Attachment 5: Capital Expenditure

Regulatory proposal for the ACT electricity distribution network 2019–24
January 2018

evoenergy

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Key points

Evoenergy's[1] capital expenditure (capex) plan for the 2019–24 regulatory period reflects the need to address the rapidly changing electricity market, manage an ageing asset base to meet safety and reliability standards, accommodate major urban developments in the Canberra metropolitan area, and meet increasing requirements from the Australian Capital Territory (ACT) Government's planning and system security regulations. Despite this, Evoenergy's proposed capital program maintains about the same level of expenditure compared to both Evoenergy's actual expenditure and the Australian Energy Regulator's (AER's) final decision allowance for the 2014–19 regulatory period.

The main drivers of Evoenergy's proposed capex are:

- upgrades to information technology and secondary systems to address challenges arising from the emergence of distributed energy resources (DER) in the electricity market;
- the construction of feeders and a new mobile zone substation to maximise existing asset utilisation to meet demand for electricity in new urban areas; and
- the continuation of asset renewal and replacement to address ageing assets with increasing risk profiles.

The industry landscape is predicted to change rapidly in the next few decades, with major changes in the way electricity is generated and supplied. Evoenergy is mindful of the looming impact of DER technologies and is focused on changes to its operational practices, and the opportunities to delay, reduce or even remove the need for substantial network expenditure. The impact of these technologies will also flow through to future asset management practices and ensuring that the business meets technical and consumer-driven challenges relating to demand, cost effectiveness, reliability, and power quality.

Within this arena, Evoenergy's network is undergoing significant transformation to retain value for consumers in distributing electricity while at the same time allowing energy market transactions by consumers and generators through DER. Evoenergy is guided in its transformation by the comprehensive Electricity Network Transformation Roadmap (ENTR), developed by Energy Networks Australia (ENA) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO), which anticipates a consumer-centric future where, in the long term, almost half of electricity generation is derived from DER.[2]

Evoenergy intends that the proposed capex program for the 2019–24 regulatory period will deliver benefits through activities in the following three areas.

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[1] ActewAGL Distribution's energy networks business was rebranded as Evoenergy from 1 January 2018 in accordance with the AER's Ring-fencing Guidelines.

[2] CSIRO and Energy Networks Australia, Electricity Network Transformation Roadmap: Final Report, April 2017 (Source: www.energynetworks.com.au/roadmap).

Meeting consumer expectations and adapting to industry changes

- Ensuring that Evoenergy's network meets consumer expectations and service standard obligations in the face of increasing power quality and reliability challenges posed by an increasing uptake of DER.
- Developing a risk-based top-down framework to allow the assessment of non-network alternatives (e.g. demand-side management, embedded generation) against network augmentation. This includes a net present value (NPV) approach where all options are fully investigated and evaluated before initiating any major capital augmentation project. Augmentation projects with a capital cost exceeding $5 million will be subject to the Regulatory Investment Test for Distribution (RIT-D) prior to proceeding.
- Investing in Information and Communications Technology (ICT) and analytics to transition the business towards the themes of digital transformation, meet industry changes, and maintain reductions in operating expenditure (opex) implemented during the current regulatory period. Evoenergy's proposed expenditure also includes replacement of aged corporate and operational systems to provide a stable technology platform and enable regulatory compliance.

Ensuring the effective operation of Evoenergy's network

- Developing a combined top-down and bottom-up risk-based methodology to forecast asset replacement programs. Expenditure is optimised across asset classes within the replacement and renewals expenditure (repex) portfolio, ensuring that Evoenergy's proposal reflects the efficient costs of achieving an acceptable risk level where reliability standards are adequately met and safety levels maintained.
- Adopting a comprehensive risk-based planning framework which will deliver value for money to consumers by continuing to improve the way it manages Evoenergy's assets and delivers capital works projects. The risk-based framework provides transparency and accountability in the way Evoenergy manages its assets and operating costs.
- Improving reliability and quality through expenditure on a targeted roll-out of distribution network monitoring to areas of the network impacted by DER in order to manage quality of supply, support network planning and deployment of non-network solutions.
- Replacing secondary systems programs including upgrade of specific protection, supervisory control and data acquisition (SCADA) and communications systems to ensure compliance with current National Electricity Rules (Rules) standards and to meet power quality issues as impacted by DER.

Efficiently managing growth and promoting greater network utilisation

- Constructing a lower cost option of a mobile zone substation at Molonglo to meet demand from new residential suburbs in the Molonglo Valley District, which is being developed by the ACT Government's Suburban Land Agency at a proposed rate of approximately 1,000 dwelling per year, plus shopping centres, schools and community facilities.

- Completing the Second Supply to the ACT Project (see section 5.11.9.1) in association with TransGrid, to fully meet the security of supply requirements of the ACT Government's Electricity Transmission Supply Code.
- Constructing various feeder projects to form a low-cost option to meet shortfalls identified in high-growth metropolitan areas with increasing peak demand and provide greater utilisation of existing zone substations.

5.1 Regulatory requirements

The AER's requirements with respect to Evoenergy's capex forecasts, methodology and assumptions are set out in the Rules (Chapter 6 and schedule 6), the AER's Expenditure Forecast Assessment Guideline and the Regulatory Information Notice (RIN).

5.1.1 Requirements of the National Electricity Law and the Rules

The Rules set out the framework for the AER's assessment of capital expenditure proposals and the necessary components of the regulatory proposal. The requirements are supplemented by the AER's RIN. In deciding whether to accept a service provider's forecasts, the AER is required to have regard to the *capital expenditure factors* set out in clause 6.5.7(e).

Clause 6.5.7(a) of the Rules states that a building block proposal must include the total forecast capex for the relevant regulatory control period which the Distribution Network Service Provider (DNSP) considers is required to achieve each of the *capital expenditure objectives*.

The *capital expenditure objectives* are as follows:

- meet or manage the expected demand for *standard control services* over that period;
- comply with all applicable *regulatory obligation*s *or requirements* associated with the provision of *standard control services*;
- to the extent that there is no applicable regulatory obligation or requirement in relation to:
  - the quality, reliability or security of supply of *standard control services*; or
  - the reliability or security of the *distribution system* through the supply of *standard control services*,
- to the relevant extent:
  - maintain the quality, reliability and security of supply of *standard control services*; and
  - maintain the reliability and security of the *distribution system* through the supply of *standard control services*; and
- maintain the safety of the *distribution system* through the supply of *standard control services*.

Clause 6.5.7(c) of the Rules requires the AER to accept the DNSP's capex forecast if it is satisfied that the forecast reasonably reflect each of the capex criteria:

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

Clause 6.5.7 and S6.1.1 of the Rules and Schedule 1 of the RIN set out the information and matters relating to capex that the DNSP must provide in its building block proposal in order for the AER to determine whether it will accept or reject the capex forecasts provided by the DNSP.

5.1.2 Expenditure Forecast Assessment Guideline

The Rules require the AER to develop and publish Expenditure Forecast Assessment Guidelines.[3] The AER's Expenditure Forecast Assessment Guideline was published in November 2013 and describes the process and techniques that the AER might adopt in setting expenditure allowances for network businesses, and associated data requirements. It also sets out the AER's principles for guiding its reliance on assessment techniques and a business's forecasting approach. To ensure that forecast capex meets the capex criteria of the Rules, Evoenergy has used the tools set out in the AER's Expenditure Forecast Assessment Guideline. This is set out in section 5.3. Section 5.7 outlines Evoenergy's capex forecasting methodologies and assumptions. Evoenergy's expenditure forecasting methodology was submitted to the AER on 30 June 2017.

5.1.3 Regulatory Information Notice

On 20 October 2017, the AER issued Evoenergy with a RIN under Division 4 of Part 3 of the National Electricity Law. The RIN requires Evoenergy to provide, prepare and maintain the information in the manner and form specified in the notice. The AER requires the information to publish network service provider performance reports (annual benchmarking reports) and to assess benchmark operating expenditure (opex) and benchmark capex that would be incurred by an efficient DNSP relevant to building block determinations.[4]

The RIN specifies the information that the AER requires, in addition to the requirements set out in clause S6.1.1 of the Rules, to allow it to assess forecast capex. Schedule 1 of the RIN sets out additional information requirements for Evoenergy to address, and specifies in detail the types of supporting documentation that Evoenergy is required to provide in support of its regulatory proposal.

In accordance with Schedule 1 clause 1.5(e), Evoenergy has compiled a table that references each response to a paragraph in Schedule 1 of the RIN, and where it is provided in or as part of the regulatory proposal. This table can be found in RIN Appendix 1 (Compliance with RIN Schedule 1). Where a Schedule 1 RIN requirement has not been addressed in this submission or in the attached RIN templates, the required information is provided in RIN Appendix 2 Supplementary Information.

In accordance with clause S6.1.1 of the Rules and clause 5.2 of Schedule 1 of the RIN, the following sections describe the methodology used in developing Evoenergy's capex forecasts and some of the key underlying assumptions that have been made. Further

[3] Rules, clause 6.2.8(a)(1).

[4] AER letter to ActewAGL Distribution, 7 March 2014.

details on drivers for each capex category are contained in asset-specific plans and individual project justification reports.

5.1.4 Capital expenditure objectives and factors

The principal drivers of Evoenergy's capex program, referred to in the Rules as the *capital expenditure objectives*, broadly encompass:

- service standard obligations, as described in Attachment 2 (Consumer engagement);
- regulatory obligations; and
- demand and energy forecasts, as described in Attachment 3 (Energy, customer numbers and peak demand forecasts).

Clause 6.5.7(a) of the Rules stipulates that the DNSP must include the total capex that is required to achieve the *capital expenditure objectives*. Furthermore, paragraph 4.1 of Schedule 1 of the RIN requires Evoenergy to provide justification for Evoenergy's total forecast capex including, among others:

- why the total forecast capex is required for Evoenergy to achieve each of the objectives in clause 6.5.7(a) of the Rules;[5]
- how Evoenergy's total forecast capex reasonably reflects each of the criteria in clause 6.5.7(c) of the Rules;[6]
- how Evoenergy's total forecast capex accounts for the factors in clause 6.5.7(e) of the Rules;[7]
- an explanation of how Evoenergy's plans, policies, procedures and regulatory obligations, consultants reports, economic analysis and assumptions have been incorporated;[8] and
- an explanation of how each response provided to paragraph 4.1 is reflected in any increase or decrease in expenditures or volumes, particularly between the *current and forthcoming regulatory control periods*.

This attachment outlines Evoenergy's approach to planning future capex in order to meet its service standard and regulatory obligations in a prudent and strategic manner. In accordance with requirement 4.1 of Schedule 1 of the RIN, it explains how key plans, policies and procedures have been incorporated into the capex forecasts. Proposed expenditures are based on a realistic expectation of the demand forecast as described in Attachment 3 and efficient costs as described throughout this attachment.

5.1.5 AER constituent decisions

Under clause 6.12.1(3) of the Rules, a distribution determination is predicated on a decision in which the AER either:

[5] RIN Schedule 1, clause 5.1(a).

[6] RIN Schedule 1, clause 5.1(b).

[7] RIN Schedule 1, clause 5.1(c).

[8] RIN Schedule 1, clause 5.1(d).

i. *acting in accordance with clause 6.5.7(c), accepts the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal; or*

ii. *acting in accordance with clause 6.5.7(d), does not accept the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors*.

This attachment sets out Evoenergy's forecast capex for the 2019–24 regulatory control period that is included in the current building block proposal.

Evoenergy has not included any contingent projects in its forecast capex for the 2019–24 regulatory control period.

Historical and forecast expenditures presented in this chapter do not include margins referable to arrangements that reflect non-arms-length terms, or expenditure that should have been treated as opex in accordance with Evoenergy's capitalisation policy.

5.1.6 Regulatory Investment Test Rule changes

Network businesses must apply a regulatory investment test to individual projects to test their efficiency. The test requires a network business to evaluate a proposed investment against credible alternatives (including non-network options) on a level playing field. Section 5.16 of the Rules describes the Regulatory Investment Test for Transmission (RIT-T) and Section 5.17 describes the Regulatory Investment Test for Distribution (RIT-D).

These tests must be carried out for any proposed investment where the augmentation or replacement cost of the most expensive credible option exceeds $5 million. In each, a proposed investment must pass a cost/benefit analysis or provide the least cost solution to meet network reliability standards.

Until recently, the regulatory investment test only applied to augmentation expenditure (augex). In June 2016 the AER proposed a rule change to widen the scope to cover replacement expenditure. The change also imposes new requirements on network businesses to justify asset retirement decisions in annual planning reports, and allow interested parties to propose alternatives to asset replacement. The Australia Energy Market Commission (AEMC) accepted the proposed rule change in July 2017. [9] On 18 September 2017, the AER amended its RIT-T and RIT-D application guidelines.[10] As a result, replacement and renewal projects are now treated in the same way as augmentation projects for the purpose of the RIT-D.

Within the itemised cost of all projects in Evoenergy's replacement program (see Evoenergy's Capex Model in the modelling appendices), there are few high-level projects above the $5 million threshold. However, it is unlikely that any of these categories would be considered a single program for the purposes of the RIT-D threshold calculation. This is because the RIT-D requires all replacements to meet the same identified need. As a

[9] AEMC, Replacement expenditure planning arrangements, Rule determination, 18 July 2017, Sydney.

[10] AER, Regulatory investment test of distribution application guidelines, 18 September 2017. AER, Regulatory investment test of transmission application guidelines, 18 September 2017.

result, Evoenergy considers that no projects contained within its forecast repex would be subject to RIT-D.

5.1.6.1 IT and communications systems

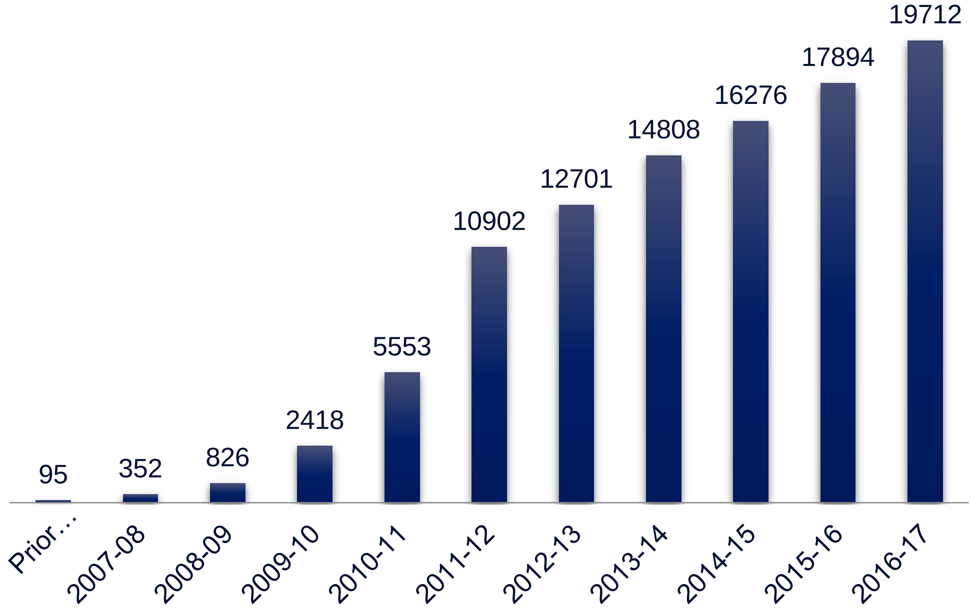
There is also a separate but related rule change clarifying that DNSPs need to report investment in IT and communications systems related to management of network assets which occurred in the preceding year and planned investments for the forward planning period in the Distribution Annual Planning Report. For Evoenergy, this pertains to network Asset Information Systems (AIS) assets (formerly known as Network IT in the AER's non-network expenditure category—see section 5.12.3).

While 'replacement' is not defined in the Rules or in the National Electricity Law, Evoenergy considers that it refers to work that maintains the size of the system or its capacity to transmit or distribute energy. Rules clause 5.17.3(a) refers to cases for which the RIT-D is exempt. Clause (5) states the following exemption: *the RIT-D project is related to the maintenance of existing assets and is not intended to augment a network or replace network assets*. This links augmenting a network and replacing network assets. As AIS neither enlarges, increases nor maintains the capacity of the system to transmit or distribute electricity, Evoenergy does not consider that the RIT-D processes would apply to AIS expenditure.

5.2 DER and industry transformation

DNSPs face challenges and opportunities as demand for traditional services declines and the uptake of DER, such as solar photovoltaic (PV) arrays, batteries, wind farms and embedded generators, increases. Domestic rooftop solar PV generation systems are currently installed on approximately 12 per cent of homes in the ACT. Figure 5.1 shows that this market share has increased steadily over the last decade.

Figure 5.1 **Number of connected and approved PV installations in the ACT 2007–17**



Source: Appendix 5.8, ActewAGL Quality of Supply Strategy SM11150, p. 24.

Increased uptake of PV systems is due to a number of reasons, including:

- decreasing cost of PV systems due to increasing economies of scale;
- some developments (notably Denman Prospect Estate, see Attachment 1 Asset management and governance) have mandated that PV systems must be installed on all new detached dwellings to be constructed;
- the climate in the ACT is conducive to PV with long sunshine hours annually;
- increased public awareness of climate change; and
- the ACT Government's 100 per cent renewable energy target.

5.2.1 Short-term to mid-term challenges

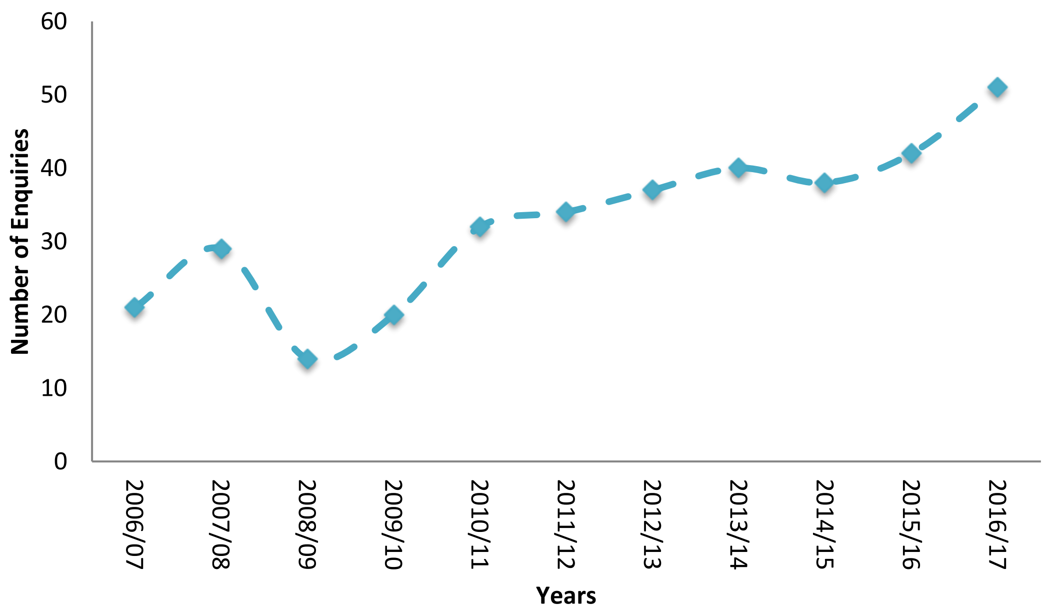
As a result, Evoenergy faces significant technical and financial risks/opportunities in planning its capex program. A combination of new technologies, energy efficiency and structural change will likely result in flat or declining future energy consumption. However, peak demand may not decline proportionately with declining energy consumption. This means that to recover the cost of network expenditure driven by peak demand, a challenge is presented with respect to managing price impact on consumers.

Given this context, Evoenergy recognises the importance of network pricing and a capital program that reflects the prudent and efficient costs of operating in the current electricity market.

DER technical issues arise from the large demands that they place on the management of energy flows in Evoenergy's network. In particular, what were once predominantly unidirectional power flows from network to customer will become two-way power flows between the parties. Historically, distribution networks were constructed for energy flows from the generators to transmission systems and through distribution systems to customers. The two-way power flows will have long-term technical implications for the traditional electrical distribution businesses in meeting the Network System Standards of the Rules (Schedule 5.1).

For example, a major consequence surrounds quality of supply to customers whereby PV systems introduce numerous voltage fluctuations within short time periods as compared to traditional generators. These fluctuations require sophisticated technical solutions to modulate power output, and with the absence of these solutions in recent years, Evoenergy has been facing increasing enquiries in relation to power quality, as shown in Figure 5.2.

Figure 5.2 **Number of enquiries about power quality 2006–17**



Source: Appendix 5.8, ActewAGL Quality of Supply Strategy SM11150, p. 9.

In response to these issues, Evoenergy needs to adopt advanced planning and operational systems to facilitate network outcomes foreseen by Schedule 5.1 and Section 6.5.7 (a) of the Rules.

5.2.2 Opportunities

Evoenergy has strategically reviewed the impact of DER on its capital program and proposes a two-pronged strategic focus:

- maintain value of the core business by optimising expenditure programs, operationally streamline asset management and service delivery functions, maximise network use, and ensure a sustainable financing model; and
- implement the conceptual distribution system operator (DSO) transition to prepare for industry transformation to a more consumer-centric future (more detail on the DSO transition is contained in Attachment 1.

Evoenergy's proposed capex program is a critical lever in ensuring both of these goals are met, especially in the areas of optimising spending, greater network use, efficient service delivery, and technological capabilities to enable the DSO transition.

As part of its strategic direction, Evoenergy intends to adopt the principles in the ENTR for its corporate and operational processes. The ENTR recommends major transformations under five key domains to be undertaken over the next 10 years to respond effectively to the changing electricity generation landscape. If the recommended changes are implemented, it predicts that compared to business as usual, consumers will receive the following benefits:[11]

- electricity sector achieves zero net emissions by 2050;
- $16 billion in network infrastructure investment can be avoided;
- reduction in cumulative total expenditure of $101 billion by 2050; and
- reduction in expenditures results in 30 per cent decrease in network charges.

Key domains of the ENTR that are addressed by Evoenergy's proposed capital program are:

- intelligent networks and markets;
- power system security; and
- customer-orientated electricity.

