in 2017–18 by ramping up volumes to 3269 units per annum from 2014–15. In its technical review, EMCa observed that the proposed accelerated low voltage fuse retrofit program had not been adequately justified.⁸⁶

In response, Energex submitted two new documents—a strategy document explaining the history and rationale for the program and an Aurecon technical review of the program (together with a review of the reliability and power quality aspects of the forecasts).⁸⁷ Supported by the Aurecon report, Energex submit that the proposed ramp-up in volumes is sound and efficient and is necessary for compliance with the ENA guidelines (which represents good industry practice).⁸⁸

We retained EMCa to review this new material provided by Energex and update its original report to us in light of this new information. EMCa agree that the installation of these fuses is consistent with good industry practice.⁸⁹ However, EMCa conclude that Energex has not presented sufficient evidence to justify the completion of the program

⁸⁵ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.6, p. 6.

⁸⁶ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 55.

⁸⁷ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.5 (Aurecon report) and 4.6.

⁸⁸ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.6, p. 1.

⁸⁹ EMCa, *Review of Proposed Capital Expenditure in Energex’s Revised Regulatory Proposal 2015-2020*, September 2015, p. 15.

within the 2015–20 regulatory control period.⁹⁰ In particular, they disagree with the risk assessment undertaken by Aurecon, which they consider has overestimated the likelihood rating of a fatality occurring in a fallen wires situation.⁹¹ In total, EMCa consider that 10 to 20 per cent of the forecast could be prudently deferred until the next regulatory control period. It recommends a prioritisation process, the continuation of mitigation measures and the packaging of retrofitting work on lower risk sites with related augex and repex programs over time.⁹²

We accept that the retrofitting of low voltage fuses is a prudent program when it is prioritised, combined with mitigation practices and lower risk sites are packaged with other work. The remaining question in our view is whether the ramp up in volume to 3269 units a year has been justified by Energex as prudent and efficient. That said, we note that even if we were to accept the top end of EMCa’s range and defer 20 per cent of the volume into the next regulatory control period, this would only leave 1960 pole top transformers left to retrofit at the end of the 2015–20 regulatory control period. Assuming a constant rate of work, the remaining work would be completed within the first year of the next period. Therefore it is questionable whether there are any significant benefits from this sort of adjustment. We have therefore not sought to defer any of this expenditure into the next period.

However, while we do not consider that any of the forecast should be deferred until the next period, we do accept EMCa’s advice that the ramp-up of volumes such that the work is completed by 2017–18, has not been adequately justified. This suggests that the proposed expenditure profile may not reflect a prudent and efficient amount for each year of the 2015–20 regulatory period.

We note that Energex’s justification is based on completion of a program within a “reasonable” timeframe of the publication of the ENA guideline in 2006. We note that there is clearly a degree of subjectivity around the interpretation of when the work should reasonably be completed. We consider that a smooth expenditure profile that allows for the completion of work by the end of the 2015–20 regulatory control period could also be said to be reasonable as the work would be completed within two full regulatory reset periods following the 2006 ENA review.

We have therefore included a smooth expenditure profile for low voltage fuse installations into pole mounted transformers. We also note that this slightly longer timeframe would increase the scope for Energex to prudently bundle transformer retrofits with other packages of work, as suggested by EMCa.

⁹⁰ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 10.

⁹¹ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, pp. 9-10.

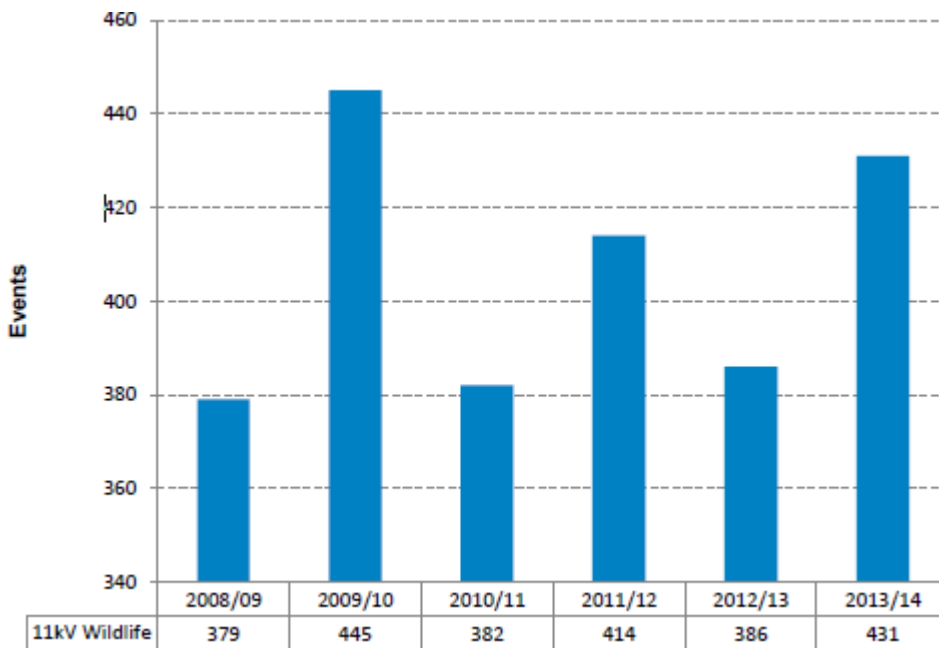
⁹² EMCa, *Review of proposed capital expenditure in Energex's revised regulatory proposal, report to the AER*, September 2015, p. 9.

Project review: 11kV wildlife proofing

This small program includes installation of wildlife proofing to protect electricity network equipment at identified sites. Energex state that wildlife proofing will be applied to targeted sites as part of a specific feeder improvement program or individual site following network event.⁹³

To assess the reasonableness of the forecast associated with wildlife proofing we have had regard to the trends in the number of events on the electricity network being caused by interference from wildlife. As shown in Figure , the number of wildlife events on the network has not shown any particular trend. We consider that Energex’s forecast that holds expenditure constant on this small program from actual levels recorded since 2013–14 is reasonable given the lack of trend in the number of wildlife events.

Figure B.4 11kV Wildlife Events



Source: Energex Network Asset Management Program – Distribution Augmentation 2015-2020.

Project review: bushfire and flood mitigation

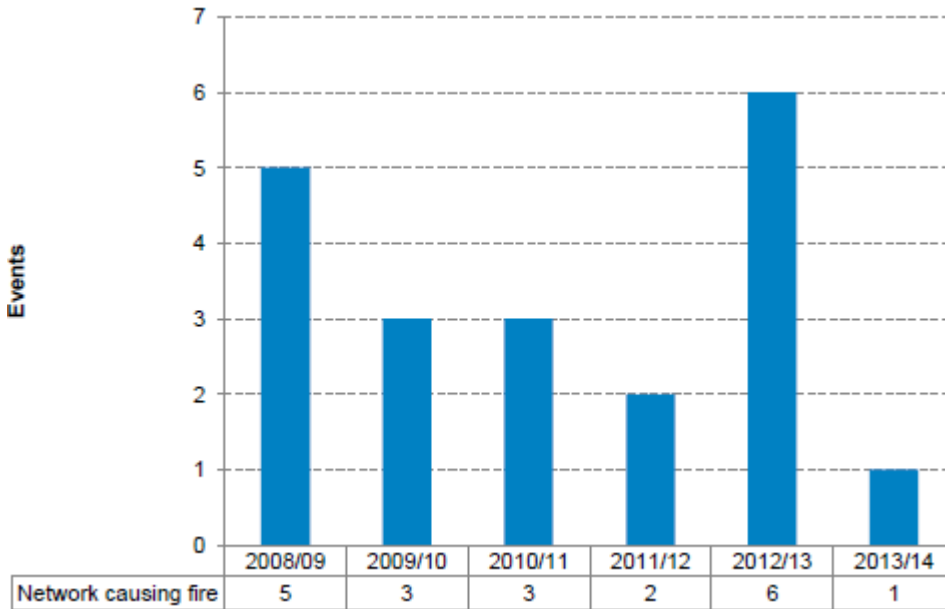
Energex’s revised proposal included \$10 million (\$2014–15) for bushfire and flood mitigation. Energex stated that the bushfire component of this program provides funding to undertake specific bushfire network improvements on overhead assets in the vicinity of “High Risk” bushfire areas across Energex’s network.⁹⁴

⁹³ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 16.

⁹⁴ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 27.

To test the reasonableness of the bushfire component of this forecast, we have had regard to the number of network incidents that have caused a fire. Figure shows that the trend in the number of fires cause by network incidents has been declining since 2008–09, apart from 2012–13.

Figure B.5 Number of Network Incidents Causing Fire



Source: Energex Network Asset Management Program – Distribution Augmentation 2015-2020.

The low and declining number of network incidents leading to fire highlights that Energex has effective measures in place to mitigate bushfire hazard risk. Accordingly, there is limited justification for a step-up in this expenditure, given that the existing expenditure levels have been successful in managing and reducing the annual fires caused by networks.

Energex stated that capex for bushfire mitigation works have previously been included in the “Low Voltage Augmentation - Minor Works” category prior to 2014–15, which is considered below.⁹⁵ As we explain below, we have included in our substitute estimate a forecast for “Low Voltage Augmentation - Minor Works” that is consistent with the capex for this category observed since 2012–13. Accordingly, our substitute estimate for this category will include an amount associated with bushfire mitigation equal to that Energex had spent prior to 2014–15.

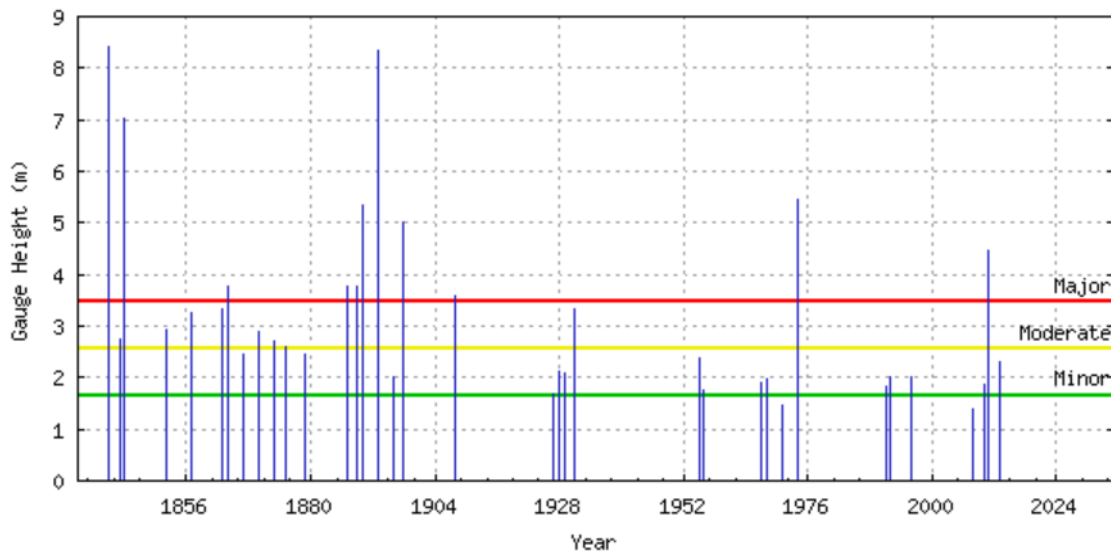
Energex also propose a new program for flood and storm damage mitigation. In support of this program, Energex reference the extent of the damage caused by the 2011 Brisbane River floods and the 2013 ex-tropical cyclone Oswald. Energex submit

⁹⁵ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 37.

that it would be prudent to ensure the 11kV network is fully resilient to moderate flood level.⁹⁶

To assess the need for this program, we have had regard to Brisbane River flooding data from the Bureau of Meteorology. As Figure shows, apart from the major flooding that occurred in 2011, moderate level flooding is a very rare occurrence and has not been recorded since the Wivenhoe Dam was completed in 1984. The 2013 flooding associated with ex-tropical cyclone Oswald was the most significant since the dam was completed. However, Energex note that only minimal numbers of assets were inundated during this event, with most customer outages caused by high winds and falling trees.⁹⁷

Figure B.6 Brisbane River highest annual flood peaks at city gauge



Source: Australian Government, Bureau of Meteorology.

Accordingly, we do not consider that a new program for flood mitigation is justified. However, as noted above with respect to bushfire mitigation, we consider that an amount consistent with past expenditure in this category reflects a prudent and efficient amount for the 2015–20 period. This should be contained within Energex’s ‘augmentation & minor works’ forecast.

Project review: neutral integrity monitoring

Energex proposes \$8.8 million (\$2014–15) for a new pilot program to install 37,000 smart meters to enhance its existing systems for detecting issues with the neutral connection to customer premises. In a standard household situation, the electricity service has two wires: an active and neutral. While a failure of the active connection leads to a power outage, degradation of the neutral connection is more difficult to

⁹⁶ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 29.

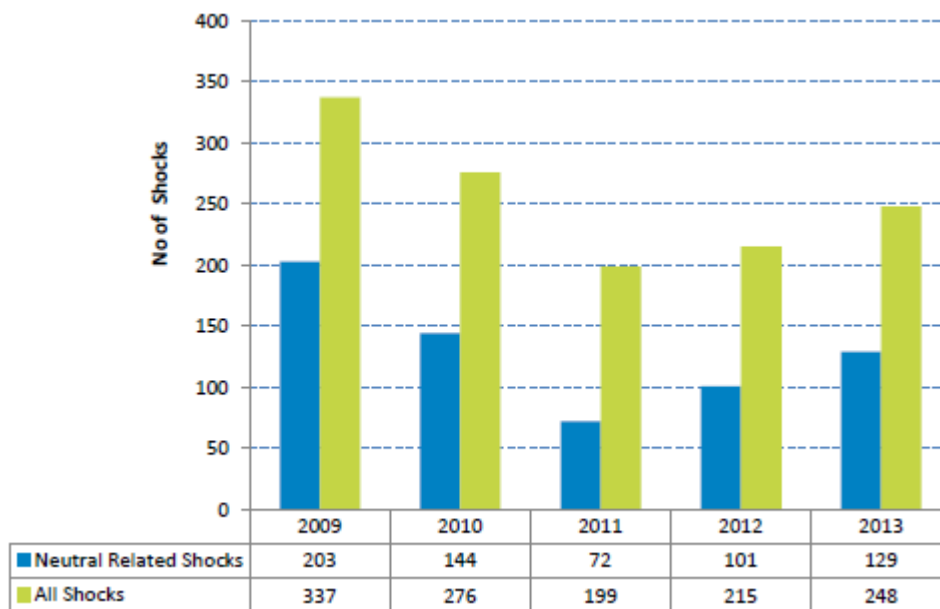
⁹⁷ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 28-29.

detect. If the neutral connection degrades there is a risk of electrical shock. Energex state that the program will initially target areas of the network where historical evidence indicates best value can be achieved and that preliminary research is pointing towards coastal areas where corrosion is a problem.⁹⁸

To assess whether this expenditure is required to achieve the capex objectives, we have had regard to the trends in both neutral related shock complaints and insurance claims. Of most relevance in this consideration is whether this expenditure is required to maintain the quality, safety, reliability and security of supply of standard control services.

As shown in Figure , since 2009 neutral related shock complaints had been consistently falling until 2012 and 2013 which recorded increases.

Figure B.7 Neutral Related Shock Complaints

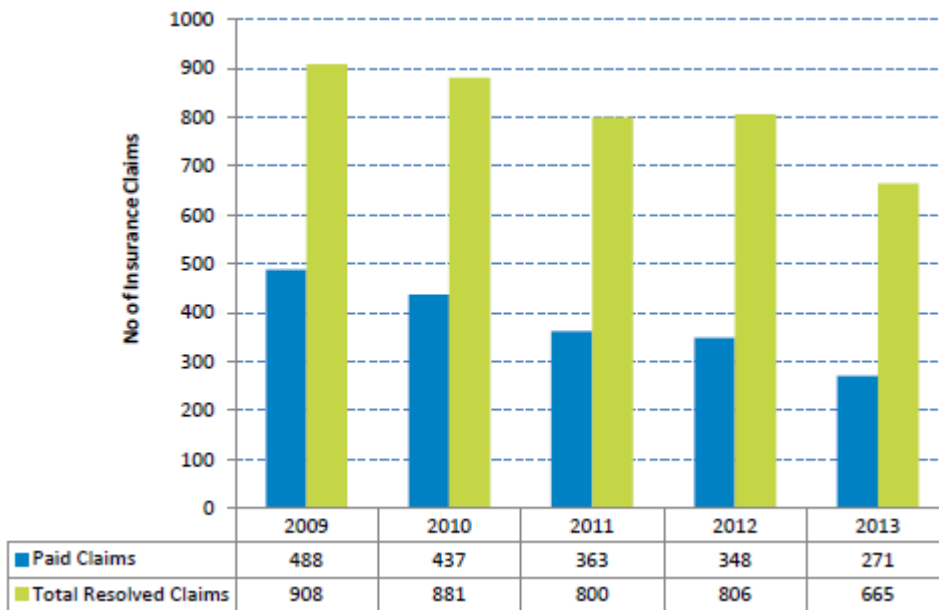


Source: Energex Network Asset Management Program – Distribution Augmentation 2015-2020.

However, as shown in Figure , neutral related insurance claims (paid and resolved) have continued the same downward trajectory from 2009 onwards. We consider that the better indicator of trends in neutral related issues is the trend in insurance resolved claims. This is because they represent verified incidents of issues with neutral connection failures, whereas the ultimate cause and resolution of complaints is unclear.

⁹⁸ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 31.

Figure B.8 Neutral related Insurance Claims



Source: Energex Network Asset Management Program – Distribution Augmentation 2015-2020.

Because neutral related insurance claims have shown a downward trajectory from 2009 onwards, this suggests that Energex business-as-usual approach to addressing neutral related issues is sufficient to maintain the quality, safety, reliability and security of supply of standard control services.

Accordingly, we consider that the expenditure associated with the new pilot program is not required to achieve the capex objective to maintain quality, reliability and security of supply of standard control services. We also note that Energex submitted that while its existing five year system based maintenance inspection program should identify obvious neutral issues, “it is not sophisticated enough to detect intermittent or incipient problems.”⁹⁹ We take from this statement that the proposed program is an enhancement and is not necessary for the maintaining acceptable current practices.

We also note that this pilot program appears to be in a very early stage of development. For example, the Energex documentation refers to the number of sites to be included in the program being “identified and prioritised” jointly by their metering group and their reliability and power quality department.¹⁰⁰

In addition, Energex submit that depending on the results of this pilot program, the smart meter rollout may continue into the next regulatory period, “with scope for continuing targeted rollout of 9,000 units per annum.”¹⁰¹ Notwithstanding Energex’s plans for a rollout of smart meters, there will in any case be a market led rollout of

⁹⁹ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 31.

¹⁰⁰ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 31.

¹⁰¹ Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 34.

Advanced Metering Infrastructure in Queensland. As noted by Energex, the national smart meter minimum functionality specification requires that all smart meters to be installed under the market-led rollout include the ability to perform the neutral integrity monitoring function. It therefore appears that this pilot program is an unnecessary duplication of technology that will be provided by smart meters installed as part of the market led process from 2017.

