Consideration of Risk for Evoenergy Regulatory Proposal 2019 -2024

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1 Overview of Risk at Evoenergy

Evoenergy's provision of distribution network services inherently involves risk.

These risks 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

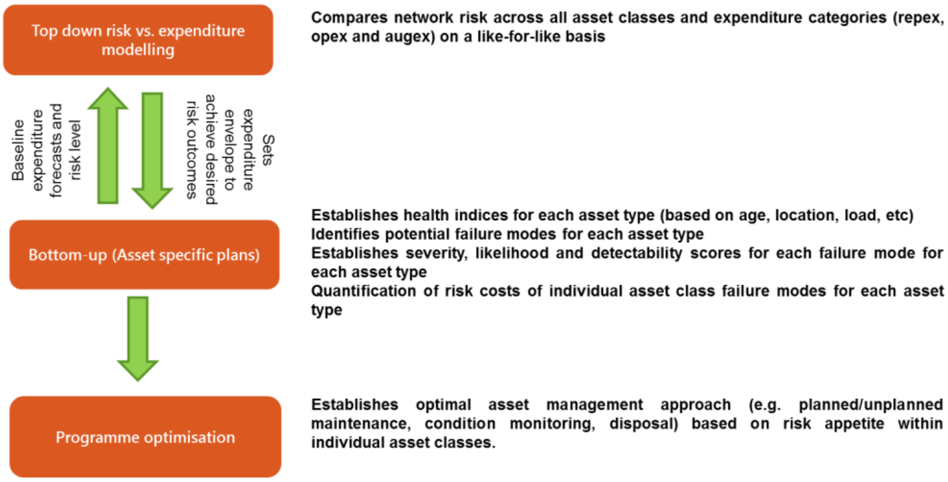
Evoenergy seeks to minimise risks via the following activities:

- Programmatic replacement of ageing, defective, failed and otherwise high risk assets
- Monitoring of assets to detect and/or predict defects and failure
- Inspection of assets to detect ageing, defective, failed and otherwise high risk assets
- Routine and non-routine maintenance to rectify ageing, defective, failed and otherwise high risk assets
- Provision of sufficient capacity (including redundancy) to meet demand and demand growth
- Training and management systems (underpinning the above)

Evoenergy sets expenditure across these activities to achieve a level of quantified residual risk that is acceptable to its customers and the community as well as to meet relevant regulatory and license based 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 reduced beyond acceptable levels) does not leave customers exposed to unnecessarily high prices.

Evoenergy achieves this via a top-down and bottom up approach to risk assessment as shown in Figure 1 below.

Figure 1 – Top down and bottom up approaches to risk assessment



The bottom up approach requires asset managers, via asset specific plans to identify 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, whereby the same risk outcome is targeted by multiple activities.

To mitigate potential over-expenditure due to the bottom up expenditure forecast, Evoenergy applies a top-down approach to risk management. The top-down approach considers how expenditure can be optimised across asset categories and expenditure categories to achieve the desired level of risk at least cost.

Evoenergy considers the results of both the top-down and bottom up expenditure forecasts and determines a final expenditure envelope. The final expenditure envelope reflects the expenditure envelopes set via the top-down approach tempered by the technical and practical realities of individual asset needs as determined via the bottom-up approach.

2 Regulatory Requirements

2.1 Regulatory Proposal Requirements

While there is no requirement for the regulatory proposal to contain a stand-alone risk chapter, Evoenergy recognises that there is a need to assess the extent to which its expenditure across the regulatory period influences the network risk.

This is in part due to the shift towards more customer centric processes, allowing customers to understand trade-offs between network prices and risk and in part due to AER's concerns, expressed in its draft determination for Evoenergy's previous 2014 to 2019 determination, that:

> *"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 ActewAGL applies poor risk management tools and is overly risk averse."*[1]

This chapters therefore seeks to address AER's previous concerns by providing a risk based justification of Evoenergy's proposed expenditure forecasts.

[1] Australian Energy Regulator, Draft decision, ActewAGL distribution determination 2015–16 to 2018–19: Overview, November 2014

2.2 National Electricity Law Revenue and Pricing Principles

Chapter 7A of the National Electricity Law provides the revenue and pricing principles which the AER must take into account in its determination. The two key principles in relation to risk include that:

- Regard should be had to the **economic costs and risks** of the potential for under and over investment by a regulated network service provider
- Regard should be had to the **economic costs and risks** of the potential for under and over utilisation of a distribution system or transmission system

Accordingly, Evoenergy seeks to identify the economic costs and risks associated with its proposed expenditure within its regulatory proposal.

2.3 National Electricity Rules Expenditure Objectives and Criteria

The NER provides further guidance in terms of setting acceptable risk and expenditure trade-offs via the capital and operating expenditure objectives and criteria for standard control services. These capital and operating expenditure objectives, specified in clause 6.5.6(a) and 6.5.7(a) of the NER describe the outcomes or outputs to be achieved by the expenditure. The objectives include:

1) Meet or manage the expected demand for standard control services
2) Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services
3) 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:
    a. Maintain the quality, reliability and security of supply of standard control services
    b. Maintain the reliability and security of the distribution system through the supply of standard control services
4) Maintain the safety of the distribution system through the supply of standard control services.

The objectives therefore set out a requirement for Evoenergy to set its expenditure at levels which reduce risk in order to meet regulatory or legislative requirements, or where these requirements do not exist, sufficient to maintain the existing risk profile[2].