5.2.2.1 Intelligent networks and markets

Developing intelligent electricity networks involves creating an integrated suite of distributed grid intelligence and control tools, network planning models, and network operation mechanisms. This integrated system will allow real-time monitoring and control at lower voltage levels, greater network visibility, and information systems that can handle the amount of data required from the vastly increased number of participants in the electricity market. In recent years, Evoenergy has made significant investments in overhauling its network planning systems (the adoption of RIVA DSS), asset information systems (e.g. advanced distribution management systems (ADMS), SCADA, and cyber security). For further information, see sections 5.8.6, 5.12.3, and 5.12.4.

Key outcomes pursued include faster fault response times, digitalisation of the network, much greater staff mobility, the capture of PV data in current ADMS/ArcFM systems, and control room visibility of the whole network in real time.

Improved monitoring and control creates new opportunities in network optimisation given the range and diversity of distributed electricity sources and their reliance on the network. The expectation over the long term is a high level of utilisation of connected devices which maximises the benefit of network assets, and minimising the need to further augment poles and wires to support higher peak loads.

Evoenergy's proposed network augmentation program demonstrates that the uptake of battery and PV systems can result in deferring of substantial augmentation expenditure (e.g. the deferral of Strathnairn Zone Substation – see section 5.11.4.1). In the long term, substantial opportunities exist with the electrification of transport to optimise network use.

[11] CSIRO and Energy Networks Australia, Electricity Network Transformation Roadmap: Final Report, April 2017, p iv. Source: www.energynetworks.com.au/roadmap.

5.2.2.2 Power system security

As described above, there are emerging power quality issues in the ACT that are required to be addressed; this is also identified as one of the key domains in the ENTR. These factors render existing operating and control approaches obsolete. New approaches are needed to transform Evoenergy's system architecture in the areas of active network management, protection systems, and increasing network visibility.

In this regard, Evoenergy proposes to implement reliability measures at the distribution substation level (section 5.9), upgrade various protection systems (section 5.8.6), and make further investments in its AIS and SCADA (see section 5.12.3) to improve real-time control room visibility of the network.

5.2.2.3 Customer-orientated electricity

Customers will be at the forefront of the future electricity system as they increasingly have greater choice, control and autonomy. In particular, the distinction between consumers and producers will become blurred as consumers become prosumers (i.e. they both consume and produce power). Evoenergy considers that the electricity grid will form a crucial role in enabling this by providing security and other benefits, such as financial valuing the excess capacity produced from DER. In this environment, DNSPs will need to improve relationships with customers through expanding customer services, increasing analytics capabilities, and obtaining a better understanding of customer needs. In relation to the capital program, this poses considerable challenges in the area of IT systems and processes. Systems will need to be in place to ensure a more active focus for the network to manage their demand profile through intelligent dynamic control.

Major capital upgrades to corporate ICT and AIS systems further Evoenergy's capabilities in addressing these requirements (see section 5.12). Key upgrades result in increased automation and improvements to how customers access information (e.g. enabling an ADMS mobile solution for electrical operators, and allowing customers to fill in electronic request for service and request for service marking forms) and mapping of customer outage data to network supply points and outage notifications. In the area of corporate ICT, a transformation program is proposed to overhaul Evoenergy's capabilities in business intelligence and implement new IT platform initiatives such as a new Digital Commerce Platform.

5.2.3 Future role of DNSPs

At present, the market is still in an early phase of transition and technologies are still maturing to drive costs to a level that is competitive to large-scale augmentation. Evoenergy is currently undertaking R&D programs to identify technological and operational gaps in regards to grid transformation and optimisation in the ACT (see Attachment 1 for more detail on the R&D projects under consideration).

In conclusion, existing networks will retain a crucial role as the backbone of the electricity system to enable efficient sharing of resources between customers (including customers with DER). The value of this can only increase as more customers opt for DER. Existing DNSPs like Evoenergy will continue to serve their functions, but in a more flexible and consumer-centric manner that is competitive and responsive to changes in customer demand.

5.3 Capital expenditure program

In this section, Evoenergy explains why the total forecast capex is required for Evoenergy to achieve the objectives in the Rules clause 6.5.7(a) and other criteria set out below.

When forecasting capex for the 2019–24 regulatory period, Evoenergy considered the *capital expenditure factors* set out in the Rules clause 6.5.7(e). Evoenergy's expenditure forecasts reflect the efficient cost of service provision and this is demonstrated through:

- sound asset management and governance in the form of long-term plans, strategies and procedures (see Attachment 1) to ensure the optimal project solution is chosen;
- option analyses, including assessment of non-network alternatives and demand-side management (following the process outlined in sections 0, 5.5, 5.11.2, the Annual Planning Report, and described in attached Project Justification Reports);
- an approach to asset management during the 2019–24 regulatory period of extracting maximum value from assets;
- the application of corporate policies in respect of contract management and procurement that ensure contract arrangements reflect arms-length terms, and all goods and services provided to Evoenergy meet specified performance requirements and minimise the total acquisition cost;
- the use of cross industry, independently verified, standard estimates/escalators of input cost growth for major capital inputs as described in section 5.7.4;
- an asset management framework and system that is certified as compliant with ISO 55001, as discussed in Attachment 1;
- analysis of the actual and expected capex for each asset category in the current and past regulatory periods;
- consideration of the relative prices of different capital and operating inputs;
- wherever possible, non-network alternatives to network augmentation capital works have been assessed as part of both bottom-up and top-down routine network planning processes (see sections 0 and 5.5); and
- a total system-level assessment of the trade-off between capex and opex, as well as consideration on a project-by-project basis where such optimisation may be possible.

According to clause 6.5.7(c) of the Rules, the AER must accept a forecast of required capex that is included in a building block proposal if the AER is satisfied that the expenditure reasonably reflects efficient costs, the costs are prudent and are based on a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives. Evoenergy believes that its proposed capex program meets all three of these requirements.

Evoenergy has also had regard to the provisions in the AER's Expenditure Forecast Assessment Guidelines in this respect. Some specific examples are described below.

- Evoenergy's internal governance, asset management and planning processes ensure the production of expenditure forecasts that are prudent and efficient.
- The adoption of good industry practice processes in governance, strategic planning, risk management, asset management and prioritisation, and application of top-down

assessment of its capex forecasts (discussed in section 5.5) to further test the efficiency and prudence of its capex program.[12]

- Unit costs on which capex forecasts are based have been independently verified and found to be reasonable.
- The forecasts of load growth relied on to derive the capex forecasts and the forecasting methodology used to derive these forecasts are consistent with principles of best practice demand forecasting as set out in the Rules and the Expenditure and Forecasting Assessment Guidelines.
- Bottom-up repex forecasts are assessed against a top-down risk-based methodology and age-based repex modelling; both estimates reflect the efficient volumes and cost of replacement work required during the regulatory control period.
- Capex productivity performance is benchmarked against other distribution network service providers (DNSPs) using the AER's most recent benchmarking report (as required under the Rules, see clause 6.5.7(e)(4)).[13] This report, published by the AER in November 2017, ranks Evoenergy seventh out of 13 DNSPs in terms of multilateral total factor productivity (MTFP), and eighth in terms of capital multilateral partial factor productivity (MPFP).

Evoenergy's forecast capex is developed with regard to historical capex, which ensures that the proposed expenditure level maintains Evoenergy's standing when benchmarked against other DNSPs on the capital MFPF measure.

However, it is important to note that the AER's analysis does not capture some operating environment factors which are beyond a DNSP's control. For example, the AER's MTFP and MPFP results do not capture Evoenergy's backyard reticulation obligations which increase its costs relative to other DNSPs. For this reason, the AER states that its results are only indicative of relative performance.[14] To the extent that the AER's benchmarking can be used to assess relative performance, Evoenergy's mid-range ranking does not suggest any inherent inefficiencies in its total expenditure or capex performance.

To ensure a cost-effective outcome for consumers, Evoenergy has developed its repex and augex program using its conventional bottom-up asset planning systems and tested the outcome with a top-down methodology. This approach is further described in sections 0 and 5.5.

5.3.1 Consumer engagement

Customer engagement has played an important role in developing Evoenergy's forecast capex program. Evoenergy has engaged with customers via a number of methods and has received substantial feedback in the capex area. The key themes of customer feedback and how these have been factored into Evoenergy's capex forecast are presented in Table 5.1.

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[12] Since 2014, Evoenergy has undertaken continuous improvement in asset management and governance. Evoenergy achieved certification to ISO 55001 standard for asset management in November 2017, and holds existing ISO certifications for environmental management systems, quality management systems, and risk management standards.

[13] AER 2017, Annual Benchmarking Report, Electricity distribution network service providers.

[14] Ibid, p.13.

Table 5.1 Consumer feedback and Evoenergy's forecast capex program

Theme of customer feedback	How these views are reflected in the capex forecast
Predictability and certainty across many aspects of Evoenergy's five-year plan is important, particularly with respect to price changes.	The capex forecast provides for safe, reliable distribution services and is similar to historical AER-determined and actual capex levels, contributing to price stability.
Taking a balanced approach to the adoption of new technology—neither too aggressive, nor being a reluctant adopter of technology.	The capex forecast reflects a gradual shift towards in investment in technology, while maintaining sufficient expenditure for crucial network augmentation and asset replacement works. This has been achieved within a total capex envelope that is similar to the AER final decision capex allowance for the 2014–19 regulatory period.
Technology has the potential to be an important enabler for the electricity network and should play a role in the future of Evoenergy; with the potential to provide innovative solutions and cost-effective outcomes.	The capex forecast reflects the increasing role of technology in ensuring the network is prepared for the impact of DER and prosumers. The forecast capex program includes investments made in repex and non-network areas to provide greater dynamic control, data management, and automation of business processes to provide greater value for the consumer.
The cost/reliability trade-off approach with respect to opex currently adopted by Evoenergy is supported by customers.	Evoenergy has responded to feedback on the trade-off between costs and reliability by ensuring its capex and opex forecasts reflects customer preferences on what is the right balance.
Maintaining security of supply is important, particularly during the adoption of new technology.	The capex forecast has been prepared on a basis that ensures the security of supply is maintained in an era of rapid change. Flexible solutions, such as facilitating the uptake of DER and deploying a mobile substation in the Strathnairn and Molonglo areas respectively, show that Evoenergy has been proactive in investigating alternative ways to maintain supply security at a lower cost to customers over the long term.
Understand the consumer impacts of any new technology.	Relevant projects in the capex forecast are a Business Intelligence capability uplift and real time monitoring systems to further predict the impacts on and the needs of consumers and prosumers. In addition are investments in new IT platform initiatives, such as a Digital Commerce Platform.

5.4 Bottom-up approach

Evoenergy uses RIVA, a decision support system (DSS) to develop its bottom-up repex forecasts and, to lesser extent, its bottom-up augex forecasts. RIVA DSS is a series of algorithms that provide for an optimal repex/augex program and maintenance work schedule. RIVA uses a risk-based approach to prioritise capex based on key asset attributes including age, condition, probability of failure, consequence of failure and replacement cost. The output of RIVA DSS is used to develop asset-specific plans and inform and optimise forecast expenditure.

Information is extracted from the GIS and the Cityworks works management system to generate profiles for each distinct asset. Each asset contains all of the attributes defined for it, such as age, in-service, material, diameter, voltage. It also contains a set of events and activities that have been generated for that asset based on Evoenergy's asset management strategy, predicted values of future measures, and probability, consequence and risk profiles. Figure 5.3 summarises how the RIVA DSS generates the risk profiles and optimised work schedules for each asset from various source materials.

Figure 5.3 RIVA DSS asset model

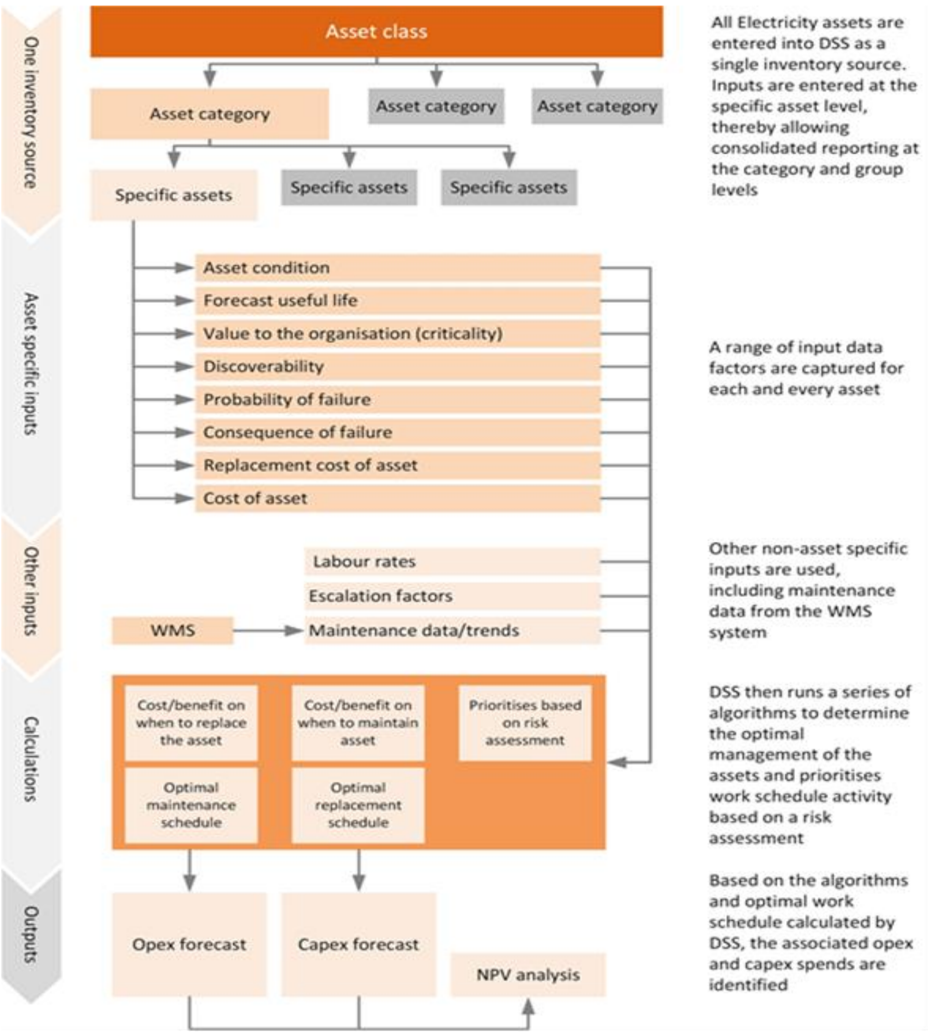


Figure 5.3 shows that all electricity assets are entered into RIVA DSS as a single inventory source. The inputs are entered at the specific asset level, thereby allowing consolidated reporting at the category and group levels. A range of input data factors are captured for each asset. These include:

- asset condition;
- forecast useful asset life;
- probability of failure;
- consequence of failure;
- replacement cost of the asset; and
- event (triggered by asset management strategy by asset type) and activity (work inserted manually) costs.

These variables then allow the algorithms to conduct a risk assessment for each asset. These algorithms are based on the Reliability Centred Maintenance framework and associated methodologies, in particular Failure Modes and Effects Analysis. Attachment 1 contains more detail on the application of these methodologies. Each asset is subsequently prioritised according to the exposure that the organisation would experience if the asset failed.

For the majority of asset forecasts, RIVA DSS pulls information from the Cityworks works management system for up-to-date works history data, ensuring work schedule projections are based on relevant asset data, and as an input to determining asset condition and criticality.

RIVA DSS runs a series of algorithms to determine the optimal management of the assets and prioritises work schedule activity based on a risk assessment. These algorithms include:

- cost/benefit on when to replace the asset;
- optimal replacement schedule;
- cost/benefit on when to maintain the asset;
- optimal maintenance schedule; and
- priorities based on risk assessment.

RIVA DSS then uses the algorithms and optimal work schedule to project the associated operational and capex forecasts. The outputs from RIVA DSS, together with outputs of the top-down methodology (discussed in section 5.5.1), inform Evoenergy's asset-specific plans (ASPs). Within the ASPs, cost/benefit analyses are undertaken to compare different replacement strategies. These typically examine a 10-year and 30-year life-cycle cost estimate for replacing the asset against the alternative option of maintaining the asset over the same periods. All forecasts are adjusted for the time value of money, ensuring that the impact of cash flow timing is correctly accounted for.

5.4.1 Bottom-up augmentation expenditure

Evoenergy uses outputs from probabilistic analysis techniques and investigates non-network alternatives to develop its bottom-up augex forecasts. In particular, Evoenergy runs a load-flow model of the network using ADMS software. This system is linked to the Supervisory Control and Data Acquisition (SCADA) system which obtains and analyses network data in real time. This allows Evoenergy to identify issues such as power flow constraints or voltage level issues on the network, and is used to model what-if scenarios such as the effect of a new load or generation connection. Using this tool, Evoenergy is able to identify existing and emerging constraints which form the basis of our asset management and network development plans.

Evoenergy uses a two-hour emergency cyclic rating for all its zone substation power transformers. The ADMS regularly records and reassesses the cyclic loading capability of zone substation equipment, based on equipment manufacturer's recommendations and relevant Australian and international standards. As a result of this (and effective load balancing between zone substations wherever possible) Evoenergy is able to maintain a high level of zone substation power transformer use.

Evoenergy uses probabilistic planning techniques when carrying out economic analysis. When assessing the economic benefits of a proposed solution to an issue, we calculate the probability of an event occurring that would result in an interruption of supply to customers. This probability is used as part of the economic analysis to determine whether the benefits of the proposed solution exceed the costs. For example if the supply demand to a part of the network could not be met fully in the event of a contingency, existing assets may be upgraded or new assets may be installed if justified economically. Changes to system losses are included in the economic evaluation of a project.

The early identification, consultation and monitoring of emerging network limitations and prospective network developments is aimed at providing proponents of non-network solutions adequate time to prepare proposals.

Evoenergy's planning process is an annual process and covers a minimum forward planning period of ten years. The process commences with a comprehensive analysis of all indicators and trends to forecast the future load on the network. A detailed analysis of the network is then carried out to identify performance and capability shortcomings, i.e. constraints.

Evoenergy uses a net present cost analysis of different options based on the total values of:

- reliability risk (based on value of customer reliability);
- reputational risk;
- litigation risk; and
- financial risk.

This approach ensures that the costs and benefits of each supply and non-network option relative to the 'do-nothing' option is appropriately accounted for in evaluating the most prudent and efficient solution to an identified need.

5.5 Top-down challenge

The bottom-up approach requires asset managers to identify, via ASPs, the activities required to maintain acceptable levels of risk across individual asset groups and the associated level of expenditure. The bottom-up approach is sufficiently detailed to enable consideration of risk at the asset level, but has the potential to result in over-expenditure at the aggregate level because the same risk outcome is targeted by multiple activities.

Evoenergy accordingly conducts a top-down assessment of expenditure. This approach considers how expenditure can be optimised across asset categories and expenditure categories to achieve the desired level of risk at least cost. The objective is to identify opportunities to reduce expenditure to levels below that produced by the bottom-up modelling and still maintain or improve overall network risk.

Evoenergy strategically reviews the results of both the top-down and bottom-up expenditure assessments and determines a final capex forecast envelope. Generally, the results of the top-down approach form a baseline for forecasting expenditure, on to which adjustments are made to reflect a strategic review of technical and practical realities of individual asset needs as determined via the bottom-up approach.

Evoenergy notes the importance of applying a rigorous challenge to a capex program constructed using the bottom-up approach. In the AER 2017 TransGrid price review, two key findings by the AER's consultant EMCa were that:

- 'bottom up' aggregation of individual projects is likely to lead to an overstatement of capex due to the absence of a rigorous challenge to its portfolio;[15] and
- the capital investment framework does not incorporate an effective portfolio optimisation process in developing the capex forecast.[16]

In addition, Evoenergy is aware of the shift towards more customer-centric processes, allowing customers to understand trade-offs between network prices and risk. In the draft determination for the 2014-19 regulatory period, the AER stated that:[17]

> ActewAGL's forecasting methodology applies a bottom-up assessment and does not have sufficient regard to top-down efficiency tests or delivery strategies … There is also evidence that Evoenergy applies poor risk management tools and is overly risk averse.

For the 2019–24 determination, Evoenergy addresses these issues via a top-down and bottom-up risk-based approach to setting its augex and repex (excluding secondary systems),[18] as shown in Figure 5.4.

Section 5.6.3 contains the projects that were deferred or eliminated as a result of applying the methodology. Evoenergy identified approximately $32.2 million in repex and $13.4 million in augex ($45.6 million total for the 2019-24 regulatory period) that could be deducted from the bottom-up forecast in order to achieve the same risk outcome.

The sections below provide an overview of the top-down approach in the areas of replacement and augmentation expenditure.

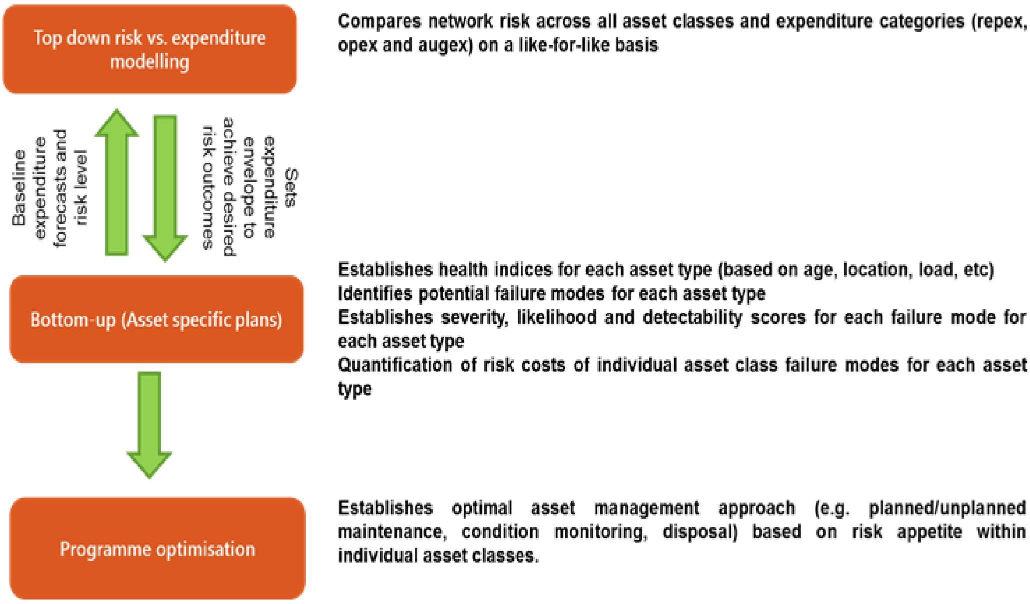
[15] EMCa, Review of aspects of TransGrid's forecast capital expenditure 2018–23, June 2017, p. 41.