Project review: augmentation & minor works

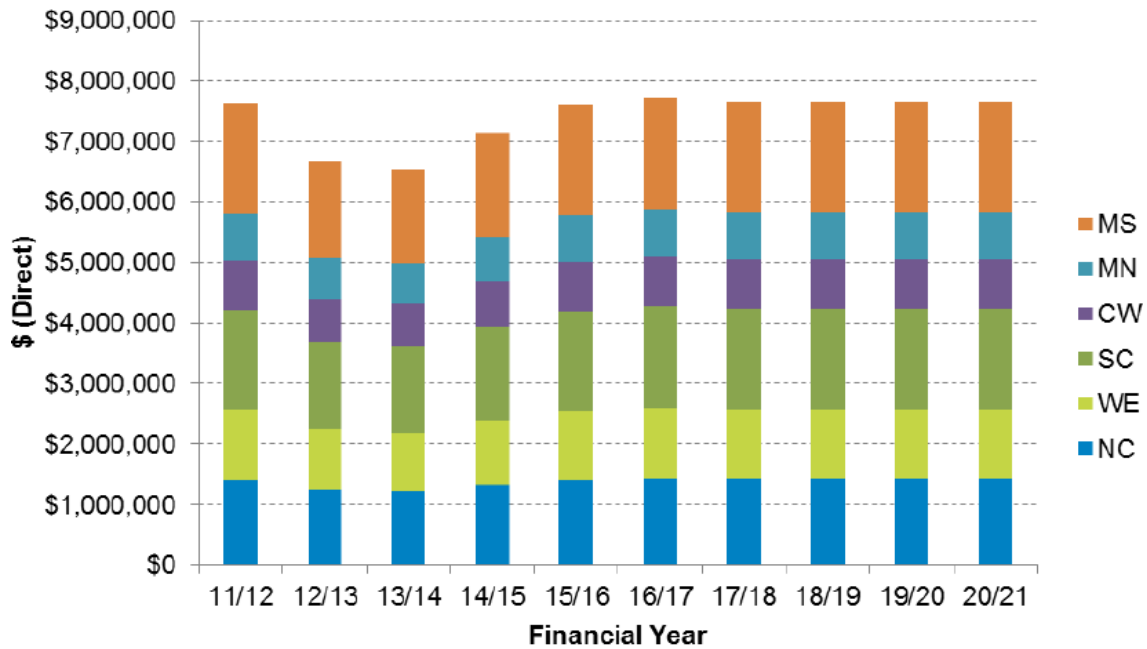
Energex has included in its forecast a \$41.6 million (\$2014–15) program to undertake network augmentation triggered through network investigations following network incidents, customer complaints or reports from field staff. For example, expenditure in this category would include work to address customer complaints regarding low voltages or flickering lights.¹⁰²

We accept that an augex forecast necessarily includes a reactive work component. However, we are not satisfied that Energex has justified the step-up in expenditure that it has forecast, as explained below. We have instead forecast an amount of \$35.2 million (\$2014–15), consistent with Energex’s past expenditure in this category.

As shown in Figure , expenditure in low voltage augex – minor works has been decreasing since 2011–12. The expenditure shown from 2014–15 onwards are forecasts proposed by Energex. The step-up in expected expenditure has not been explained by Energex. For example, we have not observed in the information provided in Energex’s original proposal, its revised proposal or information received in response to information requests, evidence of trends in customer complaints or other incidents that drive this form of expenditure.

¹⁰² Energex, *Network Asset Management Program – Distribution Augmentation 2015-2020*, p. 36.

Figure B.9 Energex forecast - low voltage augex – minor works (\$2014–15)



Source: Energex Network Asset Management Program – Distribution Augmentation 2015-2020.

In addition, as we noted above, until 2014–15, this category included forecasts for bushfire and flood mitigation works. As the Energex forecast separately identified bushfire and flood mitigation in its 2015–20 forecast, it would be expected that the forecast for low voltage augex would actually fall.

We have therefore included a forecast of low voltage augex – minor works consistent with historic expenditure levels. As historically works associated with flood and bushfire mitigation were included in the low voltage augex category, we consider that our forecast will enable to Energex to achieve the capex objective to maintain quality, safety, reliability and security of supply of standard control services.

Power quality

Our estimate of required power quality expenditure for Energex for the 2015–20 regulatory control period is \$25.3 million (\$2014–15). We consider that this reflects a prudent and efficient amount for Energex to comply with its power quality regulatory obligations. This is 33 per cent less than Energex’s \$38.4 million (\$2014–15) proposal.

Energex is subject to voltage regulation under Queensland Electricity Regulation 2006. Under this regulation, Energex must supply electricity to customers on its low voltage at 240 volts (with an allowable margin of +/- 6 per cent from this standard voltage).¹⁰³

¹⁰³ See section 11 and 13 of *Queensland Electricity Regulation 2006*.

Energex submitted in its original proposal that the rise in distributed generation (e.g. solar PV) means that “power flows can now occur in directions, leading to greater voltage regulation to be managed and operational issues to be addressed.”¹⁰⁴

Energex propose that capex is required over the 2015–20 period to install transformer monitoring to identify the extent of voltage fluctuations across its network, and drive a targeted LV remediation program to meet its voltage compliance obligation under the Queensland Electricity Regulations 2006.¹⁰⁵

Energex initially proposed \$38.4 million (\$2014–15) for seven power quality programs, of which only two exist in the current regulatory control period.¹⁰⁶ Of that amount \$25 million (\$2014–15) was directed towards power quality monitoring, and \$13.4 million (\$2014–15) was directed towards remediation work on known or foreseeable power quality issues.

In our preliminary decision, we did not accept Energex's initial proposed \$38.4 million (\$2014–15) to monitor and manage power quality issues.¹⁰⁷ We concluded that it did not reasonably reflect the capex criteria, informed by a review of Energex’s proposal by our consultants EMCa. Our reasons for this position were:¹⁰⁸

- Energex's proposed level of network monitoring is above the level of power quality monitoring undertaken by most network operators, and an appropriate cost benefit analysis was not provided to justify the proposed increases in the number of monitors forecast to be installed.
- The projected increase in solar panel connections was likely overstated as it did not account for the expected softening of solar growth and was not supported by the evidence that Energex relied upon in its initial proposal.
- No evidence of risk assessments undertaken by Energex that relate directly to these programs were supplied by Energex.

Revised Proposal

In its revised proposal, Energex has not changed its proposed power quality expenditure. Energex provided further information to support its proposed expenditure. A summary of this information is given below:¹⁰⁹

- Energex submitted that the reason its proposed level of network monitoring was higher than most network operators was due to its current and forecast PV penetration being higher than any other supply area. Energex also submitted that it

¹⁰⁴ Energex, *Regulatory Proposal: July 2015 to June 2020*, October 2014, Appendix 29, p. 4.

¹⁰⁵ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.8.

¹⁰⁶ Energex, *response to AER EGX010*, p. 1 and Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 113.

¹⁰⁷ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, pp. 56-57.

¹⁰⁸ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, pp. 56-57.

¹⁰⁹ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.8.

did not have sufficient penetration of remote monitoring devices as compared to NSW and Victoria.

- Energex revised its previous analysis to account for an increase in the average size of solar PV inverters from 3kVA to 4kVA. This is expected to result in a 10 per cent increase to its 2020 forecast capacity from 1,352 MVA to 1,518 MVA. Energex stated that “the increase in installed inverter capacity will increase the number of areas on the network above the threshold expected to cause voltage issues for customers.”¹¹⁰
- Energex provided further information to support their projected increase in solar panel connections:
 - AEMO’s latest forecast is higher than Energex’s June 2015 PV forecast;¹¹¹ and
 - the new Queensland government has introduced a target of one million PV installations by 2020 and Energex has not further increased its allowance for the potential impact of this policy.¹¹²
- Energex rated the safety risk from high PV penetration as a Medium risk, with the remaining risk after the monitoring program is implemented as Low to Medium, reducing to Low once the transformer tap-resetting program¹¹³ is complete.¹¹⁴ Energex’s risk framework requires risks rated as medium to be managed in line with assessing the cost of a risk mitigation program against the benefits to determine whether the proposed remedial action is justified.

Energex engaged Aurecon to review its monitoring program.¹¹⁵ Aurecon concluded that Energex’s proposed expenditure of \$25 million on its monitoring program is the minimum expenditure necessary and that a reduction to the number of monitors would result in insufficient accuracy for the results to be effective.¹¹⁶

AER Position

We have reviewed all information provided by Energex in its revised proposal. We also engaged EMCa to review new evidence provided by Energex in its revised proposal.¹¹⁷ Based on our review and considering EMCa’s report, we do not accept Energex’s revised proposal of \$38.4 million as we are not satisfied that it reasonably reflects the capex criteria. We have instead included \$25.3 million in our alternative estimate.

¹¹⁰ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.8, p. iii.

¹¹¹ AEMO, *National Electricity Forecasting Report (NEFR)*, 18 June 2015, pp. 22-88.

¹¹² Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.8, p. iii and 3.

¹¹³ As part of its opex program Energex intends to carry out targeted transformer tap adjustment programs to address voltage issues in areas with solar penetration of greater than 30 per cent.

¹¹⁴ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.9, p. 9.

¹¹⁵ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.5 (Aurecon report).

¹¹⁶ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.5 (Aurecon report), p. 20.

¹¹⁷ EMCa, *Review of Proposed Capital Expenditure in Energex’s Revised Regulatory Proposal 2015-2020*, September 2015, pp. 13-18.

While Energex has provided new evidence to support the expected increase in solar PV penetration on its network (and the associated voltage issues), we do not consider that Energex's level of proposed capex reflects the efficient costs that a prudent operator would require to maintain power quality levels of the network and meet its voltage obligations.

The primary driver of Energex's power quality proposal is projected increases in solar PV penetration on its network. Energex forecasts that by 2020 it will have 3,959 transformers where over 50 per cent of its customers are connected to solar PV generation, a 70 per cent increase compared to 2013–14 levels.¹¹⁸ While we questioned Energex's forecast increases in solar PV in our preliminary decision, we accept these forecasts for our final decision. This is based on the most recent AEMO forecast, increases in average installed inverter capacity, and the potential impact of the new Queensland government's one million PV installation target.

We also agree that there is likely to be some power quality issues that will need to be addressed over the following regulatory control period or beyond. This is supported by evidence from Energex that the rate of customer power quality enquiries has been steadily increasing over the last four years, with 43 per cent of issues driven by solar PV.¹¹⁹ However, we consider that the monitoring program proposed by Energex is likely not required over the 2015–20 period and hence that Energex's proposed capex is not entirely prudent and efficient to meet its voltage supply obligations. This is for the following reasons.

First, Energex recently introduced a new standard for the connection of small-scale rooftop solar PV systems on its network (in conjunction with Ergon Energy).¹²⁰ This standard specifies technical requirements and performance standards for installed solar PV systems. Under this connection standard, a particular solar PV system must cut its electricity output to the distribution network if voltage exceeds 255 volts.¹²¹

As set out in this connection standard, it is Energex's responsibility to ensure all proposed solar PV connections comply with the requirements of the standard. It is not clear how or whether Energex has taken this into account in its forecast increase in overvoltage issues by 2020. However we consider that, if Energex enforces the voltage cut-off requirements, then new solar PV connections installed over 2015–20 should create very few overvoltage issues on Energex's network. This suggests that the need for further and ongoing monitoring of voltage levels is lessened.

¹¹⁸ Energex revised regulatory proposal, Appendix 4.5, p. 11; Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Appendix 29, p. 17.

¹¹⁹ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Appendix 29, pp. 9-10.

¹²⁰ Ergon Energy and Energex, "Connection Standard: Small Scale Parallel Inverter Energy Systems up to 30 kVA". Available at <https://www.energex.com.au/contractors-and-service-providers/solar-pv-installers/new-inverter-energy-systems-ies-connection-standard>; accessed on 15 September 2015.

¹²¹ Ergon Energy and Energex, "Connection Standard: Small Scale Parallel Inverter Energy Systems up to 30 kVA", clause 6.11.

Second, as we stated in the preliminary decision, Energex has not undertaken a risk assessment of a failure to meet its voltage supply obligations resulting from an increase in solar PV.¹²² Without adequately considering risk and probability of failing to meet its obligations, Energex will likely overstate the amount of work required to comply with its obligations. This is based on EMCa's review of Energex's risk management practices and its specific power quality proposal. In its review of Energex's revised proposal, EMCa stated that Energex has not provided any new evidence to show that it has considered risk in relation to satisfying its regulatory obligations.¹²³

Energex considered risk only in terms of safety from high penetration of solar PV. As set out in its revised proposal, Energex stated:

A safety risk assessment for the high penetration of solar PV assessed the risk as Medium Risk. This was based on a worst case safety risk scenario for high solar PV penetration of a high voltage (above 260 V) at a premise causing equipment/appliance fire, leading to houses catching fire and multiple fatalities.¹²⁴

EMCa found that Energex has not provided compelling information to support this assessment.¹²⁵ This supports the view that the risk mitigation benefit of the monitoring program is overstated.

Third, Energex has not considered options that would reduce the cost and scope of the monitoring program. Energex proposes a fixed monitoring program that will be deployed over time with a large increase in monitors installed in the final two years of the 2015–20 period. Aurecon recommended that a more gradual deployment may be more appropriate:

Energex proposes to limit the roll out in the early years to provide the opportunity to review and improve the monitoring schemes. This is a prudent approach, but the sharp increase after year 3 may prove to be challenging to resource. Aurecon would expect that a gradual increase over the first three years may be easier to manage, and this could be further supported in the submission with some consideration of the resourcing issues.

After this five year period, further monitoring may or may not be necessary. Five years of experience is likely to provide Energex with sufficient data to determine if further expansion of the monitoring program is required or whether it could be held at the level achieved in 2020. Further, the possibility of a smart meter role out should not be discounted, which would render monitoring of LV circuits unnecessary, such that only the transformer monitoring would still be

¹²² AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 56.

¹²³ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 17.

¹²⁴ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.8, p. iii.

¹²⁵ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 17.

necessary. Aurecon would recommend that the continuation of the monitoring program is subject to review prior to the 2020 regulatory submission.¹²⁶

This view is supported by EMCa which stated that, as areas of high PV penetration are identified and voltage issues addressed, the usefulness of permanent monitoring is significantly diminished.¹²⁷ EMCa recommended that mobile monitoring could be considered in greater detail over the fixed monitoring approach proposed. This may reduce the cost of the monitoring program.

We note that a market led role of Advanced Metering Infrastructure (i.e. smart meters) is expected to commence in 2017. This may deliver the functionality that Energex requires to monitor voltage levels across its low voltage network, except it will not require investment in additional fixed network monitoring over the 2015–20 period.

Finally, Energex is directing more capex to monitoring rather than remediating existing voltage issues. Given the newly installed solar PV systems over the 2015–20 period should not lead to significant overvoltage issues, it may be more prudent for Energex to divert capex to addressing existing voltage issues rather than installing monitoring. This is supported by EMCa, who stated that:

Given the disproportionate cost versus the benefit of the proposed monitoring program, we consider that a reasonable and prudent allowance should be based on a revised strategy that directs more expenditure to addressing readily identifiable network issues and prioritising the work according to greatest risk.¹²⁸

These views suggest that Energex's proposed power quality capex is overstated and does not reflect a prudent and efficient amount to maintain voltage levels consistent with its regulatory obligations. In our view, Energex could achieve savings by applying an appropriate risk based cost benefit analysis to its expenditure; directing costs to remediation rather than monitoring; and considering alternative options to fixed monitoring in the short-term.

In our preliminary determination we reduced the proposed capex by 37.5 per cent, which was the mid-point of EMCa's recommended reduction of 25 to 50 per cent. We stated that the mid-point is reasonable in the absence of evidence pointing towards to the top or bottom of the range.

We maintain this position in our final determination. This was supported by EMCa, who advised that there is no new and compelling evidence to support a change to their initial findings. EMCa advised a reduction of between 25 to 50 percent less that Energex's revised forecast is likely to represent a prudent and efficient amount. As set out previously, we consider that the mid-point is reasonable in the absence of evidence

¹²⁶ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.5 (Aurecon report), p. 14.

¹²⁷ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 17.

¹²⁸ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 19.

pointing towards to the top or bottom of the range¹²⁹ and reasonably reflects the capex criteria. This results in an inclusion in our forecast of \$25.3 million (\$2014–15), including on-costs.

Reliability augex

Our estimate of required reliability capex for Energex for the 2015–20 regulatory control period is \$33.4 million (\$2014–15). We consider that this reflects a prudent and efficient amount for Energex to comply with its reliability obligations set out in its Distribution Authority. This is 20 per cent less than Energex’s revised proposal.

Energex’s Distribution Authority, determined by the Queensland Department of Energy and Water Supply, sets out the network reliability performance targets and planning criteria Energex must meet. Energex’s relevant reliability obligations under its Distribution Authority include meeting specified minimum service standards¹³⁰ and implementing a program for improving the worst performing distribution feeders.¹³¹

Energex initially proposed \$58.9 million (\$2014–15) in reliability capex (excluding overheads) to target worst performing feeders. The worst performing feeder improvement program requires Energex to improve 11 kV feeders where their performance is:

- ranked the worst 10 per cent of 11 kV feeders, based on a three year average, and
- greater than 150 per cent of the performance target for the feeder category.¹³²

For the worst performing feeder improvement program, Energex proposed 22 reliability projects per annum based on its review of the worst performing feeders. This includes 18 rural worst performing feeders and 4 urban worst performing feeders. Energex submitted that it selected its worst performing feeders based on the reliability performance of its feeders cohort over the 2011–12 to 2013–14 period. It assumes similar numbers of feeder improvements will be required over the 2015–20 period.¹³³

In our preliminary determination we reduced Energex’s reliability capex forecast by 65 per cent to \$20.6 million (\$2014–15).¹³⁴ We considered this was an appropriate amount to allow Energex to implement its reliability program and satisfy its regulatory

¹²⁹ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, pp. 56-57; EMCa, *Review of Proposed Capital Expenditure in Energex’s Revised Regulatory Proposal 2015-2020*, 17 August 2015, pp. 13-16.

¹³⁰ The minimum service standard targets are expressed as the minimum duration and frequency of outages experienced by the average customer in a year. These are expressed as the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).

¹³¹ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, pp. 1-7; Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, pp.59–60, 79.

¹³² Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, pp. 1-7; Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 79.

¹³³ Energex, response to AER EGX051, pp. 1-2.

¹³⁴ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, p. 61.

obligations. Our analysis of Energex's worst performing feeder performance indicated that the proposed capex was likely overstated. This was because:¹³⁵

- In identifying the proposed worst performing feeders, Energex may not have removed isolated trends or events (such as specific one-off causes that require no further action) from the calculation of average three year SAIDI.
- Energex had not provided appropriate cost benefit or trend analysis justifying the scope and cost of the proposed program to meet its obligations. Advice from our consultant EMCa was that some proposed projects could be deferred or be adjusted for greater risk tolerance and timing.
- There is scope for reducing the reliability improvement programs on the basis of current reliability performance being achieved on Energex's network and Energex's own customer research.
- The proposed options for addressing the worst performing feeders have contributed to a higher unit cost and were not sufficiently justified.

Revised Proposal

In their revised proposal Energex proposed \$39.8 million (\$2014–15) in capex to meet the reliability obligations under its Distribution Authority. This is a reduction of \$19.1 million (\$2014–15) on their initial proposal, but \$19.2 million (\$2014–15) more than our preliminary decision.

In their revised proposal Energex has maintained the 22 feeders per annum that it proposes to address in the 2015–20 regulatory control period. However, Energex has reduced the overall assumed unit costs cost of the works by assuming less expensive solutions will suffice over the 2015–20 period.

Energex has responded to the AER's concerns to support its revised expenditure proposal. Energex submitted:¹³⁶

- in selecting the feeders to be rectified during the 2015–20 regulatory control period, Energex confirms it had removed isolated or one-off events
- Energex has set its expenditure at what it believes is the minimum requirement to comply with its Distribution Authority because each feeder must meet the Distribution Authority requirements as outlined in the previous section
- deferral of any worst performing feeder projects will result in customers on these feeders receiving continued unacceptable levels of reliability and an increased number of complaints in affected areas
- Energex has provided worst performing feeder reliability trend information which show deteriorating average performance.

¹³⁵ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, pp. 57-61.

¹³⁶ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, pp. 1-7.

Energex engaged Aurecon to review its revised reliability expenditure forecast.¹³⁷ Aurecon analysed the worst performing feeder performance data over the last five years. Aurecon also analysed Energex's reliability expenditure in the current regulatory control period. Aurecon concluded that Energex's revised reliability capex is the minimum required to comply with its obligations in its Distribution Authority.¹³⁸

We received the following stakeholder submissions on the proposed reliability capex:

- AGL and the Chamber of Commerce and Industry Queensland questioned the size of the proposed reliability augex, noting that Energex has already been outperforming reliability targets.¹³⁹
- COTA Queensland questioned the customer engagement research program Energex used to arrive at its reliability capex forecast.¹⁴⁰
- The Queensland Farmers' Federation and Canegrowers noted that the proposed augex should be reviewed due to declining demand trends and recently reduced reliability standards.¹⁴¹
- The Queensland Council of Social Services contends that our final determination should take greater account of a number of factors, including changes in reliability standards and declining demand.¹⁴²

We consider Energex's revised proposal and submission views in the next section.