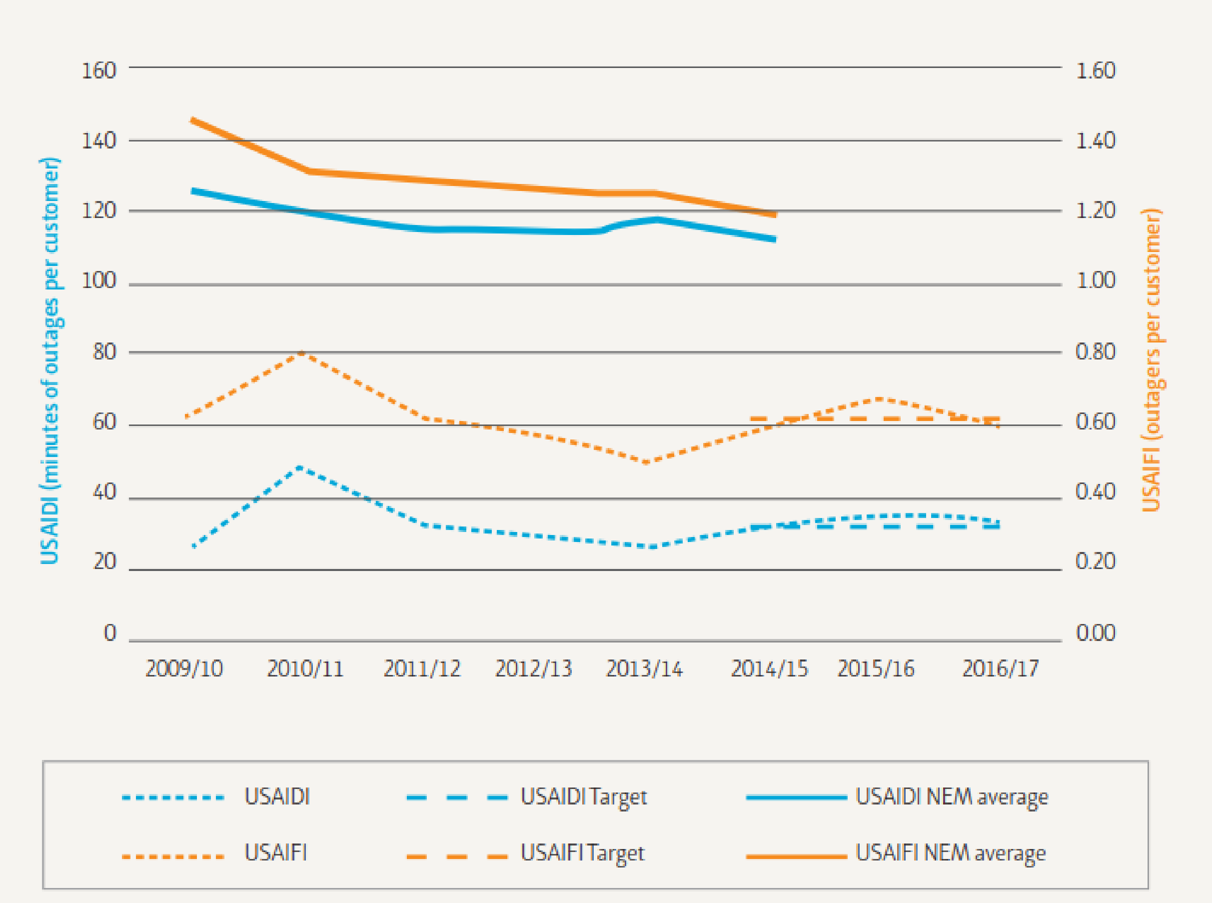
Evoenergy is subject to a comprehensive set of jurisdictional regulatory requirements with respect to reliability, power quality, security of supply and safety risks. The *Electrical Safety Act, Electrical Safety Regulation, Work Health and Safety Act Work Health and Safety Regulation* set out Evoenergy's regulatory obligations in relation to electrical safety and work place safety. The *Electricity Distribution Supply Standards Code* established under Part 5 of the *Utilities Act* sets out Evoenergy's regulatory obligation in relation to quality and reliability including minimum targets for unplanned minutes off supply (USAIDI), unplanned outages (USAIFI) and voltage dips.

In addition, the AER sets reliability targets for Evoenergy under its service target performance incentive scheme (STPIS). The STPIS targets for USAIDI and USAIFI are set at the beginning of each regulatory control period based on historical performance. Penalties are applied where reliability performance does not meet the targets and incentives applied where reliability performance is better than the target. For the current regulatory control period, the STPIS targets are much more stringent than the jurisdictional requirements.

[2] The capex and opex objectives were amended by the AEMC as part of its 2013 Rule change on NSP expenditure objectives. In making its decision, the AEMC set out how it considered the amended objectives should be interpreted by DNSPs when developing their regulatory proposal including that, in the absence of standards being set by the jurisdiction, the objective will be to maintain previous performance.

As shown below, Evoenergy's USAIDI in 2015/16 and 2016/17 has increased over the most recent years to be slightly more than the AER's established target. USAIFI also increased to slightly exceed the AER's target, before improving to slightly better than the target.

Figure 2 – Evoenergy's reliability compared to Regulator's target and NEM average



Aligned with the capital and operating expenditure objectives, Evoenergy sets its expenditure levels to ensure compliance with the above regulatory requirements and maintain its existing risk profile.

The expenditure criteria, set out in Clause 6.5.6(c) and Clause 6.5.7(c) of the NER, further outline requirements for the way in which expenditure must be set to achieve the objectives above. These include:

1) The efficient costs of achieving the operating expenditure objectives;

2) The costs that a prudent operator would require to achieve the operating expenditure objectives; and

3) A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The above criteria therefore imply that the acceptable risk profile, determined in line with the expenditure objectives, must be met via prudent and efficient expenditure. Therefore, the acceptable risk profile is to be achieved at least cost.

2.4 Electricity Network Transformation Roadmap

In April 2017, the Electricity Networks Association, in partnership with CSIRO, released its Energy Network Transformation Roadmap. The Roadmap provides detailed milestones and actions to guide an efficient and timely transformation over the 2017-27 decade. An integrated set of 'no regrets' actions are identified to enable balanced, long term outcomes for customers and position Australia's networks for resilience in uncertain and divergent futures. Importantly, the Roadmap identified two key milestones with implications for the way in which NSPs consider risk within the regulatory process.

Electricity Network Transformation Roadmap Key Milestones

Milestone 1: By 2018, the customers' role is central to regulatory processes covering core regulated services for agreeing network outputs and risk allocation. This milestone is aimed at reaching reformed regulatory determination processes which are based around the needs of current and future consumers, and which provide for a clear and agreed allocation of risks between consumers, networks, and other participants. These customer centric processes should aim to deliver those outputs most valued by consumers.

Milestone 2: By 2018, structured trialling of alternative regulatory approaches is well advanced, including customer settlement approaches, as well as TOTEX trials. TOTEX is adopted as default approach by 2027.

Milestone 1 allows the customer an increased role in determining the level of acceptable risk exposure. While milestone 1 envisages a more customer centric process in the near term, ultimately this approach leads to a *customer settlement* regulatory approach whereby the customer (or customer advocate) negotiates with the NSP to determine the acceptable risk allocation and associated network expenditure.

Milestone 2 requires trials of the customer settlement approaches in the next regulatory periods. Milestone 2 further requires trialling a TOTEX regulatory approach whereby expenditure is set across all categories and the NSP is then able to optimise between opex, repex and capex. This approach necessarily requires consideration of the most prudent and efficient way to manage risk.

Milestone 2 specifically calls out the need for trialling of such customer settlement approaches (whereby the independent regulator's role is drastically reduced) by 2018.