[16] EMCa, Review of aspects of TransGrid's forecast capital expenditure 2018–23, June 2017, p. 12.

[17] AER, Draft decision, ActewAGL distribution determination 2015–16 to 2018–19: Overview, November 2014.

[18] The top-down approach incorporates all of Evoenergy's asset categories and expenditure categories considered material to network risk. Secondary systems were excluded from the modelling due to the complexity and error margin in quantifying risk resulting from secondary systems failures coincident with primary system faults. With potential high consequence of secondary systems failure, asset replacement is driven by asset health assessment. As a result, about 81 per cent of the proposed repex was captured within the top-down model. Secondary systems expenditure is subject to Evoenergy's bottom-up process to planning capex, which also uses a risk-based approach.

Figure 5.4 **Application of top-down risk expenditure modelling**



5.5.1 Top-down assessment of replacement expenditure

The objective of the top-down challenge is to optimise the capex portfolio across different asset classes such that the same risk can be provided at a lower cost. Under the methodology, Evoenergy seeks to identify and minimise a number of risks, which include:

- risks to the community and workforce:
  - electrical safety risks;
  - workplace safety risks;
  - bushfire and other environmental risks;
- risks to customers' quality of supply including:
  - power quality;
  - reliability.

Under the top-down methodology, Evoenergy's capex program can seek to minimise risks via the following activities:

- programmatic replacement of ageing, defective, failed and otherwise high-risk assets;
- monitoring of assets to detect and/or predict defects and failure; and
- provision of sufficient capacity (including redundancy) to meet demand and demand growth.

The top-down methodology allocates capex across these activities to achieve a level of residual risk that is acceptable to customers and meets relevant regulatory and licensing requirements. Quantifying risk in this way ensures that under-investment does not leave Evoenergy's community, its workforce or its customers exposed to unacceptable risk and, conversely, that over investment (whereby risk is materially reduced beyond current or reasonable levels) does not leave customers exposed to unnecessarily high prices.

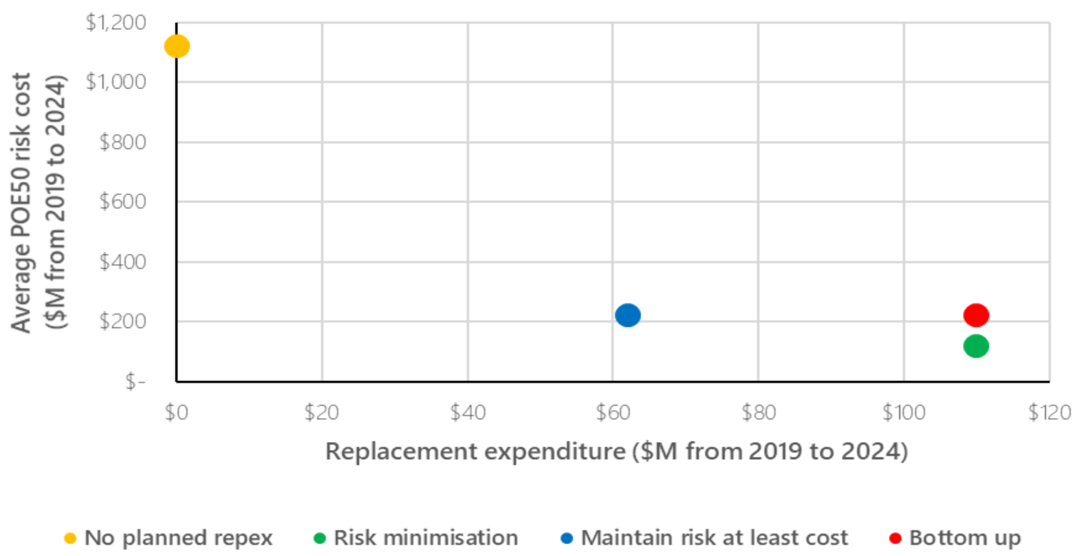
The results of Evoenergy's repex modelling are demonstrated in Figure 5.5 which shows the risk of repex portfolios under four different scenarios:

- Maintain Existing Assets
- Minimise risk
- Maintain risk at least cost
- Bottom-up

Each data point in the chart represents the average risk of simulated portfolios under each scenario. The use of Monte Carlo simulation in the top-down methodology introduces a powerful probabilistic element to evaluate the sensitivity of risk due to operational uncertainties.

Evoenergy's repex forecasts are largely based on the blue dot (maintain risk at least cost), while the other scenarios represent the cheapest option of maintain existing assets (upper bound case with highest risk), or achieving the most expensive outcome of minimising risk.

Figure 5.5 Modelling outcomes: risk cost of simulated repex portfolios



Note: The expenditure modelling excludes secondary systems, see footnote 16.

Source: Appendix 5.1, Consideration of risk for Evoenergy Regulatory Proposal 2019–24, November 2017, p. 11.

Figure 5.5 demonstrates that the 'maintain risk at least cost' and 'bottom-up' scenarios result in almost the same risk cost (around $250 million), but the former is achieved at significantly less financial cost to Evoenergy than the bottom-up approach. In other words, the former represents the least risk cost for every dollar of financial outlay and the optimisation of the capex portfolio. This indicates an optimised portfolio that reduces costs while maintaining the same level of risk.

The cheapest scenario of 'maintaining existing assets' (yellow) revealed an unacceptable level of risk cost, which simulated portfolios where the risk costs are around $1.1 billion.

The most expensive ‘minimising risk’ scenario (green) drives risk to lower levels than currently being achieved, but is likely to be considered excessively risk averse.

The ‘maintain acceptable risk’ portfolio was then used to challenge the bottom-up portfolio via a strategic review involving the asset managers across the business. This involved comparing detailed top-down model outputs with outputs from conventional bottom-up modelling to identify opportunities for Evoenergy to reduce expenditure without compromising network risk. Further explanation of the CutlerMerz repex model applied to consideration of the repex profile is provided in Appendixes 5.1 and 5.2.

5.5.2 Top-down assessment of augmentation expenditure

For forecasting augex, Evoenergy undertook a risk-based evaluation of project needs and options. This included the consideration of ‘energy at risk’ via the Augex Uncertainty Risk Appraisal (AURA) model. For existing areas, the energy at risk is determined based on the likelihood of load exceeding both the firm rating and emergency ratings of existing assets. Where load exceeds the firm rating, it is not considered at risk unless the redundancy of the area is compromised coincident with the exceedance.

This approach allows Evoenergy to consider the risk costs associated with pushing assets above firm rating, after accounting for redundancy in the network. For example, load above the firm rating of one transformer is not considered at risk where there is a second operational transformer. However, there is a small chance that the second transformer may be compromised at the same time the load exceeds the firm rating of the first transformer. The risk is therefore calculated as the fraction of hours in any given year likely to be over the firm rating multiplied by the fraction of hours in any given year that the second transformer is compromised.

The risk costs in pushing assets above emergency rating are considered unacceptable and inconsistent with the expenditure criteria which requires that demand is met or managed.

The emergence of DER and the considerable network demand uncertainty that results requires existing approaches to network planning to value the risk of demand uncertainty. In this regard, the top-down approach used by Evoenergy performs a risk-based assessment of augmentation expenditure which considers how different proposed options perform under different demand scenarios.

Under the AURA model, the incorporation of demand-side and modular network-side solutions (such as network batteries) have two potential types of value:

- deferral of capital-intensive network solutions; and
- options value (whereby the modular option can be ramped up or down as demand changes, reducing the potential for over-expenditure compared to long life fixed assets; the higher the demand uncertainty, the greater the options value).

At its core, the AURA model undertakes a probabilistic demand forecast (in the form of upper and lower bounds) and determines, via Monte Carlo analysis, which augmentation solution is most likely to result in the highest NPV across the full range of demand forecasts. This approach allows the network planner to identify the (high or low) likelihood that the traditional network solution will result in the highest NPV, as compared with other traditional or non-traditional solutions, or an option to do nothing on the basis of falling peak demand.

Evoenergy notes the following from AER’s consultant EMCa:

> Good industry practice now includes demonstrating that the timing of expenditure is economically optimised by comparing the annualised capital cost of the 'solution' against an increasing annual risk cost over time. The economically optimum project implementation time is when the annual risk cost exceeds the annualised cost of avoiding/mitigating the risk.[19]

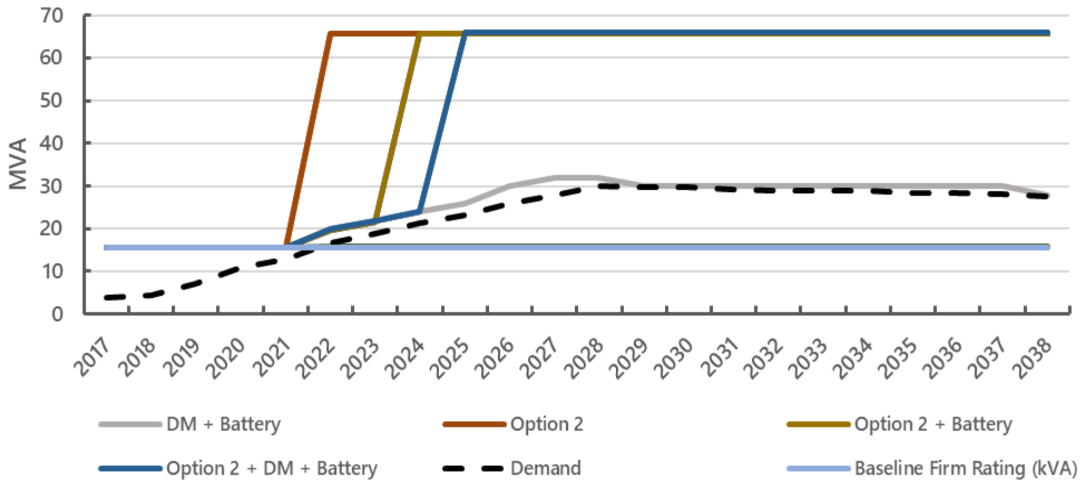
Evoenergy's AURA model addresses this by its nature as a dynamic model. For each projected year, the model assesses the option to defer projects by using demand management and non-network alternatives. Deferring is economic when the value of the capital invested in a network upgrade is higher than the cost of investment in non-network options.

The basic methodology of the model is as follows.

- When the firm rating is breached, compare the cost of deferral to the benefit of deferral and if cheaper then invest in demand management and non-network options.
- Otherwise, the first stage of a network option is installed.
- If the first stage does not provide enough capacity to meet forecast demand over the design life of the network option, additional stages will be built immediately.
- Otherwise, additional stages will be built if and when another breach of the firm rating occurs.

Figure 5.6 below shows an example of the build profiles for a single simulation. In 2022 peak demand crosses the firm rating of the asset. If the network option is selected the firm rating immediately increases to a higher level, which in this case far exceeds forecast demand growth. When non-network options are allowed, the firm rating is able to track demand growth until a future point, at which time a network option is implemented. If only non-network options are used, the firm rating can track demand growth downwards if demand falls in the future by redeploying batteries, which can be seen in 2029.

Figure 5.6 Network capacity under different augmentation options



[19] EMCa, Review of aspects of TransGrid's forecast capital expenditure 2018–23, June 2017, p. 34.

In short, the AURA model takes into account the following trade-offs:

- more modular solutions, such as network batteries, tend to perform well in conditions of high uncertainty as they can be ramped up or down in a relatively short time frame; whereas
- traditional network solutions are generally much cheaper on a dollar per megavolt-ampere (MVA) basis, but tend to perform poorly when there is demand uncertainty, particularly when there are short-term demand increases but longer term demand declines.

The AURA model undertakes on a probabilistic-based analysis of network and non-network options under plausible scenarios of future demand. The probabilistic-based analysis allows Evoenergy to determine the subset of demand forecasts for which the proposed traditional network solutions is able to meet demand at lowest cost, and the subset of demand forecasts for which alternative options including deferral are able to meet demand at lowest cost.

This allows the AURA model to form an assessment which accounts for the timing of implementing each solution in relation to simulated future demand scenarios.

Likewise with repex, the top-down estimates of augex were used to challenge estimates from the bottom-up approach by considering the risks of over expenditure posed by demand uncertainty. Further explanation of the CutlerMerz AURA model applied to consideration of augex risk and demand uncertainty is provided in Appendix 5.3.

5.6 Overview of historical and forecast capex

5.6.1 Snapshot of capex

In April 2015, the AER released its Final Decision on prices for electricity distribution services in the ACT for the period 2014–19. This included the capex allowances shown in Table 5.2.

Table 5.2 Evoenergy capex versus AER allowance 2014–19

$ million (2018/19)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
AER allowance	79.5	66.2	70.7	61.6	60.5	**338.6**
Evoenergy actual 2014–19	76.9	62.7	55.4	67.7	66.1	**328.8**
Variance from AER allowance	**(2.6)**	**(3.6)**	**(15.3)**	**6.1**	**5.7**	**(9.8)**
	2019/20	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**Total**
Evoenergy forecast 2019–24	62.4	65.3	75.9	65.6	60.6	**329.8**
Variance from AER allowance						**(8.8)**

Evoenergy's forecast and historical capex for the current period reflects a significant decrease from the regulated allowance determined by the AER in 2015. As shown in Table 5.2, forecast capex is $8.8 million (2.6 per cent) below the level of capex approved in the 2014–19 regulatory period, and actual capex is $9.8 million (3.0 per cent) below the level approved.

It is important to note that this was achieved during a period of intense organisational reform in asset management, capital governance and program delivery processes as a result of the reduction in Evoenergy's opex allowance from the previous Determination. Furthermore, expenditure reflected preparing the network for the emergence of distributed energy (see section 5.2).

Table 5.3 compares movements in Evoenergy's actual and forecast capex at category level from the AER allowance. Figure 5.7 provides a graphical overview of the movements at category level contained in Table 5.3.

Table 5.3 Actual and forecast capex versus AER allowance by category

$ million (2018/19)	2014–19 Allowance	2014–19 Actual	2019–24 Forecast	Variance (Actual vs AER)	Variance (Forecast vs AER)
Augmentation	51.7	33.4	47.2	(18.3)	**(4.5)**
Connections	85.4	90.6	85.9	5.2	**0.5**
Replacement	115.1	80.1	91.6	(35.0)	**(23.5)**
Reliability and quality improvements	7.3	6.6	6.2	(0.8)	**(1.1)**
Non-network	63.0	89.8	58.3	26.7	**(4.7)**
Capitalised overheads	57.5	68.2	75.6	10.7	**18.1**
Less capital contributions	(33.4)	(39.6)	(34.2)	(6.2)	**(0.7)**
Less disposals/materials escalation adjustment	(8.2)	(0.4)	(1.1)	7.8	**7.1**
Net capex	**338.6**	**328.8**	**329.8**	**(9.8)**	**(8.8)**

Figure 5.7 Actual and forecast capex versus AER allowance

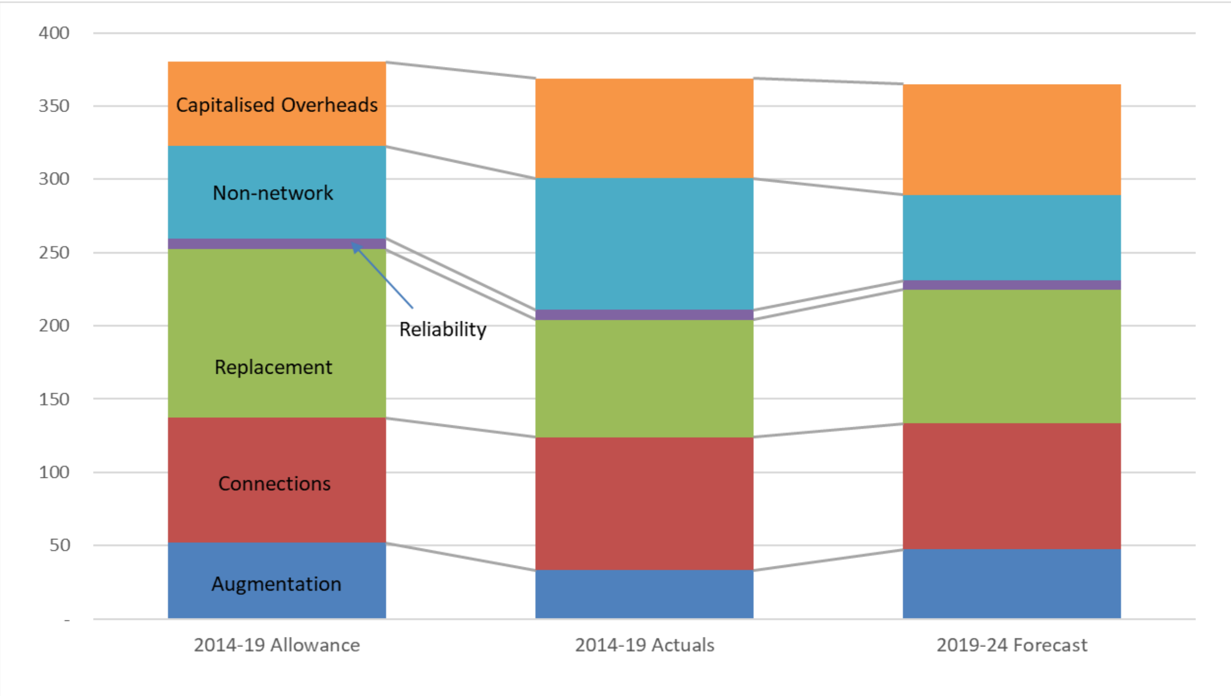


Figure 5.7 shows that, consistent with expected efficiencies from applying the top-down and bottom-up approach to its capex forecasts, Evoenergy has significantly reduced augex and repex compared with the AER’s 2015 final determination. However, there has been an offsetting increase in capitalised overheads and non-network spending. Total actual and forecast expenditure are both at similar levels to the AER’s allowed capex.

The underlying cost driver for increases in non-network and capitalised overheads is a reprioritisation of business needs towards overhauling IT infrastructure. This is to prepare the business for significant industry changes in the electricity market (section 5.2) and to be a substantial driver of Evoenergy’s opex savings in response to reductions in the opex allowance in the 2015 AER Final Decision (see Attachment 6).

In particular, factors that were not foreseen in the last determination include Power of Choice regulatory changes, the accelerating pace of industry transformation from increased DER, and the need to improve services to customers from increased automation and information. These are costs that are essential to ensure Evoenergy meets increasing demands in a rapidly changing industry, as outlined broadly in the ENTR, or are non-controllable costs arising from regulatory changes. Section 5.12 outlines Evoenergy’s non-network expenditure.

As a result of this expenditure, there has been a relative increase in the proportion of short-lived ICT system assets in the Regulatory Asset Base, which in turn has had significant implications for Evoenergy’s forecast depreciation for the 2019–24 regulatory period. The impact of this on Evoenergy’s forecast revenue requirement for the 2019–24 period is further discussed in Attachment 7 (Regulatory asset base). Appendix 5.9 describes in more detail Evoenergy’s ICT expenditure.

The proportional increase in capitalised overheads is largely due to significant corporate ICT investments in the previous and current regulatory periods made at the enterprise level to overhaul analytics capabilities.[20] The overheads associated with this have resulted in a significant increase in short-lived assets and associated depreciation. Evoenergy has also spent more than the AER’s opex allowance in the 2015 final determination, which was a significant reduction from historical levels (see Attachment 5 Capital expenditure). The impact of the increase in short-lived assets and the increased spending on the opex allowance due to an increase in cloud-based systems and platforms, and an increase in IT security costs have resulted in an increase on capitalised overheads relative to that allowed in the 2015 final determination. In addition, Evoenergy notes that the relationship between capitalised overheads and expenditure is often unclear due to year-end accounting adjustments such as employee entitlements.

Lastly, the increase in augex in the forecast period over the current period is largely attributable to a one-off deployment of a mobile substation in the Molonglo area (in lieu of a permanent zone substation that was proposed for the current period) and the installation of feeders to service high-growth areas (see section 5.11.3).

[20] Evoenergy’s cost allocation method (CAM) is described in “ActewAGL Distribution Cost Allocation Methodology, November 2012” which was approved by AER under NER clause 6.5.4 (c) in June 2013. The document will be updated before 1 July 2018 to reflect the requirements of the AER’s Ring-fencing Guideline published in October 2017 and explicitly account for gas distribution networks, gas facilities and organisational changes arising from the creation of separate legal entities. Evoenergy’s methodology of allocating costs for the electricity distribution business is not expected to change.

5.6.2 Historical expenditure 2014–19

Evoenergy’s actual capex by category for the 2014–19 regulatory period is shown in Table 5.4.

Table 5.4 Historical capex by category 2014–19

$ million (2018/19)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Augmentation	3.1	3.9	5.9	9.0	11.6	**33.4**
Connections	19.9	19.2	17.3	18.0	16.3	**90.6**
Replacement	20.2	17.9	15.2	12.7	14.1	**80.1**
Reliability and quality improvements	0.0	0.2	1.7	4.2	0.6	**6.6**
Non-network	26.5	16.1	12.1	17.4	17.6	**89.8**
Capitalised overheads	14.9	14.0	13.0	14.1	12.2	**68.2**
Less capital contributions	(7.7)	(8.6)	(9.5)	(7.7)	(6.2)	**(39.6)**
Less disposals	-	(0.1)	(0.3)	-	-	**(0.4)**
Net capex	**76.9**	**62.7**	**55.4**	**67.7**	**66.1**	**328.8**
AER Allowance	79.5	66.2	70.7	61.6	60.5	**338.6**
Variance	**(2.6)**	**(3.6)**	**(15.3)**	**6.1**	**5.7**	**9.8**

Table 5.4 shows that net actual capex represents a significant underspend on allowed expenditure for most years of the 2014-19 regulatory period. Table 5.3 above also shows there are significant variations at the category level. Key drivers of expenditure are described below.