AER Position

Our final estimation is \$33.4 million (\$2014–15) in augex for Energex to meet its reliability obligations set out in its Distribution Authority. This is 20 per cent reduction to Energex's revised reliability expenditure forecast of \$41.8 million (including on-costs).

We have reviewed Energex's reliability capex proposal in light of Energex's historical and current reliability performance, and its reliability obligations to address the worst performing feeders in its network. We also considered advice from EMCa who reviewed the new information provided by Energex in their revised proposal.¹⁴³

Based on our review, we consider there is further scope for Energex to reduce its reliability augex program while still meeting the requirements set out under its Distribution Authority. As such, we consider that Energex's proposed reliability augex

¹³⁷ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.5 (Aurecon report).

¹³⁸ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.5 (Aurecon report), pp.3-9; Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, pp. 1-7.

¹³⁹ AGL, *Submission to preliminary decision*, July 2015, p. 11.

¹⁴⁰ COTA, *Submission to preliminary decision*, July 2015, p. 2.

¹⁴¹ Canegrowers, *Submission to preliminary decision*, July 2015, p. 5; Queensland Farmers' Federation, *Submission to preliminary decision*, July 2015, p. 6.

¹⁴² Queensland Council of Social Service, *Submission to revised proposal*, July 2015, pp. 6-9.

¹⁴³ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, 17 August 2015, pp. 10-13.

does not reflect the prudent and efficient costs of complying with its obligations. EMCa recommends that a reduction of between 15 to 25 per cent on Energex's revised forecast represents a prudent and efficient amount. We have adopted EMCa's recommendations because it has demonstrated that it has applied independent engineering expertise to Energex's own planning documentation and supporting evidence. We are satisfied that this amount reflects the efficient costs a prudent operator would require to achieve the capex objectives, given a realistic expectation of demand and cost inputs.

The remainder of this section considers:

- the identification of worst performing feeders to be addressed, and
- the costs of addressing these feeders.

Selection of worst performing feeders

In preparing its proposed reliability expenditure forecast Energex stated it reviewed all the 2013–14 worst performing feeders and prioritised expenditure based on the average SAIDI performance over three years. Energex intends to address 110 feeders over five years. Energex submitted that this equates to approximately 4 per cent of its rural feeder program and 0.3 per cent of the urban feeder population per annum.¹⁴⁴ This is the same as Energex's initial proposal.¹⁴⁵

We have reviewed the reliability performance data provided by Energex. On the basis of the current information, the 22 feeders appear to satisfy the requirements of the Distribution Authority to be categorised as a worst performing feeder. This is also the view of EMCa.¹⁴⁶ We also accept that Energex has removed one-off events from its feeder selection.

However, there are two reasons to suggest that the number of feeders that should be addressed over the 2015–20 period will be lower:

- Some of the identified feeders have improved dramatically over the 2011–12 to 2013–14 period, despite the average performance over three years exceeding the 327 minute worst performing feeder threshold.¹⁴⁷ In particular, the reliability performance of the Innisplain, Amamoor, Gympie South, Palmwoods Central, Toogoolawah and Redland Bay feeders.
- Energex has not updated its feeder selection despite having more recent performance data from 2014–15. We consider that these feeders (and potentially others) may no longer be candidates for improvement based on improvement data trends (as discussed in the point above). This is supported by EMCa, who consider

¹⁴⁴ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, p. 3.

¹⁴⁵ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, pp.59–60.

¹⁴⁶ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 12.

¹⁴⁷ See Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, p. 4.

that there is scope to reduce the number of feeders without materially affecting the average worst performing feeder performance over the medium term.¹⁴⁸ This is based on EMCa's analysis that the reliability performance of a number of feeders has been improving dramatically in recent years.

Given this, we consider that there is scope for a lower number of feeders than proposed by Energex while still meeting the requirements set out under its Distribution Authority.

Our preliminary decision questioned the scope of the program given improved reliability over its network, and customer views on reliability.¹⁴⁹ Energex's revised proposal shows that the trend in reliability performance of its worst performing feeders has been stable even though overall network reliability has improved.¹⁵⁰ We are satisfied with this information which leads us to conclude that Energex's overall network reliability performance may not be indicative of the need to improve individual worst performing feeders.

Submissions from the Queensland Farmers' Federation and Canegrowers, and the Queensland Council of Social Services, stated that we should take into account declining demand trends and recent changes in reliability standards. We note that changes in reliability standards primarily were about applying less stringent network planning requirements, rather than on worst performing feeder requirements. Energex is required to address its worst performing feeders and this capex goes towards this obligation.

Cost Analysis

Energex submitted its program is built up from unit cost estimates. Energex stated scope of work in their worst performing feeder program is based on typical standard solutions that are expected to be realistic representations of average cost per feeder to be rectified.¹⁵¹ In its revised proposal Energex has evaluated the scope of work used to prepare the worst performing feeder program. This has allowed them to remove a number of key inputs, which has resulted in a lower revised capex forecast.¹⁵²

However, Energex's proposed unit costs remain significantly higher than the previous regulatory control period. EMCa reviewed Energex's historical unit costs.¹⁵³ It found that Energex's average direct costs for urban feeders in the previous regulatory control period were \$178,000 and for rural feeders were \$259,000. Using the 18/4 rural/urban

¹⁴⁸ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 12.

¹⁴⁹ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, April 2015, p. 60.

¹⁵⁰ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, pp. 5-6.

¹⁵¹ Energex, *Revised Regulatory Proposal*, July 2015, pp. 42-43 .

¹⁵² Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, pp. 1-7; Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.5 (Aurecon report), pp.3-9.

¹⁵³ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 14-15.

feeder split proposed for Energex's 2015–20 program, this would equate to an average cost per feeder of \$245,000 per feeder. This compares to an average cost of Energex's revised proposal average of \$363,000 per feeder.¹⁵⁴ It is also significantly higher than the \$110,000 per feeder in Ergon Energy's program.¹⁵⁵

Energex submitted that it is their expectation that more expensive solutions, on average, will be required in the 2015–20 regulatory control period. This is because it addressed the lowest cost feeders in the 2010–15 period.¹⁵⁶ Energex stated that the typical topology and performance of Energex's worst performing feeders often requires higher levels of investment per feeder to meet its Distribution Authority requirements. Further, Energex is planning to implement reliability solutions that will remove targeted feeders from the worst performing list, rather than lower cost and shorter term options. This will result in a higher average cost for network augmentation.¹⁵⁷

It is not clear from Energex's proposal and supporting information why the average cost of remediating worst performing feeders is forecast to be almost 50 per cent higher than the average cost in the 2010–15 period. EMCa also questioned the increase:

We have not seen sufficient evidence to support a near 50% higher average unit cost relative to Energex's 2010–15 regulatory control period, nor have we seen evidence to support an average unit cost that is approximately 300% higher than Ergon Energy's.

Based on Aurecon's analysis, we consider it reasonable that real direct costs per feeder will increase on average over the 2015–20 period as more expensive solutions are deployed, but not to the extent proposed.¹⁵⁸

In conclusion, we are not satisfied that Energex's proposed unit costs to address its worst performing feeders reflect a realistic estimate of efficient costs. While we accept that an increase in unit costs from the 2010–15 period may be reasonable, we are not satisfied based on the information provided by Energex that a 50 per cent increase in unit costs reflects an efficient amount.

On-costs

Energex's revised proposal includes \$16.9 million for 'on-costs'. This is 9 per cent less than Energex's original proposal, which Energex stated is consistent with the reduction in total forecast augmentation capex.¹⁵⁹

¹⁵⁴ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.5 (Aurecon report), pp.3-9; Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, pp. 1-7.

¹⁵⁵ Ergon Energy, *Reliability quality of supply expenditure forecast summary*, p. 21.

¹⁵⁶ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, p. 6.

¹⁵⁷ Energex, *Revised Regulatory Proposal*, July 2015, Appendix 4.7, pp. 1-7.

¹⁵⁸ EMCa, *Review of Proposed Capital Expenditure in Energex's Revised Regulatory Proposal 2015-2020*, September 2015, p. 15.

¹⁵⁹ Energex, *Revised Regulatory Proposal*, July 2015, p. 46.

We did not accept Energex’s proposed augmentation on-costs in our preliminary decision. This was because it is not clear on the information provided by Energex whether the capex should be categorised as augmentation direct costs or capitalised overheads, or how it has been calculated.¹⁶⁰

Energex submitted that these costs represent “fleet and materials ancillary costs that are incurred as a consequence of all network maintenance and construction services.”¹⁶¹ These costs satisfy the definition of direct costs and direct materials within our regulatory information notice (RIN) requirements, but also capitalised overheads. Energex includes these on-costs as a negative balance item within its reset RIN to avoid double counting, which offset the proposed capitalised overheads forecast.

Energex also submitted that:

As a consequence of the deduction from capitalised overheads it is not appropriate to also remove these costs from direct augmentation capex. Energex notes that this is inconsistent with the treatment used when assessing the other categories of capital expenditure e.g. replacement and connections where these costs have correctly remained as direct costs consistent with RIN requirements. Where the direct costs of the replacement and connection capex categories have been reduced through the AER’s assessment these costs have consequently fallen also.¹⁶²

We accept Energex’s explanation of its augex on-costs and no longer propose to remove these on-costs entirely from the augex forecast.

Energex stated that its on-costs are allocated to projects and/or services on the basis of the value of material or labour charged to each service.¹⁶³ We asked Energex to allocate its forecast on-costs across its proposed augmentation programs and projects according to how it expects to allocate these costs over the 2015–20 period. We then allocated the proposed on-costs across Energex’s proposed augex projects in accordance to Energex’s response. Therefore our alternative estimate of total augex and the augex for individual projects (e.g. sub-transmission, distribution, reliability, power quality) includes a proportion of Energex’s on-costs, rather than considering on-costs as a separate capex item.

Land and easements

Energex proposes \$29.6 million (\$2014–15) to purchase land and easements for new substations and overhead lines in advance of the need to build the necessary network infrastructure.¹⁶⁴

In support of this capex, Energex submitted in its original regulatory proposal that:

¹⁶⁰ AER, *Preliminary Decision Energex 2015-20 to 2019-20*, Attachment 6, p. 63.

¹⁶¹ Energex, *Revised Regulatory Proposal*, July 2015, p. 45.

¹⁶² Energex, *Revised Regulatory Proposal*, July 2015, p. 46.

¹⁶³ Energex, *Revised Regulatory Proposal*, July 2015, p. 46.

¹⁶⁴ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 113.

Energex undertakes 30 year scenario planning to identify long term network development requirements. Areas such as the Ripley Valley, Caloundra and Yarrabilba have been identified as areas where infrastructure is likely to be required during the 2020–25 regulatory control period. The cost of purchasing land in these areas has been included in the 2015–20 expenditure forecast.¹⁶⁵

We accepted Energex’s proposed land and easement costs in our preliminary decision. This is because we were satisfied with Energex’s system wide demand forecasts for 2015–20 reflected a realistic expectation of demand for the period, and we considered it was not unreasonable for this growth to continue through the 2020–25 period. However we noted that we would consider updated demand forecasts in the final decision.

Energex has reviewed the expenditure forecast for land and easements based on the revised system demand forecast (refer to chapter 3 of the revised proposal). However, it did not propose any changes to its forecasts in this category of expenditure. For the final decision, we have reviewed Energex’s land and easement forecasts using Energex’s 10 year connection point forecasts that were published in Powerlink’s 2015 Transmission Annual Planning Report (APR).¹⁶⁶ These forecasts reflect Energex’s updated 2015 demand forecasts that it supplied to Powerlink.¹⁶⁷ While Energex has slightly increased its maximum demand forecasts at the total system level, its forecasts at some of its connection points have decreased.

Our alternative estimate is \$7.9 million for the purchase of easements; we do not provide a forecast for land purchases. While we considered that the capex may be necessary based on a consideration of Energex’s 2014 maximum demand forecasts, Energex’s updated 2015 demand forecasts show a significant drop in demand over the 2015–25 period in the Ripley Valley and Yarrabilba regions. This suggests that Energex’s longer-term demand projections are likely less than originally forecast, and therefore that purchasing land and some easements to build infrastructure can be prudently deferred beyond the 2015–20 regulatory period. As such we do not consider that the proposed expenditure reasonably reflects the efficient costs that a prudent operator would require to meet or manage expected demand for standard control services over the 2015–20 regulatory control period.

We informed Energex of our decision to use connection point demand forecasts in our assessment of land and easement costs.¹⁶⁸ Energex responded that they do not use connection point demand forecasts to plan the need for land and easement purchases. Energex noted that transmission connection point forecasts provide an indicative view of long term average growth.¹⁶⁹ However it stated that these forecasts only cover the

¹⁶⁵ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 113.

¹⁶⁶ Powerlink, *Transmission Annual Planning Report 2015*. Appendix A.

¹⁶⁷ Powerlink, *Transmission Annual Planning Report 2015*, Appendix A, p. 120.

¹⁶⁸ AER information request AER EGX 072.

¹⁶⁹ Energex response to AER EGX 072, p. 2.

first 10 years of a 30 or more year outlook, whereas land and easement acquisitions are driven by localised long term land use objectives in localised growth pockets.¹⁷⁰

We recognise that Energex may need to purchase land and easements well in advance of the need to build infrastructure, and that Energex requires detailed and long-term forecasts to determine prudent land and easement acquisitions. Our decision is about whether Energex's proposal to purchase specific land and easements is prudent, recognising that uncertainties exist in long term demand forecasts. To this end, 10 year connection point demands forecasts are a useful tool to observe how Energex's demand projections have changed over time and what this may mean for demand growth beyond 10 years. That said, these observations are not a substitute for Energex's own planning forecasts.

We discuss our assessment of Energex's proposed land and easements expenditure separately below.

Land

Energex proposes \$12.2 million to purchase land in Ripley Valley, Yarrabilba and Flagstone.¹⁷¹ We do not consider these land purchases are required in the 2015–20 regulatory control period. We discuss the proposed land purchases by area.

Ripley Valley

Energex proposes to purchase land for a new 110/33kV bulk supply substation, associated 33/11kV zone substations and a corridor for 110kV sub-transmission supply. This is to meet forecast demand for the Ripley development area over the next 50 years:

The Ripley development area is located approximately 10 km south of the Ipswich CBD in the southern part of the Ipswich City Council Local Government Area. The Ripley Area is being planned as a significant residential community in the growing "South Western Growth Corridor" with a population between 100,000 and 120,000 people in approximately 50,000 dwellings in a fifty year timeframe.¹⁷²

The proposed expenditure is associated with the establishment of Ripley North Bulk/Zone Substation in 2020–21, with land purchase five years prior in 2015–16; and Ripley Central zone substation in 2027–28 with land purchase eleven years prior in 2015–16.

Blackstone substation is the Powerlink connection point relevant to Ipswich and Ripley Valley. The Powerlink APR provides Energex's forecast of summer native peak

¹⁷⁰ Energex response to AER EGX 072, p. 2.

¹⁷¹ Energex has claimed confidentiality over the individual costs of its proposed land purchases. We have presented the costs in aggregate. As we do not accept that the individual purchases are required in the 2015–20 period, we do not consider it necessary to present the individual costs through this section.

¹⁷² Energex response to AER EGX 010, Att 7. Planning Proposal - Land and Easements, 24 September 2014, p. 20.

demand for each connection point. The 2015 APR forecasts lower demand for Blackstone substation compared to that published in 2014. For example the 2014 APR forecast a demand of 97MW by 2019-20,¹⁷³ but demand in the 2015 APR is not forecast to reach 97 MW until 2023-24.¹⁷⁴ This suggests the need for the earlier substation is likely to be delayed until 2024–25 and the need for land purchase can be delayed to the next period. We have therefore not provided an allowance for the purchase of land in Ripley Valley for the 2015–20 regulatory control period.

Yarrabilba and Flagstone

Energex proposes to purchase land for two new 110/33kV bulk supply substations and 33/11kV zone substations (Yarrabilba Central and Undullah) and eight associated 33/11kV zone substations across both areas. This is to meet forecast demand for the Yarrabilba and Flagstone development areas over the next 50 years.

In the Yarrabilba area, Energex explain:

This development covers an area of approximately 2,200 hectares and is located approximately 40 km south-east of the Brisbane CBD in the southern part of the Logan City Council Local Government Area. Yarrabilba is being planned as a significant residential community in the growing “South Western Growth Corridor”. When fully developed it is expected to have a population of approximately 50,000 people in over 20,000 dwellings in a fifty year time frame.¹⁷⁵

The proposed expenditure in Yarrabilba is associated with the establishment of Yarrabilba West Zone Substation in 2027, with land purchase ten years prior in 2016–17. The other four substations are proposed for 2029 and beyond with land purchase ten years prior in 2018–19 and 2019–20.

Similarly, Energex explain that the greater Flagstone area is being planned as a residential community in the South Western Growth Corridor with a population of between 100,000 and 120,000 people.¹⁷⁶

The proposed expenditure in Flagstone is associated with land purchases in 2017–18 for two substation sites and in 2019–20 for the other three substations sites. Energex did not provide its forecast timing for the construction of the substations. In line with the Yarrabilba development, we consider that this is likely to be around ten years later than the land purchases.

Loganlea substation is the Powerlink connection point relevant to Flagstone and Yarrabilba. The 2015 APR forecasts significantly lower demand for Loganlea substation compared to that published in 2014.¹⁷⁷ For example the 2014 APR forecast

¹⁷³ Powerlink, *Transmission Annual Planning Report 2014*, p. 103.

¹⁷⁴ Powerlink, *Transmission Annual Planning Report 2015*, p. 127.

¹⁷⁵ Energex response to AER EGX 010, Att 7. Planning Proposal - Land and Easements, 24 September 2014, p. 26.

¹⁷⁶ Energex response to AER EGX 010, Att 7. Planning Proposal - Land and Easements, 24 September 2014, p. 20.

¹⁷⁷ Powerlink, *Transmission Annual Planning Report 2015*, p. 127

a demand of 457MW by 2014–15,¹⁷⁸ but the highest demand in the 2015 APR is 429MW in 2024–25. This suggests the need for land purchase associated with any of the proposed substations for the Yarrabilba and Flagstone projects can be delayed to the next period. We have therefore not provided an allowance for the purchase of land in Yarrabilba and Flagstone for the 2015–20 period.

Easements

Energex proposes \$17.4 million for corridor/easement acquisitions for future overhead feeders. There are six corridor or easement acquisitions included in the proposed expenditure. Table sets out Energex’s proposed easement purchases.

Table B.8 Energex’s proposed easement purchases (\$2014–15, million, excluding overheads)

Corridor program	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Loganlea – Jimboomba 110kV single circuit	0.7	0.7	0.7	0.3		2.4
Sunsouth – 132kV single circuit and 132kV double circuit	0.1	0.9	1.1	1.1	1.1	4.4
Jimboomba –Beaudesert 110kV single circuit	0.8	1.6	2.1	2.0	2.2	8.8
Pacific Paradise – H9 Palmwoods and ABM Abermain – WKA Wulkuraka Tee – LRE Lockrose BS	0.6	0.2	0.1	0.0	0.0	0.9
Blackstone PLQ – SFC Springfield Central	0.0	0.0	0.0	0.0	0.7	0.7
ABM Abermain – WKA Wulkuraka Tee – LRE Lockrose BS	0.2	0.0	0.0	0.0	0.0	0.2
Total	2.4	3.4	4.0	3.4	4.1	17.4

Source: Energex response to AER EGX 070.

Note: Energex has not claimed confidentiality over the individual costs of its proposed easements purchases. Hence we have presented the individual costs in our decision.

We have considered each of these easement purchases noting the updated demand forecasts in Powerlink’s 2015 APR. We accept ongoing projects and projects in high-growth areas, where the demand forecast has not fallen between 2014 and 2015. Our findings are noted below:

¹⁷⁸ Powerlink, *Transmission Annual Planning Report 2014*, p. 103.