Evoenergy, as a key stakeholder in the development and implementation of the Roadmap, is committed to work towards these milestones. To transition towards these customer centric approaches, Evoenergy must firstly quantify risk versus expenditure across the network enabling a deeper understanding of the trade-offs and decision making with respect to risk allocation.

3 Consideration of Risk

3.1 Enterprise Risk Framework

Evoenergy adopts a business wide framework for the effective management of risk and compliance both within and outside of the regulatory proposal process. The framework and underpinning processes guide the conduct of all Evoenergy activities and the management of all Evoenergy assets to provide for:

- The safe and reliable utility services to Evoenergy's customers and the community
- Design, operation, maintenance and retail of electricity and gas utilities/services without harm to its workers or the community
- Minimal environmental impact of its operations

The framework considers seven different risk types:

1. Health/safety incident
2. Damage to the environment
3. Damage to reputation or competitive position
4. Legal/compliance breach

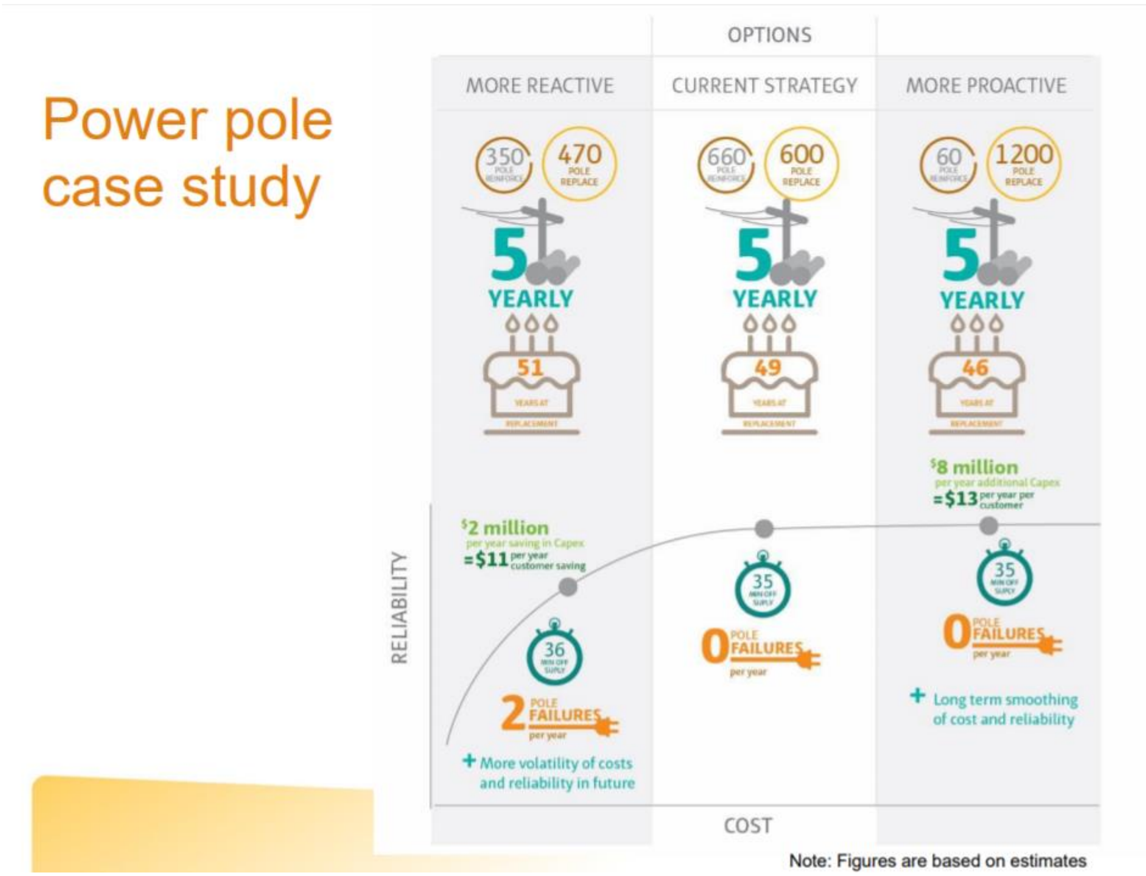
5. Financial damages, losses or costs
6. Disruption to operations
7. Disruption to program/project

While each of these risks is applicable to Evoenergy's business, only a subset of these risks, likely to give rise to an economic impact, are considered via the regulatory process.

3.2 Customer Engagement

Evoenergy is currently engaging with its customers as part of its regulatory proposal preparation process to understand consumer expectations for risk and the associated price trade-off. As part of this engagement Evoenergy ran an exercise asking customers to specify to what extent they would like Evoenergy to undertake a more proactive, but more expensive, approach to pole replacement. Such an approach would reduce the likelihood of pole failure compared to a more reactive approach thereby reducing the potential for safety risks and risks to property.

Figure 3 – Risk vs expenditure customer case study



In response to this, there was a general consumer preference towards a more proactive approach, with consumers citing the relatively low impact to prices to provide for this additional risk mitigation. Customers were also interested in technology based approaches to risk mitigation including increasing the underground network in more areas.

3.3 Replacement Expenditure

3.3.1 Bottom-up modelling

Since the 2014 draft decision, Evoenergy has invested significant time and resources into better understanding and managing network risks. This includes investment in Riva, a software tool which enables detailed bottom up forecasts of asset risk and prioritisation of risk management options for asset categories to enable programme optimisation. Evoenergy has populated Riva with asset data including age, location, condition, material types and a probability of failure assigned to each failure mode.

The asset specific plans utilise the data contained within Riva to identify the asset categories and asset failure modes which represent the highest risk over the regulatory period. Risk is determined in terms of:

- Probability of failure for each failure mode based on asset health index (depending on age and/or condition); and
- Consequence of failure for each risk type based on severity (depending on load and/or location)

This bottom-up approach assigns a risk priority to each asset type to enable asset managers to prioritise repex and opex programs.

3.3.2 Top-down Modelling

Evoenergy commissioned top-down modelling of network risks and replacement expenditure for the 2019 to 2024 regulatory period in order to provide a challenge to its bottom up results. The top-down modelling was undertaken using CutlerMerz' Risk vs Expenditure model. The model aims to quantify residual risk (in monetary terms) as a function of replacement expenditure specifically for Australian NSPs.

Network risk included the model are described in Table 1:

Table 1 – Risk types

Risk Type	Details
Safety (Public)	Injury to the public associated with network assets
Safety (Workforce)	Injury to network workers associated with work on the network
Outage	Loss of supply from unplanned interruptions
Fire	Losses (human and property) incurred from fires started by network assets

The approach to risk valuation is described in Appendix A.