- A change in scope for the Second Supply to the ACT Project. Technical issues and operational risks were identified with the original plan for supplying the ACT from Williamsdale under contingent events. A more viable solution was identified with the proposed construction of a double circuit 132 kV transmission line from the new TransGrid Stockdill Substation to connect into Evoenergy’s existing Canberra–Woden 132 kV line.
- The deferral of Molonglo Zone Substation, Gold Creek Zone Substation 11 kV switchboard extension, Belconnen Zone Substation third transformer and the Mitchell Zone Substation due to load growth being less than forecast in the last determination. This was a result of the slower than expected progress in land releases by the ACT Government in the relevant areas.
- A focus on asset renewal and replacement to address Evoenergy’s ageing asset base and increasing risk profiles in the areas of underground cable and pole replacement.
- Delivery of additional AIS projects above what was included in the regulatory submission and changes in scope in existing projects that were proposed in the submission. This is due to a number of environmental and regulatory changes not anticipated since the AER’s 2015 final determination. Further detail on AIS expenditure is contained in section 5.12.3 and Appendix 5.9.

5.6.3 Overview of capex forecasts

Evoenergy's capex plan for the 2019–24 regulatory period continues key capex reform programs that were initiated during the current period to ensure the ongoing reliability of the network and alignment with the ACT Government's planning and system security requirements. It also reflects a new approach to capex forecasting as described in section 5.5, using both bottom-up and top-down methodologies to ensure that expenditure forecasts reflect the lowest cost outcome and an optimised portfolio. As a result of this new approach, Evoenergy has identified reductions of approximately $32.2 million of repex and $13.4 million of augex compared to the bottom-up forecasts (see Table 5.5 for more details). The $45.6 million in total reductions represents a 33 per cent reduction from the initial bottom-up forecasts over the 2019-24 regulatory period.

The majority of forecast augex is attributed to planning and construction of Molonglo Zone Substation and various feeders to maximise use of existing zone substations,[21] and stage two of the Second Supply to the ACT project, a requirement of the ACT Government's Electricity Transmission Supply Code 2016.

As with the previous determination, asset replacement remains dominated by the current pole and underground cable replacement programs, with underground cable expenditure marginally outweighing pole replacement expenditure. To constrain increases in proposed replacement costs, significant savings on cables and poles were identified from the application of the top-down challenge. Overall, expenditure on asset replacement remains a significant reduction from the AER's allowance.

Following application of the top-down methodologies (see section 5.5) to Evoenergy's bottom-up forecasts, Evoenergy has identified considerable opportunities where costs can be eliminated or deferred from the initial bottom-up forecasts. The main opportunities identified are presented in Table 5.5. In addition, Figure 5.8 provides a more detailed overview of the adjustments made to all asset classes in repex.

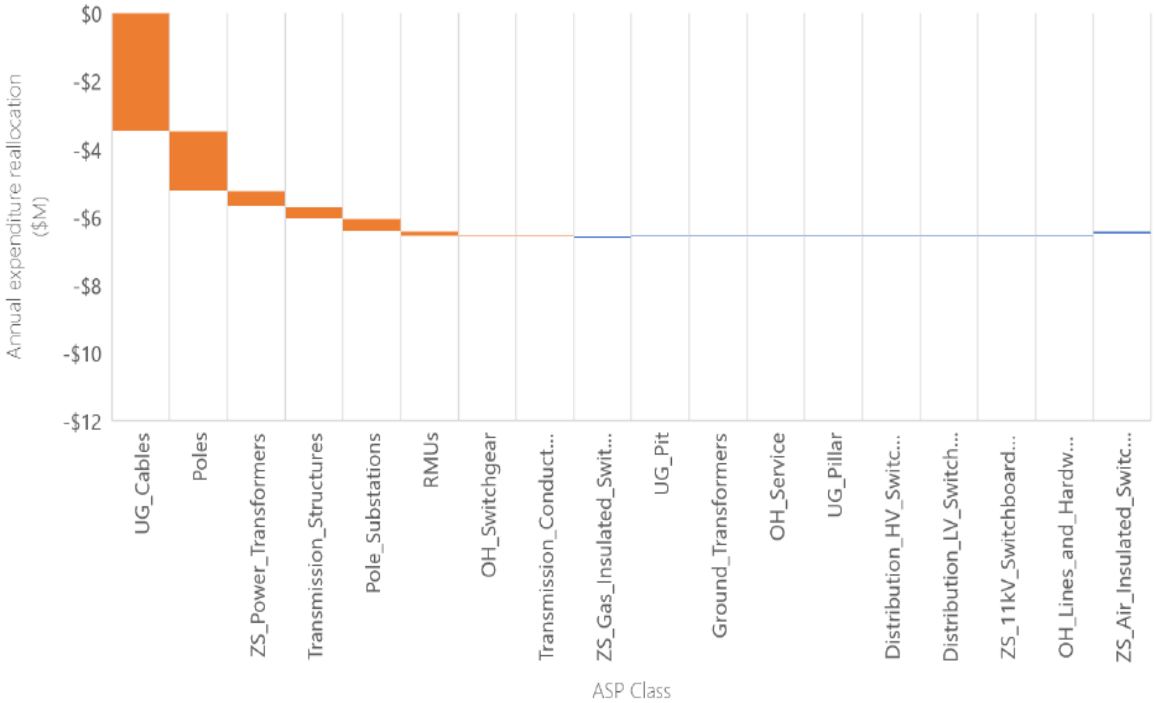
Table 5.5 Key opportunities identified from top-down challenge

Opportunity	Category	Description	Savings identified
Molonglo Zone Substation	Augex	Deferral of permanent Molonglo Zone Substation, replace with interim Mobile Substation	$6.2m
Strathnairn Zone Substation	Augex	Deferral of permanent Strathnairn Substation, assume uptake of PV and batteries supplemented by incentive payments will absorb demand	$7.2m
Underground cables	Repex	Underground cables replacement expenditure	$17.4m
Pole replacements	Repex	Pole replacement expenditure	$8.8m
Other repex asset classes	Repex	Other replacement and renewal asset classes (see Figure 5.8)	$6.0m
Total			**$45.6m**

[21] In the ACT, dwelling construction must be commenced within one year and completed within three years of land sale.

Percentage reduction (from initial augex and repex forecasts)	33%

Figure 5.8 Top-down adjustments to repex by asset class



Notably, Evoenergy proposes to defer Strathnairn Zone substation due to significant investment risks in the face of DER, as recommended by the top-down approach. This demonstrates Evoenergy's commitment to deliver the most cost-effective outcome, given the expectation that there will be significant uptake of DER by consumers in the Strathnairn new development area. This is further discussed in sections 5.11.4 and 5.11.5.

Non-network expenditure in the 2019–24 regulatory period is reduced to levels allowed for in the 2014–19 period by the AER's 2015 final determination. This reflects the expectation that AIS expenditure, which accounted for most of the overspend in the 2014–19 period, will have reached a period of stabilisation and maturity by the 2019–24 regulatory period. The proposed investment mainly reflects further asset replacement and integration of key management systems to a single integrated geospatial platform, further maintaining operational efficiencies that were made in the current regulatory period. This is discussed in more detail in section 5.12.3.

Connections expenditure remains relatively stable and consistent with historical levels (see section 5.10.5). Evoenergy has significantly improved its methodology for forecasting connections expenditure, see Appendix 5.5.

Reliability capex reflects the need to undertake an upgrade of distribution level monitoring to address power quality issues arising from the emergence of DER in the electricity market (see section 5.9).

A summary of forecast capex by category for the 2019–24 regulatory period is provided in Table 5.6. This table provides consolidated expenditure forecasts with respect to Evoenergy's standard control (transmission and distribution) services.

Transmission capex is identified separately in section 0.

Table 5.6 Forecast standard control capex for 2019–24

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Augmentation	11.1	13.8	10.9	5.7	5.8	**47.2**
Connections	16.2	17.2	17.5	17.8	17.3	**85.9**
Replacement	17.3	17.7	16.4	17.1	23.1	**91.6**
Reliability and quality improvements	1.2	1.2	1.2	1.2	1.2	**6.2**
Non-network	8.9	7.7	19.9	15.7	6.1	**58.3**
Capitalised overheads	14.3	14.8	17.1	15.3	14.2	**75.6**
Less capital contributions	(6.5)	(6.9)	(6.9)	(7.1)	(6.8)	**(34.2)**
Less disposal	(0.2)	(0.3)	(0.2)	(0.2)	(0.3)	**(1.1)**
Net capex	**62.4**	**65.3**	**75.9**	**65.6**	**60.6**	**329.8**

5.7 Forecasts, methodology and assumptions 2019–24

This section explains Evoenergy's approach to capex forecasting, as per the capex objectives and factors set out in the Rules and the AER guidelines. Clauses 6.8.1A and 11.56.4(o) of the Rules require Evoenergy to inform the AER of the methodology it proposes to use to prepare the forecasts of capex and opex that form part of its *regulatory proposal* at least 19 months before the expiry of a distribution determination that applies to the *Distribution Network Service Provider*.[22]

Evoenergy's capex and opex forecasting methodology was submitted to the AER on 30 June 2017. The methodology was prepared in accordance with the AER's guidelines.[23]

The sections that follow (sections 5.8 to 5.12) provide forecasts for each of Evoenergy's capex categories and a discussion of the particular assumptions and methodologies adopted for each category.

[22] Clause 6.8.1A(b)(1) of the Rules requires a DNSP to submit its forecasting methodology at least 24 months before the expiry of a distribution determination. Clause 11.56.4(o) of the *Savings and Transitional Measures* takes this timeframe back to at least 19 months before the expiry of the distribution determination.

[23] AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013.

5.7.1 AER capex categories

Evoenergy notes the high-level capex categories specified by the AER in the guideline,[24] but has presented capex forecasts in this proposal in categories that are consistent with its own internal reporting and forecasting processes. Evoenergy believes that presenting information in this way will result in a submission that is more informative and reflective of Evoenergy's key asset management objectives.

Figure 5.9 reconciles the AER's high-level capex categories with Evoenergy's own capex categories. Historical and forecast information presented in the RIN templates have been provided in accordance with the AER's high-level categories.

Figure 5.9 AER and Evoenergy capex categories

AER high-level categories	Evoenergy categories
Replacement capex	Asset renewal and replacement
Augmentation capex	Augmentation capex
	Demand-side management
Reliability and quality improvements	Reliability and quality improvements
Connection and customer-driven works capex	Customer-initiated capex
Non-network capex	Non-system assets
	Asset information systems (formerly Network IT)
	Facilities
	Corporate services business support
	Finance lease assets

5.7.2 Evoenergy's expenditure forecasting methodology

Evoenergy uses a combination of zero-based, top-down, and base-year approaches when forecasting capex. The zero-based method assumes a bottom-up construction of capex associated with projects. The actual unit rates used by Evoenergy in constructing project costs are detailed in individual project justifications, and asset management plans. Expenditure forecasts are then escalated throughout the regulatory period in line with independently verified material and labour cost escalators. Evoenergy's application of its top-down methodology is detailed in section 5.5.

Both the key unit rates and the cost escalation factors that have been applied by Evoenergy in building up capex forecasts for the 2019–24 regulatory period have been developed with the assistance of independent consultants and have been verified by external experts.

Evoenergy's key asset management processes, forecasting models and demand assumptions have been reviewed internally, and independently verified to ensure that the capex forecasts contained in this proposal are free of error and reasonably reflect efficient costs. In certain cases, capex is based on a tendering process to secure the lowest life-cycle costs for Evoenergy in accordance with the Evoenergy procedure for purchasing of goods and services. Attachment 1 contains more detail on Evoenergy's asset management processes.

[24] AER, Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013.

Evoenergy has not included contingencies in its forecasts.

5.7.3 Unit rates

Evoenergy engaged CutlerMerz consulting to undertake a comparative review of unit rates for a selection of activities that are included in Evoenergy's expenditure programs. CutlerMerz conducted the review using two approaches. For activities that were comparable to similarly scoped activities carried out at peer DNSPs, and where CutlerMerz had rates available, Evoenergy's rate was compared to a benchmark unit cost. For activities that were unique to Evoenergy, or scoped with a high specificity, a comparison to activities at peer DNSPs was impractical, and therefore the rate was assessed from an efficiency and reasonableness point of view. For a few unit rates where a comparison rate or efficiency review could not be done, CutlerMerz verified that these rates were market tested and made use of appropriate standardisations.

Overall, Cutler Merz found that Evoenergy's activity unit rate estimates for the selected activities are reasonable and efficient. CutlerMerz's report can be found in Appendix 5.4 of this proposal.

5.7.4 Input cost escalation

Evoenergy engaged BIS Oxford Economics and GHD to assist in undertaking an independent forecast of the material and labour cost escalators applied to various asset classes in forecasting capex for the 2019–24 regulatory period.

As a first step in developing cost escalators for each asset class, Evoenergy calculated percentage breakdowns of each asset class into material and labour costs based on its recent history with asset construction and management. These weights were reviewed by GHD and assessed against GHD's database of unit rates and a number of bottom-up asset assessments it had previously undertaken. GHD found Evoenergy's material and labour cost breakdowns to be reasonable, and this data was used to determine the effect that each escalator has on the overall installed price of an asset.

Applying the escalation factors differs in complexity between cost categories. For labour costs, the process is relatively simple, with costs escalated by the appropriate labour index (general, utility or professional) each financial year. The process is more complicated when forecasting capex, particularly the acquisition and replacement of assets. To escalate forecasts, the asset base must be further broken down into its material categories (e.g. aluminium, copper, steel, crude oil).

Real cost escalation indices for the following material and labour cost drivers were calculated for Evoenergy by BIS Oxford Economics for the 2019–24 regulatory period:

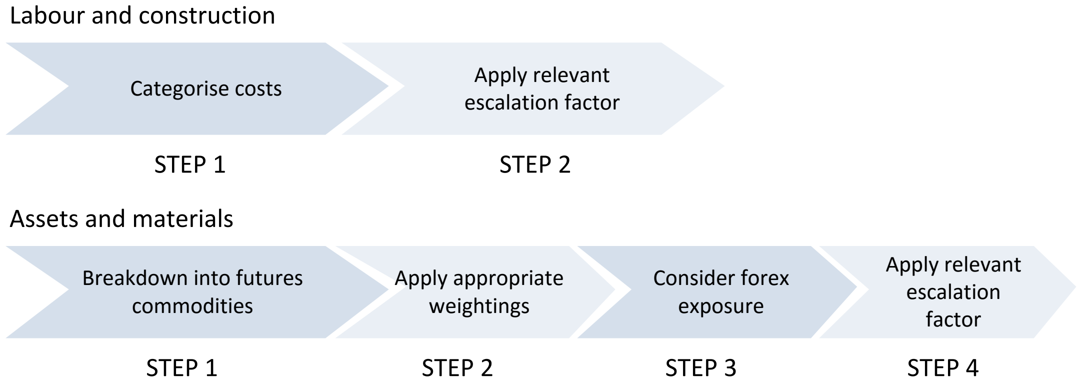
- aluminium (Al);
- copper (Cu);
- steel;
- crude oil;
- labour, including utilities industry, professional services and general labour; and
- construction—both engineering and non-residential.

Using these individual material and labour cost escalators, GHD calculated escalation factors specific to various asset classes by applying the weights that were independently verified by GHD.

The final step in developing escalation factors for each asset class is to take into account foreign exchange movements (primarily the United States dollar to Australian dollar relationship) to convert the price of international commodities that are typically quoted in US dollars.

The input cost escalation process is depicted in Figure 5.10.

Figure 5.10 Input cost escalation process



GHD's calculated real annual material and labour cost escalation indices for 15 of Evoenergy's standard asset classes, as shown in Table 5.7.

Table 5.7 **Real annual material and labour cost escalation indices for capex**

Evoenergy Asset Type	Real cost escalation factor *					
	Jun-19	Jun-20	Jun-21	Jun-22	Jun-23	Jun-24
Transmission overhead	1.003	0.991	1.005	1.007	1.009	1.019
Transmission underground (Cu)	1.015	1.004	1.008	1.005	1.006	1.018
Distribution overhead lines	1.010	1.006	1.012	1.015	1.016	1.017
Distribution underground lines (Al)	1.011	1.006	1.011	1.013	1.014	1.017
Zone substation switchgear	1.014	1.006	1.012	1.010	1.012	1.021
Zone substation transformer	1.015	0.999	1.009	1.006	1.008	1.027
Zone substation electronics/other	1.025	1.020	1.022	1.019	1.019	1.027
Zone substation civils	0.997	0.987	0.995	0.992	0.993	1.004
Distribution substations	1.017	1.009	1.014	1.013	1.014	1.023
Meters	1.018	1.014	1.017	1.018	1.018	1.021
Relays (protection & control)	1.014	1.011	1.015	1.017	1.018	1.018
ITC systems (Networks)	1.014	1.014	1.017	1.019	1.019	1.018
Other non-system assets (Corporate)	1.000	1.000	1.000	1.000	1.000	1.000
Other non-system assets (Networks)	1.000	1.000	1.000	1.000	1.000	1.000
Motor vehicles	1.000	1.000	1.000	1.000	1.000	1.000

* Annual average year-to-June real cost escalation factors, using weights applied to raw material and labour escalators produced by BIS Oxford Economics.

The independent report provided by BIS Oxford Economics and GHD in support of the escalation factors used by Evoenergy in its capex forecasting is provided in Appendixes 5.6 and 5.7 respectively.

5.8 Asset renewal and replacement methodology and forecasts

Asset replacement and renewal programs are necessary to manage the performance of the network and ensure Evoenergy complies with its regulatory obligations, particularly in respect of network reliability and safety. For example, safety and reliability concerns drive projects such as the ongoing wooden pole replacement program and the proposed underground cable replacement program.

Repex is driven by an assessment of risk, which is a function of:

- asset condition—that is, where deterioration of the physical state of assets result in increasing probability of failure, maintenance costs, or safety hazards; and
- criticality—that is, the relative importance of reliable asset operation, as measured by the consequences of failure or insufficient functionality.

With respect to the future, enhancing condition data will form a major component of Evoenergy's broader plan to increase capabilities in assessing risk, dynamic monitoring and control (see section 5.12.3). Enhancement of data is a crucial element in ensuring that the network responds effectively to changes in load flows, asset condition, and risk profiles from the emergence of DER. This also leverages the benefits arising from other tools and improvements that are in place; for example, producing accurate data for input into Evoenergy's top-down new risk versus expenditure model, which further optimises the repex planning process.

5.8.1 Overview of current period asset renewal and repex

An overview of total repex in the 2014–19 regulatory period is set out in Table 5.8. This section provides an overview of the two major primary systems programs (pole replacements and underground cables) and an overview of secondary systems programs.

Table 5.8 Historical replacement and repex programs 2014–19

$ million (2018/19)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Distribution	16.7	13.8	12.0	10.6	11.9	**65.0**
Zone substations	2.0	2.1	1.8	0.7	0.4	**7.1**
Transmission	0.4	0.2	0.0	0.0	0.1	**0.8**
Secondary systems	1.0	1.7	1.3	1.4	1.7	**7.1**
Remote area power supply	-	0.0	0.0	-	-	**0.1**
Total renewal and replacement	**20.2**	**17.9**	**15.2**	**12.7**	**14.1**	**80.1**
AER allowance	22.5	24.0	23.9	23.2	21.5	**115.1**
Variance	**(2.3)**	**(6.1)**	**(8.7)**	**(10.5)**	**(7.4)**	**(35.0)**

Table 5.8 shows that repex during the current period was about 30 per cent lower than the AER allowance. Savings were realised due to reduced numbers of poles forecast for replacement and reduced overhead pole top upgrades due to changes in serviceability criteria, and a realignment of business priorities towards addressing issues relating to DER, with an emphasis on spending in the information technology areas (see sections 5.2 and 5.12).

5.8.2 Methodology for estimating repex

Evoenergy's forecast repex is mostly based on a bottom-up and top-down approach. An overview of these approaches is provided in sections 0 and 5.5.1, respectively.

Asset renewal investment is driven primarily by the need to address an ageing asset base and complying with relevant safety and reliability obligations. The objective of repex is to manage risks and requirements relating to:

- managing electricity supply and reliability;
- maintaining operational functionality of the network;
- providing a safe work environment for Evoenergy's employees and contractors;
- ensuring public safety;
- environmental compliance;
- avoiding property damage;

- complying with legal and regulatory obligations; and
- optimising the balance between capex and opex.

Currently, forecast expenditures are determined through consideration of:

- historical trends;
- escalation of material and contractor costs;
- the assessed condition of the assets;
- assessment of asset failure rates;
- risk management review and prioritisation;
- unit rates;
- pole replacement and refurbishment modelling;
- the requirements of the Technical Regulator;
- the need to achieve and comply with service and technical standards;
- assessment of work health safety and environmental requirements; and
- assessment of capex/opex trade-offs.

Assets are generally replaced either as a result of equipment failure or deteriorating condition of an asset indicating imminent failure. Other asset replacement considerations include the added value that new assets may provide because of integrated features through new technology, such as online condition monitoring of assets. Evoenergy conducts failure modes, effects and criticality analysis for all critical assets (e.g. transformers, switchgear and cables) to refine the results of RIVA DSS asset risk modelling (see Attachment 1 for more detail on Evoenergy's asset management processes).

In response to the changing electricity market and the ENA's ENTR, Evoenergy intends to further its capabilities with respect to condition assessment, asset failure assessment, and risk management. More detail on these initiatives are contained in section 5.8.6, which concerns secondary systems replacement.

The adoption of an asset management system that is consistent with ISO 55001 means that once an asset replacement need has been identified, Evoenergy is able to generate the most cost-effective asset replacement solution and schedule.

5.8.3 Overview of forecast repex

Evoenergy's forecast repex for each year of the 2019–24 regulatory period are set out in Table 5.9. Total repex in the 2014–19 period is expected to be significantly lower than in the current period (see Table 5.7). This is a result of the new RIVA DSS asset management system that was implemented during the 2014–19 period and a new risk-based bottom-up methodology that produces less conservative estimates of expenditure than anticipated.

Table 5.9 **Forecast repex programs 2019–24**

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Distribution	14.3	14.5	13.2	13.9	17.1	**73.0**
Zone substations	0.2	0.6	0.4	0.5	3.4	**5.2**
Transmission	0.1	0.1	0.1	0.1	0.1	**0.5**
Secondary systems	2.7	2.5	2.6	2.6	2.4	**12.9**
Remote area power supply	-	-	-	-	-	**-**
Total renewal and replacement	**17.3**	**17.7**	**16.4**	**17.1**	**23.1**	**91.6**

The majority of repex is attributed to several major replacement and renewal programs. These are summarised in Table 5.10.