- Loganlea – Jimboomba 110kV single circuit is an ongoing project, with the forecast costs reflecting risks of project delays. We accept the proposed expenditure for this project.
- Sunsouth – 132kV single circuit and 132kV double circuit is intended to meet demand in high-growth areas. The demand from the relevant Palmwoods connection point is forecast to increase to 348MW in 2023–24 according to the 2015 Powerlink APR. This is a higher forecast than the 325MW forecast in 2023–24 according to the 2014 APR. We accept the proposed expenditure for this project.
- Jimboomba – Beaudesert 110kV single circuit and Blackstone PLQ – SFC Springfield Central are related to the Yarrabilba and Flagstone projects, which, based on the latest demand forecasts are likely to be significantly delayed. Consequently, we consider the purchase of these easements in the 2015–20 regulatory control period is not prudent.
- Regarding the Jimboomba – Beaudesert easement, Energex claim it needs to ensure sufficient time for community consultation, which can extend the acquisition of line easement over a 10 year period.¹⁷⁹ Energex note that the requirement for the feeder is beyond 2030; our expectation is that it can be delayed further, meaning the acquisition process could begin in the 2020–25 regulatory period at the earliest.
- Pacific Paradise – H9 Palmwoods and ABM Abermain – WKA Wulkuraka Tee – LRE Lockrose BS are ongoing projects and nearing completion. We accept the proposed expenditure for these projects.

We accept all easement projects with the exceptions of Jimboomba – Beaudesert 110kV single circuit and Blackstone PLQ – SFC Springfield Central, therefore we include \$7.9 million in our alternative estimate. We consider that this reflects a prudent and efficient amount for Energex to acquire easements for the construction of new overhead lines, in order to meet or manage expected demand for standard control services.

B.3 AER findings and estimates for customer connections capex, including capital contributions

Connections capex is incurred by Energex to connect new customers to its network and where necessary augment the shared network to ensure there is sufficient capacity to meet the new demand.

New connection works can be undertaken by Energex or a third party. The new customer provides a contribution towards the cost of the new connection assets. This contribution can be monetary or in contributed assets. In calculating the customer

¹⁷⁹ Energex response to AER EGX 010, Att 7. *Planning Proposal - Land and Easements*. 24 September 2014, p. 7.

contribution, Energex is required to take into account the forecast revenue anticipated from the new connection.¹⁸⁰ These contributions are subtracted from total gross capex and as such decrease the revenue that is recoverable from all consumers. Customer contributions are sometimes referred to as capital contributions or capcons. The mix between net capex and capcons is important as it determines from whom and when Energex recovers revenue associated with the capex investment. For works involving a customer contribution, Energex recovers revenue directly from the customer who initiates the work at the time the work is undertaken. This is different from net capex where Energex recovers revenue for this expenditure through both the return on capital and return of capital building blocks that form part of the calculation of Energex's annual revenue requirement.¹⁸¹ That is, Energex recovers net capex investment across the life of the asset through revenue received for the provision of standard control services.

B.3.1 AER Position

We do not accept Energex's revised proposal for connections capex of \$330.9 million (\$2014–15). We have instead included an amount of \$294.6 million (\$2014–15) in our substitute estimate of forecast capex, as shown in Table . This is 11.0 per cent lower than Energex's revised proposal. We are satisfied that this amount reasonably reflects the capex criteria. Further, we accept Energex's revised proposal for customer contributions of \$172.3 million (\$2014–15) which, consistent with our preliminary decision, reflects with forecast construction activity in Queensland.

Table B.9 AER adjusted connections capex (\$2014–15 million excluding overheads)

	2016	2017	2018	2019	2020	Total
Connections capex	56.7	56.0	56.8	60.4	64.7	294.6
Customer contributions	30.0	33.2	34.7	36.8	37.6	172.3

Source: AER analysis.

B.3.2 Revised proposal

In its revised proposal, Energex included a forecast of connections capex of \$330.9 million (\$2014–15). Energex's forecast is made up of four components:

- network connections - a program for large individual projects and connections to the domestic and rural network
- new connections – installation of overhead service connection for new customers and the energisation of underground services

¹⁸⁰ NER Chapter 5 – Part A - Network Connection.

¹⁸¹ For more information on the building blocks included in the determination of Energex's annual revenue requirement see our attachments on the regulatory asset base and regulatory depreciation.

- commercial and industrial - a program to extend the network to connect commercial and industrial customers, and
- a provision for on-costs associated with connections work.¹⁸²

In its revised proposal, Energex accepted the AER’s preliminary decision in relation to the network connection forecast. This includes the removal of the connections capex associated with the Brisbane CBD bus and train tunnel and the reclassification of local or state authority undergrounding works as an alternative control service.¹⁸³ However, Energex has revised up its projections of new connections and commercial projects. It submitted this increase is necessary due to recently observed stronger recovery in economic activity in South East Queensland.¹⁸⁴ Table provides a comparison of the forecasts expenditure on connection components.

Table B.10 Connections capex component comparison (\$2014–15 million, excluding overheads)

	Regulatory proposal ¹	Preliminary Decision	Revised regulatory proposal	Final Decision
Network Connections	92.3	51.8	51.8	51.8
New service connections	51.3	51.3	64.5	64.5
Commercial project connections	156.8	156.8	201.6	166.7
On-costs	12.1	12.1	12.9	11.5
Total	312.5	272.0	330.8	294.6

Source: AER analysis.

Notes: Regulatory proposal excludes the community amenity amount that was reclassified to ACS. Totals may not add due to rounding.

B.3.3 Reasons

Network connections

In our preliminary decision, we accepted the network connections forecast, except for the expenditure related to the Brisbane CBD bus and train tunnel project. In its revised proposal, Energex has removed these costs from its network connections forecast. Accordingly, we are satisfied that this is consistent with our preliminary determination and we accept Energex’s revised proposal for network connections for the reasons set

¹⁸² Energex, *Revised regulatory proposal*, July 2015, p.48.

¹⁸³ Energex, *Revised regulatory proposal*, July 2015, p.47.

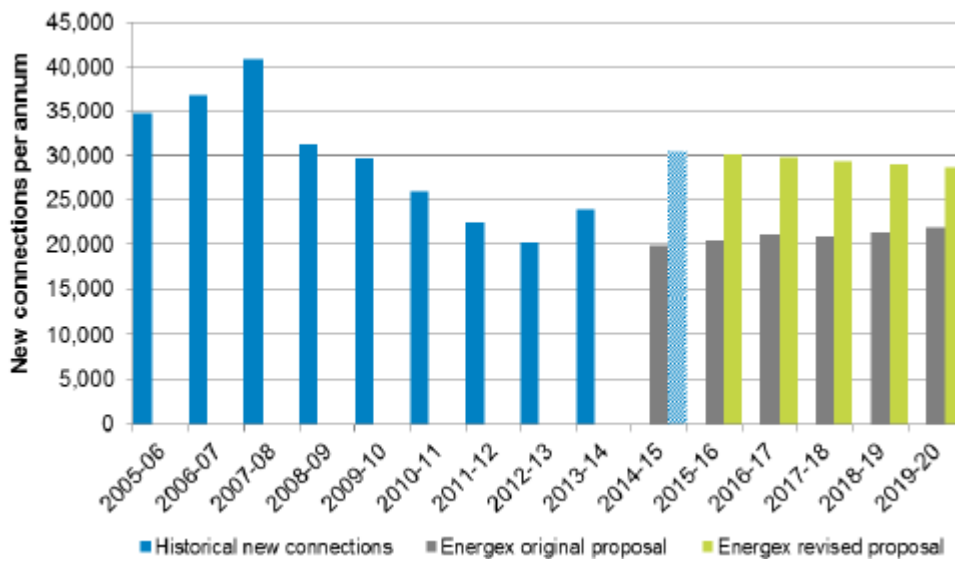
¹⁸⁴ Energex, *Revised regulatory proposal*, July 2015, p.47.

out in our preliminary decision as we consider Energex’s forecast is consistent with forecast construction activity in Queensland.¹⁸⁵

New service connections

In its revised proposal, Energex submit that connection activity has shown a stronger recovery than previously expected.¹⁸⁶ Energex has provided updated actual volumes of new connections to the end of April 2015. As shown in Figure , when extrapolated to the end of 2014–15, Energex now expects 30,486 new connections for the year.

Figure B.10 New connection quantities – 2005–06 to 2019–20



Source: Energex, *2015-20 revised regulatory proposal*, figure 4.9, p. 49.

With respect to the number of new connections observed for 2014–15, Energex considered that:

This strongly suggests that the initial signs of recovery in 2013–14 have strengthened in 2014–15, providing confidence that activity levels are sustainably returning to levels last seen at the end of the last decade (but still well down from levels observed in the mid-2000s).¹⁸⁷

Further, Energex considered the latest Housing Industry Association (HIA) housing start forecast for Queensland supports its revised connection forecasts.¹⁸⁸ We note the HIA data underlying Energex’s forecast is a reasonably well accepted industry standard indicator of commercial and industrial connection activity. HIA is a private-

¹⁸⁵ AER, *Energex determination 2015–20, Attachment 6 – Capital expenditure* p. 6-63.

¹⁸⁶ Energex, *Revised regulatory proposal*, July 2015, p.48.

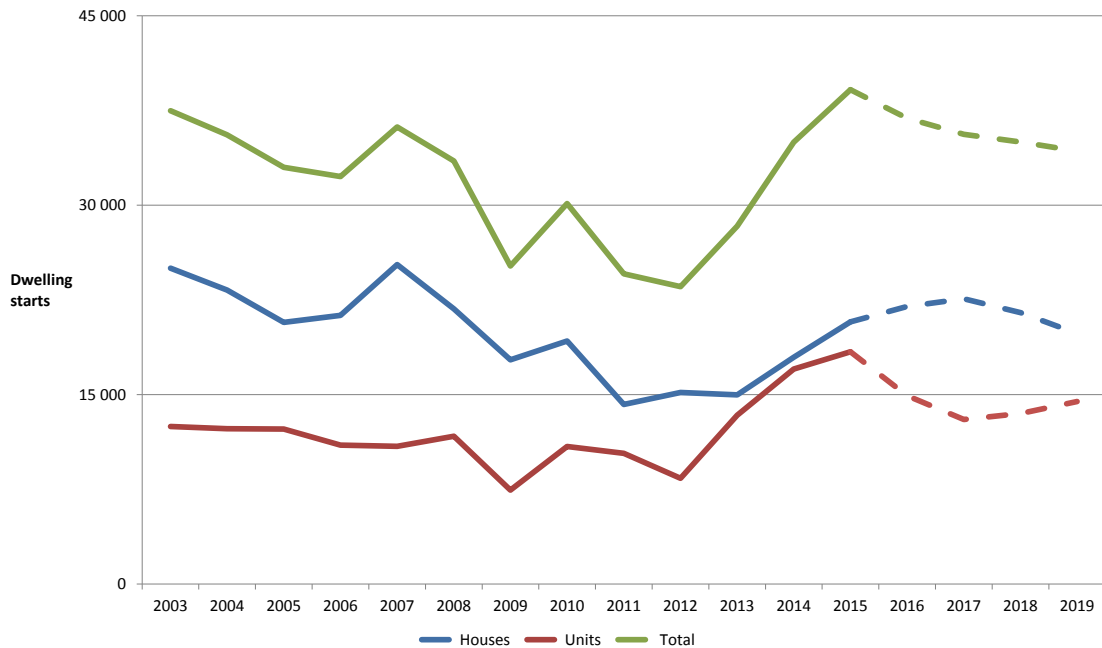
¹⁸⁷ Energex, *Revised regulatory proposal*, July 2015, p.48.

¹⁸⁸ Energex, *Revised regulatory proposal*, July 2015, p.49.

sector industry association comprising mainly house construction contractors. HIA forecasts have been used by the industry since 1984.¹⁸⁹

Figure shows house and unit construction starts in Energex’s distribution area since 2003. It shows that Energex’s recent connections activity is consistent with dwelling starts and its forecast is consistent with the HIA expenditure trend.

Figure B.111 HIA housing actual and forecast dwelling starts for Energex distribution area Queensland – 2015



Source: AER analysis of HIA actual and projected dwelling starts for Queensland October 2015.

We accept that there has been a strengthening in the outlook for dwelling starts in Queensland as demonstrated by upward revisions to HIA projections. We accept that electricity is an essential service and we consider that an increase in dwellings would result in a near equal increase in connections.

Accordingly, we are satisfied that Energex has demonstrated that the recently observed increase in new connections and the forecast trend in HIA building starts justifies the increases in the volume of new service connections. We have therefore accepted Energex’s forecast of \$64.5 million (\$2014–15) for new connections expenditure.

¹⁸⁹ Mills, Anthony and Harris, David and Skitmore, Martin R, *The Accuracy of Housing Forecasting in Australia*, *Engineering Construction and Architectural Management* 10(4), 2003, pp. 245-253. Accessed from: <http://eprints.qut.edu.au/archive/00004441/>.

Commercial projects

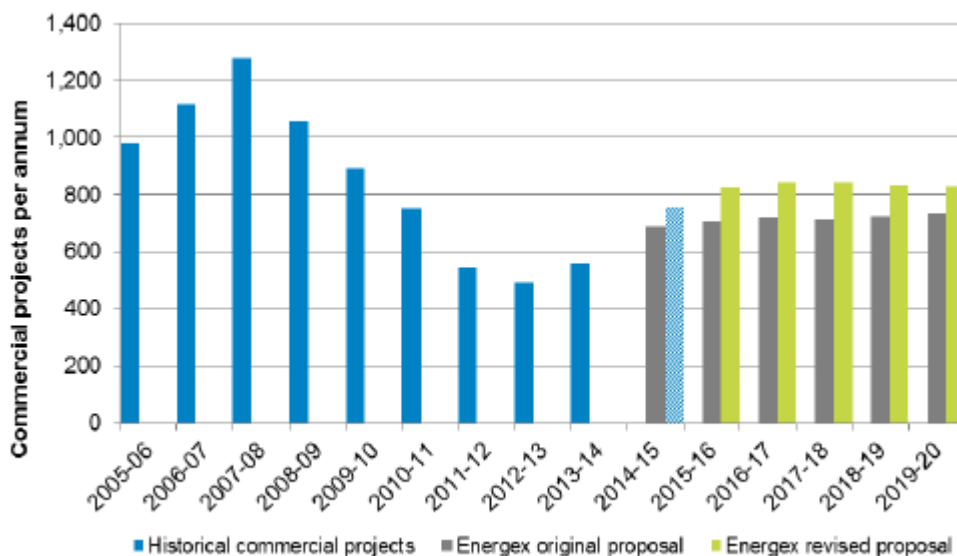
Similar to new service connection activity, Energex noted that connection activity associated with commercial projects has shown a stronger recovery than previously expected.¹⁹⁰ As a result of this recent activity, Energex has increased its forecast for commercial projects from \$156.8 million in its initial proposal, to \$201.6 million (\$2014–15) in its revised regulatory proposal.

Energex in its revised proposal noted:

As for new service connection activity, Energex has prepared updated forecasts of commercial project activity since the original proposal was submitted. In 2013–14 there were signs that the decline in commercial project activity in preceding years had slowed, which indicated an emerging recovery. The latest reported data adds further support to the view of a recovering commercial market. The 2014–15 data indicates a modest, but enduring, upwards trend in projects per month.¹⁹¹

Importantly, Energex stated that “it is reasonable to assume that 2014–15 levels of connection activity are likely to be maintained in broad terms over the whole 2015–20 regulatory control period.”¹⁹² However, as shown in Figure , in forecasting its expenditure, it has included additional forecast growth in volumes in 2015–16, and then maintained this level for the remainder of the 2015–20 regulatory control period.

Figure B.12 Commercial project quantities 2005-06 to 2019-20



Source: Energex, *Revised regulatory proposal*, Figure 4.11, July 2015, p. 51.

¹⁹⁰ Energex, *Revised regulatory proposal*, July 2015, p.51.

¹⁹¹ Energex, *Revised regulatory proposal*, July 2015, p.51.

¹⁹² Energex, *Revised regulatory proposal*, July 2015, p.51.

We are satisfied that Figure shows that the outturn number of commercial projects in 2014–15 is higher than initially expected at the time Energex submitted its initial proposal. However we consider that the forecast increase between 2014–15 and 2015–16 has not been justified and is inconsistent with Energex’s own statement on the expected maintenance of 2014–15 expenditure levels.

Consistent with Energex’s statement, we consider it is reasonable to expect that the overserved 2014–15 levels will be maintained for the 2015–20 regulatory control period. While we note that there are pockets of growth in Energex’s network, as set out in the appendix C, Energex is only forecasting peak demand to grow at 1.2 per cent. We consider that forecast stability in peak demand indicates that observed trends in network growth capex (including connections) are reasonable indicators of future capex requirements.

Accordingly, while we agree with Energex that the outlook for commercial project connections has strengthened, we consider Energex’s updated forecast commercial connections capex is overstated. Our substitute forecast of \$167.0 million (\$2014–15) adopts the 2014–15 commercial project quantities as a starting point for 2015–16 and applies the same growth rate as proposed by Energex for the remainder of the period. This results in an increase to the forecast included in our preliminary decision but is less than the increase proposed by Energex.

Table shows our substitute estimate for commercial project connections that we have included Energex’s revised proposal for comparison.

Table B.11 AER final decision and Energex revised proposal – commercial projects connections net capex (\$2014–15, million excluding overheads)

	2016	2017	2018	2019	2020	Total
Energex revised proposal	39.4	40.9	40.6	40.4	40.3	201.6
AER final decision	33.0	33.5	33.4	33.5	33.7	167.0

Source: Energex, *Revised regulatory proposal*, Table 4.24, July 2015, p. 52.
AER analysis.

On-costs

Energex also includes provision for on-costs that relate to its forecast of direct cost forecasts.¹⁹³ With respect to its revised connections capex forecast, Energex noted:

Energex has revised on-costs as a result of changes to the direct cost forecast. The revised forecast is \$12.9 million (\$2014–15) excluding overheads. This represents a 6 per cent increase from Energex’s original proposal. The small

¹⁹³ Energex, *Revised regulatory proposal*, July 2015, p. 52.

increase is due to the new mix of connections expenditure. Energex has recalculated the on-costs based on the removal of the BAT tunnel (which did not attract many on-costs due to a larger mix of contractor costs) and the inclusion of additional costs relating to new connections and commercial projects.¹⁹⁴

We acknowledge that as the composition of projects included in Energex’s forecasts change, the level of on-costs will change. Consistent with our approach in the augex section of this attachment, we have scaled the on-costs to reflect the adjustments we have made to Energex’s revised proposal. As a consequence, there is a slight downward revision in the on-costs associated with connections work, as set out in Table .

Table B.12 AER final decision and Energex revised proposal – connections net capex on-costs (\$2014–15 million, excluding overheads)

	2016	2017	2018	2019	2020	Total
Energex revised proposal	2.7	2.5	2.5	2.6	2.6	12.9
AER final decision	2.3	2.2	2.2	2.2	2.2	11.5

Source: Energex, *Revised regulatory proposal*, Table 4.25, July 2015, p. 52.
AER analysis (note may not add due to rounding).

B.4 AER findings and estimates for replacement expenditure

Repex is driven by the inability of network assets to meet the needs of consumers and the overall network. The decision to replace can be based on cost, quality, safety, reliability, security, or a combination of these factors. In the long run, a service provider's assets will no longer meet the requirements of consumers or the network and will need to be replaced, refurbished or removed.¹⁹⁵

Replacement is commonly driven when the condition of the asset means that it is no longer economic or safe to be maintained. It may also occur due jurisdictional safety regulations, or because the risk of using the asset exceeds the benefit of continuing to operate it on the network. Technological change may also advance the timing of the replacement decision and the type of asset that is selected as the replacement.

Electricity network assets are typically long-life assets and the majority will remain in use for far longer than a single five year regulatory period. Many of these assets have economic lives of 50 years or more. As a consequence, a service provider will only

¹⁹⁴ Energex, *Revised regulatory proposal*, July 2015, p.52.

¹⁹⁵ Assets may also be replaced due to network augmentation. In these cases the primary reason for the asset expenditure is not the replacement of an asset that has reached the end of its economic life, but the need to deploy new assets to augment the network, predominantly in response to changing demand.

replace a portion of its network assets in each regulatory control period. The majority of network assets will remain in commission well beyond the end of any single regulatory control period.

Our assessment of repex seeks to establish the portion of Energex's assets that will likely require replacement over the 2015–20 regulatory control period, and the associated expenditure.