The model incorporates all of Evoenergy's asset categories and expenditure categories considered material to network risk. For the purposes of the top-down modelling this was limited to primary systems due to the relatively low level of risk posed by failure of secondary systems. Secondary systems tend to be duplicated and the replacement driven by obsolescence and an inability to maintain them. As a result of this, approximately 81% of the proposed repex was captured within the top-down model.

The model prioritises expenditure across these asset categories based on the potential to minimise network risk. Overall expenditure can accordingly be allocated in a prioritised way to either:

a) Achieve a pre-set level of risk at least cost; or

b) Determine the minimum level of risk achievable for a pre-set level of expenditure.

For example (using prioritisation approach a) above), the model prioritises expenditure on asset classes that represent the highest risk reduction for each investment dollar. in this way, the prioritised expenditure corresponding to the risk level achieved by the bottom-up expenditure forecast can be determined. Section 4 presents the details of this approach as applied to Evoenergy's replacement expenditure.

Further explanation of the CutlerMerz Risk vs Expenditure Model (REM) applied to consideration of replacement expenditure is provided in Appendix A.

3.4 Augmentation expenditure

3.4.1 Consideration of energy at risk

For augex projects, Evoenergy undertook a bottom-up risk based evaluation of project needs and options. This includes consideration of energy at risk via CutlerMerz' Augex Uncertainty and Risk Appraisal (AURA) model. For existing areas, the energy at risk is determined based on the likelihood of load to exceed 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.

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.

Where load exceeds the emergency rating, the portion of the load above the emergency rating is considered at risk, even where there is redundancy in place.

For greenfield areas, not served by any existing assets, the entire load is considered at risk until it is electrically connected. For staged greenfield developments, subsequent stages following connection are treated in the same way as existing areas.

This approach allows Evoenergy to consider the risk costs associated with pushing assets above firm rating and the risk based value of provision of redundancy. 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 (See Section 2.3).

3.4.2 Consideration of demand uncertainty

The risk based assessment to augex also considers how options, including both traditional network solutions and more modular supply or demand side solutions perform under demand uncertainty. 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, compared to traditional network solutions. Traditional network solutions are generally less expensive on a $ per MVA basis, but tend to perform poorly in environments of demand uncertainty, particularly where there is potential for short term demand increases but longer term demand is forecast to decline.

CulterMerz reviewed Evoenergy's augex proposal by considering the risks of over expenditure posed by demand uncertainty. To achieve this CutlerMerz undertook a probabilistic based assessment of network and non-network options under plausible scenarios of future demand via the AURA model. 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.

Further explanation of the CutlerMerz AURA model applied to consideration of augex risk and demand uncertainty is provided in Appendix B.

4 Evoenergy risk position for the 2019 to 2024 regulatory period

4.1 Replacement expenditure

4.1.1 Scenarios

The top-down modelling considers four potential scenarios:

1. No planned repex – This scenario represents a run-to-fail approach for all network assets in which there is no expenditure allowed for the replacement in a planned or conditional manner. This scenario is an unrealistic option for Evoenergy as it does not meet any of the regulatory expenditure criteria, but has been retained as a boundary condition.

2. Risk minimisation – The pre-set level of replacement expenditure is determined from the bottom-up approach and the risk minimised by prioritising the total allocated expenditure on a risk reduction per dollar invested basis.

3. Maintain acceptable risk at least cost – The pre-set level of risk is maintained in line with the expenditure objectives and the expenditure minimised

4. Bottom up – The replacement expenditure determined from a bottom up approach and corresponding risk

Scenario 3, maintaining risk at acceptable levels at least cost is considered to be the preferred outcome, from a regulatory perspective due to its alignment with the expenditure objectives. However, in practice, the prioritised spend determined via the top-down model is likely to be unobtainable, in that it does not allow for the practicalities of work delivery (packaging of work, movement of resources, etc.). It therefore represents a theoretical risk/expenditure position that could only be reached with perfect information and timely access to the required labour and material resources.

4.1.2 Risk vs expenditure

Figure 4 shows the overall risk profile for each of the scenarios modelled. Figure 5 plots the risk level (with 50% probability of exceedance) against the associated expenditure.