Table 5.10 **Major asset replacement and renewal programs**

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Pole replacement, pole substation replacement and pole reinforcement	5.9	5.6	5.7	5.8	6.1	**29.0**
Underground cables planned replacement	3.7	4.1	2.7	3.3	6.6	**20.3**
Overhead lines and pole hardware	1.6	1.6	1.6	1.6	1.6	**7.9**
Share of asset replacement and renewal expenditure						**62.0%**

The underground cable and pole replacement programs continue to dominate the repex forecast. This is a continuation of an existing program of work that was approved by the AER in 2014 and will continue beyond the 2019–24 regulatory period. Other key asset replacement programs to be commenced in the next regulatory period include various upgrades to secondary systems to improve the robustness of the network against an increasingly volatile future electricity market (see section 5.2). These programs are discussed in more detail below.

5.8.4 Pole replacement, pole substation and reinforcement programs

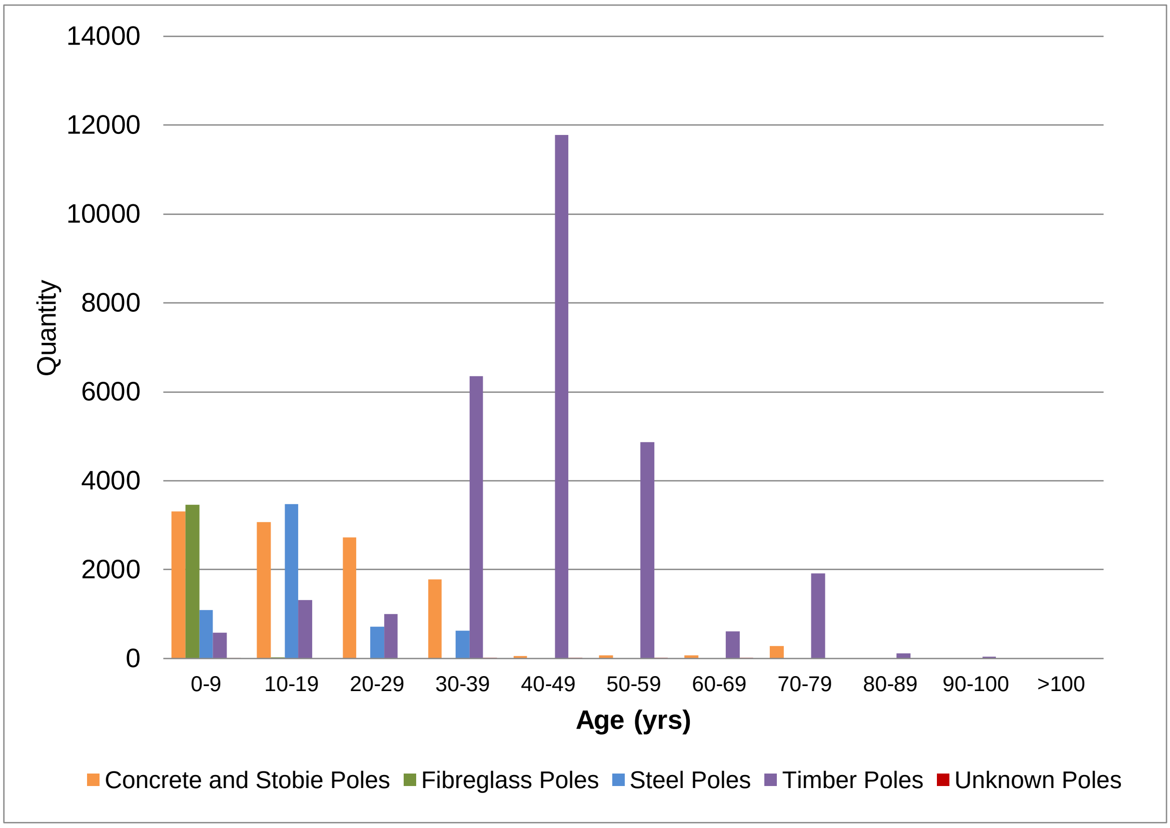
Poles are a key element in Evoenergy's network, supporting electrical current carrying equipment above ground level and are predominantly used in Evoenergy's high voltage (HV) and low voltage (LV) networks. It is a critical component in the performance, reliability and safety of an overhead network. Poles generally contribute around 20–30 per cent of the total capital cost of an overhead line on a per kilometre basis.

Evoenergy's pole replacement, pole substation and reinforcement program accounts for almost 30 per cent of the repex budget, and is the largest single component of Evoenergy's forecast capex. The current program was approved by the AER in 2014 and will continue beyond the end of the next regulatory period, with a marginal increase in underground cable spending relative to the previous submission.

The Evoenergy network includes approximately 49,000 poles, the majority of which are wooden and subject to gradual rotting and subsequent loss of strength. As wooden poles deteriorate they require strengthening works such as nailing or attaching steel armour guards and are therefore no longer used for augmentation projects.

Figure 5.11 shows there are a large number of timber poles (natural round timber, tanalith, creosote) that are over 40 years of age, and a small number of assets nearing the top end of the expected life of 80 years.

Figure 5.11 Age profile of distribution poles



The replacement of wooden poles with concrete and fibreglass poles over the next regulatory period will ensure continued reliability and safety of the network and will contribute to a reduction in future maintenance expenditure.

With the aged nature of the wood pole assets, Evoenergy has developed and implemented strategies to extend the life of wood poles, determined economic strategies for when to replace pole top assemblies (verses replacing the whole pole structure), and has investigated, sourced and implemented an innovative pole replacement methodology which is unique in Australia. The latter was the result of an unusual LV network dominated by rear-of-block overhead reticulation which prevents heavy vehicle access for pole replacement.

The replacement poles now used by Evoenergy have a demonstrably lower whole-of-life asset cost, and are safer in rear-of-block reticulation situations.

5.8.4.1 Pole replacement approach

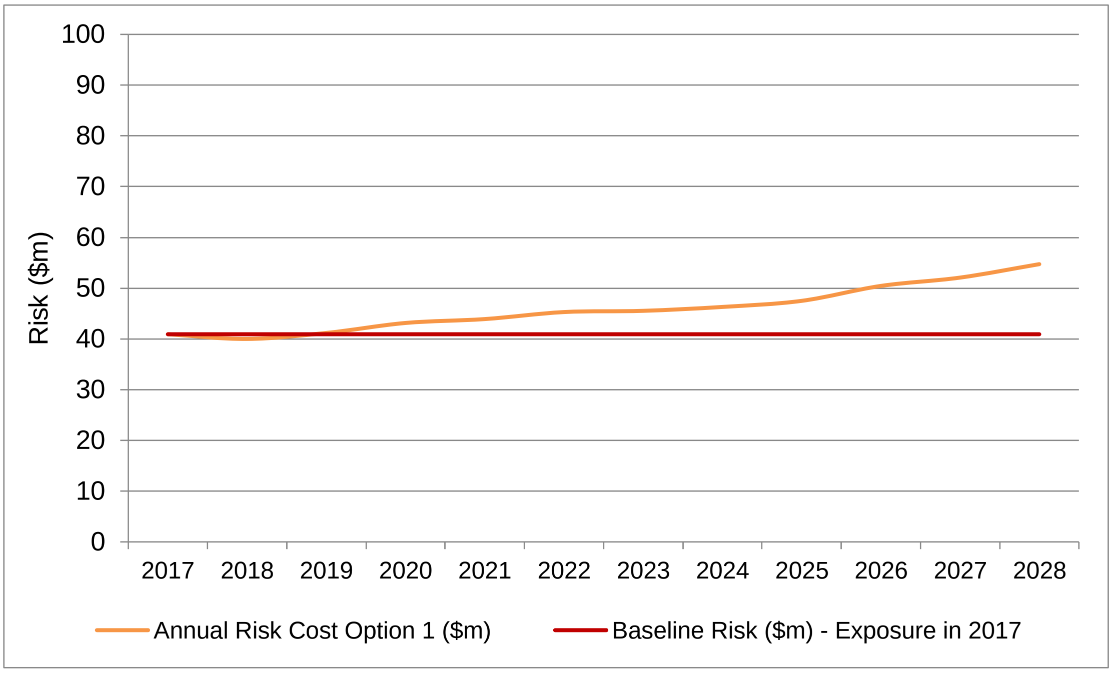
Evoenergy currently undertakes a condition-based monitoring (CBM) approach to managing its pole and cable assets. This approach is considered by industry to be the most efficient method of asset management in terms of asset life-cycle. The majority of Evoenergy's pole population are timber poles which experience different rates of deterioration due to their naturally occurring material and the environmental conditions they are subjected to. CBM ensures that poles are only replaced when they need replacing, plus replacement can be deferred even if the pole has exceeded its service life.

Evoenergy also undertakes planned refurbishment of poles as their condition merits. Planned refurbishment is a cost-effective treatment to extend the service life of poles while managing the risk. Pole refurbishment is ‘nailing’ or ‘staking’ of timber poles, increasing the strength of the weakest part of the pole to extend its service life by an average of eight years. Poles are refurbished when the minimum criteria for wall thickness is reached below ground, while the serviceability criteria is met for wall thickness above ground.

The frequency of monitoring, replacement and refurbishment is set by serviceability criteria. The current serviceability criteria that Evoenergy uses is detailed in its Pole Replacement Asset Specific Plan (Appendix 5.16). Other strategies based on different serviceability criteria were investigated. However based on RIVA DSS (see section 0), it was determined that the current strategy represented the optimal approach. The resultant risk profile produced by RIVA DSS is provided in Figure 5.12.[25] This shows that the current strategy adopted, which includes significant changes in the criteria to reduce costs further, involves a marginal increase in risk over current levels. This is a result of adopting a careful approach that constrains spending, and thus price increases to customers, while maintaining an acceptable level of risk to Evoenergy.

[25] Note that the risk assessed by RIVA is similar to that of the top-down expenditure modelling; the main exception being that it doesn’t optimise across different asset classes.

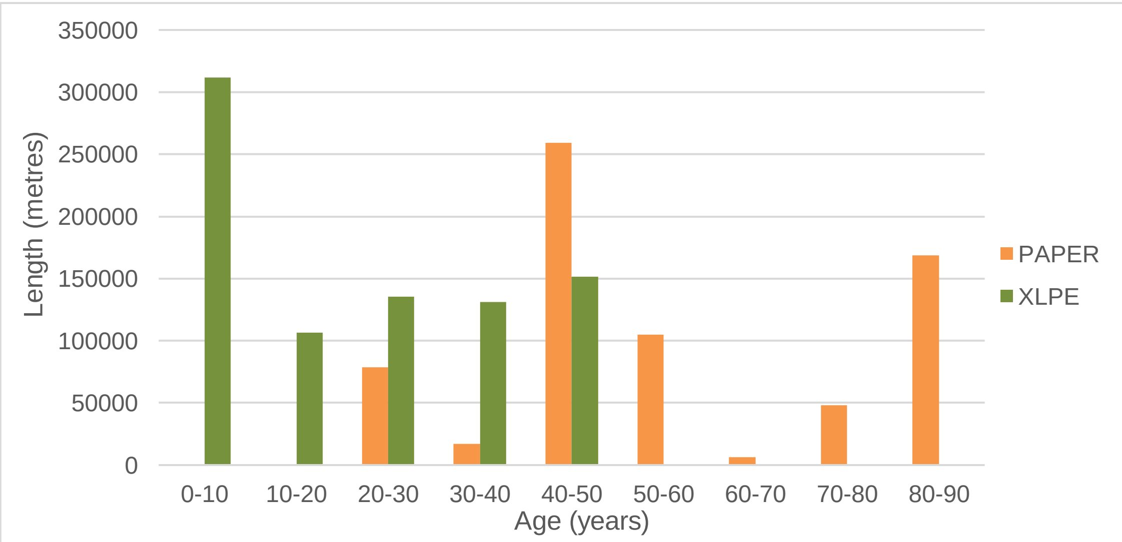
Figure 5.12 **Projected risk profile of distribution poles**



5.8.5 Underground cable replacement

Evoenergy has an aged and growing underground distribution network. There is approximately 1,475 km of HV underground cables in the Evoenergy network. Many cables are approaching the end of their design life. Figure 5.13 shows a significant proportion of XPLE cables are in the 40–50 age bracket (design life 45 years), and PAPER cables over 70 years (design life 70 years).

Figure 5.13 **Age distribution of 11 kV cable assets**



Until recently, Evoenergy has predominantly adopted a strategy of running the underground cables to failure. No asset health monitoring or systematic replacement programs were employed. Assets are replaced when they fail or are deemed as being too unreliable to continue in service.

However, with an ageing cable population and increasing number of asset failures, Evoenergy deems it necessary to address the rising risk exposure by changing to a CBM approach to managing underground cable assets. This approach is considered by industry to be the most efficient method of asset management in terms of asset life-cycle use. This strategy would see at-risk feeders (based on deteriorating reliability) being subject to engineering tests to determine actual health and risk, and replaced once certain thresholds are met. The main benefit with this strategy is that healthy feeders are left in service for longer, and at-risk feeders are replaced sooner, irrespective of their theoretical design service life.

Three other options have been considered.

- Reactive strategy—Operate assets until failure and restore by performing corrective maintenance (e.g. cable fault repair) or reactive replacement (e.g. termination replacement).
- Age-based replacement—On the assumption that all assets in the same class deteriorate at the same rate, replace all assets at the same age (i.e. at end of their design life).
- Keep existing strategy—Similar to reactive strategy but with limited condition monitoring and proactive replacement. Feeders are identified for condition assessment and replacement on an ad hoc basis considering recent poor performance (fault) history, generally when the feeder is deemed unsuitable to be left in service.

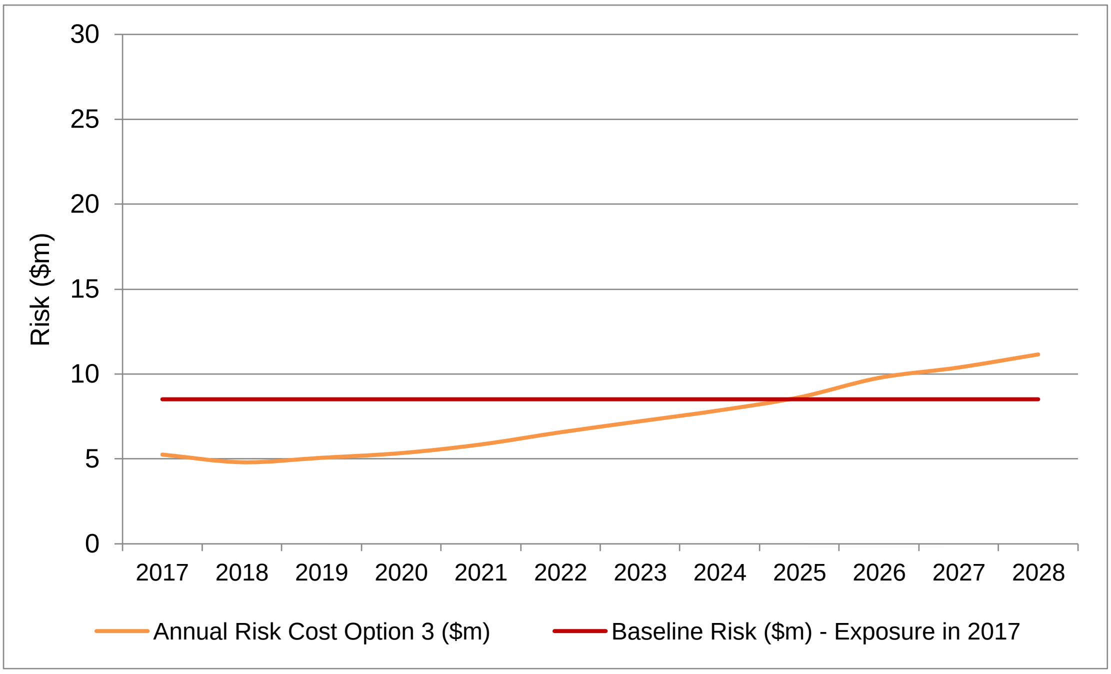
The advantage of CBM (over time-based monitoring or aged-based replacement) arises from the fact that the condition or performance of any two assets of the same make, model and chronological age, can differ significantly. Not all assets deteriorate at a standard uniform rate. CBM can prolong the in-service time of a healthy asset, and replace an asset at the optimum point in time before the occurrence of an in-service failure which may have far reaching adverse consequences and higher cost implications.

Key operational changes that need to be implemented as part of the CBM strategy are:

- proactive cable condition monitoring (as opposed to reactive condition assessment which includes:
  - Tier 1 tests – ongoing desktop analysis of feeder performance
  - Tier 2 tests – tan delta and/or online PD tests
  - Tier 3 tests – offline partial discharge tests
- HV cable termination condition monitoring (partial discharge testing as part of the existing substation inspection program).

Implementation of condition monitoring for pole replacements commenced in August 2017. Figure 5.14 shows that under the CBM strategy, there will be a higher risk exposure at the end of the 10-year forecast period as compared to current exposure levels in 2017. Evoenergy considers this an acceptable trade-off due to the considerably higher cost effectiveness of this option owing to the underground nature of this asset class reducing overall safety concerns. Appendix 5.15 contains Evoenergy's Asset Specific plan on underground cable repex.

Figure 5.14 **Risk profile of Evoenergy's underground cable assets**



5.8.6 Secondary systems replacement

Evoenergy's secondary systems are aging with many of the installed devices at end of life and having reliability issues. Replacement of these devices requires bringing older systems up to current standards and maintaining the network to Rules and ACT legislative requirements.

The impact of DER on network stability and security is becoming a major consideration in network operations and control. Dynamic energy flows from DER (PV), micro-generators, battery storage and electric vehicles require monitoring and control on a real-time basis. This results in additional needs for secondary system asset requirements in ensuring power quality and network security.

With the advent of newer technologies, such as numerical protection relays and other Intelligent electronic Devices (IEDs), there is an opportunity with secondary system replacement projects to enhance operational data collection. Improved monitoring is an important enabler for demand management and permitting better planning outcomes. These additional needs and opportunities are detailed in the secondary systems strategy, ASPs and project justification reports for asset replacement programs.

As with primary systems assets, forecast spending for secondary systems assets is founded on a risk-based approach. In particular, a significant number of zone substation protection and communications assets require replacement due to ageing and/or increased requirements that place greater criticality on the failure of a specific asset class.

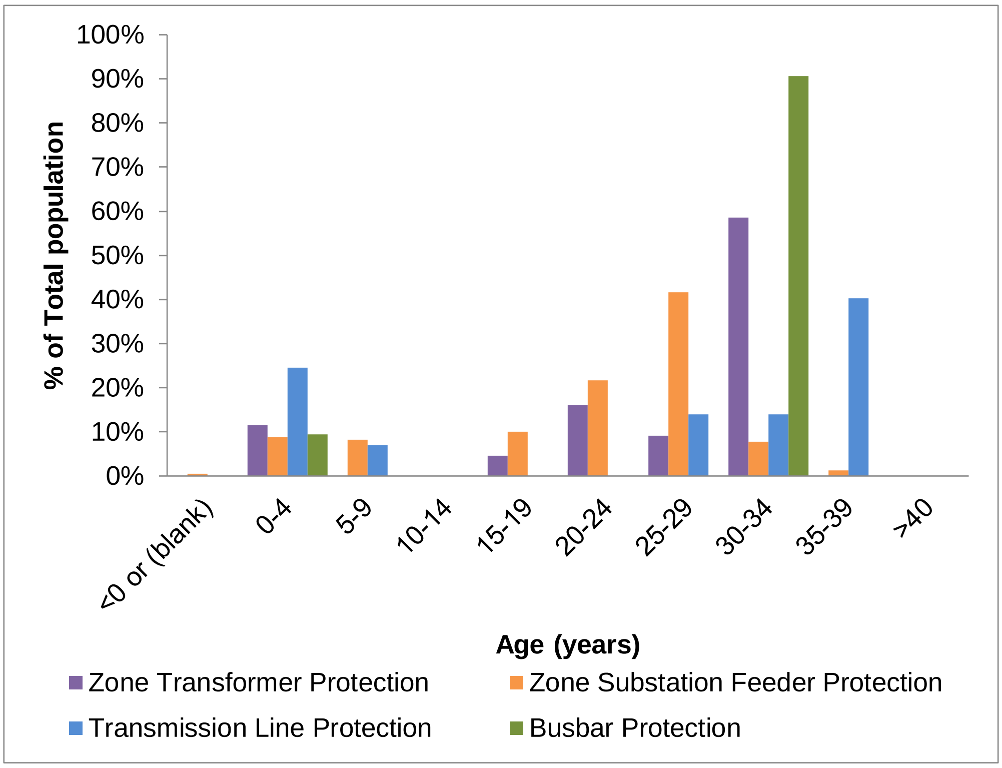
5.8.6.1 Protection systems

Evoenergy has identified the need to replace a significant number of protection relays due to defect occurrence, performance issues, obsolescence or functional deficiencies in a number of critical protection applications on both transmission and distribution networks. These relays are integral to the safe and secure performance of the network. During the current 2014–19 regulatory period, Evoenergy has undertaken planned relay replacement programs at Theodore Zone Substation, Gilmore Zone Substation and Bruce Substation. Over the next period, targeted programs are proposed for the replacement of 132 kV line protection relays and zone substation 11 kV overcurrent relays.

For the proposed 132 kV line protection replacement program, Evoenergy plans to implement line differential protection with backup distance protection elements in multifunction relays. This program follows the optical ground wire rollout implemented over the 2014–19 regulatory period and will use optical fibre as the protection communication medium. The line differential protection system will meet the requirements of Evoenergy's relatively short transmission lines and also bring Evoenergy 132 kV protection systems into compliance with current Rules standards for fault clearance time and protection system duplication. It is planned that ageing and defective protection relays will be replaced through replacement or augmentation programs over the regulatory period.

Figure 5.15 contains the asset age profile of zone substation assets and shows a large number of assets older than 25 years and beyond the expected life of 30 years. During the next regulatory period, protection assets reaching end-of-life condition with a high risk of failure have been included for replacement.