B.4.1 Position

We accept Energex's revised proposed repex of \$987 million (\$2014–15) and have included this amount in our alternative estimate of overall total capex for repex, excluding overheads. We are satisfied that this amount reasonably reflects the capex criteria.

B.4.2 Revised proposal

Energex's revised proposal is \$987 million, \$267 million or 21 per cent lower than its initial proposal of \$1250 million. Energex's revised proposal is \$361 million higher than the AER's preliminary decision which substituted a replacement capex of \$622 million. In response to the AER's preliminary decision, Energex:

- engaged engineering consultants Jacobs to review the inputs and outputs of the repex model¹⁹⁶
- corrected data issues in its RIN response
- revised its proposed expenditure for SCADA network protection and control systems from \$124 million to \$62 million, and provided further information in support of its SCADA program
- revised its proposed expenditure for assets categorised as "other" in its reset RIN from \$281 million to \$100 million, and provided further information in support of the replacement of these assets.

Energex did not provide commentary on the advice provided to the AER by EMCa before the preliminary decision in relation to the six asset categories included in the repex model. Rather, Energex focussed its revised proposal on how we applied the repex model in the preliminary decision. Energex did not accept our preliminary decision due to:¹⁹⁷

- Concerns with our assessment approach. In particular, a report by its consultant Jacobs suggested that we did not give adequate consideration to obsolescence and asset condition assessment and more generally arguing for an extension of our assessment of Energex's engineering considerations.¹⁹⁸ In support of its

¹⁹⁶ Jacobs, *AER REPEX Review – Energex*, 15 June 2015.

¹⁹⁷ Energex, *Revised Regulatory Proposal*, July 2015, p. 1.

¹⁹⁸ Jacobs, *AER REPEX Review – Energex*, 15 June 2015, p. 3.

position, Energex also engaged engineering consultants Advisian to review its business cases.

- The sensitivity of asset lives which are inputted into the repex model.¹⁹⁹
- The adoption of historic unit rates to calibrate forecast modelling through the repex model.²⁰⁰

B.4.3 AER approach

We applied several assessment techniques to assess Energex's forecast of repex against the capex criteria. These techniques were:

- analysis of Energex's historical total repex trends
- technical review of Energex's approach to forecasting, costs, work practices and risk management
- predictive modelling of repex based on Energex's assets in commission.

In response to Energex's comments about some of the above assessment techniques, we have clarified our application of those techniques and the extent to which we have relied on the outcomes of each in this final decision. In the course of doing so, we have addressed the further information Energex has provided in its revised proposal.

In the preliminary decision, we used predictive modelling (specifically, the repex model) to assess around 61 per cent of Energex's proposed repex. This assessment was undertaken in combination with the findings of EMCA's technical review, which provided a qualitative assessment of Energex's proposal. As Energex did not raise new matters in the revised proposal in relation to EMCA's technical review, this final decision is mainly concerned with addressing Energex's submissions regarding the use of predictive modelling (for those asset categories where predictive modelling was used).

For the remaining categories of expenditure, we did not use predictive modelling in our consideration of an alternative estimate of capex. For these categories (referred to as "unmodelled asset categories") we relied on the analysis of historical expenditure, supported by the findings of EMCA's technical review.

In response to our preliminary decision, Energex submitted a lower capex forecast for these unmodelled asset categories, together with new supporting information. EMCA was engaged to provide technical analysis of the revised proposal for the unmodelled asset categories, and our analysis is primarily based on its findings.²⁰¹

¹⁹⁹ Jacobs, *AER REPEX Review – Energex*, 15 June 2015, p. 3.

²⁰⁰ Jacobs, *AER REPEX Review – Energex*, 15 June 2015, p. 4.

²⁰¹ EMCA, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal*, September 2015.

Trend analysis

We recognise the limitations of expenditure trends, especially in circumstances where replacement needs may change over time (e.g. a distributor may have a lumpy asset age profile or legislative obligations may change over time). In recognising these limitations, we have used this analysis to draw general observations in relation to the modelled categories of repex, but we have not used it to reject Energex's forecast of repex or develop our alternative estimate. However, we have relied on trend analysis, in combination with the findings of EMCa, to assist our assessment of the unmodelled categories of repex.

Predictive modelling

Our predictive model, known as the repex model, can be used to predict a reasonable amount of repex Energex would require if it maintains its current risk profile for condition-based replacement into the next regulatory period. Using what we refer to as calibrated replacement lives in the repex model gives an estimate that reflects Energex's 'business as usual' asset replacement practices. We explain the calibrated replacement life scenario, along with other input scenarios, further below.

As part of the 'Better Regulation' process the AER undertook extensive consultation with service providers in developing the repex model. This consultation process was used by the AER to develop the repex model. The repex model that was developed through this consultation process is well-established and has been successfully implemented by the AER in a number of revenue determination processes including the recent NSW/ACT revenue determination process. It builds on repex modelling undertaken by the AER in previous Victorian and Tasmanian distribution pricing determinations.²⁰²

The repex model has the advantage of providing both a bottom up assessment, as it is based on detailed sub-categories of assets using data provided by the service providers, and once aggregated it provides a well-founded high level assessment of that data. The model can also be calibrated using data on Energex's entire stock of network assets, along with Energex's actual replacement practices, to estimate the repex required to maintain its current risk profile.

We recognise that predictive modelling cannot perfectly predict Energex's necessary replacement volumes and expenditure over the next regulatory period, in the same way that no prediction of future needs will be absolutely precise. However, we consider the repex model is suitable for providing a reasonable statistical estimate of replacement volumes and expenditure for certain types of assets, where we are satisfied we have the necessary data. We explain our reasons for this in appendix E of

²⁰² We first used the predictive model to inform our assessment of the Victorian distributors' repex proposals in 2010. We undertook extensive consultation on this technique in developing the Expenditure Forecasting Assessment Guideline. We have since used the repex model to inform our assessment of repex proposals for Tasmanian, NSW, ACT, QLD and SA distributors.

the preliminary decision. We also note that the service providers (including Energex) rely on similar repex modelling to support their forecast amount for repex.

We use predictive modelling to estimate a value of 'business as usual' repex for the modelled categories to assist in our assessment. However, predictive modelling is not the only assessment technique we have relied on in assessing Energex's proposal. Our other techniques, which are qualitative in nature, allow us to form a view on whether or not 'business as usual' expenditure appropriately reflects the capex criteria.

Any material difference from the 'business as usual' estimate could be explained by evidence of a non-age related increase in asset risk in the network (such as a change in jurisdictional safety or environmental legislation) or evidence of significant asset degradation that could not be explained by asset age. We use our qualitative techniques, particularly EMCa's technical review, to assess whether there is any such evidence. In this way, we consider that the repex model does serve as a 'first pass' test, as set out in our Expenditure Guideline.²⁰³

We recognise that there are reasons why some assets may be better assessed outside of the model. Where we considered it was justified, we have separately assessed those assets which we thought may be better assessed outside the model by using techniques other than predictive modelling.

Technical review

The repex forecast in Energex's initial proposal was subject to a technical review by EMCa. EMCa assessed Energex's approach to forecasting, including whether it has had regard to robust cost-benefit analysis. It also assessed Energex's costs, work practices and risk management approach. This was to identify whether risk was systematically overestimated and, in turn, whether its approach to repex and repex forecasts in the next regulatory period were in accordance with its risk profile. EMCa provided a further report in response to Energex's revised proposal. We evaluated EMCa's findings in its subsequent report in the course of our repex assessment in this final decision.

We have relied on EMCa's reports to assess whether Energex's risk profile is different in the next regulatory period, such that it requires repex above the business as usual prediction of our repex model. We have also relied on it, in combination with an analysis of historic repex, to inform our assessment of repex programs to which we did not apply our predictive modelling.

²⁰³ AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 11.

B.4.4 AER repex findings

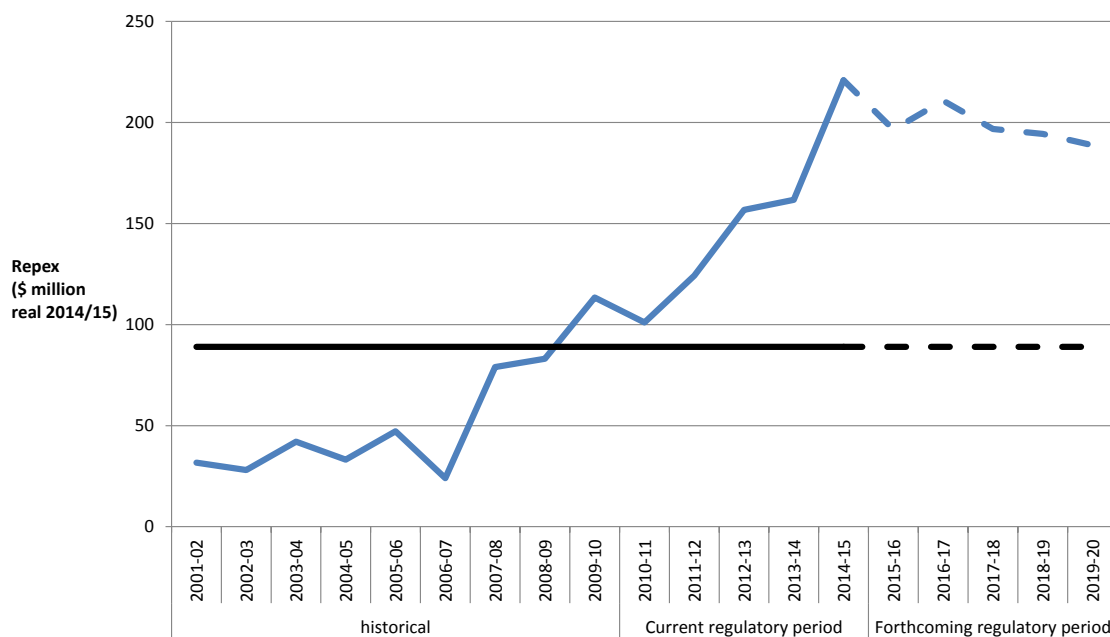
Trends in historical and forecast repex

We have conducted a trend analysis of repex. The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period.²⁰⁴

Our use of trend analysis is to gauge the degree to which the proposed repex is consistent with past expenditure. We recognise limits of expenditure trends, especially in circumstances where replacement needs may change over time (e.g. a service provider may have a lumpy asset age profile or legislative obligations may change over time).

Figure below indicates that Energex's revised repex proposal for the 2015–20 regulatory control period is well above that incurred in the previous regulatory control period and the early 2000s.

Figure B.13 Energex's repex – historic actual and revised proposed for 2015–20 regulatory control period (real \$ million 2014–2015)



Source: Historical years: *Energex 2010-15 Revised Regulatory Proposal - RIN response - Table 2 - Capital expenditure by purpose*. Current and forthcoming regulatory periods: *Energex - Regulatory Proposal 2015-20 - Reset RIN - Table 2.1.1 - Standard Control Services Capex Energex Revised Proposal Attachment 3 - Energex Revised Proposal Capex Model_AERV7.xlsx] Capex_*

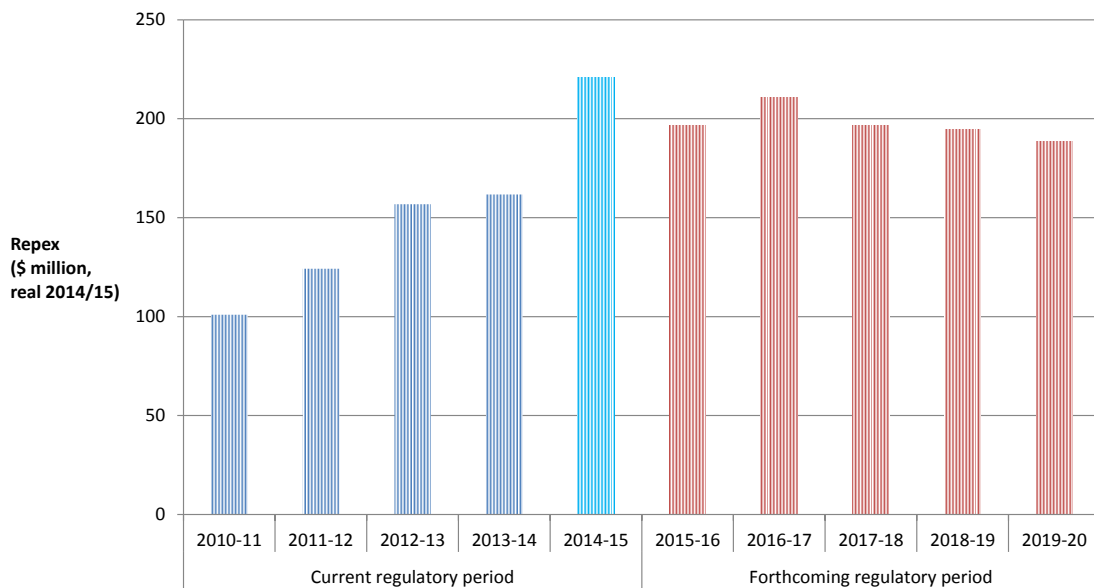
²⁰⁴ NER, cl. 6.5.7(e)(5).

When considering the above trend we acknowledge there are limitations in long term year on year comparisons of replacement expenditure. In particular, we are mindful that:

- Energex's regulatory reporting has been subject to varied definitions of replacement expenditure across time.²⁰⁵
- There are natural variations in a distributor's replacement needs over time. Such variations can be a result of lumpy asset age profiles or changes in relevant regulatory obligations.²⁰⁶

Figure B compares actual and expected repex in the current and forthcoming regulatory control period.

Figure B.14 Actual and expected repex (\$ million real June 2015)



Source: Energex - Regulatory Proposal 2015-20 - Reset RIN - Table 2.1.1 - Standard Control Services Capex Energex Revised Proposal Attachment 3 - Energex Revised Proposal Capex Model_AERV7.xlsx] Capex

Figure B indicates the proposed repex for the 2015–20 regulatory control period is an increase from the current regulatory control period. In the context of this increase we have applied our other assessment techniques to assess the basis for the proposed increase and to ascertain the efficient and prudent amount of total proposed repex.

²⁰⁵ In the Reset RIN we defined replacement expenditure to be: *Repex: The non-demand driven capex to replace an asset with its modern equivalent where the asset has reached the end of its economic life. Capex has a primary driver of replacement expenditure if the factor determining the expenditure is the existing asset's inability to efficiently maintain its service performance requirement.*

²⁰⁶ NER cl. 6.5.7 (a).

Technical review

Our preliminary decision set out our approach to engaging EMCa to undertake a technical review to test Energex's repex forecast against the capex criteria. We engaged EMCa to test whether Energex's:

- repex forecast is reasonable and unbiased
- costs and work practices are prudent and efficient; and
- risk management is prudent and efficient.

Broadly, on these aspects EMCa found in its April 2015 report that:²⁰⁷

- Energex had conducted insufficient project and program analysis to support the timing and volume of activity. Further, its replacement targets appeared to coincide with regulatory period end points.
- Risk assessment had been undertaken at too high a level to assist meaningful decision-making both within and across the program.
- Aggregate repex modelling prepared by Energex presented alternative outcomes that are so wide as to be of little merit for use in a top-down challenge to validate the proposed expenditure levels.
- There was inadequate justification of the significant proposed step increase in expenditure.

In considering whether Energex's revised forecast repex reflected an efficient and prudent expenditure forecast we engaged EMCa to review Energex's revised proposal and in particular the new information Energex provided. Energex's new information related to proposed repex for the "SCADA" and "other" asset categories.

For SCADA, EMCa found that Energex had taken steps to:²⁰⁸

- review the requirement for the programs, including the assessment of risk
- consider the optimal scope of work, including opportunities for prudent deferral
- consider an expanded number of options in its analysis, including targeted risk mitigation techniques.

For the "other" asset category, EMCa found that Energex had taken steps to:²⁰⁹

- review the requirement for the programs, including re-assessment of risk

²⁰⁷ EMCa, *Review of Energex's Augex and Repex Regulatory Proposal*, April 2015, p. iii.

²⁰⁸ EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal*, September 2015, p. 32.

²⁰⁹ EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal*, September 2015, p. 26.

- consider the optimal scope of work, including consideration of priority based approaches to the work and opportunities for prudent deferral
- consider an expanded number of options in its analysis, including targeted risk mitigation techniques
- consider lower cost solutions.

EMCa formed the view that the steps taken by Energex in its revised proposal were more likely to result in a forecast allowance for SCADA and ‘Other’ repex that meets the expenditure requirements of the NER than was the case with its initial proposal. However, it could not exclude the possibility that a lower amount would still represent a reasonable forecast of the prudent and efficient level of required expenditure.

EMCa concluded that, on balance, Energex’s revised expenditure for these categories appears likely to be reflective of a prudent and efficient level.²¹⁰

Predictive modelling

We use predictive modelling to estimate how much repex Energex is expected to need in future, given how old its current assets are, and using age as a proxy for asset condition, when it is likely to replace the assets. We modelled six asset groups using the repex model. These were poles, overhead conductors, underground cables, service lines, transformers and switchgear. To ensure comparability across different service providers, these asset groups have also been split into various asset sub categories. Pole top structures and SCADA were not modelled, along with specialised categories of capex defined by Energex that were not classified under the six asset groups above. In total, the assets modelled represent 71 per cent of Energex’s revised proposed repex. Our predictive modelling calculation process is described in appendix E of the preliminary decision.

In total for all six modelled categories we have accepted Energex’s forecast for these categories of \$753 million. This was after incorporating updated asset information supplied by Energex in response to our preliminary decision. We set out below our views on the modelling input scenarios, and our views on their suitability for use in our assessment.

Submissions on Energex’s proposal also considered that its proposed repex for the 2015–20 regulatory control period was higher than necessary. We consider these submissions support the reduction in expenditure achieved in Energex’s revised proposal:

- The CCP considered the distributors’ proposals were not justified on asset condition and that the risks and drivers of repex were not substantially justified. The CCP also noted the variation in distributors’ estimated asset lives, and was of the

²¹⁰ EMCa, *Review of proposed capital expenditure in Ergon Energy’s revised regulatory proposal*, September 2015, p. 34.

view we should have a more standardised approach to asset lives.²¹¹ We consider this supports our use of calibrated asset lives.

- Total environment centre supported reductions to forecast repex. It stated that the distributors had not made a case for a significant increase in repex and appeared to have overly conservative approaches to asset management.²¹²
- The Chamber of Commerce and Industry Queensland supported reductions to the repex, particularly as it was a large part of capex. It considered the levels of repex proposed by the network businesses was concerning given the average age of assets have been rapidly decreasing since 2006.²¹³
- The Energy Retailers Association of Australia supports the decision to adopt risk based and relevant unit cost forecasts to determine the capital expenditure allowance in preference to trending historic spends. It supports the proposed reductions repex.²¹⁴
- Origin Energy considered that the proposed repex programs were high when taking into account the changed operating conditions in Queensland. It agreed with our view that in the absence of evidence to demonstrate otherwise, to the extent that forecast unit costs are higher than historical unit costs, that historic unit costs are more likely to reflect a realistic expectation of future input costs.²¹⁵

Professionals Australia submitted our reduction to forecast repex would create safety risks.²¹⁶

In relation to this, we are satisfied that the business as usual approach described above will provide Energex with sufficient capex to manage the replacement of its assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system. This is because the business as usual will continue Energex's replacement practices that it used to meet the capex objectives in the last regulatory control period.

However, we also considered whether the service provider's replacement practices from the last regulatory control period did more than maintain safety, reliability and security of the distribution system, such that applying the business as usual approach for asset replacement may result in replacement practices that provide for a higher level of expenditure than is necessary to satisfy the capex objectives.

²¹¹ Consumer Challenge Panel Subpanel 2, *Submission, AER Preliminary 2015-20 Revenue Determinations Energex and Ergon Energy Revised Revenue Proposals*, September 2015, pp. 30–33.

²¹² Total Environment Centre, *Submission to the AER on the Preliminary Decisions on the QLD DBs' Regulatory Proposals 2015-20*, July 2015, pp. 7–8.

²¹³ Chamber of Commerce and Industry Queensland, *Submission to the AER on the Preliminary Determinations for Ergon Energy and Energex Revenue Determination*, 3 July 2015, p. 4.