Figure 4 – Modelling outcomes: Risk vs Expenditure

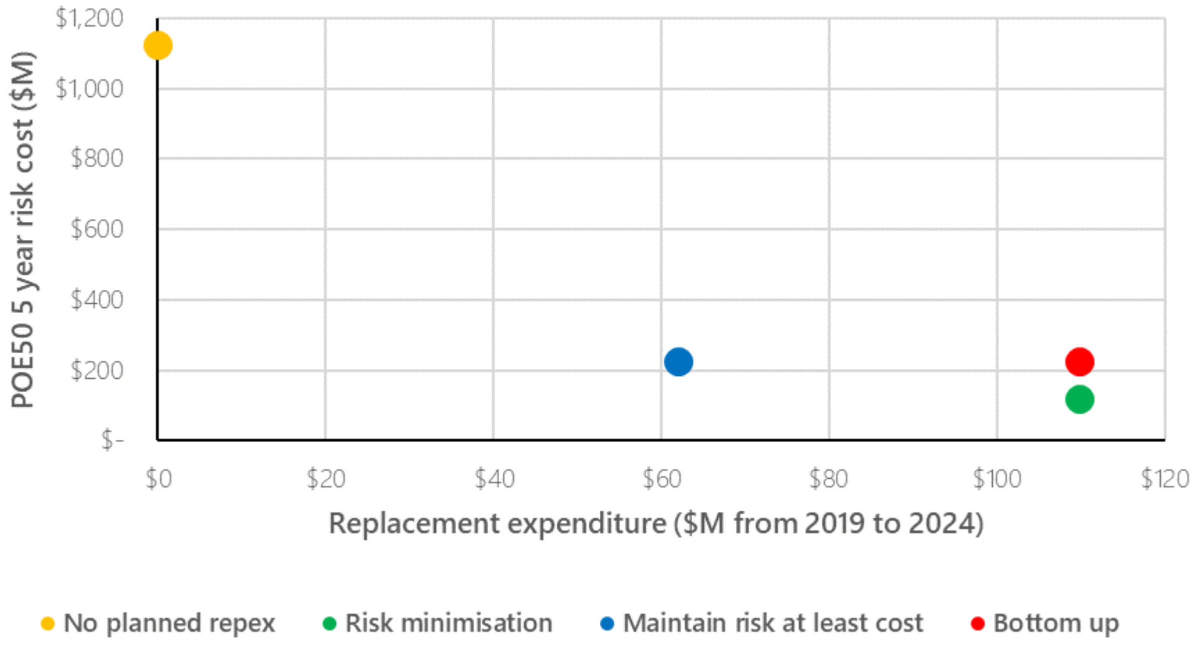
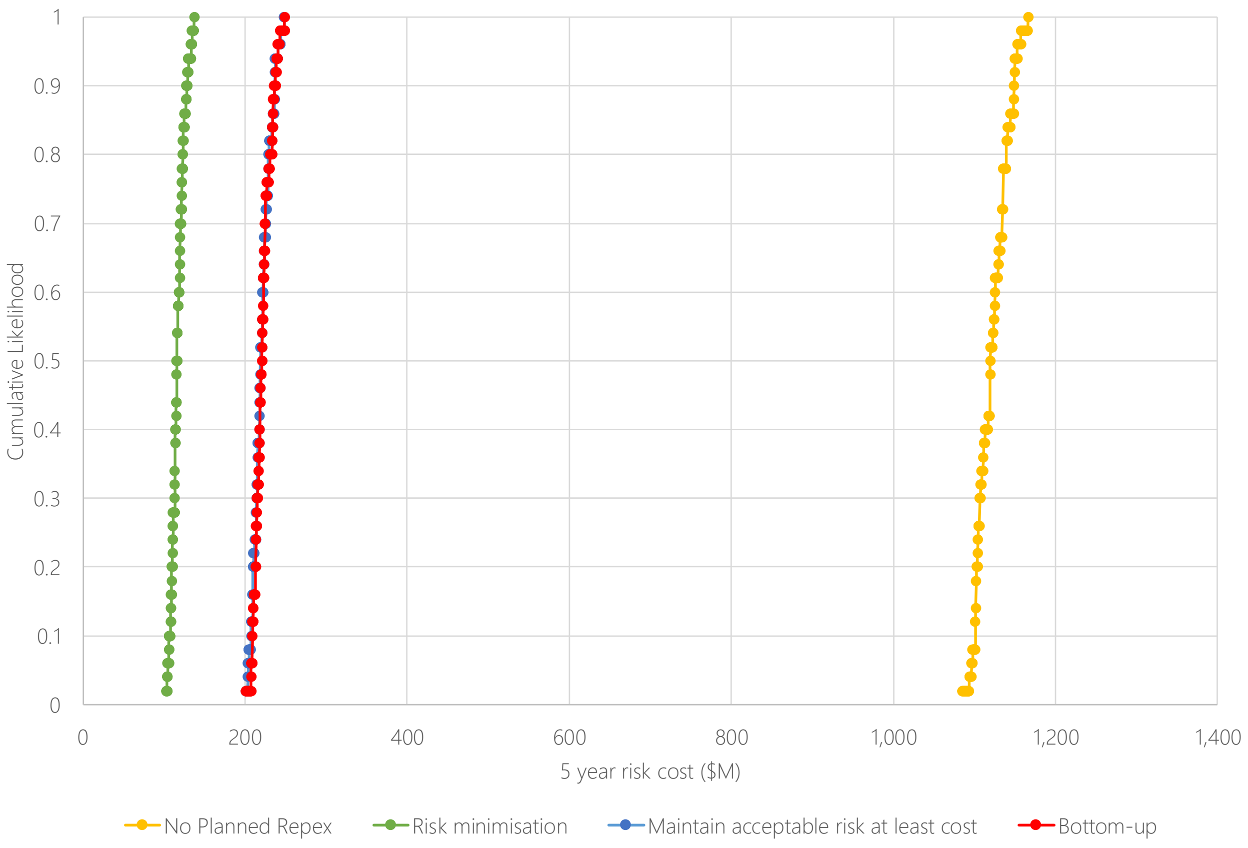


Figure 5 – Modelling outcomes: Risk profiles



Scenario 1 (No planned repex) revealed an unacceptable level of risk with a 50% probability of risk costs exceeding $1.125B over the five year regulatory period.

Scenario 2 minimises risk such that there is a 50% probability of residual risk costs exceeding $120M over the five year period. That is, scenario 2 is able to reduce risk by $1B (compared to Scenario 1) for a cost of $1B over a five year period.

Scenario 3 and the bottom-up scenario both maintain risk at current levels, such that there is a 50% probability of risk exceeding $225M over the five year period. Under Scenario 3, this is achieved at least cost. That is, Scenario 3 is able to reduce risk by $900M (compared to Scenario 1) for a cost of $224M over a five year period.

At face value, it therefore appears that Scenario 2, where risk is further reduced but expenditure increased, is likely to give rise to a higher net benefit than Scenario 3. However, it is considered that reducing risk below existing levels (under Scenario 2) is not consistent with the expenditure objectives (See Section 2.3), nor is there evidence that customers will be willing to pay for the reduced level of risk. Scenario 3 results were therefore considered the most applicable in challenging the bottom-up modelling.

4.1.3 Top-down challenge of bottom up expenditure

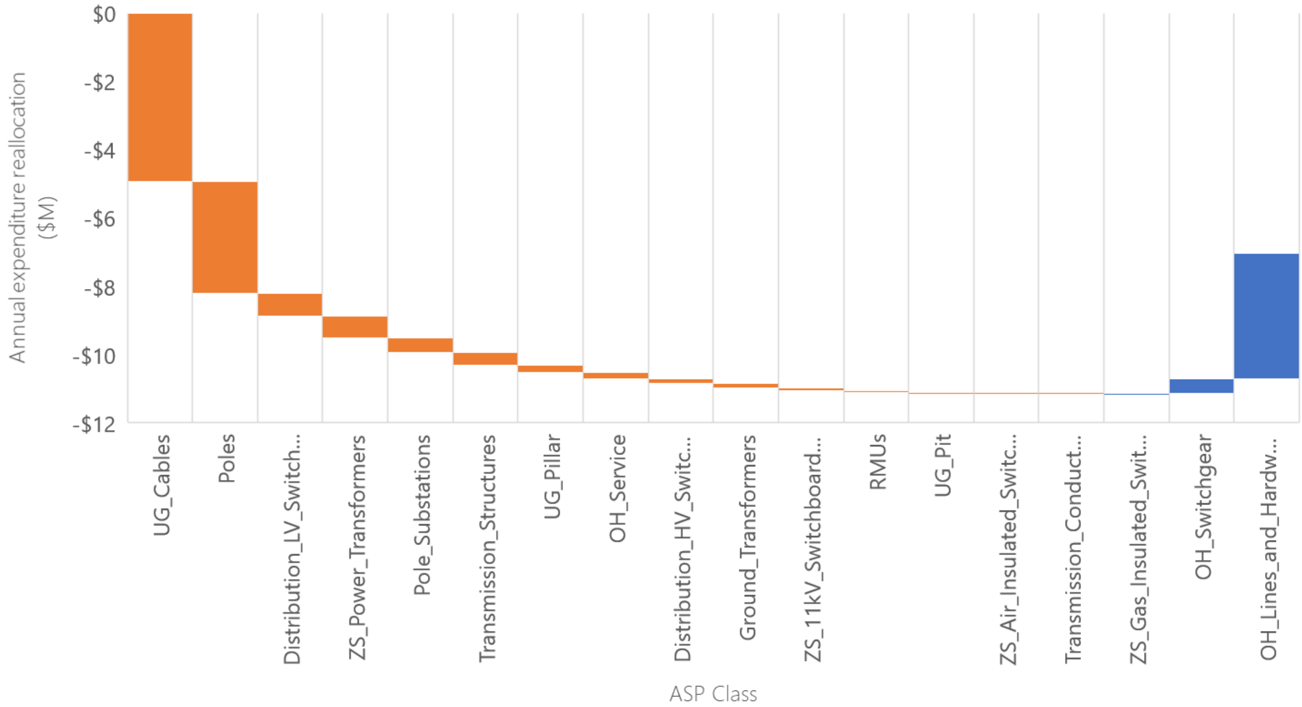
The scenario modelling process (as described in Section 3.3.2) has been used to execute a top-down challenge to the bottom-up expenditure profile proposed by Evoenergy.