Figure 5.15 Age profile of zone substation protection assets (as of 2017)



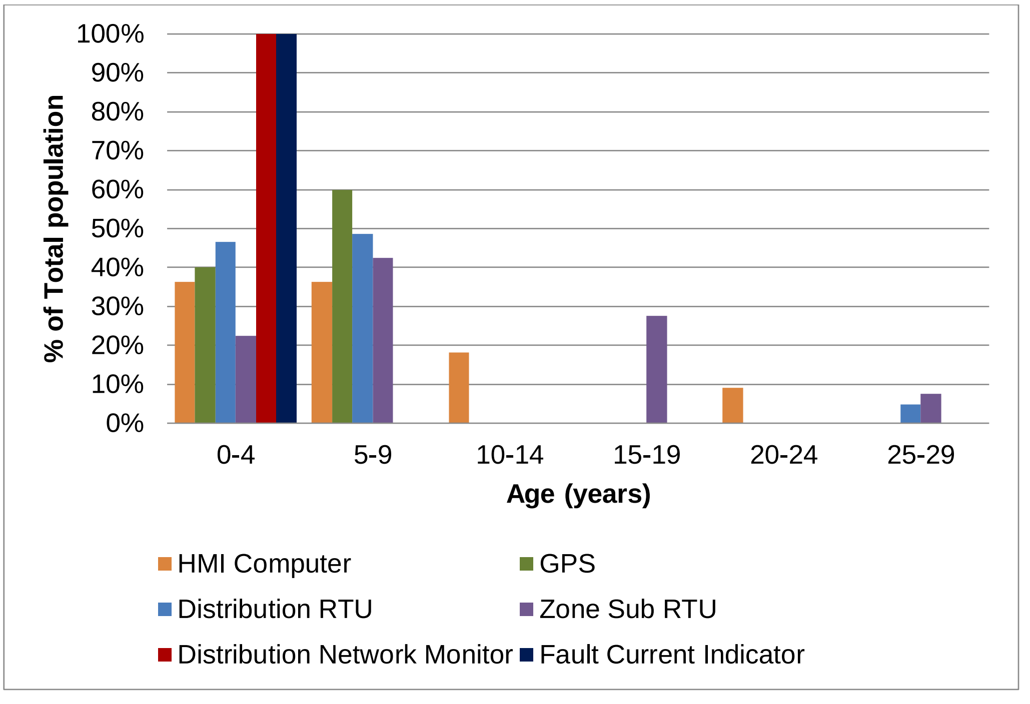
The program to implement this work is detailed in the Zone Substation Protection ASP (Appendix 5.11) and the Distribution Substation Protection ASP (Appendix 5.12).

5.8.6.2 SCADA

Evoenergy SCADA system implementations have transitioned to an integrated systems approach combining protection, monitoring and control functions in multifunction intelligent electronic devices (IEDs). Since 2010, Evoenergy has ensured that all devices installed, replaced or upgraded include SCADA control functions in numerical protection relays. This capability, combined with the installed ADMS and the new communications network, will give Evoenergy an integrated secondary systems environment that will yield significant benefits for the management of assets and control of the electricity network.

SCADA asset health is excellent for younger assets deployed over the current regulatory period and critical for older assets that are beyond expected service life. Figure 5.16 shows that a number of the remote terminal units (RTUs) and human machine interfaces (HMIs) are older than 15 years and are programmed to be replaced in the regulatory period.

Figure 5.16 Age profile of SCADA assets (as of 2017)



Evoenergy's current plans are that zone substations are brought up to 3rd generation integrated SCADA and protection standard with asset replacements. For replacements, this is proposed as numerical IEDs combining protection and control and an integrated HMI server within the RTUs. For replacing SCADA and communications equipment in existing zone substations, a case-by-case assessment will be made to determine if a refurbishment to full integrated SCADA and protection standard is strategically and/or economically justified. The program to implement this work is detailed in the SCADA ASP.

The mimic panels installed in the zone substations are in varying states of functionality due to age, end-of-life componentry and technological obsolescence. Some of the mimic panels have non-operational elements meaning that the panel is not presenting an accurate indication of the operational configuration of the substation. The missing indications present an issue when operators are on site, as they must verify the status and alarm state of the substation by other means, such as contacting the control centre or by site inspections. The existing mimic panels can be modified to work with IEDs, but this is an expensive and inefficient process. The IEDs come supplied with an integral HMI, which allows for most of the functions of the mimic panels to be covered, but is limited in functionality and expandability.

Evoenergy is proposing the installation of stand-alone HMIs which allow the full functionality of the IED to be used, with only one display screen, and the ability to add additional outputs by configuring additional display pages as required. This approach allows for the removal of old and redundant technologies from the substations while providing the most effective use of the IEDs.

Evoenergy's strategy is that as the previous generation RTUs and protection relays are replaced in the zone substations, the opportunity will be taken to replace mimic panels with HMIs at the same time. This will provide full functional integration with the SCADA/ADMS systems and allow for the decommissioning and removal of the substation mimic panels post project.

The program to implement this work is detailed in the SCADA ASP (Appendix 5.13).

5.8.6.3 Communications

The secondary systems communication strategy is developed around delivering a unified communications network to provide multiple services while maintaining cyber security and meeting individual service performance requirements.

Over the 2014–19 regulatory period, Evoenergy established a multi-service, multi-protocol label switching IP network to zone substations together with a rollout of optical ground wire to zone substations. For the 2019–24 regulatory period, SCADA radio system replacements are the key focus. These radio assets are beyond their expected asset life and their low bandwidth performance means they do not meet the operational requirements of current SCADA systems and the ADMS master station.

Evoenergy proposes a number of upgrades to enable effective network functionality, and replacement of some assets deemed in critical need of replacement owing to operational requirements and/or an ageing asset base. The program to implement this work is detailed in the Communications ASP (Appendix 5.14).

5.9 Reliability and quality improvements expenditure

An overview of reliability and quality improvements expenditure in the 2014–19 regulatory period is provided in Table 5.11.

Table 5.11 Historical reliability and quality improvements capex 2014–19

$ million (2018/19)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Zone substation	-	-	-	-	-	**-**
Secondary systems	-	-	-	-	0.6	**0.6**
Distribution	-	-	1.7	4.1	-	**6.0**
Total reliability and quality improvements	**0.0**	**0.2**	**1.7**	**4.2**	**0.6**	**6.6**
AER allowance	1.5	1.3	2.5	1.8	0.2	**7.3**
Variance	**(1.4)**	**(1.1)**	**(0.9)**	**2.3**	**0.4**	**(0.8)**

Expenditure on reliability and quality improvements during the 2014–19 regulatory period was minimal and related primarily to optical ground wires on the 132 kV transmission network.

Under the Rules, Evoenergy has the obligation to maintain and control the quality of supply through the distribution and transmission networks within its franchise area. With the increasing penetration of micro-generators such as PVs, and the introduction of fixed batteries and electric vehicle batteries to the network, there is an increasing need to extend network monitoring to lower levels of the distribution network (see section 5.2) to maintain existing levels of reliability.

The presence of PVs has already been shown to have adverse direct consumer impacts caused by excessive voltage rise, thermal overload of LV feeders, harmonic saturation, and load balancing issues on distribution feeders. To address this, monitoring will need to occur at lower levels within the electrical network than has previously been the practice within Evoenergy's network. Rapid detection, isolation and control of power quality incidents will be necessary to prevent localised damage to customer appliances or premises, to protect Evoenergy network assets from damage, and to ensure public and staff safety.

Evoenergy proposes that 100 distribution substations per year will have monitoring devices installed over the 2019–24 regulatory period. The result is that substation monitoring will be extended to 10 per cent of the substations by 2025. In addition, two other upgrades to the network that address voltage rise issues are:

- replacing smaller cross-sectional area LV circuit mains and/or service conductors to consumers; and
- reducing excessive lengths of LV circuit mains (those in excess of 400 m) by installing additional distribution transformers points and reconfiguring LV open points.

These solutions work by reducing the impedance at the customer point of connection, and have the advantage of providing additional benefits for the network in terms of safety and capacity improvements. The program to implement this work is detailed in the Communications ASP (Appendix 5.14).

The forecast costs of the LV monitoring program for the 2019–24 regulatory period are presented in Table 5.12.

Table 5.12 Forecast reliability and quality improvements capex 2019–24

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Zone substation	-	-	-	-	-	-
Secondary systems	1.2	1.2	1.2	1.2	1.2	6.2
Distribution	-	-	-	-	-	-
Total reliability and quality improvements	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**6.2**

5.10 Customer-initiated capex methodology and forecasts

Customer-initiated capital works is dominated by land releases for development by residential, commercial and industrial customers. It also provides for large spot loads that are known and considered definite, likely or potential loads depending on the timing of their development.

In essence, customer-initiated capital works are non-discretionary. Evoenergy is obligated to ensure that adequate budget exists to meet all customer requests in a timely and cost-effective manner.

5.10.1 Overview of customer-initiated capex in the 2014–19 regulatory period

An overview of the actual and estimated total customer-initiated capex during the 2014–19 regulatory period is set out in Table 5.13.

Table 5.13 Customer-initiated capex program 2014–19

$ million (2018/19)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Commercial and industrial developments	6.3	5.0	6.4	8.4	6.5	**32.6**
Community and associated developments	0.0	0.0	(0.0)	0.0	0.0	**0.1**
New urban development	7.4	6.7	4.7	4.6	4.4	**27.7**
Rural developments	0.1	0.1	0.0	0.2	0.1	**0.5**
Services	1.5	1.9	2.0	1.3	1.9	**8.5**
Special customer requests	1.0	0.5	0.2	0.3	0.6	**2.5**
Urban infill	3.1	4.6	2.7	3.3	2.4	**16.2**
Embedded generation	0.5	0.4	1.3	0.0	0.4	**2.6**
Total capex	**19.9**	**19.2**	**17.3**	**18.0**	**16.3**	**90.6**
AER Allowance	17.8	17.2	15.2	16.5	18.7	**85.4**
Variance	**2.0**	**2.0**	**2.1**	**1.5**	**(2.4)**	**5.2**

Total customer-initiated capex for the 2014–19 regulatory period was $90.6 million, or around 28 per cent of total capex for the period. This expenditure slightly exceeds the AER's decision in the current determination (by around $5 million) and was mainly driven by stronger than anticipated growth in urban development and a disproportionate increase in multi-unit developments due to the reduced availability of single dwelling blocks.

The variance between forecast and actual expenditure also reflects the difficulty associated with forecasting customer-initiated expenditure particularly in the out years of the regulatory period. Much of the customer-initiated capex incurred by Evoenergy during a regulatory control period is unforeseen and beyond the organisation's control.

5.10.2 Methodology for estimating customer-initiated capex

Customer-initiated capex relates to new housing and similar developments, where the customer (being the developer) contributes to the cost of the electricity infrastructure. As such, where the nature and timing of the project is reasonably well known, expenditure is typically forecast using a zero-based approach. For some customer-initiated capex categories, particularly in the outer years of the regulatory period, forecasts are based on historical expenditure levels.

In developing forecast customer-initiated capex, Evoenergy takes account of:

- direct customer or developer enquiries;
- major public and private development initiatives identified through public or media announcements;
- future development activity identified through ACT Government planning, preliminary assessment and agency consultation processes;
- future development activity identified through consultation with the ACT Government on land release programs;
- investigation and reconciliation of ACT Government land release programs;
- BIS Shrapnel economic forecasting data; and
- historical expenditure in the various customer-initiated work categories, adjusted to reflect the anticipated broader short-term economic environment.

5.10.3 Impact of known and probable projects

Evoenergy maintains a current database of known and probable new customer-initiated projects, with estimates of the electrical loading for each project. Evoenergy usually only becomes aware of customer-initiated projects of this sort within an 18–24 month timeframe before supply is required (sometimes shorter). Consequently, the 2019–24 customer-initiated capex forecast is a hybrid of ‘known and probable’ projects, combined with trend analysis.

The estimated electrical loading of the known and probable customer initiated projects is analysed on an individual zone substation basis, and where the spot loads are substantially above historical load growth, the zone substation forecasts are adjusted accordingly. Analyses of the probability weighted maximum (customer estimated) and minimum (Evoenergy estimated) estimates of additional electrical loadings by zone substation are shown in Table 5.14.

Table 5.14 Estimate of additional electrical loading by zone substation

Zone substation	2016/17 max demand in MVA		22023/24 forecast increase in MVA		% of min forecast increase	
East Lake	21	20	27	14	68	71
Gold Creek	58	65	31	23	40	36
Gilmore	31	30	11	10	33	35
Belconnen	57	56	22	16	28	29
Molonglo Valley	74	76	22	19	25	25
Civic	58	49	20	10	17	20
Latham	52	68	7	7	14	10
City East	77	66	14	10	13	15
Wanniassa	64	77	10	5	8	7
Telopea Park	84	83	10	5	6	7

Table 5.14 provides an indication of the high growth areas, the primary driver for which can be summarised as:

- East Lake—strong commercial load growth in Fyshwick area and more medium to high density residential growth around the Kingston area; and
- Gold Creek—greenfield land development is forecast to be growing rapidly in the Gungahlin area according to the ACT Government's land release program.

5.10.4 Land releases in the ACT

Land released for development within the ACT is controlled by the ACT Government which maintains a four-year indicative land release program. This program sets out the Government's intended program for residential, commercial, industrial and community land releases. The projected releases are indicative and subject to change as market conditions change or as government priorities are adjusted.

The objectives of the land release programs include:

- promoting the economic and social development of the Territory, including contributing to the vision set out in the Canberra Plan of a city representing the best in Australian creativity, community living and sustainable development;
- meeting the on-going strong demand for residential land in the Territory, particularly generated by increased levels of migration into the ACT;
- establishing an appropriate inventory of serviced land;
- maintaining flexibility of land releases to ensure they reflect market conditions and do not contribute to rapid land price changes;
- providing a mix of land and housing options;
- facilitating the provision of affordable housing;
- addressing the locational objectives set out in key Government documents such as the Territory Plan and the Spatial Plan;

- achieving satisfactory returns to the Territory from the sale of unleased Territory land; and
- assisting the operation of a competitive private sector land development market.

Once blocks of land are purchased, dwelling construction must commence within one year of purchase, and be completed within three years.[26] As a result, Evoenergy's customer-initiated expenditure is largely driven by the timing and extent of land sales in new areas of Canberra and can be difficult to forecast, particularly in the out years of the five-year regulatory period.

5.10.5 Overview of customer-initiated expenditure in the 2019–24 regulatory period

Customer-initiated capex (residential and commercial) is expected to be lower in the 2019–24 regulatory period, but will remain relatively stable, averaging around $17 million per year.

About 31 per cent of the total customer-initiated program will be recovered as capital contributions in accordance with Evoenergy's Connection Policy.

Table 5.15 sets out the customer-initiated capex forecasts for the 2019–24 regulatory period.

Table 5.15 Forecast customer-initiated capex programs (excluding capital contributions)

$ million (2017/18)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Commercial and industrial developments	6.6	7.1	7.0	7.3	6.8	**34.7**
Community and associated developments	0.0	0.0	0.0	0.0	0.0	**0.0**
New urban development	4.5	4.7	4.9	4.9	4.9	**23.8**
Rural developments	0.1	0.1	0.1	0.1	0.1	**0.5**
Services	1.6	1.7	1.9	1.9	1.9	**8.9**
Special customer requests	0.6	0.6	0.6	0.6	0.6	**2.8**
Urban infill	2.4	2.6	2.7	2.7	2.7	**13.0**
Embedded generation	0.4	0.4	0.4	0.4	0.4	**2.1**
Total capex	**16.2**	**17.2**	**17.5**	**17.8**	**17.3**	**85.9**

5.10.6 Forecasting customer-initiated capex

The methodology for forecasting each category in Table 5.15 is described in Evoenergy's customer-initiated works report which can be found at Appendix 5.5.

Expenditure forecasts for developer-related categories—commercial and industrial, new services, new urban development and urban infill development—are based on BIS Oxford Economics Building and Construction Industry indicators in its Building in Australia series (33rd edition—2013 to 2028) because Evoenergy's historical trends for

[26] *Building Act 2004* (ACT), s.36(1)(a).

these categories correlate closely with activity in the construction industry. The expenditure profile for most of these categories is predicted to trend downwards over the 2019–24 regulatory period primarily due to public sector budget cuts resulting in weaker population growth and underlying demand for construction in the ACT.

The remaining customer-initiated capex categories—community and associated development, relocations, customer initiated replacements, rural development and special customer requests—tend not to follow any particular market indicator. Consequently, Evoenergy forecasts a provisional amount for each category based on expenditure in previous years.

5.11 Network augmentation expenditure methodology and forecasts

Augmentation expenditure (augex) can be demand or non-demand driven. Demand driven augmentation is usually undertaken to meet growing demand in new and existing suburbs, address voltage issues caused by growing demand, or to meet planning criteria where growing demand results in one or more planning criteria no longer being valid.

Non-demand driven augmentation would be undertaken to address supply security, resolve power quality issues not directly linked to demand driven works, address environmental, safety and compliance issues or to enhance functionality of network assets (for example, improved SCADA, additional switching flexibility).

As described in section 5.2, Evoenergy notes that DER creates an opportunity to defer network augmentation by revisiting the feasibility of non-network alternatives. This constrains investment risk for Evoenergy and also minimises increases in prices to consumers. As a result, Evoenergy's approach to developing its augex program now incorporates and captures the costs and benefits of demand side and/or modular network solutions. This is described in more detail in sections below.

5.11.1 Overview of augex in the 2014–19 regulatory period

An overview of total network augex during the 2014–19 regulatory period is set out in Table 5.16. Key augmentation projects undertaken during the 2014–19 regulatory period include the following examples.

- The extension of three 11 kV feeders (Streeton, Hilder and Black Mountain) to provide the urgently required capacity for major developments in the Molonglo district. The feeder extensions will allow the continued servicing of the district via the Woden and Civic Zone Substations. Note that demand growth in the district is forecast to exceed the augmented feeder capacity by 2020–21.
- Doubling of feeders to circuit breakers at the Gold Creek 11 kV switchboard.
- Commencement of the Stage 2 of the Second Supply to the ACT project, which will also continue into the 2019–24 regulatory period. This involves the construction of a double circuit 132 kV transmission line from the new Stockdill Substation to connect in and out of Evoenergy's existing Canberra–Woden 132 kV line.
- A second 132/11 kV 30/55 MVA transformer and 11 kV switchboard at East Lake Zone Substation to be completed by 30 June 2019 at an estimated cost of $4.2m.

Table 5.16 Historical augex 2014–19

$ million (2018/19)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Zone substations	0.6	0.2	0.6	0.9	2.6	**4.9**
Secondary systems	1.5	3.0	2.8	3.6	0.5	**11.4**
Distribution system	0.9	0.4	0.7	5.0	3.6	**10.5**
Transmission	0.1	0.5	1.8	(0.5)	4.8	**6.7**
Total augmentation capital expenditure	**3.1**	**4.1**	**5.9**	**8.9**	**11.6**	**33.4**
AER Allowance	8.0	9.8	16.1	9.6	8.3	**51.7**
Variance	**(4.9)**	**(5.7)**	**(10.3)**	**(0.7)**	**3.3**	**(18.3)**

Evoenergy's augex in the 2014–19 regulatory period was approximately 35 per cent lower than the allowance set by the AER in 2015. The key driver for this underspend is the deferral of the permanent Molonglo Zone Substation, which is now subject to further deferrals given the interim solution of a mobile zone substation, uptake of batteries and PVs (see section 5.11.5). Other contributors to the underspend are as follows.

- A change in scope for the Second Point of Supply to the ACT project. The upgrade of Evoenergy's two 132 kV transmission lines between Theodore and Gilmore zone substations, as originally proposed, will now not be required. The required scope of works for Evoenergy is the construction of a double circuit 132 kV transmission line from the new Stockdill Substation to connect in and out of Evoenergy's existing Canberra–Woden 132 kV line, and to install 11 kV reactive support devices at various zone substations in the northern network to maintain voltage levels within regulatory limits. Further detail in provided in Appendix 5.25.
- The deferral of the Gold Creek zone substation 11 kV switchboard extension and the third transformer for Belconnen zone substation due to load growth being less than forecast in the last determination. With regard to Gold Creek, Evoenergy's actual expenditure in the current regulatory period reflects the interim solution of doubling up two feeder cables to each of four 11 kV circuit breakers.

5.11.2 Methodology for estimating augex

When forecasting augex, factors that Evoenergy considers are:

- system load requirements with particular reference to 'hot spots', system capacity issues and other points of potential vulnerability;
- load forecasts;
- the scope for non-network alternatives to be employed;
- forecasts of land development;
- the assessed condition of critical assets and asset failure rates;
- risks and priorities;
- compliance with requirements of the Rules;
- compliance with requirements of the Technical Regulator and technical standards;
- achievement of service standards; and

- health, safety and environmental issues.

As detailed in sections 0 and 5.5, Evoenergy's proposed augex is based on a combined top-down and bottom-up approach. Importantly, the emergence of DER highlights the value of Evoenergy's risk-based approach and its effectiveness at identifying opportunities for incorporating non-network solutions to provide the most cost-effective outcome and adequately addressing the factors listed above.

In particular, Evoenergy employs the AURA model to quantify the relative value of non-network and network augmentation options. Appendix 5.3 describes the AURA model in more detail.

Key drivers of augex in the 2019–24 regulatory period, and the projects that Evoenergy intends to undertake to address them are set out below.

5.11.3 Overview of forecast augex for the 2019–24 regulatory period

Evoenergy's forecast augex for the 2019–24 regulatory period is set out in Table 5.17.

Table 5.17 Forecast augex programs 2019–24

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Zone substations	0.7	-	6.3	-	-	**7.0**
Transmission	1.2	1.2	1.2	1.4	1.1	**6.0**
Distribution system	7.8	12.6	3.0	4.2	4.7	**32.4**
Secondary systems	1.4	-	0.4	-	-	**1.8**
Total augex	**11.1**	**13.8**	**10.9**	**5.7**	**5.8**	**47.2**

Evoenergy's proposed augex reflects a prudent approach where important augmentation expenditure that was identified for the 2014–19 regulatory period will continue to be deferred. This ensures that investment risk is carefully managed and that the lowest cost outcomes for the consumer ensue.

Major augmentation projects expected to be undertaken during the 2019–24 regulatory period include:

- construction of zone substation[27] in the Molonglo district for the provision of power to the new suburbs of Whitlam, Denman Prospect, Coombs, Wright and North Weston;
- the construction of a double circuit 132 kV transmission line from the new Stockdill Substation to connect in and out of Evoenergy's existing Canberra–Woden 132 kV line, and to install 11 kV capacitor banks at four zone substations, known as Second Supply to the ACT Project—Stage 2. This is a network security project aimed at meeting the requirements of the *Electricity Transmission Supply Code 2016* and will increase security of supply to the ACT.