²¹⁴ Energy Retailers Association of Australia, *Preliminary Decisions for Ergon Energy and Energex determinations 2015-16 to 2019-20*, July 2015, p. 1.

²¹⁵ Origin Energy, *Re Submission to AER Preliminary Decision Queensland Electricity Distributors*, July 2015, pp. 6–7.

²¹⁶ Professionals Australia, *Response to the Australian Energy Regulator's preliminary determinations*, July 2015, pp. 4–9.

In considering the efficiency of recent replacement practices, we have placed some weight on the ex-ante capex incentive framework under which the service providers' operate. There are incentives embedded in the regulatory regime that encourage a service provider to spend capex efficiently (which may involve spending all of the allowance, less or more, in order to meet the capex objectives). A service provider is only funded in the regulatory control period to meet the capex allowance. The service provider keeps the funding cost obtained over the regulatory control period of any unspent capex for that period, and, conversely, bears the funding cost of any capital expenditure that exceeds the allowance. In this way, the service provider has an incentive to spend efficient capex, or close to the allowance set by the regulator, as it is essentially rewarded (penalised) for any underspend (overspend). This provides some assurance that a service provider reacting to these incentives will undertake efficient capex to meet the capex objectives. This means that to some extent we can rely on the ex-ante capex framework to encourage the service providers to engage in efficient and prudent replacement practices.

Going forward, this incentive will be supplemented by a Capital Expenditure Sharing Scheme, which will provide a constant incentive to spend efficient capex over the regulatory control period, as well as the ability to exclude capex overspends from the RAB as part of an ex-post review. These additional arrangements will provide us with greater confidence that the service provider's past replacement practices are likely to reflect efficient and prudent costs, such that business as usual asset replacement approach is likely to be consistent capex objectives.

Possible future rule changes may also extend the regulatory investment test for distribution (RIT-D) to repex. Such a change would make it incumbent upon the service provider to develop credible options for asset replacement, including considering whether the asset life could be extended or whether the asset could be retired rather than replaced or expenditure be deferred because of the use of non-network options.

Finally, the collection of a longer period of data on changes in the asset base as part of our category analysis RIN will provide us with further information into the service providers' asset replacement practices over a longer period of time. This will further inform our understanding of business as usual replacement practice to estimate repex. More time series data would also strengthen our ability to use benchmarked information (e.g. asset life inputs) in the repex model in the future, which is intended to drive further efficiency in replacement expenditure.

Model inputs

The repex model uses the following inputs:

- The asset age profile input is the number of assets in commission and when each asset was installed.
- The replacement life input is a mean replacement life and standard deviation (i.e. on average, how old assets are when they are replaced).
- The unit cost input is the cost of replacing a single unit of an asset (i.e. on average, how much each asset costs to replace).

In the preliminary decision, we described using the repex model to create three modelling scenarios.²¹⁷ In each of the three modelling scenarios (base case scenario, calibrated scenario and benchmark scenario) we combined different data for the final two inputs.

Under all scenarios, the first input is Energex's asset age profile (how old Energex's existing assets are). This is a fixed input in all three scenarios.

The second and third inputs can be varied by using different input assumptions about:

- how long we expect an asset to last before it needs replacing; and
- how much it costs to replace it.

The repex model takes the replacement life input for each asset category and applies it to the actual age of the assets in each asset category. In doing this it calculates how many assets are likely to need replacement in the near future.²¹⁸ The model then applies a unit cost input to calculate how much expenditure is needed for that amount of replacement in each asset category. This is aggregated across all asset categories to a total repex forecast for each of the next 20 years.

In the remaining part of this section, we outline the replacement lives and unit cost inputs we tested in the repex model to assess Energex's proposed repex. As part of our assessment, we compared the outcomes of using Energex's estimated replacement lives and its unit costs, both forecast and historical, with the replacement lives and unit costs achieved by other NEM distributors. We also used the repex model to determine calibrated replacement lives that are based on Energex's past five years of actual replacement activity. These reflect Energex's immediate past approach to replacement.²¹⁹ We calculated historic unit costs by dividing historic expenditure by historic volumes and forecast unit costs by dividing forecast expenditure by forecast volumes. Detail on how we prepared the model inputs is at appendix E of the preliminary decision.²²⁰

'Business as usual' repex

The calibrated asset life scenario gives an estimate based on Energex's current risk profile, as evidenced by its own replacement practices. Our estimate brings forward the current replacement practices that Energex has used to meet replacement practices in the past. Calibrated replacement lives use Energex's recent asset replacement practices to estimate a replacement life for each asset type. These replacement lives are calculated by using Energex's past five years of replacement volumes, and its

²¹⁷ AER, *Preliminary decision, Energex distribution determination, Attachment 6*, April 2015, pp. 75-80.

²¹⁸ The repex model predicts replacement volumes for the next 20 years.

²¹⁹ For discussion on how we prepared each of the inputs see AER, *Preliminary decision, Energex distribution determination Attachment 6: Capital expenditure, Appendix E: Predictive modelling approach and scenarios*, May 2015.

²²⁰ AER, *Preliminary decision, Energex distribution determination, Attachment 6: Capital expenditure, appendix E*, May 2015.

current asset age profile (which reveals how many, and how old, Energex's assets are), to find the age at which, on average, Energex replaces its assets.

The calibrated asset life scenario has been our preferred modelling scenario in recent reviews of other service providers.²²¹ This is because we considered the calibrated replacement lives formed the basis of a business as usual estimate of repex, as they are derived from the service provider's actual replacement practice observed over the past five years and the observable (or revealed) economic replacement lives of the assets.

A service provider decides to replace each asset at a certain time by taking into account the age and condition of its assets, its operating environment, and its regulatory obligations. If the service provider is currently meeting its network reliability, quality and safety requirements by replacing assets when they reach a certain age, then by adopting the same approach to replacement in future they are likely to continue to meet its obligations. Consequently, the estimates derived from the model reflect the replacement practices that Energex has used in the past to meet the capex objective of maintaining the safety and reliability of the network.

However, if underlying circumstances are different in the next regulatory control period, then this approach to replacement may no longer allow a service provider to meet its obligations. We consider a change in underlying circumstances to be: a genuine change in the underlying risk of operating an asset; genuine evidence that there has been a change in the expected non-age related condition of assets from the last regulatory control period; or a change in relevant regulatory obligations (e.g. obligations governing safety and reliability).

If we are satisfied that there is evidence of a change in a service provider's underlying circumstances, we will accept that future asset replacement should not be based on a business as usual approach. This means that where there is evidence that a service provider's risk profile has changed then it may be necessary to provide a forecast of repex different to the business as usual estimate. This alternative forecast would be required in order to satisfy us that the amount reasonably reflects the capex criteria.

Calibrated scenario outcomes

In the preliminary decision, we used Energex's actual historic unit costs and Energex's own and calibrated lives to form an alternative estimate of repex. In the preliminary decision we found there was a significant difference between the calibrated scenario outcomes when using Energex's historical or forecast unit costs. This difference occurred because Energex's forecast unit costs for the next five years were, on average, higher than its unit costs over the last five years.

In our preliminary decision we concluded that in the absence of a reasonable explanation, we would not expect forecast unit costs to be higher than historical unit

²²¹ See AER draft decisions for Essential Energy, Endeavour Energy, ActewAGL and Ausgrid, October 2014.

costs given the incentive framework encourages a distributor to become more cost efficient over time. On that basis we applied Energex's historic unit costs rather than their forecast unit costs. We remain of this view for our final decision.

In its revised proposal, Energex engaged Jacobs to undertake a high level review of the AER's calculated unit costs.²²² Jacobs concluded that:²²³

The unit costs applied in the AER preliminary decision are too low to provide a sustainable replacement forecast and has been calculated based on incomplete historical data drawn from the RIN submissions.

The analysis by Jacobs suggested there were anomalies in the RIN data submitted in Energex's initial proposal which resulted in understated historical unit costs. We have addressed this concern by relying on the corrected data submitted by Energex with their revised proposal.

Using Energex's corrected data the calibrated scenario gives an output of \$765 million using Energex's historical unit costs and \$764 million using Energex's forecast unit costs. This compares with Energex's forecast of \$753 million for the six modelled asset categories. This suggests that Energex's revised forecast is likely to be a reasonable estimate of business as usual repex for these categories and we have included this amount in our alternative estimate of total forecast capex.

Calibrated replacement lives

While we have accepted Energex's revised proposed repex forecast for the modelled categories, Energex raised issues with the use of calibrated lives in the repex model which we address below.

Calibrated replacement lives are calculated by using Energex's past five years of replacement volumes, and its current asset age profile (which reveals how many, and how old, Energex's assets are), to find the age at which, on average, Energex replaces its assets. The calibrated replacement life represents this age. We explain the process of calculating calibrated lives in our repex model handbook.²²⁴

Energex submitted that the repex model is dependent on the circumstances of the distribution business over the previous five year period and in particular the replacement volumes undertaken.²²⁵ Energex considered their asset replacement rates are lower than would otherwise be expected for a business with a similar asset age profile and operating environment.²²⁶ Energex stated that their lower asset replacement rate reflects the fact that between 2004 and 2011 they were focusing on complying with other regulatory obligations and responding to significant growth in

²²² Jacobs, *AER REPEX Review – Energex*, 15 June 2015, pp 20-22.

²²³ Jacobs, *AER REPEX Review – Energex*, 15 June 2015, pp 23.

²²⁴ AER, *Replacement expenditure model handbook*, November 2013, p. 20.

²²⁵ Energex, *Revised Regulatory Proposal*, July 2015, p. 30.

²²⁶ Energex, *Revised Regulatory Proposal*, July 2015, p. 30.

peak demand.²²⁷ To address their concerns, Energex submitted we should introduce an implied upper age limit to the repex model which would serve to create a point at which assets are assumed to need replacing.²²⁸

We do not consider Energex's arguments would justify departing from our use of calibrated replacement lives in repex modelling. Our predictive modelling approach is well established having been used by us in previous distribution determinations and by other regulators.²²⁹ It has been refined following extensive consultation as part of the Better Regulation program. It was clear from our engagement with stakeholders in that process that calibration is understood to be an integral part of good practice in repex modelling for the very reason that it utilises updated data provided by the business being regulated. It is not an arbitrary process or one which involves manipulation of inputs to arrive at a pre-determined outcome. It is a systematic process, with a transparent purpose. We consider that any modification of the calibrated lives such as a "life-cap" would be an arbitrary manipulation of the data. Further, any lowering of the calibrated lives will always necessarily forecast greater volumes of repex. We do not consider Energex has established that this is a more desirable approach than the use of a calibrated model.

Ultimately, the calibrated lives reflect the fact that some assets on a distributor's network are actually lasting longer than anticipated by the distributor. We do not see a reason to depart from the calibrated lives to an untested alternative without significant justification for this substitution.

We also note that Energex's provision of correct information led to modelling which apparently more accurately predicted Energex's business as usual level of repex using the calibrated scenario.

Un-modelled repex

As with the preliminary decision, repex categorised as: supervisory control and data acquisition (SCADA), network control and protection; Pole top structures; and "Other" in Energex's RIN response was not included in the repex model. As noted in appendix E of the preliminary decision, we did not consider these asset groups were suitable for inclusion in the model, either because of lack of commonality, or because we did not possess sufficient data to include them in the model.²³⁰ Together, these categories of repex account for \$230 million of Energex's revised forecast repex. Our analysis of these is included below.

²²⁷ Energex, *Revised Regulatory Proposal*, July 2015, pp. 30-31.

²²⁸ Energex, *Revised Regulatory Proposal*, July 2015, pp. 30-31.

²²⁹ OFGEM, *Strategy decisions for the RII0-ED1 electricity distribution price control - Tools for cost assessment*, March 2013, p. 44; AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, October 2010; AER, *Final decision: Aurora Energy distribution determination*, April 2012.

²³⁰ AER, *Preliminary decision, Energex distribution determination, Attachment 6, Appendix E*, April 2015, p.132.

We consider that the replacement of network assets is likely to be relatively recurrent between periods. There will be period-on-period changes to repex requirements that reflect the lumpiness of the installation of assets in the past. Using predictive tools such as the repex model allows us to take this lumpiness into account in our assessment. For repex categories we cannot model, historical expenditure is our best high level indicator of the prudence and efficiency of the proposed expenditure. Where past expenditure was sufficient to meet the capex criteria it can be a good indicator of whether forecast repex is likely to reasonably reflect the capex criteria. This is due to the relatively predictable and recurrent nature of repex.²³¹

For unmodelled asset categories we consider that if the forecast expenditure for the next period is similar or lower than the expenditure in the last period, the distributor's forecast is likely to satisfy the capex criteria. If forecast repex exceeds historical expenditure, we would expect the distributor to sufficiently justify the increase.

SCADA, network control and protection

Energex's initial proposal included \$125 million for SCADA, network control and protection. In our preliminary decision we saw no justification for the step change from historic expenditure proposed by Energex, which was supported by EMCa's review. We considered Energex's SCADA, network control and protection, network control and protection repex from last period of \$42 million was likely to reflect the capex criteria.

Energex's revised proposal includes \$62 million for SCADA, network control and protection repex, along with further supporting documentation. EMCa reviewed Energex's revised proposal for SCADA, network control and protection and concluded that the steps taken by Energex in its revised proposal are more likely to have resulted in a forecast for SCADA, network control and protection repex that meets the expenditure requirements of the rules than was the case with its initial proposal.²³² EMCa concluded that, on balance, Energex's revised expenditure appeared likely to be reflective of a prudent and efficient level.²³³

In particular, EMCa reviewed Energex's proposed replacement expenditure for protection relays, Core IP-MPLS Telecommunications network, Optic fibre cable infill and pilot cable replacement. Together, these accounted for \$52 million or 81 per cent of Energex's proposed replacement of SCADA, network protection. In its review, EMCa identified evidence that Energex had taken steps to:

- review the requirement for the programs, including the assessment of risk
- consider the optimal scope of work, including opportunities for prudent deferral and

²³¹ AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 7–9.

²³² EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal*, September 2015, p. 33.

²³³ EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal*, September 2015, p. 34.

- consider an expanded number of options in its analysis, including targeted risk mitigation techniques.²³⁴

We are of the view Energex has provided sufficient justification to support its revised increase to SCADA, network control and protection repex for the 2015–20 period. We are satisfied that Energex's revised forecast for SCADA, network control and protection repex of \$62 million reflects the capex criteria and have included this in our alternative estimate of total forecast capex.

Pole top structures

In the preliminary decision, we did not consider there was sufficient justification to support Energex's forecast expenditure of \$80 million on pole top structures, a 19 per cent or \$13 million increase on the previous regulatory control period. We considered that Energex's historic repex on pole top structures during the previous regulatory control period was likely to reflect the capex criteria.

In their revised proposal, Energex accepted our preliminary decision.²³⁵ We remain satisfied that Energex's historic repex on pole top structures of \$68 million reflects the capex criteria and we have included this amount in our alternative capex forecast.

Other repex

In the preliminary decision, we did not consider there was sufficient justification to support Energex's forecast of \$281 million for "other" repex. This represented a \$242 million increase on the previous regulatory control period. The assets included in "other" in the preliminary decision included among other things SCADA development, condition monitoring schemes and reactive works.

In their review of Energex's initial proposal, EMCa concluded that the step increases in this category were not justified and that the programs did not provide sufficient consideration of risk to support the proposed level of expenditure.²³⁶ We saw no justification for the step change proposed by Energex and in the absence of any persuasive reason to depart from Energex's actual historic spending we included the amount of \$39 million in our alternative estimate of total forecast capex.

Energex's revised proposal includes forecast \$100 million for "other repex" along with further supporting documentation.²³⁷ EMCa reviewed Energex's revised proposal for SCADA and concluded that the steps taken by Energex in its revised proposal are

²³⁴ EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal*, September 2015, p. 33.

²³⁵ Energex, *Revised Regulatory Proposal 2015-20*, July 2015, p. 38.

²³⁶ EMCa, *Review of Energex's Augex and Repex Regulatory Proposal*, April 2015, p. 72.

²³⁷ Energex, *Revised Regulatory Proposal 2015-20*, July 2015, p. 35.

more likely to have resulted in a forecast for SCADA repex that meets the expenditure requirements of the rules than was the case with its initial proposal.²³⁸

We are of the view Energex has provided sufficient justification to support its revised increase to “other” repex for the 2015–20 period. We are satisfied that Energex's revised forecast of \$100 million reflects the capex criteria and have included this in our alternative estimate of total forecast capex.

B.5 AER findings and estimates for capitalised overheads

Capitalised overheads are costs associated with capital works that have been capitalised in accordance with Energex's capitalisation policy. They are generally costs shared across different assets and cost centres.

B.5.1 Position

We do not accept Energex's proposed capitalised overheads. We have instead included in our alternative estimate of overall total capex an amount of \$834.3 million (\$2014–15) for capitalised overheads. This is two per cent lower than Energex's proposal of \$852.5 million. We are satisfied that this amount reasonably reflects the capex criteria.

B.5.2 Our assessment

We consider that reductions in Energex's forecast expenditure should see some reduction in the size of Energex's total overheads. Our assessment of Energex's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in Energex's proposal. It follows that we would expect some reduction in the size of Energex's capitalised overheads. We do accept that some of these costs are relatively fixed in the short term and so are not correlated to the size of the expenditure program. However, we maintain that a portion of the overheads should vary in relation to the size of the expenditure.

We have also considered the relationship between opex and capex, specifically whether it is necessary to account for the way the CAM allocates overheads between capex and opex in making this decision. We considered this was not necessary in order to satisfy the capex criteria. This is because:

- Our opex assessment sets the efficient level of opex inclusive of overheads and so has accounted for the efficient level of overheads required to deliver the opex program by applying techniques which utilise the best available data and information for opex.

²³⁸ EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal*, September 2015, p. 33.

- The starting point of our capitalised overheads assessment is Energex's proposal, which is based on its CAM. As such, Energex's forecast application of the CAM underlies our estimate. We have only reduced the capitalised overheads to account for the reduced scale of Energex's approved capex based on assessment techniques best suited to each of the capex drivers. In doing so we have accounted for there being a fixed proportion of capitalised overheads.

Our adjustments to Energex's overheads use the approach from our preliminary decision (which used information that Energex provided). We consider that a \$1.0 million reduction in Energex's forecast capex should result in a \$0.096 million reduction in Energex's capitalised overheads.²³⁹ We reduced Energex's direct capex (that attract overheads) by \$96.1 million. We therefore consider a reduction of \$18.2 million in capitalised overheads reasonably reflect the capex criteria.²⁴⁰

We also note that a proportion of Energex's proposed capitalised overheads is attributable to information, communications and technology (ICT) services. We discuss our assessment of Energex's forecast for ICT services in section B.6.

B.6 AER findings and estimates for non-network capex

The non-network capex category for Energex includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and plant and equipment.

The majority of Energex's ICT expenditure was not included in the non-network capex category in Energex's proposal. Energex's ICT services are delivered by SPARQ Solutions (SPARQ) which is a jointly owned company between Energex and Ergon Energy, and is classified by Energex as a capitalised overhead rather than non-network capex. However, we have included the assessment of this expenditure under the non-network category to allow comparisons with other network service providers and for consistency with our other regulatory determinations. There is no regulatory requirement that Energex report its ICT expenditure in the non-network category. The actual adjustment to total capex is included in the capitalised overheads section at section B.5.

In our preliminary decision, we accepted Energex's forecast of non-network capex as a reasonable estimate of the efficient costs required for this capex category on the basis that:²⁴¹

- Energex has forecast capex for this category at historically low levels

²³⁹ AER, *Preliminary decision: Energex determination 2015–16 to 2019–20: Attachment 6 – Capital expenditure*, April 2015, pp. 90–91.

Note, we did not apply this adjustment to the SPARQ component of capitalised overheads. We made the adjustment to the SPARQ component of capitalised overheads separately (see section B.6).

²⁴⁰ This includes the adjustments to the SPARQ component of capitalised overheads as we mentioned previously.

²⁴¹ AER, *Energex Preliminary Decision - Attachment 6: Capital expenditure*, April 2015, pp. 6-91 to 6-94.