The top-down modelling undertaken by CutlerMerz revealed that there are opportunities to reduce expenditure to levels below that produced by the bottom-up estimates provided in the Asset Specific Plans whilst still maintaining overall network risk. The results of this modelling were used to execute a top-down challenge to the Asset Specific Plan expenditure profile proposed by Evoenergy.

The top-down modelling was used to challenge the Asset Specific Plan estimates via several workshops with Evoenergy asset managers. During the workshop, the detailed top-down model outputs were explored and compared with outputs from bottom-up modelling to identify opportunities for Evoenergy to reduce expenditure while maintaining network risk.

The top-down modelling revealed significant opportunities to reduce expenditure in pole replacements, underground cables, distribution switchboards, and zone substation power transformers as shown in Figure 6, as well as a number of other categories. The top-down modelling also suggested expenditure in overhead lines, specifically pole tops should increase.

Figure 6 – Modelled changes in initial (bottom up) replacement expenditure to achieve same risk at least cost (Scenario 3)



Asset managers, through a workshop session and subsequent investigations, identified expenditure reductions in the top-down challenge that were practical to implement. The final adjustments made by asset managers is shown in Figure 6 below and Table 2.

Figure 7 – Adjustment of initial (bottom up) replacement expenditure to final (after top-down challenge)