5.11.4 Zone substation constraints and proposed developments

Evoenergy has twelve 132/11 kV zone substations (including Tennent), one mobile 132/11 kV substation, one 66/11 kV zone substation, and two 132 kV switching stations. Due to the dual function categorisation of assets, all 132/11 kV zone substations are

[27] Construction of the Molonglo Zone Substation was originally planned for the 2014–19 period but was deferred due to deferred urban development in the area.

classified as transmission assets, except Fyshwick (66/11 kV), Telopea Park (132/11 kV) and the mobile substation (132/11 kV) which are classified as distribution assets.

The 10-year zone substation 50 per cent probability of exceedance load forecast (see Attachment 3), combined with analysis of system limitations on the 11 kV distribution system, indicates that some zone substation augmentation or a non-network solution will be required to meet increased demand within the 2019–24 regulatory period.

Evoenergy has identified cost-effective solutions to address the existing and emerging constraints at zone substations, and on the related distribution feeder systems. These include consideration of non-network and network sharing measures, such as potential demand management solutions, equipment upgrades, load transfers between zone substations, and network expansion.

The result of these efforts are substantial reductions of network augmentation in the West Belconnen, and Molonglo areas (see sections 5.11.4.1 and 5.11.5). In the case of Molonglo, they have resulted in much lower augmentation expenditure due to replacing a permanent zone substation with a mobile zone substation (see section 5.11.5).

5.11.4.1 Deferral of Strathnairn Zone Substation and capex/opex trade-off

The maximum demand in the West Belconnen area is forecast to increase steadily to 45 MVA over the next 30 years as load grows in the new and developing suburbs of Strathnairn and Macnamara. The development is expected to accommodate a population of approximately 30,000 within an estimated 11,500 dwellings plus shopping centres, schools and community facilities. In particular, maximum demand in the Strathnairn suburb is forecast to increase to at least 14.7 MVA by 2026.

Evoenergy notes that the existing 11 kV feeder network for the area has insufficient capacity to meet the forecast load beyond 2019. Bottom-up forecasts suggest a need for a new zone substation during the 2019–24 regulatory period. However, analysis conducted with Evonergy’s top-down methodology indicates that a suite of non-network measures, such as increasing rates of rooftop PV penetration and battery energy storage, coupled with demand-side management and a single feeder extension, could defer augmentation until 2025-26.

Using the AURA model methodology (described in section 5.5.2), the option that included significant non-network measures produced a higher Net Present cost (NPC) compared with any of the conventional options that Evoenergy has investigated. Appendix 6.2 provides a detailed overview of the methodology used to value the non-network measures, the options considered and how the final recommendation was developed. The recommended option represents a significant trade-off of deferred capex (zone substation) in favour of opex (demand management measures), that results in lower costs to consumers. Evoenergy proposes a step change to account for the demand management measures, as discussed in Attachment 6.

The recommended option includes the installation of a single new feeder, which is an extension of the existing O’Loghlen feeder from Latham Zone Substation. The program to implement this work is detailed in the Supply to Strathnairn PJR (Appendix 5.24).

5.11.5 Molonglo Zone Substation

The Molonglo Valley district is situated in Canberra’s west, approximately 10 km from the Canberra central business district (CBD). It is expected that over the next 20 years, land releases in the Molonglo Valley district will result in the new suburbs of North Weston, Coombs, Wright, Denman Prospect and Whitlam with a total population of 55, 000. The

ACT Government's Suburban Land Agency has published an indicative land release program that indicates development will proceed at approximately 1,000 dwellings per annum.

Land servicing has already commenced in the initial land release areas, and maximum demand in the Molonglo Valley is forecast to grow steadily to approximately 50 MVA over the next 20 years. Existing 11 kV feeders to the area have insufficient capacity to meet the forecast load beyond winter 2021. To address the looming shortage, Evoenergy expects that DER such as PVs and batteries will play an increasingly important role in the Molonglo area, providing opportunities to forego considerable augex. Rooftop solar PV generation is installed on approximately 10 per cent of all dwellings in Coombs, Wright and North Weston suburbs to date, whereas battery storage penetration to date is minimal (< 0.5 per cent).

Evoenergy proposes a cost-effective approach by installing a mobile substation (rated 132/11 kV 14 MVA)as the initail stage of Molonglo Zone Substation by June 2022. When demand exceeds the power capacity of the mobile substation, a permanent 132/11 kV 30/55 MVA transformer and 11 kV switchboard will be installed, with space provided for a future two additional transformers and two additional 11 kV switchboards. This represents a flexible, cost-effective approach that minimises the investment risk of stranded assets and ensures that consumers only pay for the capacity they need.

A 132 kV supply to Molonglo will be provided by a loop-in-loop-out connection to the proposed Woden–Stockdill 132 kV transmission line. The new zone substation site will be established and developed, complete with all earthworks, earthing, fencing, and 132 kV structure and bus bar, to enable the mobile substation to be connected and commissioned and be able to operate continuously until the permanent zone substation infrastructure is constructed and commissioned. Upon the construction of the permanent infrastructure, 11 kV feeders will be installed under separate projects to serve the residential areas as they develop. The program to implement this work is detailed in the Molonglo Zone Substation and Molonglo Valley 11 kV feeders Project Justification Reports (PJRs) (Appendixes 5.23 and 5.24).

5.11.6 Supply to Belconnen and Mitchell

Evoenergy proposes a number of feeder projects as a cost-effective measure to increase the use of existing zone substations. These will address significant shortfalls driven by a number of new developments in the Belconnen and Mitchell areas.

5.11.6.1 Belconnen

Evoenergy forecasts a shortfall of approximately 9.5 MVA to 2022 in the Belconnen area. Major contributors to this shortfall are major developments at Calvary and Canberra University hospitals, and a large high-rise residential complex in the Belconnen Town Centre. Land release forecasts by the SLA for Lawson are used as the basis for the demand of the new estate, assuming similar usage rates to those observed in the Molonglo Valley.

The best option identified is the staged installation of three new underground 11 kV cable feeders to the Belconnen area from the Belconnen Zone Substation to meet the shortfall, with a feeder installed every year from 2020/21 to 2022/23. Each new feeder would provide up to 5.5 MVA firm capacity (summer). The program to implement this work is detailed in the Supply to Belconnen PJR (Appendix 5.35).

5.11.6.2 Mitchell

The existing 11 kV feeders that currently supply the Mitchell area are heavily loaded and have no spare firm capacity during summer. Evoenergy forecasts a shortfall of approximately 14.9 MVA capacity by summer 2022 onwards with the development of a number of new light industrial and commercial customers, including data centres. The Hamer feeder which was installed in December 2017 will enable some load to be transferred off the Antony Rolfe feeder, but there is little capacity in other feeder ties to enable sufficient load transfers from other feeders.

Evoenergy proposes three new 11 kV cable feeders to be installed from Gold Creek Zone Substation to the Mitchell area. Spare conduits will be installed along the feeder route to provide for future developments and load growth. The program to implement this work is detailed in the Supply to Mitchell PJR (Appendix 5.34).

5.11.7 Decommission Fyshwick Zone Substation and supply to Fyshwick

The Fyshwick Zone Substation was constructed and commissioned in 1982. It was originally deemed to be a ‘temporary’ substation. It is supplied from TransGrid’s Queanbeyan 132/66 kV Substation via two single-circuit wooden pole 66 kV transmission lines.

Primary assets supplying and located at Fyshwick Zone Substation are approaching the end of their economic lives, as are the secondary assets on the site. The two 66 kV transmission lines from Queanbeyan to Fyshwick (3.6 km) are in poor condition. These lines were constructed in 1959 with wooden poles, most of which have been nailed and will require replacement within the next 5–10 years. The 66 kV circuit breakers, conductors, and relays at Fyshwick are also nearing the end of their economic lives within the next 5–10 years.

Evoenergy proposes that instead of replacing these assets, the Fyshwick Zone Substation be decommissioned. It is considered that this trade-off in replacement expenditure in favour of using spare capacity in augex reflects the least cost option. Fyshwick Zone Substation will be converted to an 11 kV switching station, after installing some high-capacity express 11 kV feeders (i.e. feeders with no intermediate loads) from East Lake to Fyshwick.

One of the original drivers for the establishment of the East Lake Zone Substation in 2013 was to transfer the Fyshwick load to East Lake to enable the Fyshwick Zone Substation to be retired and the 66 kV assets decommissioned.

Cables proposed are 11 kV 3c/400mm^2 Cu XLPE and these would replace the existing transformer incomer cables at the three Fyshwick 11 kV switchgear groups. These express cables would be rated at approximately 10.5 MVA each continuous, providing 31.5 MVA maximum capacity to Fyshwick and 21 MVA firm capacity. Other feeders would be run from East Lake to the Fyshwick and Majura areas (under separate projects), to reduce the maximum demand on the Fyshwick 11 kV switchboard to less than 21 MVA. The program to implement this work is detailed in the Decommission Fyshwick Zone Substation PJR (Appendix 5.21).

5.11.8 HV distribution feeder augmentation and inter-zone tie capacity

There is also a number of large HV feeder projects scheduled to be undertaken over the 2019–24 regulatory period. Some of these projects will be required to cater for local area load growth, while others are designed to strengthen inter-zone ties and to rebalance and optimise zone substation loading into the future. These include but are not limited to supply to:

- Whitlam (Appendix 5.26);
- Canberra City and Dickson (Appendix 5.27);
- Kingston (Appendix 5.28);
- Griffith (Appendix 5.29);
- Tuggeranong Town Centre (Appendix 5.30);
- Canberra CBD West (Appendix 5.31);
- Pialligo (Appendix 5.32); and,
- Gungahlin Town Centre (Appendix 5.33);

5.11.9 Transmission augmentation capital expenditure

Major augmentation projects being undertaken on Evoenergy's transmission network include the completion of the Second Supply to the ACT Project and the installation of transmission connection point metering.

5.11.9.1 Second Supply to the ACT

In 2006, the ACT Government introduced the Electricity Transmission Regulation 2006, the objective of which was to increase security of electricity supply in the ACT by introducing a second point of supply.

The commissioning of TransGrid's Williamsdale 330/132 kV Substation in February 2013 introduced a second 132 kV bulk supply point into the ACT to address power system security requirements by providing two geographically independent 330 kV points of connection to the ACT network. Williamsdale substation is linked to Evoenergy's network at Theodore and Gilmore 132 kV zone substations.

Table 5.18 outlines key requirements from the latest version of the ACT Electricity Transmission Supply Code (July 2016) and how Evoenergy's proposed program addresses them.

Table 5.18 ACT Electricity Transmission Supply Code (July 2016) requirements

Supply Code Requirement	Evoenergy Response
The provision of two or more geographically separate connection points operated at 132 kV and above to supply electricity to the ACT 132 kV network	Met already by Canberra and Williamsdale 330/132 kV bulk supply point substations.
At all times provide continuous electricity supply at maximum demand to the ACT 132 kV and 66 kV network throughout and following a single credible contingency event	Met already by Canberra and Williamsdale 330/132 kV.

Supply Code Requirement	Evoenergy Response
Until 31 December 2020, provide electricity supply at 30 MVA to the ACT 132 kV or 66 kV network within one hour following a single special contingency event and 375 MVA within 48 hours of this event	Will be met by supplying 30 MVA via Queanbeyan 132/66 kV (to Fyshwick 66/11 kV Zone Substation) in the event of a special contingency event affecting Canberra Substation (and consequently affecting Williamsdale Substation also as Williamsdale is connected radially at 330 kV from Canberra). The 375 MVA criteria within 48 hours requirement would be met by constructing a temporary 330 kV connection between the Upper Tumut–Canberra line and the Canberra–Williamsdale line, thus bypassing Canberra Substation.
From 31 December 2020, provide continuous electricity supply at 375 MVA to the ACT 132 kV network immediately following a single special contingency event and agreed maximum demand within 48 hours of this event	Evoenergy will construct a new double circuit 132 kV line section from Stockdill to connect to the Canberra–Woden 132 kV line to form a Canberra–Stockdill–Woden line. This will provide the immediate 375 MVA back-up capability to the ACT. Construction of the double circuit 132 kV line section from Stockdill Substation to the Canberra–Woden line will be carried out in coordination with the construction of TransGrid's 330/132 kV Stockdill Substation with proposed completion by December 2020. TransGrid proposes to construct a 330/132 kV Substation at Stockdill Drive, West Belconnen. This will have one 375 MVA transformer. The Upper Tumut–Canberra and Canberra–Williamsdale 330 kV lines will be reconnected to Stockdill Substation. A new 330 kV line section will be constructed from Stockdill to Canberra.

An independent power system analysis was carried out by GHD to verify that the proposed development is a cost effective solution that will meet all requirements of the Electricity Transmission Supply Code for the foreseeable future. The analysis confirmed that if a special contingency event affecting the whole of Canberra Substation, that voltage levels in the northern part of Evoenergy's network would fall below regulatory levels and that reactive support equipment would be required to mitigate this (Appendix 5.26).

In order for voltage levels to be maintained, Evoenergy has investigated the installation of reactive support equipment at Canberra's northern zone substations. Evoenergy considers that the most cost effective solution is the installation of five 11 kV 10 MVA capacitor banks at each of the following zone substations:

- Latham;
- Gold Creek;
- Belconnen;
- Strathnairn (proposed); and
- Molonglo (proposed).

For the interim period until completion of this project, a contingency plan has been developed by TransGrid to address the event of a loss of Canberra Bulk Supply Substation. The plan is that within one hour of a failure at Canberra Substation, TransGrid proposes to reconnect Queanbeyan 132 kV from Yass Substation (via Spring Flat Switching Station) and within 48 hours to construct a temporary connection from the Yass 330 kV line to the Canberra–Latham 132 kV line and reconnect to Yass 132 kV bus. This would provide full load capacity to the ACT. Power systems analysis shows that under this development the originally proposed Theodore–Gilmore 132 kV line upgrade will not be required.

The program to implement this work is detailed in the Second Supply to the ACT PJR (Appendix 5.25).

5.11.10 Secondary Systems augex

5.11.10.1 Distribution substation monitoring

With the increasing penetration of micro-generators such as PVs, and the introduction of fixed batteries and electric vehicle batteries to the supply grid, there will be an increasing need to extend network monitoring to lower levels of the distribution network. The presence of disruptive technologies has already been shown to have direct impacts such as excessive voltage rise, thermal overload of LV feeders, harmonic saturation, and load balancing issues on distribution feeders. Evoenergy is embarking on a program of installing monitors and IEDs in distribution substations to supply information on network performance at the lowest levels. Rapid detection, isolation and control of these incidents will be necessary to prevent localised damage to customer appliances or premises, and to protect Evoenergy network assets from damage.

Under the Rules, Evoenergy has the obligation to maintain and control the quality of supply through the distribution and transmission networks under its control. Currently the principal control of these parameters, such as voltage and reactive power, occurs at zone substation level. Increasingly Evoenergy will have to be able to compensate for localised deviations in the quality of supply within its distribution network. The roll-out of IEDs to selected distribution substations will allow Evoenergy to fulfil its obligations with regard to quality of supply.

5.11.10.2 Cybersecurity program

The occurrence of recent cyber-attacks on critical infrastructure has demonstrated that cyber security is critical to the operation and safety of the electricity network. Evoenergy’s implementation of IP-based networks requires it to maintain currency of security measures deployed to mitigate against penetration or crippling of the network. In implementing the IP-based network, segregated virtual networks have been used, minimising the potential impact if any of the virtual networks are compromised. Under this design, protection functions, SCADA functions, physical security functions and the corporate network are on different virtual networks.

Evoenergy’s approach is to set up a defence-in-depth cyber security regime to ensure the integrity of the network protection and ADMS/SCADA networks. This is to provide the highest level of protection against targeted attacks as well as against phishing or other malware attacks.

Further details of the cyber security program can be found in the Secondary Systems Strategy.

5.12 Non-network capex

Non-network capex relates to network AIS, facilities, non-system assets, finance lease arrangements and corporate services business support. Investments in ICT assets typically comprises the largest proportion of Evoenergy's non-network costs. This expenditure has been undertaken in accordance with Evoenergy's long term strategic planning, which has identified three horizons in transforming Evoenergy's technological capabilities and outcomes – Stabilise, Drive and Thrive. The main outcomes are to successfully transition the business in line with industry changes (section 5.2) and realise operating efficiencies achieved during the current regulatory period.

The role of ICT expenditure and the outcomes sought from these three horizons is summarised in Table 5.19.

Table 5.19 Mapping of technology initiatives to strategic outcomes

	Stabilise	Drive	Thrive
	End to end governance, management and visibility of processes for Standard Control Services.	Enhance contacts and experience of existing and new customer (complete customer lifecycle) and community engagement.	Enhance delivery of network services, including standard control and alternative control services.
Business Strategy	• Improve governance and management of processes to ensure that full end to end processes are visible to all stakeholders. • Unlock the benefits of existing data and ICT systems that have been installed. • Improved access to timely, customised and correct information by field workers and management. • Improved management of assets including predictive fault detection and 24/7 management and response.	• Customer and Community Engagement to enhance network services and responsiveness to customers expectations • Using new sources of customer data (smart meters, aggregators) to adjust pricing, better utilise assets, dynamically manage localised peak demand, inform demand forecasting, network capacity planning and opportunities	• B2B and B2C customer contacts and lifecycle management for network and standard control services • Improvement in logistics, supply chain and works management to accommodate works on assets maintenance and development.

	Efficiency Initiatives	Improve Customer Engagement	Enhance delivery of network services
ICT Requirements	**Efficiency Initiatives** • Increased automation, including automated decision making enabling 24/7 responses and improved response times • Increased use of predictive analytics for fault detection and prevention • Streamlining of field worker processes and procedures including mobile, real time access to reduce error rates and improve safety	**Improve Customer Engagement** • Integrate smart metering data and demand aggregators into other real time data streams • Expose services in the OT platform externally **Improved use of information to drive decision making** • Increased use of integrated information from multiple sources across the business. • Leverage time of day and location geo-spatially-based intelligence	**Enhance delivery of network services** • Identification and contact data of network services consumers • Information for specific onsite installation requirements
ICT Direction	• Reduced cost to serve • Enable efficient field operations via mobile solutions and analytics • Harmonised operational and back office processes across the business • Removal of work around tasks and manual processes by process automation and integration	• Improved systems integration and information management • Information availability across applications and lines of business. • Analytics and decision support capability	• Improved information accessibility and systems flexibility and agility

5.12.1 Overview of non-network capex 2014–19

Table 5.20 shows total expected non-network capex for the 2014–19 regulatory period.

Table 5.20 Historical non-network capex 2014–19

$ million (2018/19)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Network AIS systems	16.8	12.2	6.6	11.5	3.7	**50.8**
Facilities	1.8	1.2	2.0	2.0	7.2	**14.2**
Non-system assets	0.3	0.5	0.5	0.7	0.5	**2.6**
Finance lease assets	5.9	0.7	1.3	1.0	3.7	**12.6**
Corporate services business support	1.7	1.5	1.7	2.2	2.5	**9.6**
Total non-network capex	**26.5**	**16.1**	**12.1**	**17.4**	**17.6**	**89.8**
AER Allowance	25.8	11.6	8.9	6.6	10.1	**63.0**
Variance	**0.7**	**4.6**	**3.2**	**10.8**	**7.5**	**26.7**

Evoenergy's total non-network capex of $89.8 million was significantly higher (42 per cent) than the AER allowance ($63 million) due to two major transformation programs undertaken during the latter half of the 2014–19 regulatory period.

- The delivery of additional ICT projects above what was included in the regulatory submission. This was to accommodate a number of industry and regulatory changes not anticipated since the AER's 2015 final determination, and to be a substantial driver of operating efficiencies achieved during the current regulatory period. Further details are contained in section 5.12.3 and Appendix 5.9.
- Spending on facilities for 2017/18 and 2018/19 reflect major refurbishment and relocations works at operational centres. This includes refurbishments made in the Greenway centre (Building 1 ground floor and the entire South Building), and relocation of the control room from Fyshwick to Greenway.

This reflects a shift in business priorities towards increasing Evoenergy's customer centricity, and capabilities with regard to enabling a greater penetration of DERs, while maintaining power quality. This is important as Evoenergy's customers become more informed, and as building a relationship in the face of new initiatives including demand management, is becoming more important. The completion of various AIS projects (e.g. the implementation of the LV network in ADMS, ADMS mobility and the integration between Cityworks and the ADMS), places Evoenergy among industry leaders in terms of visibility, control and management of the network to the edge of the grid. This ultimately provides improved consumer outcomes in customer service while maintaining power reliability and quality despite ongoing industry disruption.

5.12.2 Forecast non-network capex 2019–24

Evoenergy's forecast non-network capex for the next regulatory period is set out in Table 5.21.

Table 5.21 **Forecast non-network capex program 2019–24**

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Network AIS systems	2.2	2.3	14.5	12.7	3.0	**34.6**
Facilities	3.1	0.5	0.4	0.2	0.2	**4.4**
Non-system assets	0.5	0.5	0.5	0.5	0.5	**2.6**
Finance lease assets	2.7	2.6	2.5	1.7	2.3	**11.9**
Corporate services business support	0.3	1.8	2.1	0.6	0.1	**4.8**
Total non-network capex	**8.9**	**7.7**	**19.9**	**15.7**	**6.1**	**58.3**

Non-network capex is forecast to be $58 million for the 2019–24 regulatory period, or $38 million less than in the 2014–19 regulatory period. This reflects a transition from a period of technological investment growth and innovation, into a period of agile innovation and realisation of benefits to support the continual and rapid changes expected to occur in the electricity distribution industry.

In particular, reductions in forecast AIS expenditure reflects a period of maturity, with a focus on incremental maintenance activities and security initiatives, with strategic upgrades occurring where critical changes are required. The AIS forecast has been developed utilising a risk-based approach to ensure the activities are prudent to operations. This approach, coupled with the completion of the Power of Choice regulatory changes, has enabled the AIS forecast to be reduced from the 2014–19 regulatory period.

The reduction in forecast facilities expenditure reflects the fact that the bulk of major refurbishment works (see section 0) will be completed in the 2014–19 period.