- the significant forecast reductions in each category of non-network capex reflect the high level drivers of expenditure in these categories
- the forecast reduction in non-network capex does not simply reflect a reallocation of expenditure from capex to opex.

Energex's revised proposal for non-network capex of \$244.1 million (\$2014–15),²⁴² excluding overheads and real cost escalation, is consistent with both Energex's initial proposal and our preliminary decision. For the reasons set out in our preliminary decision,²⁴³ we accept that Energex's forecast of non-network capex reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives. We have included it in our estimate of total capex for the 2015–20 regulatory control period.

B.6.1 SPARQ ICT expenditure included within overheads

Energex's ICT expenditure is split between the expenditure for end user devices (part of the non-network capex forecast) and the expenditure for all other ICT (part of the SPARQ ICT expenditure forecast). The SPARQ ICT expenditure forecast includes both opex and capex. The ICT opex forecast is discussed in attachment 7. The SPARQ ICT expenditure is included in the capitalised overheads category, which is discussed in section B.5.

In Energex's revised proposal, it proposed \$495.7 million (\$2014–15) for ICT expenditure, 7.6 per cent less than its initial proposal. This forecast includes:

- Asset service fees (\$229.3 million) – this fee consists of SPARQ's finance and depreciation charge for Energex's consumption of ICT assets held by SPARQ
- Operational support (\$215 million) – for SPARQ's costs associated with the ongoing operation, support and maintenance of ICT services
- Telecommunications pass through (\$25.1 million) – for the costs of carrier, mobile, data, voice and device management services
- Non-capital project costs (\$26.3 million) – for non-recurrent opex reflecting the ICT specific expenses which cannot be capitalised.

Energex treats these costs as indirect opex. It then capitalises 59 per cent, or \$292.4 million of the SPARQ ICT expenditure.

In its revised proposal, Energex included SPARQ's proposed ICT capex forecast of \$238.17 million (\$2014–15).²⁴⁴ This is 1 per cent, or \$2.2 million, less than its initial proposal.

²⁴² Energex, *Revised regulatory proposal*, 3 July 2015, p. 53.

²⁴³ AER, *Energex Preliminary Decision - Attachment 6: Capital expenditure*, April 2015, pp. 6-91 to 6-94.

²⁴⁴ Energex, *Response to AER Information Request 063*, p. 2. AER analysis.

In our preliminary decision we did not propose any changes to Energex's SPARQ ICT capex forecast. However, with a view to reconsidering the level of the proposed expenditure at the final decision stage, we raised concerns with four aspects of Energex's ICT expenditure forecast, that:

1. using the 2012–13 as a base year for forecasting 'operational support' and 'telecommunications pass through' does not capture the efficiencies identified by the Independent Review Panel on Network Costs (the IRP) and ITNewCom (SPARQ's consultant);
2. Energex is over recovering the financing costs which SPARQ charges to Energex via the asset service fee;
3. Energex is relying on SPARQ ICT costs, the majority of which have not been market tested; and
4. Energex is not transparently reporting its ICT costs.²⁴⁵

Energex addressed each of these areas in its revised proposal.

Prior to our preliminary decision, we engaged Deloitte Access Economics to conduct an analysis of Energex and Ergon Energy's operating expenditure for the 2015–20 regulatory control period, including its ICT forecasts.

Regarding the 2012–13 base year for forecasting 'operational support' and 'telecommunications pass through' costs, Energex submitted that we had misinterpreted the IRP report on the efficiency of SPARQ's operational support. Energex pointed out that the IRP concluded that SPARQ was delivering operational support efficiently, compared to other organisations.²⁴⁶ In support of the efficiency of its base year, Energex cited the KMPG report, '2013 Utilities ICT Benchmarking' and noted that Energex's revealed ICT opex (excluding depreciation) was lower than the mean of a cohort of distribution network service providers.²⁴⁷ Energex submitted that SPARQ has revised its forecast operational support and telecommunications pass through costs based on more up to date information, reducing operational support costs by \$15 million and telecommunications pass through costs by \$12 million.²⁴⁸

Energex submitted that the SPARQ funding and asset charging model is cost neutral, that is, the funding and asset charging model uses equal and opposite transactions for the financing provided by Energex for ICT asset acquisition and the fees charged by SPARQ for the use of those assets. In our preliminary decision we raised concerns that Energex may over or under recover its financing costs, due to SPARQ's use of a different WACC than our approved WACC. To address this, Energex submitted that SPARQ will use Energex's approved WACC and will update it annually.²⁴⁹ KPMG,

²⁴⁵ AER, *Energex Preliminary Decision - Attachment 6: Capital expenditure*, April 2015, p. 6-94.

²⁴⁶ Energex, *Revised regulatory proposal*, 3 July 2015, pp. 61-62.

²⁴⁷ Energex, *Revised regulatory proposal*, 3 July 2015, p. 62.

²⁴⁸ Energex, *Revised regulatory proposal*, 3 July 2015, p. 63.

²⁴⁹ Energex, *Revised regulatory proposal*, 3 July 2015, p. 58.

Energex's consultant, compared the revenue allowance derived from SPARQ's asset charging model and associated reporting of IT expenditure to that derived from putting Energex's IT capex and opex into our PTRM. KPMG found no material difference in the revenue allowance resulting from these different calculation methods.²⁵⁰

Energex submitted that there has been an increase in the number of outsourced ICT services that it uses, so that as of June 2015, 45 per cent of ICT costs are related to outsourced services agreements.²⁵¹ It also submitted that SPARQ has implemented a new delivery model which includes a panel of providers that capital programs may be outsourced through. Since February 2014, \$9.1 million worth of project delivery services have been outsourced for Energex through this panel.²⁵²

Energex noted that we, and our consultants Deloitte, raised concerns about a lack of market testing of SPARQ's services and consequently implied cost inefficiency. Deloitte concluded that ICT costs are a material source of inefficiency for Energex and Ergon Energy and estimated that only 4 per cent of the SPARQ costs passed on to the businesses in 2013–14 were market tested.²⁵³ Energex submitted that Deloitte failed to recognise the limited timeframe that the panel arrangements had been in place and that Energex expects the panel arrangement to be used by SPARQ for upcoming asset replacement programs. Energex argued that Deloitte incorrectly used the volume of work that has been awarded through the panel arrangements as a proxy for the level of ICT service subject to market testing.²⁵⁴

Energex considered that the AER did not examine the current market testing or outsourcing of operational services. Further, Energex submitted that the level of work issued to the panel has increased significantly and that SPARQ and Energex have established outsourcing arrangements for certain operational ICT services. Energex submitted that SPARQ's use of the panel arrangements and outsourcing arrangements for ICT services demonstrates a level of rigour with regard to SPARQ's forecast costs.²⁵⁵

Regarding its reporting approach for ICT expenditure, Energex acknowledged that its model is different to other businesses. However, it noted that there is a trend in the ICT industry towards software as a service and other cloud based solutions, so that in the future other businesses may have similar reporting approaches.²⁵⁶ In response to our concerns that its reporting approach is not sufficiently transparent, Energex submitted that it provided details of its forecast ICT capex in appendix 32 – ICT Strategic Plan, as well as providing the AER with confidential business cases. Energex also publishes

²⁵⁰ KPMG on behalf of Energex and Ergon Energy, *Appendix 4.10 Report to the Board of SPARQ Solutions on ICT Expenditure Forecast for the period: 2015 to 2020 - KPMG*, 25 June 2015, p. 14.

²⁵¹ Energex, *Revised regulatory proposal*, 3 July 2015, p. 63.

²⁵² Energex, *Revised regulatory proposal*, 3 July 2015, p. 64.

²⁵³ Deloitte, *Queensland distribution network service providers—opex performance analysis*, April 2015, p. xxii.

²⁵⁴ Energex, *Revised regulatory proposal*, 3 July 2015, p. 64.

²⁵⁵ Energex, *Revised regulatory proposal*, 3 July 2015, p. 65.

²⁵⁶ Energex, *Revised regulatory proposal*, 3 July 2015, p. 55.

its capex costs for key ICT projects in its Distribution Annual Planning Report. Energex submitted that if the AER has continued concerns about the transparency of the ICT capex costs, these could be addressed in the annual performance reporting.²⁵⁷

Energex stated that given there is no material difference between the total service charges under SPARQ's ICT asset charging model as compared to the revenue requirements under our PTRM, it will continue to use the SPARQ model, rather than including the ICT assets in Energex's RAB.²⁵⁸ KPMG submitted that the ICT recovery model (consisting of SPARQ's ICT asset charging model, operational support costs, telecommunications pass through, and non-capital project costs) is transparent and understood by internal stakeholders.²⁵⁹ As justification, KPMG provided information on the four categories of IT expenditure that SPARQ uses, including a description of how, broadly, the asset service fees are calculated. However, KPMG's description does not explicitly describe how the fee is calculated and there remains a degree of uncertainty as to whether it is actually transparent.

Energex also submitted on the appropriate benchmark for ICT expenditure and Energex's relative efficiency. Energex submitted that we should have used a different benchmark of 7 per cent for regulated ICT capex as a percentage of regulated capex, rather than 4.48 per cent for corporate ICT capex as a percentage of total corporate capex because the latter benchmark includes capex for unregulated services.²⁶⁰ Energex cited KPMG's benchmarking as showing that Energex's ICT capex was slightly above the industry mean for the current regulatory period.²⁶¹ Energex concluded that benchmarking for ICT capex should not be given significant weight because of the variability of ICT expenditure.²⁶²

Energex submitted that it has a strong governance model for development of its ICT program of work and therefore SPARQ's forecast expenditure for the period is prudent and efficient.²⁶³

Nous Group report on ICT capital expenditure

We engaged Nous Group (Nous) to evaluate Energex and Ergon's ICT programs of work as completed by SPARQ from two perspectives, a bottom up evaluation of individual projects and an assessment of the degree to which efficiencies are being

²⁵⁷ Energex, *Revised regulatory proposal*, 3 July 2015, p. 56.

²⁵⁸ Energex, *Revised regulatory proposal*, 3 July 2015, p. 57. KPMG on behalf of Energex and Ergon Energy, *Appendix 4.10 Report to the Board of SPARQ Solutions on ICT Expenditure Forecast for the period: 2015 to 2020 - KPMG*, 25 June 2015, pp. 10-16.

²⁵⁹ KPMG on behalf of Energex and Ergon Energy, *Appendix 4.10 Report to the Board of SPARQ Solutions on ICT Expenditure Forecast for the period: 2015 to 2020 - KPMG*, 25 June 2015, p. 10.

²⁶⁰ Energex, *Revised regulatory proposal*, 3 July 2015, p. 59.

²⁶¹ Energex, *Revised regulatory proposal*, 3 July 2015, p. 60.

²⁶² Energex, *Revised regulatory proposal*, 3 July 2015, p. 61.

²⁶³ Energex, *Revised regulatory proposal*, 3 July 2015, p. 65.

achieved in the SPARQ delivery arrangements.²⁶⁴ Nous found that 79 per cent of Energex's SPARQ ICT capex program is justified based on Energex's documentation.²⁶⁵ However, Nous identified three programs that were not fully justified and therefore may not be prudent and efficient capex:

5. replacement of an asset inspections solution and works management capability as part of the enterprise asset management upgrade, estimated at \$26.2 million
6. upgrading of PEACE (customer information and network billing functionality), \$10.9 million
7. updates to the business analytics platform, \$10.9 million.²⁶⁶

Nous noted that based on the business cases provided most projects are planned to be internally delivered by SPARQ, which is at odds with current trends in ICT delivery. It also noted that there will be a significant increase in the number of common solutions across Energex and Ergon Energy in the coming regulatory control period, indicating that there are efficiencies from the SPARQ delivery model.²⁶⁷ Nous stated that there is a need for market testing of ICT services, but contrary to the findings of the IRP, argued that there can be greater efficiencies by continuing to combine services for Energex and Ergon Energy. It suggested that SPARQ move towards a role as a broker of market services rather than continuing as a developer and operator, for common services. Additionally, Energex and Ergon Energy should individually test the market for non-common services. Nous did not suggest any changes to the ICT capex forecast as a result of these observations.²⁶⁸

As we received the Nous report after we received Energex's revised proposal, we sought comment from Energex on the report.²⁶⁹ Energex agreed with Nous' suggested deferral of the PEACE upgrade and no longer seeks capex for that program as part of its SPARQ ICT capex forecast.²⁷⁰ Energex submitted that the replacement of the asset inspection and works management capabilities in the enterprise asset management upgrade are core capabilities of its particular configuration of that system, contrary to Nous' view, and therefore are not discretionary and need to be completed at the same time as the upgrade of the enterprise asset management system. It also disputed the estimate of the cost of these upgrades, submitting that the cost is significantly less than the \$26.2 million estimated by Nous.²⁷¹ Energex provided further information to justify the upgrade to its business analytics platform and explained that because the components of the platform will become unsupported during the regulatory control

²⁶⁴ We received the Nous report after Energex submitted its revised proposal. Because of this, we sought comment from Energex on the contents of the report.

²⁶⁵ Nous Group, *Energex's ICT Expenditure 2015-20*, July 2015, p. 5.

²⁶⁶ Nous Group, *Energex's ICT Expenditure 2015-20*, July 2015, pp. 8-10, 17-20.

²⁶⁷ Nous Group, *Energex's ICT Expenditure 2015-20*, July 2015, p. 25.

²⁶⁸ Nous Group, *Energex's ICT Expenditure 2015-20*, July 2015, p. 27.

²⁶⁹ AER, *Energex Information Request 060*, 17 July 2015.

²⁷⁰ Energex, *Response to AER Information Request 060*, 31 July 2015, pp. 3, 5.

²⁷¹ Energex, *Response to AER Information Request 060*, 31 July 2015, pp. 2-3.

period it is necessary to upgrade them in this period.²⁷² We accept Energex's justification that these elements of the enterprise asset management project and the business analytics platform upgrade are necessary at this time. Therefore, we are not making the adjustments suggested by Nous in this regard.

Energex noted Nous' recognition of the potential efficiency benefits of common solutions between Energex and Ergon Energy. However, Energex disputed Nous' assessment that most of the ICT projects are being delivered internally by SPARQ. It reiterated its submissions from its revised proposal on the level of outsourcing being used by SPARQ, stating that 45 per cent of ICT costs relate to outsourced service agreements.²⁷³ Energex submitted that the Nous report supports its ICT delivery model and the benefits that the arrangement with SPARQ provides.²⁷⁴ In our view, Energex should seek to market test more ICT expenditure, both within the SPARQ model, as it is currently doing, and independently from SPARQ.

AER assessment

We accept \$227.3 million (\$2014–15) of Energex's revised forecast of SPARQ ICT capex for the 2015–20 regulatory control period.²⁷⁵ This amount reflects the deferral of the PEACE upgrade as suggested by Nous and agreed to by Energex. Energex provided further information that satisfied us that the other projects that Nous suggested could be deferred are prudent and efficient, so we have accepted that expenditure.²⁷⁶ Based on the information provided by Energex, we are satisfied that Energex's revised forecast IT program is required to meet the capex objectives.²⁷⁷ We accept that Energex's forecast capex for this program reasonably reflects the efficient costs that a prudent operator, with a realistic expectation of cost inputs, would require to meet the capex objectives.²⁷⁸

The SPARQ ICT capex forecast translates into asset service fees of \$214.03 million for the 2015–20 regulatory control period. The other components of the SPARQ forecast are the operational support, telecommunications pass through, and non-capital project costs. We accept these costs as proposed in the revised proposal. Therefore, Energex's revised ICT expenditure forecast for the 2015–20 regulatory control period is \$480.4 million (\$2014–15). This is a reduction of \$56 million, or 10.4 per cent, from Energex's initial proposal.

We have some concerns in relation to the SPARQ arrangements, although overall we are satisfied that Energex's forecast for SPARQ ICT capex reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.

²⁷² Energex, *Response to AER Information Request 060*, 31 July 2015, pp. 3-4.

²⁷³ Energex, *Response to AER Information Request 060*, 31 July 2015, pp. 6-7.

²⁷⁴ Energex, *Response to AER Information Request 060*, 31 July 2015, p. 8.

²⁷⁵ Energex, *Response to AER Information Request 063*, 20 August 2015, p. 2.

²⁷⁶ Energex, *Response to AER Information Request 063*, 20 August 2015, pp. 4, 6-8.

²⁷⁷ NER, cl. 6.5.7(a).

²⁷⁸ NER, cl. 6.5.7(c).

Below we explain our concerns and provide suggestions of how Energex can resolve them over the next regulatory period.

We still have concerns regarding over or under recovery of expenditure relating to the asset service fee due to the SPARQ funding and asset charging model. SPARQ will use our approved WACC, rather than its proposed WACC, to calculate the finance charges and this WACC value will be updated annually. We encourage Energex to move from the SPARQ asset charging model to reporting its IT capex directly in its capex, as it does for end user devices, so that there is no possibility of over or under recovery due to financing charges.

We acknowledge that SPARQ has been moving towards greater use of outsourcing for both operational services and capital works. However, we still have concerns that there could be inefficiencies in SPARQ's forecasts because SPARQ itself is not subject to competitive pressures. The IRP recommended that Energex, itself, issue market tenders for delivery of capital projects and for the delivery of operational ICT services, to test the services currently delivered by SPARQ.²⁷⁹ QCOSS also noted that Energex and Ergon Energy have not implemented the market testing recommended by the IRP. It is suggested that we should only accept ICT costs that have been market tested.²⁸⁰ Origin Energy also submitted that it continues to have concerns with the level of Energex's ICT forecast.²⁸¹ We accept that Energex is moving towards more market testing and outsourcing and we encourage this to continue. However, based on the information Energex have submitted on specific projects and the further analysis undertaken for this determination, we are satisfied that Energex's revised ICT forecast reasonably reflects the efficient costs that a prudent operator would incur.

While we have approved certain capex allowances for ICT services, we still have some concerns about the transparency of the SPARQ ICT asset charging model. We suggest that Energex address these issues over the course of the forthcoming regulatory period. For example, we acknowledge that the SPARQ model may not produce materially different revenue requirements than using the PTRM. However, that the two models may produce financially similar outcomes is not itself conclusive proof that the SPARQ model is transparent.

Energex's ICT capex is not reported in the year that it is incurred; instead ICT capex becomes part of the SPARQ's asset service fee which is a combination of finance and depreciation charges for assets incurred previously and in the current year. Because of this Energex's ICT capex cannot be directly compared to other businesses' and its forecasts cannot be easily compared to previous expenditure. We disagree with Energex's conclusion that because other businesses may be moving towards using cloud based solutions, that models similar to the SPARQ ICT model will become more common. We consider that as cloud solutions where software and/or hardware are

²⁷⁹ Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, p. 55.

²⁸⁰ QCOSS, *Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-2020*, 3 July 2015, pp. 11, 17.

²⁸¹ Origin Energy, *Submission to AER preliminary decision Qld electricity distributors*, 3 July 2015, p. 10.

provided as services are adopted, businesses will substitute opex for capex, which will be reported as opex rather than as indirect opex due to an asset services fees as occurs with Energex.

Our concerns regarding transparency are not remedied by the annual performance reporting as suggested by Energex. To promote transparency, Energex should report its ICT capex in the year when the assets are purchased. Particularly given that Energex submitted that there is no material difference in the reporting approaches, we encourage Energex to report its ICT capex as it does for its other assets.²⁸²

²⁸² Energex, *Revised regulatory proposal*, 3 July 2015, p. 57.

C Maximum demand forecast

This appendix sets out our observations of forecast maximum demand in Energex's network for the 2015–20 regulatory control period. Maximum demand forecasts are an important consideration in estimating Energex's capex and opex, and to our assessment of that forecast expenditure.

We consider Energex's demand forecasts at the system level and the more local level. System demand represents total demand in the Energex distribution network. System demand trends give a high level indication of the need for expenditure on the network to meet changes in demand. Forecasts of increasing system demand generally signal an increased requirement for growth capex, and converse for forecasts of stagnant or falling system demand.

Localised demand growth (spatial demand) drives the requirement for specific growth projects or programs. Spatial demand growth is not uniform across the entire network: for example, future demand trends would differ between established suburbs and new residential developments.

In our preliminary decision, we accepted Energex's demand forecast submitted as part of its original proposal. Subsequent to our preliminary decision Energex updated its demand forecast to reflect updated demand information from the 2014–5 summer period. This is considered below.