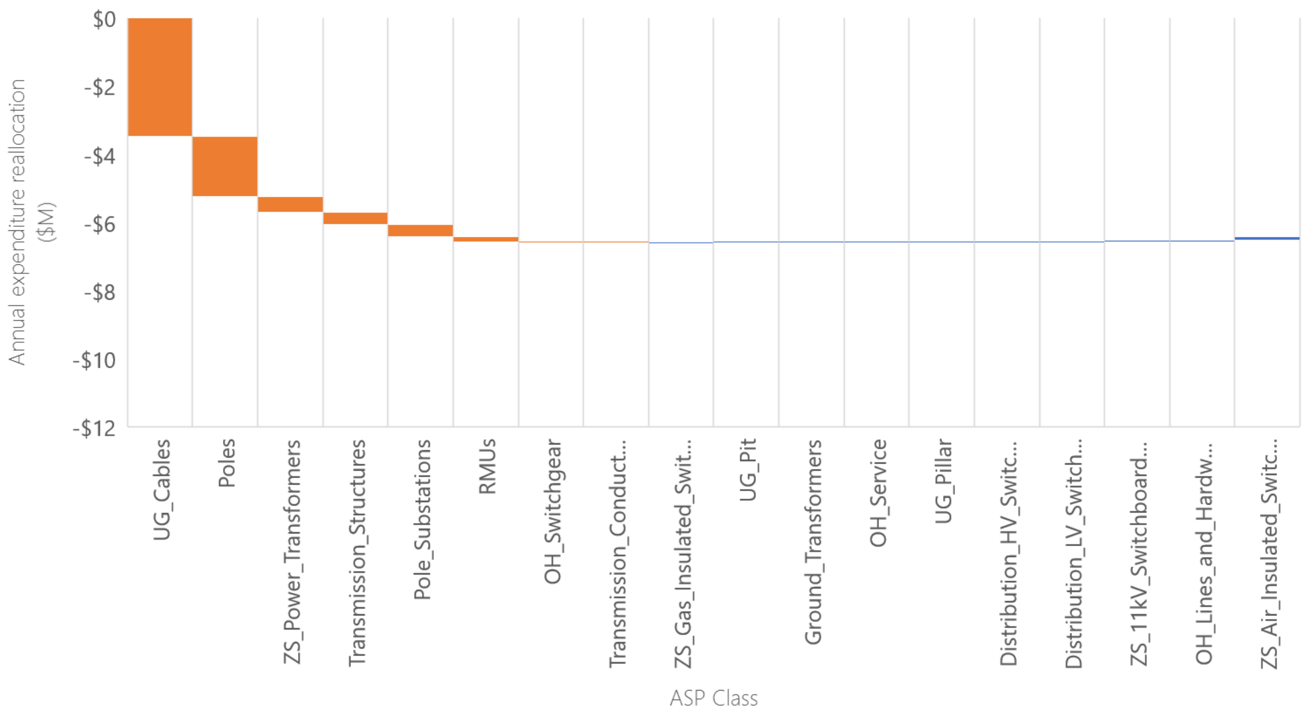


Table 2 – Outcomes of top-down challenge for annual replacement expenditure

Expenditure Category	Initial Position (Bottom-Up)	Top-Down Challenge (Scenario 3)	Difference between Initial and Top Down Challenge	Final Position	Difference between Initial and Final
UG Cables	$ 7,846,759	$ 2,903,365	-$ 4,943,394	$ 4,364,301	-$ 3,482,458
Poles	$ 7,090,175	$ 3,817,982	-$ 3,272,193	$ 5,329,700	-$ 1,760,475
ZS Power Transformers	$ 705,719	$ 60,207	-$ 645,512	$ 242,637	-$ 463,081
Transmission Structures	$ 361,086	$ -	-$ 361,086	$ -	-$ 361,086
Pole Substations	$ 416,814	$ -	-$ 416,814	$ 64,201	-$ 352,613
RMUs	$ 319,071	$ 274,643	-$ 44,428	$ 168,276	-$ 150,795
OH Switchgear	$ 551,288	$ 981,714	$ 430,426	$ 541,356	-$ 9,932
Transmission Conductors and Cables	$ 188	$ -	-$ 188	$ -	-$ 188
UG Pit	$ 15,992	$ -	-$ 15,992	$ 16,265	$ 273
Ground Transformers	$ 134,486	$ -	-$ 134,486	$ 136,430	$ 1,944
OH Service	$ 232,120	$ 49,823	-$ 182,297	$ 235,724	$ 3,604
UG Pillar	$ 228,920	$ 6,489	-$ 222,431	$ 232,831	$ 3,911
Distribution HV Switchboard	$ 402,500	$ 266,400	-$ 136,100	$ 408,319	$ 5,819
Distribution LV Switchboard	$ 676,555	$ -	-$ 676,555	$ 686,336	$ 9,781
ZS 11kV Switchboard Assembly	$ 1,228,560	$ 1,132,987	-$ 95,573	$ 1,242,873	$ 14,313
OH Lines and Hardware	$ 1,734,930	$ 5,411,718	$ 3,676,788	$ 1,757,917	$ 22,987
ZS Air Insulated Switchgear	$ 11,357	$ -	-$ 11,357	$ 96,560	$ 85,203
TOTAL	$ 21,956,520	$ 14,905,327	-$ 7,051,194	$ 15,523,726	-$ 6,432,794

Of the $3.3M of annual savings identified for poles in the top down challenge, Evoenergy reduced annual pole expenditure by $1.8M. Of the $5M of annual savings identified for underground cables identified in the top down challenge, Evoenergy reduced annual expenditure by $3.5M. Instead of complete replacement, Evoenergy identified opportunities to reduce replacements and adopt alternative measures to sectionalise underground cables to reduce the extent of impact on reliability in the event of a failure.

The top down modelling identified $3.3M of potential annual savings could be achieved by a reduction in replacement of poles compared to the bottom up estimates and $3.7M could be re-allocated to pole top replacements (under overhead lines category above). However asset managers contended that the increased expenditure pole tops identified in the top down challenge should actually be allocated to poles. This is because Evoenergy has a policy of replacing both the pole and pole top where either is conditionally failed due to the low incremental cost of replacing the pole at the same time as a pole-top. Detailed analysis (beyond that which could be achieved by the top down modelling) confirms that the overall the net present value of replacing both the pole and pole top at the same time (upon conditional failure of the pole top but prior to the conditional failure of the pole) is greater than replacing each separately.

Following the top-down challenge, Evoenergy identified additional savings across a number of other categories in recognition of the need to balance risk vs expenditure. As presented in Table 2 above, a total $6.4M of the $7.1M of annual savings identified by the top down challenge were realised. Resulting in a total saving over the five year regulatory control period of $32.2M.

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4.2 Augmentation expenditure

Evoenergy utilised CutlerMerz' AURA model to challenge the network solutions identified for each of its 17 augmentation projects. As described in Section 3.4.1, the AURA model determines the value of energy at risk and identifies the lowest cost network or non-network solution to mitigate this risk.

4.2.1 Scenarios

The results presented below are for three scenarios:

1. Initial position: Only traditional network options are allowed (including Evoenergy's one mobile zone substation) assuming certainty in demand according to Evoenergy's POE10 scenario;

2. Challenge scenario: Demand management options are allowed (up to the capacity identified within the relevant network area) as well as network batteries and assuming demand uncertainty with uniform distribution between Evoenergy's POE10 and POE90 scenario;

3. Low demand forecast scenario: Identifies the demand management that would need to either occur organically or be driven by Evoenergy through incentive payments in order to defer the project to the next regulatory period. Where the demand management required is greater than 30% of the POE10 forecast, demand management is considered infeasible.

4.2.2 Energy at risk

Table 2 below shows the associated network solution (Scenario 1 above) and the value of energy at risk under a do nothing scenario.

Table 3 – Value of Energy at Risk

Project	Network Option	Capital Expenditure to 2024 ($18/19)	Energy at risk value to 2024 ($18/19)
Kingston	Feeders from East Lake ZS	727,209	878
Molonglo ZS	New ZS	12,470,877	2,375
Molonglo Fdr	Fdr from new ZS	3,590,910	2,375
Strathnairn ZS	MOSS	8,021,892	10,327,123
Strathnairn Fdr	Feeders from new MOSS	759,900	10,327,123
Canberra CBD	Feeder from Civic ZS	910,452	1,361
City and Dickson	Fdr City East ZS + Ext	2,972,280	2,169
Griffith	Feeder from Telopea Park ZS	1,824,525	20,872,671
Pialligo	Fdr East Lake ZS +Fdr Link	3,053,370	2,038
Tuggeranong	Fdr Wanniassa + Fdr Tie	1,770,414	24,107,331
Whitlam	Feeder Spur	279,990	142,219,192
Fyshwick Dcom	Convert to Switching Station	3,897,420	677,743,481
Mitchell	Feeders from Gold Creek ZS	4,073,217	448,816,577
Belconnen	Feeders from Belconnen ZS	2,416,584	4,041
Second Supply to ACT	Capacitor Banks	1,830,900	N/A
Total		48,599,940	1,334,428,735

As can be seen from the above, there are a number of projects for which the value of energy at risk is relatively small. This coincides with a demand forecasts which exceeds the firm rating, but does not exceed the emergency rating. Since all assets include N-1 redundancy, an exceedance of the firm rating is unlikely to result in loss of supply.

Where demand exceeds the firm rating only and there is associated N-1 redundancy then the value of energy at risk is a factor of:

- The total amount of energy per year which exceeds of the firm rating;
- The probability that a contingency event will occur when demand exceeds the firm rating which is a product of:
    - The fraction of hours per year when the firm rating is exceeded; and
    - The probability that a contingency event will occur at some time during the year
- The time taken to restore service following the contingency event (usually within 24 hours)

Where demand exceeds the existing emergency rating then it assumed that that demand cannot be met. The value of energy at risk is therefore assumed to be equal to the total load in excess of the emergency rating.

4.2.3 Demand Uncertainty

The risk associated with demand uncertainty was assessed using CutlerMerz' AURA Model. The AURA model was used to assess the feasibility of demand management and non-traditional network solutions across Evoenergy's range of demand forecasts produced at zone substation level (with uncertainty driven by weather) as per Scenario 2 described in Section 4.2.1 above.

Scenario 2 revealed a number of opportunities to reduce augmentation expenditure. The most significant of these involves the Strathnairn Zone Substation project. Initially it was identified that the mobile zone substation could be used at Strathnairn, however, the Scenario 2 modelling indicated that this project was a suitable candidate for a network battery to allow for potential deferral of the zone substation into the next regulatory period. For Strathnairn, an alternative solution of extending feeders from Latham and providing a network battery was a lower cost alternative to the network solution of a new zone substation.