The stability of the finance lease forecasts reflects the fact that fleet replacement programs have been rationalised based on obtaining the maximum resale value for each vehicle. Subsequently a large number of finance leases have been extended resulting in a flattening of spend year-on-year in the forecast. An Integrated Vehicle Management System was implemented by Evoenergy during 2017. Based on the data collected via this system and future utilisation patterns, Evoenergy will continue to rationalise its fleet to ensure operational efficiency across the fleet.

5.12.3 Network Asset Information Systems

Network AIS (formerly Network IT) are those information technology systems that are directly related to the operation and support of the network business.

DER and advancements in digital technologies are changing consumer expectations and relationships in the utility sector. Traditionally, electricity retailers have managed the relationship with consumers. However, this is likely to change as customers see more benefits arising from interactions with distributors, for example participating in demand response initiatives.[28] Evoenergy's intention is to educate its consumer base on the opportunities created for them through the sector's disruption. This will facilitate the creation of partnerships with consumers to maximise the value of the grid to the ACT

[28] PWC Global Power & Utilities, Customer engagement in an era of energy transformation, p. 7. Source: https://www.pwc.nl/nl/assets/documents/pwc-customer-engagement-in-an-era-of-energy-transformation.pdf.

community. Data will also need to be visualised in new consumer-centric ways instead of the historic asset-centric structure used today.[29]

As discussed in section 5.2, Evoenergy anticipates a consumer-centric future which requires Evoenergy to drive the changes necessary to meet and exceed changes in consumer expectations. This will be achieved through providing technology that allows for strong customer engagement, cost-effective network and asset management and enabling customers to be informed and involved in managing their consumption, generation and storage.

The future implications for Evoenergy's AIS is that they will move towards a single, completely integrated geospatial solution that is supported by enterprise integration. The functional areas of asset management, works management, real time network operations, and billing management will continue to be changed to meet the expected disruption and resulting needs of consumers.

Evoenergy's use and procurement of in-support AIS applications is governed by the following principles:

- geospatial focus;
- commercial off the shelf and minimal customisation/development;
- consolidated, effective and integrated systems;
- appropriate infrastructure;
- mobility;
- enhanced communications; and
- data enablement.

These principles assist in the creation of value for both the business and consumers while minimising costs.

During the 2014–19 regulatory period, Evoenergy expects to complete most of the projects that were proposed and accepted in the AER 2015 final determination along with further projects not included in the determination, with the few remaining projects determined as low priority or no longer required. A selection of the projects that are to be completed are described below.

- Implementation of Schneider-Electric ArcFM Designer. Designer has enabled the generation of construction drawings and cost estimates using the network represented in the GIS as the underlay.
- Implementation of Evoenergy's LV Network into the ADMS system as well as integration with the HV Network Model and SCADA system. This has provided control room visibility of the entire Evoenergy electrical network to the 'edge of the grid', which supports faster fault responses, improves delivery of service to consumers as well as ensuring the safety of Evoenergy staff and the public.
- ADMS integration with Gentrack Velocity which has enabled mapping customer outage calls to network supply points as well as providing lists for notifications of customers affected by planned outages.

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[29] Ibid.

- Implementation of Cityworks mobility which has enabled field crews to execute works and asset management activities in the field leading to increased timeliness, availability and accuracy of data.
- Implementation of the customer portal which has enabled customers to view geographical outage information, report damaged assets, provide customer feedback and view consumption data.

During the current regulatory period, Evoenergy has also considered that a major transformation to its ICT systems was required to effectively respond to rapid industry changes since the 2015 determination, which included:

- increased penetration of DER requiring application upgrades to enable advanced network planning operation and intelligence systems, such as customising Velocity to track PV asset information;
- increased regulatory compliance costs, in particular Power of Choice regulatory changes; and
- rapidly expanding requirements in the electricity market requiring increased automation and improvements to provision of information (e.g. enabling an ADMS mobile solution for electrical operators, and allowing customers to fill in electronic request for service and request for service marking forms and providing retailers with a National Meter Identifier Tool tool).

To address these industry changes, the period focused on transitioning from legacy systems, integrating and automating workflow processes, enhancing the capability and capacity of the applications, and expanding to other asset classes. Importantly, the 2015 AER Final Decision had imposed a considerable reduction in Evoenergy's opex allowance for the 2014-19 regulatory period, which necessitated a rapid transformation of the business to realise operating efficiencies.

As a result, a number of initiatives were delivered, above what was included in the 2014–2019 regulatory proposal. Evoenergy's ICT proposal (Appendix 5.9) contains more details on these initiatives. A selection of the projects undertaken during the period above and beyond the regulatory proposal are described below.

- The implementation of Power of Choice changes. The regulatory changes required changes to Velocity and to Cityworks to meet the 1st December Production cut-over.
- The upgrade of the GIS. The GIS upgrade was required to ensure the application is in-support, a key AIS principle. The upgrade enabled a move to cloud infrastructure at the same time, which will reduce infrastructure costs for the application.
- Implementation of PV in Velocity. This enables the capturing of PV asset data in Velocity for later use in ADMS and ArcFM to enable more accurate load flow modelling. This also improves the accuracy of the PV inspection notification process.
- Implementation of ADMS Mobility. This enables electrical operators access to switching information and real-time data on the state of the network, enabling improved safety processes.
- Implementation of the Feeder Identification Tool which enables the automation of identification of edited feeders so that they can be updated in the ADMS, minimising the risk of edited feeders not being identified. This is a risk mitigation project, which assists in driving down breaches associated with customers not being notified of planned outages. This is an ongoing goal for Evoenergy to meet the expectations of its customers.

5.12.3.1 Forecast AIS expenditure in 2019–24

Evoenergy uses a zero-based approach to forecasting AIS capex. In planning the expenditure program for the 2019–24 regulatory period, the following processes were undertaken:

- review of business requirements;
- assessment of requirements arising from industry trends and changes;
- assessment of requirements arising from a more informed and engaged end consumer;
- review of the assessed condition of existing systems;
- review of system currency requirements, vendor roadmaps and recommendations;
- risk management review and prioritisation;
- consideration of efficiency improvements;
- consideration of cost-saving initiatives;
- integration with corporate strategies;
- compliance with corporate and networks technical standards; and
- assessment of health, safety and environmental factors.

Evoenergy intends to spend $35 million on the enhancement of AIS during the 2019–24 regulatory period. The project costs by system are set out in Table 5.22.

Table 5.22 Forecast AIS expenditure in the 2019–24 regulatory period

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
GIS/ArcFM	0.1	0.1	0.1	0.8	0.1	**1.3**
ADMS	0.3	0.3	9.3	0.3	1.6	**11.8**
Cityworks	0.8	1.2	0.8	1.2	0.8	**5.0**
Velocity	0.8	0.4	4.0	10.2	0.2	**15.7**
Power of Choice	-	-	-	-	-	**-**
Minor IT	-	-	-	-	-	**-**
RIVA	0.1	0.1	0.1	0.1	0.1	**0.4**
Outsystems	0.1	0.1	0.1	0.1	0.1	**0.5**
Productivity Review	-	-	-	-	-	**-**
AIS Wide	-	-	-	-	-	**-**
Total	**2.2**	**2.3**	**14.5**	**12.7**	**3.0**	**34.6**

Forecast AIS expenditure for 2019–24 reflects a significant decline from actual expenditure during the 2014–19 regulatory period. It represents a change in focus on incremental maintenance activities and security initiatives, with strategic upgrades occurring where critical changes are required. This is a result of the following:

- it is expected that AIS applications have reached a period of stabilisation and maturity;

- cessation of one-off compliance costs relating to the Power of Choice regulatory changes during the 2014–19 period; and
- undertaking of a top-down review has also identified some savings from the conventional bottom-up approach to estimating forecast expenditure.

Evoenergy's forecast AIS expenditure focuses on the minimum activities required to ensure security, system stability and vendor support. Expenditure during the period is primarily on two key projects which include a major upgrade to the ADMS, and an overhaul of the meter data and billing systems. These projects are discussed in more detail below and in Evoenergy's ICT Proposal (Appendix 5.9).

5.12.3.2 ADMS Upgrade

The ADMS integrates the High Voltage and Low Voltage Network Primary Control Systems and was implemented by Evoenergy in 2016. One major upgrade has been included in this regulatory period to ensure the system is kept up to date and security can be maintained. The enhanced functionality will underpin the future of electricity distribution and be able to react with agility to market disruption. With its footprint in both the US and European markets, Schneider is expected to build on the foundation implemented in the 2014–19 regulatory period and provide agile responses to the changing energy environment. Schneider's open, interoperable, Internet of Things (IoT) enabled system architecture and platform leverages advancements in IoT, mobility, sensing, cloud, analytics and cybersecurity.

5.12.3.3 Meter Data and Billing

The saturation of interval meters in the ACT is currently very low. As more interval meters are implemented as a result of the Power of Choice regulatory changes, Evoenergy will experience exponential data growth. Evoenergy will need a meter data management and billing solution that is able to effectively manage this volume of data.

The objective of this project is to implement a fit-for-purpose solution that can handle the additional data load anticipated.

5.12.4 Corporate services business support

The 2019–24 capex program includes an estimate of $3.5 million for corporate services business support, which forms part of Evoenergy's ICT transformation program. This comprises the following initiatives:

- business intelligence;
- a centralised digital content management system (IT platforms); and
- hardware and software refresh.

The rise of digital technologies has also presented opportunities from the vast increase in consumer and operational information. To harness this, Evoenergy requires business capabilities that can transform raw data into meaningful and useful information. Business intelligence and a centralised digital management system can be used to help identify, develop, and manage new opportunities for further optimising business efficiency and other value creation. Such opportunities include generating new insights into customer behaviour at a granular level, undertake predictive analytics and produce recommendations on the asset management, and driving efficiencies through automation. With the growth of large and more holistic business applications, business intelligence solutions have come to the fore as an effective management tool.

Work is also proposed on a number of IT platform initiatives to automate business processes, mobile dispatch and scheduling, improved methods of expenditure forecasting and customer analytics, and implementation of an integrated security solutions to ensure IT security requirements are met. The proposed ICT security platform ensures that security is maintained in line with the Australian Signals Directorate cyber security maturity level and Evoenergy's industry peers.

In addition, Evoenergy plans to undertake hardware and software refreshes as several core systems and corresponding hardware reach the end of their useful life and vendor support ceases or becomes prohibitively expensive. Evoenergy will apply prudent expenditure management consideration in extending the capabilities through asset extensions.

More information about the initiatives is contained in sections 7.8 to 7.10 of Appendix 5.9.

5.12.4.1 Methodology for estimating corporate services business support capex

Forecasts for corporate services business support are determined by the following process:

- review of the business requirements;
- assessment of data requirements for operational, regulatory and financial purposes;
- review of data security;
- review of the assessed condition of existing buildings and IT systems;
- assessment of the timing of obsolescence;
- risk management review and prioritisation;
- consideration of the need to be able to respond to business needs and external regulatory compliance requirements;
- integration with corporate strategies;
- compliance with corporate and Networks technical standards;
- assessment of health, safety and environmental factors; and
- the capex for corporate services has been escalated using CPI.

Corporate services capex is allocated in accordance with Evoenergy's cost allocation method.[30] Under this approach, wherever possible, corporate costs are allocated directly to the business unit (e.g. Evoenergy, ActewAGL Retail) that consumed the corporate service or asset. For example, refurbishment/security upgrade at Greenway depot is directly allocated to Evoenergy. Consistent with the AER's cost allocation guidelines,

[30] Evoenergy's cost allocation method (CAM) is described in "ActewAGL Distribution Cost Allocation Methodology, November 2012" which was approved by AER under NER clause 6.5.4 (c) in June 2013. The document will be updated before 1 July 2018 to reflect the requirements of the AER's Ring-fencing Guideline published in October 2017 and explicitly account for gas distribution networks, gas facilities and organisational changes arising from the creation of separate legal entities. Evoenergy's methodology of allocating costs for the electricity distribution business is not expected to change.

where corporate costs cannot be directly allocated using causal drivers, Evoenergy uses a non-causal allocator derived from opex and full-time equivalents for each division.

5.13 Capex—Standard Control Transmission Services

The AER in its Framework and Approach Stage 1 stated that it would apply transmission pricing rules to Evoenergy's dual function assets in the subsequent period. Dual function assets are the parts of a distributor's network that operate in a way that supports the transportation of electricity over the higher voltage transmission network. Specifically, the Rules deem as a dual function asset:[31]

> *Any part of a network owned, operated or controlled by a Distribution Network Service Provider which operates between 66 kV and 220 kV and which operates in parallel, and provides support, to the higher voltage transmission network.*

The Rules allow distributors to address dual function assets in a distribution determination to avoid the need for separate transmission revenue proposals. In making its decision on Evoenergy's revenue requirement for the 2019–24 period, the AER will determine separate average revenue caps to apply (with different X-factors) for the transmission and distribution portions of revenue for Standard Control Services.

Consequently, the allocation of capex to transmission standard control services has been netted from total capex to yield capex for distribution Standard Control Services.

Capex allocated to Evoenergy's transmission assets in the 2019–24 regulatory period are set out in Table 5.23. Evoenergy's forecast transmission capex mainly relates to the Second Supply to ACT Project—Stage 2, as discussed in section 5.11.9.1.

Table 5.23 Capex allocated to Evoenergy's transmission assets 2019–24

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Sub-transmission overhead	2.0	0.3	0.7	0.2	0.3	**3.5**
Sub-transmission underground	-	-	-	-	-	**-**
Zone substation	1.0	0.7	6.7	0.5	3.6	**12.4**
Asset information systems	1.7	1.7	4.5	4.1	1.8	**13.8**
Non-network capex	1.3	1.0	1.0	0.6	0.6	**4.5**
Total transmission capex	**6.0**	**3.6**	**12.9**	**5.4**	**6.3**	**34.2**

[31] Rules clause 6.24.2(a).

5.14 Capital Contributions

Under chapter 5A of the Rules and in accordance with the AER's *Connection charge guidelines for retail electricity customers,* (the AER guidelines), an electricity distributor may require a reasonable capital contribution towards the cost of an extension or augmentation of the electricity network necessary for providing a connection service to a customer. Charges may also apply for relocations (not related to connections), in accordance with *the Electricity Networks Capital Contributions Code (ACT)* (the Code).

Evoenergy's customer initiated capital works plan provides the basis for determining when *Capital Contributions* are likely to apply. Section 5.10 and Appendix 5.5 outlines Evoenergy's customer initiated capital works and methodologies used to forecast customer initiated capex.

Capital contributions for the 2014-19 regulatory period are shown in Table 5.24 below.

Table 5.24 Historical capital contributions 2014-19

$ million (2018/19)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Total capital contributions	7.7	8.6	9.5	7.7	6.2	**39.6**
AER Allowance	6.6	6.7	5.9	6.6	7.6	**33.4**
Variance	1.1	1.9	3.5	1.0	(1.4)	**6.2**

Capital contributions were marginally higher than the AER allowance in the 2014-19 regulatory period due to an increase in customer initiated capex over the allowance in the same period.

Forecast capital contributions are typically based on the historical levels of capital contributions for each category of customer initiated capex. Evoenergy has forecast the level of capital contributions for the 2019-24 regulatory period as per Table 5.25.

Table 5.25 Forecast capital contributions 2019-24

$ million (2018/19)	*2019/20*	*2020/21*	*2021/22*	*2022/23*	*2023/24*	*Total*
Total capital contributions	6.5	6.9	6.9	7.1	6.8	**34.2**

5.15 Capex deliverability and capability

Evoenergy has a high degree of confidence in its ability to deliver the capital spend forecast in its regulatory submission. This confidence is based on:

- its proven ability to deliver against the capital budget for the 2014–19 regulatory period;
- the amount of the forecast capex for 2019–24 period is very similar; and
- Evoenergy is following a process of continual improvement in the governance and process framework of its capital delivery and is confident that this improvement will continue to deliver further value for money.

These factors are discussed in more detail below.

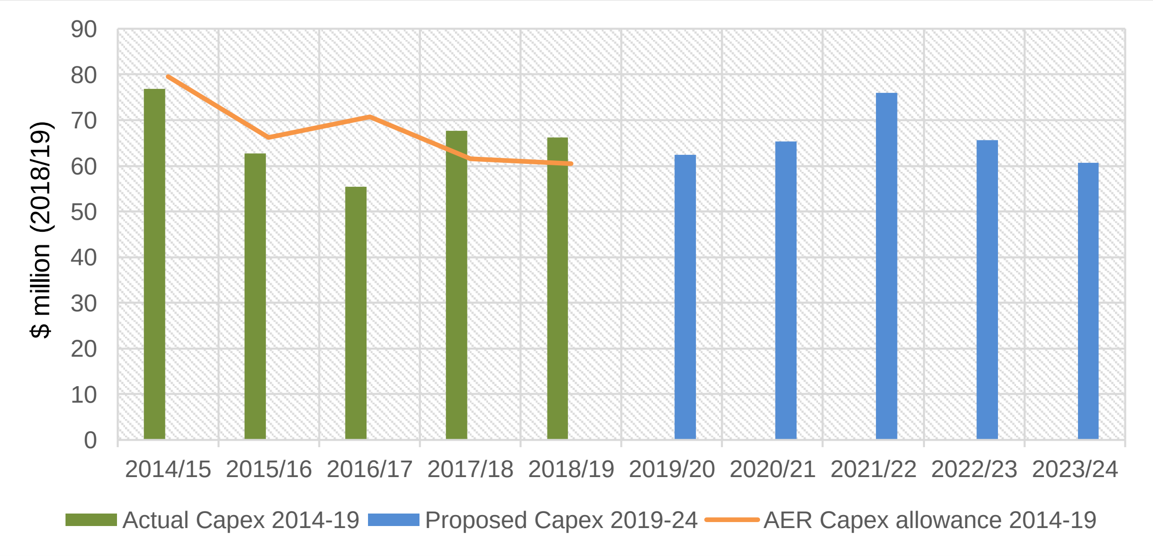
5.15.1 Capital delivery capacity and capability

Evoenergy's capex for the next regulatory period is anticipated to around the same as for the 2014–19 period. A comparison of the two periods is provided in Figure 5.17.

Figure 5.17 indicates Evoenergy's capacity to deliver the capital program to the extent of the AER approved capex. The 2021/22 year forecast expenditure is similar in magnitude to the highest forecast year of the previous period, 2014/15, indicating that no material changes will be required to Evoenergy's workforce capacity.

Evoenergy has taken a continuous improvement approach to the delivery of its capital program and has introduced a number of frameworks and approaches that have increased the efficiency of its delivery processes. This provides Evoenergy with a high degree of confidence in its ability to meet the proposed forecast capex. The improvements to capital delivery made by Evoenergy are referred to throughout the following sections.

Figure 5.17 Net capex 2014–24 $ million (2018/19)



5.15.2 Governance arrangements and delivery

Evoenergy has been, and continues to refine its capital investment governance arrangements (see Attachment 1). Effective capital investment governance is important from a regulatory perspective. A robust investment decision-making framework indicates that an organisation is actively managing its investment in programs and projects. It means that the organisation is constantly striving to achieve value for money which addresses the two main regulatory goals of prudence and efficiency.

The quantum of capital works in the next regulatory period is similar to that in the last period. As in the last period, Evoenergy will use a mix of in-house and contract-based resources for delivery. This approach maximises workforce flexibility. For large projects such as zone substations, Evoenergy has the option of outsourcing arrangements which leverages the skills of experienced personnel from larger electricity markets with the flexibility to incur such costs only when needed.

Evoenergy has established a project delivery life-cycle for major projects. The life-cycle provides a clearly defined pipeline for projects and ensures clarity of responsibility throughout the delivery process by identifying which parts of the organisation are responsible for which aspects of the life-cycle. This approach is supported by the PRINCE2 project management methodology. This methodology places great importance on the continued justification of a project with a focus on value for money, thereby supporting the prudency and efficiency of investments.

5.16 Summary of forecast capex

In summary, Evoenergy's proposed capex reflects a new approach to asset management, and continues key capex reform programs that were initiated during the 2014–19 period to ensure the ongoing reliability of the network and to meet increasingly complex needs in the volatile electricity market. This is reflected in a shift towards non-network expenditure, together with declines in repex and augex.

Table 5.26 summarises the total proposed capex program for 2019–24, including capital contributions.

Table 5.26 Forecast capex including capital contributions 2019–24

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Augmentation	11.1	13.8	10.9	5.7	5.8	**47.2**
Connections	16.2	17.2	17.5	17.8	17.3	**85.9**
Replacement	17.3	17.7	16.4	17.1	23.1	**91.6**
Reliability and quality improvements	1.2	1.2	1.2	1.2	1.2	**6.2**
Non-network	8.9	7.7	19.9	15.7	6.1	**58.3**
Capitalised overheads	14.3	14.8	17.1	15.3	14.2	**75.6**
Less capital contributions	(6.5)	(6.9)	(6.9)	(7.1)	(6.8)	**(34.2)**
Less disposal	(0.2)	(0.3)	(0.2)	(0.2)	(0.3)	**(1.1)**
Net capex	**62.4**	**65.3**	**75.9**	**65.6**	**60.6**	**329.8**

Shortened forms

Term	Meaning
ACT	Australian Capital Territory
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AIS	Asset Information Systems
Al	aluminium
ASPs	asset-specific plans
augex	augmentation expenditure
AURA	Augex Uncertainty Risk Appraisal
capex	capital expenditure
CBD	central business district
CBM	condition-based monitoring
CSIRO	Commonwealth Scientific and Industrial Research Organisation
Cu	copper
DER	distributed energy resources
DNSP	Distribution Network Service Provider
DSO	distribution system operator
DSS	decision support system
ENA	Energy Networks Australia
ENTR	Electricity Network Transformation Roadmap
HMIs	human–machine interfaces
HV	high voltage
ICT	information and communications technology
IEDs	intelligent electronic devices
IoT	Internet of Things
IP	intellectual property
kV	kilovolt
LV	low voltage
MPFP	multilateral partial factor productivity
MTFP	multilateral total factor productivity
MVA	megavolt-ampere
NPC	Net Present Cost
NPV	net present value
NSW	New South Wales

Term	Meaning
opex	operating expenditure
PJR	Project Justification Report
PV	photovoltaic
R&D	research and development
repex	replacement and renewal expenditure
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
RTUs	remote terminal units
Rules	National Electricity Rules
SCADA	supervisory control and data acquisition
WMS	works management system