In our consideration of Energex's demand forecasts, we have had regard to:

- Energex's proposal
- AEMO's independent demand forecasts
- long-term demand trends and changes in the electricity market, and
- stakeholder submissions in response to Energex's revised proposal (as well as submissions made in relation to the Queensland electricity distribution determinations more generally).

These are set out in more detail in the remainder of this appendix.

C.1 AER position

We consider that Energex's system-wide maximum demand forecasts reflect a realistic expectation of demand over the 2015–20 regulatory control period. This is because:

- Energex's forecast of low demand growth over the 2015–20 regulatory control period is consistent with recent trends in electricity demand and consumption. Growth in consumption due to population and income growth is likely to be offset by continued investment in rooftop solar PV and energy efficiency, and this is reflected in Energex's forecast.

- Independent demand forecasts from AEMO forecast slightly higher growth in demand for Energex’s network.²⁸³ This lends support that Energex’s growth forecasts are realistic.
- Energex’s demand forecasts for the 2015–20 period were considerably lower than previous forecasts, and Energex has progressively downgraded its demand forecasts since its regulatory proposal for the 2010–15 period. We consider that Energex’s forecasts for the 2015–20 regulatory control period more likely reflect a realistic expectation of demand than prior forecasts.
- The impact of this reduced demand forecast is that Energex’s augex forecast for the 2015–20 period was lower compared to the 2010–15 regulatory control period.

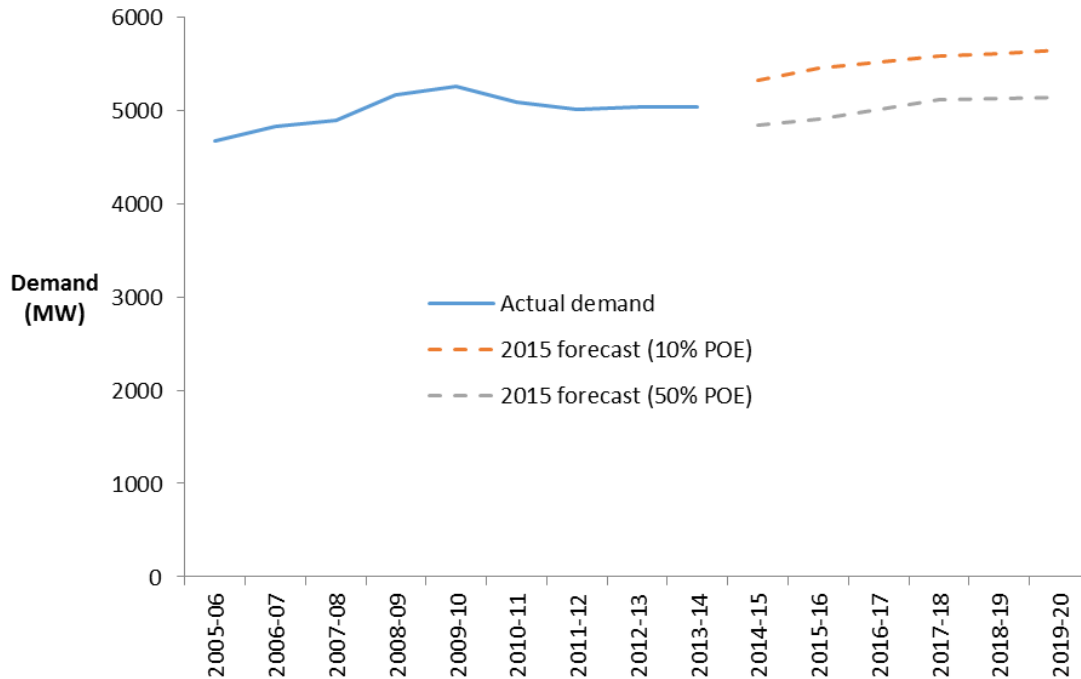
These are set out in more detail in the remainder of this appendix.

C.2 Energex’s revised proposal

Energex has forecast an average annual growth in peak demand of around 1.2 per cent in the 2015–20 regulatory control period. As shown in Figure , this is slightly higher than the generally flat peak demand over the 2010–15 period. Energex’s 50 PoE demand forecasts are less than the peak maximum demand experienced in 2009–10.

²⁸³ AEMO published its first connection point forecasts for Energex and Ergon Energy in June 2015. These forecasts provide an independent assessment of expected demand on Energex’s and Ergon Energy’s networks. In our preliminary decision, we stated that we would take AEMO’s forecasts into account for our final decision.

Figure C.1 Energex maximum demand forecast (MW, non-coincident, summated transmission connection point forecasts)



Source: Energex revised regulatory proposal; Energex response to AER EGX 064.

Energex’s revised proposal included updated demand forecasts. Energex updated its maximum demand forecasts to account for actual maximum demand experienced over the 2014–15 summer. Energex submitted that the recorded system peak demand on the Energex network for the 2014–15 summer was 5.9 per cent above the 50 PoE forecast system peak demand included in Energex’s original proposal. Energex adjusted its demand forecasts upwards for the 2015–20 period to reflect this recent demand data.

Table sets out the differences between the 2014 and 2015 forecasts.

Table C.1 Energex 2014 and 2015 maximum demand forecasts (MW, 50 PoE, non-coincident, summated transmission connection point forecasts)

Category	2015-16	2016-17	2017-18	2018-19	2019-20	Average
2014 forecast (MW)	4910	4945	4996	5072	5158	4987
2015 forecast (MW)	4909	5012	5110	5131	5142	5024
Difference (MW)	-1	67	113	59	-16	37
Difference(%)	0.0%	1.4%	2.3%	1.2%	-0.3%	0.7%

Source: Energex reset RIN; Energex revised proposal; Energex response to AER EGX 064.

Energex’s revised proposal included some commentary on the proposed impact of the 2014–15 demand data on its demand forecasts:

Energex believes that the overall step-up in summer 50 PoE demand in 2014–15 is an indication that customers are now more likely to use cooling appliances when conditions are extremely hot. The lower recorded system peak demand in 2012–13 and 2013–14 partly reflected mild summer seasons in SEQ [South East Queensland] and consequently a weaker influence of this customer behaviour. The extra peak demand recorded on the network during the 2014–15 summer season has driven a small increase in the 50 PoE forecast demand over the next ten years. The revised system demand forecasts remain below the historical high system peak demand recorded for the network in 2009–10.²⁸⁴

Energex noted that, despite the increase in its system demand forecast in its revised proposal, it is not proposing to increase growth-related capex and “will manage the associated increase in network risk while meeting its legislative supply obligations.”²⁸⁵

C.3 AEMO forecasts

In June 2015, AEMO published its first connection point forecasts for Queensland. These forecasts are AEMO’s independent electricity maximum demand forecasts at transmission connection point level, over a 10-year outlook period. The Standing Council on Energy Resources (SCER) intended these demand forecasts inform our regulatory determinations.²⁸⁶

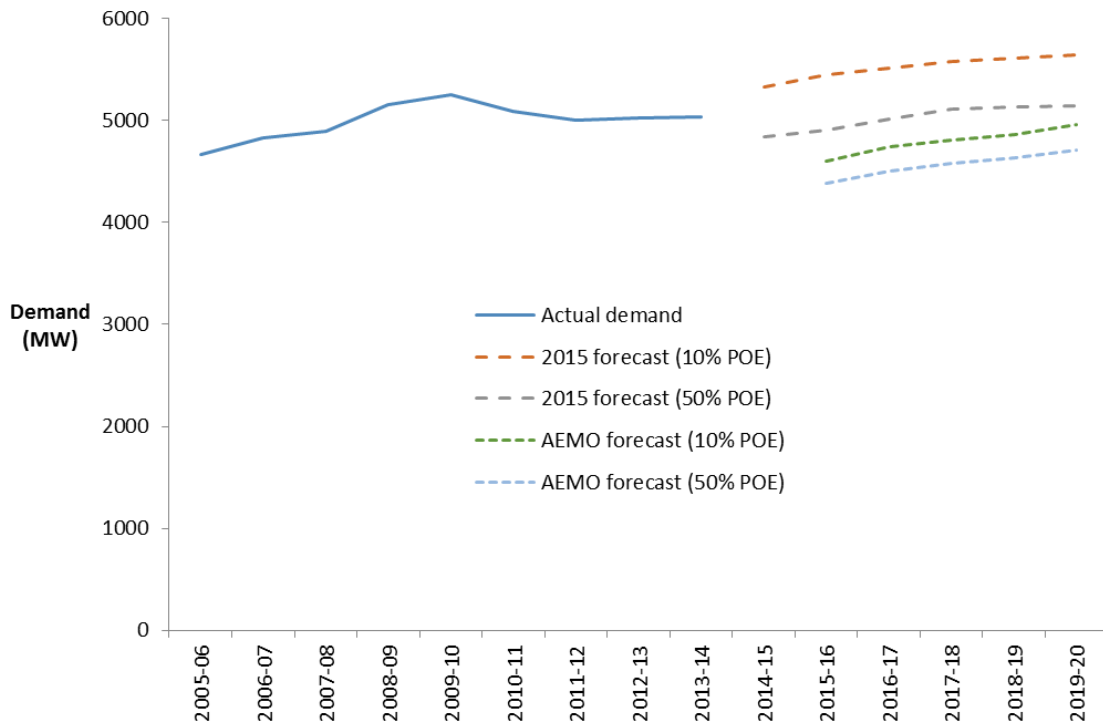
Figure shows our comparison between Energex’s system demand and AEMO’s summated connection point demand for the Energex’s network. It shows the growth trend for Energex’s system demand forecast is consistent with AEMO’s connection point forecasts for Energex’s network for the 2015–20 period. This gives us a level of confidence the trend in Energex’s forecasts are realistic (although the level of Energex’s demand forecasts are higher than AEMO’s).

²⁸⁴ Energex, *Revised Regulatory Proposal*, July 2015, p. 22.

²⁸⁵ Energex, *Revised Regulatory Proposal*, July 2015, p. 22.

²⁸⁶ AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 182.

Figure C.2 Comparison of AEMO and Energex connection point forecasts (MW, non-coincident)



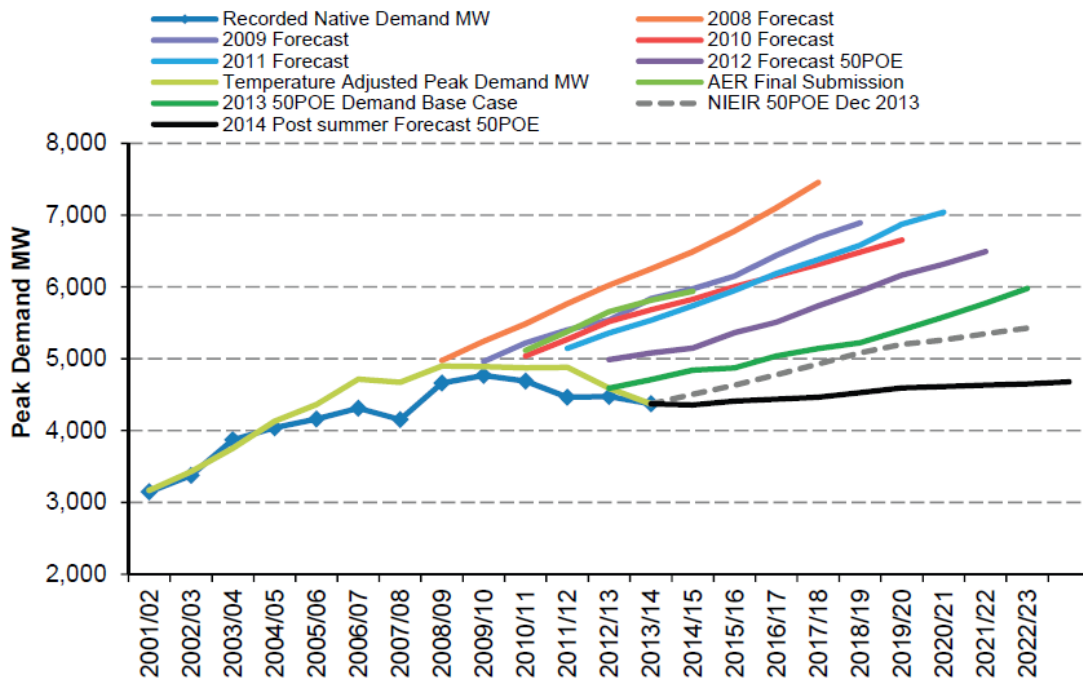
Source: Energex revised regulatory proposal; Energex response to AER EGX 064; AEMO 2015 Queensland Connection Point Forecasts.

In the next section, we discuss some of the predicted trends in demand from AEMO’s connection point forecast report.

C.4 Demand trends

The recent trend in demand forecasts across the NEM is that demand forecasts are actually progressively downgraded over time as actual demand is lower than previously forecast as forecasting methods improve. Energex follows this pattern because it is forecasting low demand growth over the 2015–20 period and it has been progressively downgrading its forecasts since its regulatory proposal for the 2010–15 period. This is reflected in the following chart taken from Energex’s distribution annual planning report.

Figure C.3 Energex maximum demand forecasts between 2008 and 2014



Source: Energex distribution annual planning report 2014/15 to 2018/19, Volume 1, 30 September 2014, Figure 40, p. 75.

A major driver of flattening demand forecasts is changing electricity consumption patterns in Queensland and across the NEM. In particular, there is strong evidence to suggest that energy consumption in Queensland is being offset by solar PV and energy efficiency measures and this is contributing to the flattening of demand:

- In Queensland, AEMO reported that residential and commercial consumption declined from 2009–10 to 2014–15 due to a rapid increase in electricity prices, uptake of rooftop PV, and greater customer engagement in reducing electricity consumption (e.g. energy efficiency).²⁸⁷
- AEMO forecasts continued growth in residential and commercial solar PV due to incentives from the Clean Technology Investment Fund and Small-scale Renewable Energy Scheme and reductions in the cost of solar PV technology.²⁸⁸ However, the impact of solar PV will likely have a diminishing impact on maximum demand over the longer-term as peak daily demand shifts to the evening.²⁸⁹

²⁸⁷ AEMO, *Detailed summary of 2015 electricity forecasts*, 2015 National Electricity Forecasting Report, June 2015, pp. 25-26.

²⁸⁸ AEMO, *Detailed summary of 2015 electricity forecasts*, 2015 National Electricity Forecasting Report, June 2015, pp. 28-29.

²⁸⁹ AEMO, *Detailed summary of 2015 electricity forecasts*, 2015 National Electricity Forecasting Report, June 2015, pp. 28-29.

- AEMO also forecasts increased energy efficiency savings over the 2014–15 to 2024–25 period.²⁹⁰

As set out in AEMO’s connection point forecast report for Queensland, the impact of expected continued growth in solar PV and energy efficiency is that this will offset growth in consumption and maximum demand from population and income growth.²⁹¹ As set out in section C.3 above, this resulted in AEMO forecasting only small increases in residential and commercial maximum demand over the 2015–20 period.²⁹² While these results reflect the total residential and commercial demand in Queensland, we consider that they are applicable to Energex’s network.

As noted in section C.2, Energex’s demand forecast actually increased marginally between its 2014 and 2015 forecasts, in contrast to recent trends in downward projections. This was due to an increase in maximum demand over the 2014–15 summer period that was higher than Energex had forecast.

The peak Queensland demand over the 2014–15 summer occurred on 5 March and was the highest-ever recorded.²⁹³ Demand on the day was significantly higher than other days with similar conditions. While actual weather conditions on the day were not extreme the forecast of extreme weather conditions likely influenced consumer behaviour, contributing to the record demand on the day. There were a number of other high demand days over the summer, with one day higher than the maxima in the previous 2 summers, reflecting higher than average maximum temperatures (i.e. a hot summer).²⁹⁴

While the temperatures were higher than average (and some of the hottest on record), the small increase in maximum demand experienced on the network was not entirely unexpected. The actual peak demand over the 2014–15 summer only exceeded Energex’s 50 PoE demand forecast. Forecast weather conditions for the peak demand, however, were extreme and closer to the ‘10 PoE’ level. A ‘50 PoE’ demand forecast means that actual demand is expected to exceed the demand forecast 50 per cent of the time, or once every two years.

Having said that, the actual peak demand over the 2012–13 and 2013–14 summers were lower than the 2014–15 summer and maximum summer temperatures between 2009–10 and 2013–14 were similar to, or lower than, the recorded average maximum

²⁹⁰ AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 29.

²⁹¹ AEMO, *Transmission Connection Point Forecasting Report for Queensland*, June 2015, p. 4.

²⁹² AEMO, *Transmission Connection Point Forecasting Report for Queensland*, June 2015, p. 4.

²⁹³ Demand for Queensland reached 8969 MW, which was marginally higher than the previous record of 8933 MW set in the 2009/10 summer. <http://www.aer.gov.au/node/9767>.

²⁹⁴ Bureau of Meteorology, *Seasonal Climate Summary for Brisbane* (‘Brisbane in summer 2014-15: Above average rainfall, warm nights’), 1 March 2015, available at <http://www.bom.gov.au/climate/current/season/qld/archive/201502.brisbane.shtml>, accessed on 9 September 2015.

temperatures in Brisbane.²⁹⁵ This contributed to the relatively low and consistent maximum demand over this period.

The combination of these observations lends support to a slightly increased maximum demand forecast over the 2015–20 period, when compared to the forecast submitted in the original proposal. Maximum summer temperatures are a key driver of electricity demand (e.g. due to consumers using energy intensive appliances such as air conditioners during hot temperatures). Maximum demand forecasts should therefore reflect all available data, including the most recent available summer demand. The extended period of average (or below) maximum summer temperatures between 2009–10 and 2013–14 may have contributed to slightly muted demand forecasts, which were subsequently exceeded over the 2014–15 summer.

The Queensland Council of Social Service (QCOSS) submitted that Energex’s forecasts of maximum demand do not seem consistent with historical trends, and stated that the continued subdued economic and population growth in Queensland do not support Energex’s forecasts of maximum demand.²⁹⁶

The Alliance of Electricity Consumers also submitted that:

Departing from its Regulatory Proposal, Energex has proposed to significantly increase its forecast network peak demand. These increases are beyond an already optimistic forecast, which appeared to defy a downward trend in peak demand.

The Alliance does not support Energex’s attempt to revise its demand forecasts upwards and calls on the AER to forensically interrogate Energex’s original forecasts, which ought to be substantially decreased.²⁹⁷

The CCP submitted that the Queensland distributors have track records of consistently over-estimating their demand forecasts.²⁹⁸ It also submitted that Energex is forecasting demand growth levels exceeding AEMO’s Queensland demand forecasts (as set out in the 2015 National Electricity Forecasting Report), which predict flat or declining demand.²⁹⁹

We do not necessarily agree with these submissions. As set out above:

- Energex’s most recent maximum demand forecast are considerably lower than previous forecasts, and we consider that they more realistically reflect the recent and forecast trends in consumption and demand in Queensland.

²⁹⁵ See Bureau of Meteorology climate summary reports for Brisbane and Queensland at http://www.bom.gov.au/climate/current/statement_archives.shtml?region=qld&period=season.

²⁹⁶ QCOSS, *Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-2020*, 3 July 2015, p. 9.

²⁹⁷ Alliance of Energy Consumers, *Submission to Energex and Ergon Energy’s Revised Regulatory Proposals (Qld)*, 24 July 2015, pp. 13-14.

²⁹⁸ Mr Hugh Grant CCP2, *Advice on AER preliminary decisions and revised proposals from Energex, Ergon Energy and SA Power Networks*, July 2015, p. 19.

²⁹⁹ Mr Hugh Grant CCP2, *Advice on AER preliminary decisions and revised proposals from Energex, Ergon Energy and SA Power Networks*, July 2015, p. 19.

- Energex's forecast demand growth is supported by AEMO's demand forecasts released in its 2015 Queensland connection point forecasts. AEMO forecasts approximately 1.8 per cent demand growth on Energex's network over 2015–20 (which excluded any LNG demand).

While Energex forecasts small growth in demand over 2015–20 (in contrast to recent flat demand), Energex's 50 PoE demand forecast are lower than the peak maximum demand experienced in 2009–10.