Under Scenario 2, the mobile zone substation can be relocated to Molongolo further deferring the new permanent zone substation at this site. Overall, Scenario 2 was assessed to avoid approximately $16.7M of augmentation expenditure.

Under the final challenge Scenario 3 with a low demand forecast (as shown in Table 4) an overall reduction of $13.4M in augmentation expenditure was identified through the challenge process.

Table 4 – Augex challenge outcomes

Project	Scenario 1 (Initial Position no DM)		Scenario 2 (with DM and AAD Existing Forecast)		Scenario 3 (Low Demand Forecast)	
	Preferred Option	Capex to 2024	Preferred Option	Capex to 2024	Preferred Option	Capex to 2024
Kingston	Feeders from East Lake ZS	$727,209	Feeders from East Lake ZS	$727,209	Feeders from East Lake ZS	$727,209
Molonglo ZS	New ZS	$12,470,877	MOSS	$6,302,172	MOSS	$6,302,172
Molonglo Fdr	Fdr from new ZS	$3,590,910	Feeders from new MOSS	$3,590,910	Feeders from new MOSS	$3,590,910
Strathnairn ZS	MOSS	$8,021,892	New ZS - Delay with Battery	$2,196,278	New ZS Deferred	$0
Strathnairn Fdr	Feeders from new MOSS	$759,900	Extend Feeders	$1,544,994	Extend Feeders	$1,544,994
Canberra CBD	Feeder from Civic ZS	$910,452	Feeder from Civic ZS	$910,452	Feeder from Civic ZS	$910,452
City and Dickson	Fdr City East ZS + Ext	$2,972,280	Fdr City East ZS + Ext	$2,972,280	Fdr City East ZS + Ext	$2,972,280
Griffith	Feeder from Telopea Park ZS	$1,824,525	Feeder from Telopea Park ZS	$1,824,525	Feeder from Telopea Park ZS	$1,824,525
Pialligo	Fdr East Lake ZS +Fdr Link	$3,053,370	Fdr East Lake ZS +Fdr Link	$3,053,370	Fdr East Lake ZS +Fdr Link	$3,053,370
Tuggeranong	Fdr Wanniassa + Fdr Tie	$1,770,414	Fdr Wanniassa + Fdr Tie	$1,770,414	Fdr Wanniassa + Fdr Tie	$1,770,414
Whitlam	Feeder Spur	$279,990	Feeder Spur	$279,990	Feeder Spur	$279,990
Fyshwick Dcom	Convert to Switching Station	$3,897,420	Convert to Switching Station	$3,897,420	Convert to Switching Station	$3,897,420
Mitchell	Feeders from Gold Creek ZS	$4,073,217	Feeders from Gold Creek ZS	$4,073,217	Feeders from Gold Creek ZS	$4,073,217
Belconnen	Feeders from Belconnen ZS	$2,416,584	Feeders from Belconnen ZS	$2,416,584	Feeders from Belconnen ZS	$2,416,584
Second Supply to ACT	Capacitor Banks	$1,830,900	Capacitor Banks	$1,830,900	Capacitor Banks	$1,830,900
Total		$48,599,940		$36,657,564		$35,194,437
% change				24.6%		27.6%

Under Scenario 3, further exploration of the potential for demand management was undertaken, by identifying how much demand needed to be reduced by in order to defer each of the projects. Where the required demand reduction in excess of 30% of the POE10 forecast, this option was discounted. This excluded all projects with the exception of Strathnairn as shown in Table 5.

Table 5 – Demand reduction required for deferral to next regulatory period

Project	Demand Reduction Required for Deferral	
	2024 Deferral Required Reduction (MVA)	% of Demand Growth (Base Case 2017-2024)
Kingston	-5.0	-35%
Molonglo ZS	-6.8	-40%
Molonglo Fdr	-6.8	-40%
Strathnairn ZS	-1.1	-15%
Strathnairn Fdr	-3.9	-65%
Canberra CBD	-4.7	-40%
City and Dickson	N/A	N/A*
Griffith	-3.4	-40%
Pialligo	N/A	N/A*
Tuggeranong	-2.7	-65%
Whitlam	N/A	N/A*
Fyshwick Dcom	N/A	N/A*
Mitchell	-16.3	-140%
Belconnen	-8.3	N/A*
Second Supply to ACT	N/A	N/A*

* N/A implies project is not demand driven

Overall, Scenario 3 revealed that there is an opportunity to replace the use of a network battery at Strathnairn with demand management. Approximately 1.1MVA of peak demand reduction would need to be sourced (or materialise organically) to defer Strathnairn without the use of a network battery. Since the majority of demand is expected to come from new residential development, it is likely that these customers would need to be provisioned with demand management solutions such as a home energy management system and/or battery storage.

At this stage, it is unknown as to:

- the extent to which new developments are likely to be provisioned with such technology without any action by Evoenergy; and
- the extent to which any new technology will reduce growth in peak demand without any action by Evoenergy.

While not included in the costs, it is estimated that up to $1.5M would need to be provided to deliver the savings required[3] assuming that the demand reduction does not occur without Evoenergy intervention.

[3] Based on an incentive payment of $4,500 per customer to adopt a 14MWh battery. This is the approximate subsidy required in order for an existing solar customer to provide a <10 year pay back on a storage system. This is considered to represent an upper bound as lower cost options are likely to be available.

5 Conclusion

Evoenergy recognises that there is a need to assess the extent to which its expenditure across the regulatory period influences the network risk due in part to the shift towards more customer centric processes, allowing customers to understand trade-offs between network prices and risk and in part due to AER's previous concerns. Evoenergy has therefore undertaken a top-down challenge to assess the extent to which expenditure can be minimised whilst not increasing network risk.

The challenge process identified a total saving of $32.2M in replacement expenditure driven by reductions in replacements in poles and underground cables compared to the bottom up estimates. Despite the saving, it is anticipated that network risk can be maintained (compared to the risk level identified from bottom up expenditure levels) at $224M over the regulatory control period.

The challenge process also identified a total saving of $13.4M via the consideration of demand uncertainty and demand management options. The challenge identified potential to defe zone substation developments in both Molongolo and Strathnairn without increasing energy at risk.

Overall, the top-down modelling and consideration of risk revealed opportunities to reduce capital expenditure by $45.6M compared to the bottom-up estimates whilst still maintaining overall network risk.

Appendix A Risk vs Expenditure Model Valuation Framework

Appendix B AURA Model