

# Appendix 5.27: Supply to Canberra City and Dickson PJR

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

Disclaimer: On 1 January 2018, the part of ActewAGL that looks after the electricity network changed its name to Evoenergy. This change has been brought about from a decision by the Australian Energy Regulator. Unless otherwise stated, ActewAGL Distribution branded documents provided with this regulatory proposal are Evoenergy documents.

## Project Justification Report

<b>Project name</b>	<b>Supply to Canberra City and Dickson</b>
Expenditure type	Capital Expenditure
Business Group	Asset Strategy
Regulatory Period	1 July 2019 to 30 June 2024
Total Project Cost Estimate	\$2,914,000 excluding corporate overheads, excluding contingency, and excluding GST
Five year total spend 2019-24	\$2,914,000 excluding corporate overheads, excluding contingency, and excluding GST
CAPEX category	ENAA Distribution
Primary driver	Load growth in Canberra City and Dickson
Project Number	20001382

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## Reference documents

Document	Version	Date
National Electricity Rules	102	
National Electricity Law		19.12.13
Utilities Act (ACT)		2000
Utilities (Management of Electricity Network Assets Code) Determination		2013
Evoenergy Maximum Demand Forecast		2017
ActewAGL Annual Planning Report		22.12.17
Distribution Network Augmentation Standard SM1197	1.1	12.5.15
Evoenergy Risk Assessment Tables PR4660.2	1.0	12.1.17
Evoenergy Quality of Supply Strategy SM11150	1.0	8.10.15
Evoenergy Asset Management Strategy SM1192	2.12	22.6.15
Land Development Agency Indicative Land Release Program 2017-21		2017
Evoenergy Peak Demand Reduction Strategy	2.0	22.8.17
Augmentation NPC Model Methodology	1.0	29.9.17

## 1. Executive Summary

This Project Justification Report addresses the growth of electricity demand in the Canberra City and Dickson areas and evaluates options re how Evoenergy can meet these needs.

The maximum demand in central Canberra City is forecast to increase steadily by 20.3 MVA, and that in the Dickson area by 9.78 MVA over the next 7 years as proposed new residential and commercial developments are completed. The load in this area is typically summer peaking.

The current maximum demand at City East Zone Substation is approximately 75 MVA. The substation's continuous summer rating is 95 MVA. The existing combined summer firm rating of 11 kV feeders supplying the Canberra City and Dickson areas is 53.8 MVA (Canberra City 25.9 MVA, Dickson 27.9 MVA), and the combined available spare capacity is 13.4 MVA (Canberra City 9.8 MVA, Dickson 3.6 MVA). The forecast load growth in these areas indicates the available spare capacity will be fully utilised by 2021 and around 11.9 MVA (Canberra City 10.5 MVA, Dickson 1.4 MVA) will be at risk by 2023.

The proposed developments include block loads such as the Canberra Metro Traction Power Station TPS4, and multi storey residential and commercial buildings proposed to be constructed in the Canberra City and Dickson areas. The ACT Government's Suburban Land Agency (SLA) has published its Indicative Land Release program for 2017-21, which states that there is approximately 24,500 m<sup>2</sup> of mixed-use development, 3,400m<sup>2</sup> of commercial development, and 1,140 residential dwellings proposed to be constructed in the Canberra City and Dickson areas.

The proposed new 11 kV feeder from City East Zone Substation will inter-tie with 11 kV feeders from Civic Zone and Telopea Park Zone Substations to provide backup security of supply in the event of an outage at City East. The extension of the Haig feeder will provide interconnection with Wattle and Cowper feeders, which are planned to supply critical block loads such as the Canberra Metro Traction Power Station TPS4.

Other options considered and evaluated were the installation of feeders from Civic zone substation, non-network demand management, utilising a grid battery to defer a network upgrade and utilising a grid battery to avoid a network upgrade.

A preliminary cost estimate for the selected option of a new feeder from City East and extension of the Haig feeder is **\$2,914,000 excluding overheads, contingency and GST**. These works will be carried out during the 2019-24 Regulatory Control Period, with proposed project completion by June 2022.

## 2. Strategic Context and Expenditure Need

Spare capacity of existing 11 kV feeders to Canberra City and Dickson cannot meet the forecast demand growth.

### 2.1. Existing infrastructure in the Canberra City and Dickson area

There are fifteen 11 kV feeders supplying the Canberra City area plus six 11 kV feeders to the Dickson area where the new loads are proposed to be developed. The maximum load supplied by each feeder as a percentage of its firm rating, is shown in Table 1 for summer and winter. Yellow denotes load above 80% of the firm rating, red denotes load above firm rating. Firm rating of an 11 kV feeder is dictated by the number of inter-connections it has to other 11 kV feeders in order to provide full back-up capacity in the event of a contingency. Thus a feeder that is inter-connected to one other feeder may be loaded to 50% of its thermal capacity, and a feeder that is inter-connected to two other feeders may be loaded to 75% of its thermal capacity. 100% firm rating should not be exceeded as this places load at risk in the event of a contingency.

**Table 1: Loading of feeders supplying Canberra City, Dickson and Lyneham**

Name	Zone	Feeder Rating (MVA)				2015		2016		2017	Spare capacity MVA
		Firm Summer Rating	Thermal Summer Rating	Firm Winter Rating	Thermal Winter Rating	Percent Loaded Summer	Percent Loaded Winter	Percent Loaded Summer	Percent Loaded Winter	Percent Loaded Summer	
<b>Canberra City</b>											
Akuna	CE	4.5	5.9	5.0	6.6	49%	30%	48%	28%	45%	2.48
Allara	CE	4.5	5.9	5.0	6.6	53%	21%	50%	31%	93%	0.31
Binara	CE	4.9	6.5	5.4	7.2	68%	72%	68%	47%	69%	1.51
Bunda	CE	4.5	5.9	5.0	6.6	50%	26%	50%	29%	51%	2.19
Chisholm	CE	5.1	6.9	5.8	7.7	97%	52%	70%	53%	85%	0.76
Constitution	CE	3.1	6.3	3.5	7.0	73%	41%	76%	40%	66%	1.07
Cooyong	CE	4.8	6.3	5.3	7.0	69%	40%	75%	49%	83%	0.80
Elec House	CE	4.8	6.3	5.3	7.0	49%	26%	48%	27%	48%	2.46
Lonsdale	CE	5.4	7.2	6.0	8.0	103%	59%	75%	60%	82%	0.95
Northbourne	CE	4.0	5.3	4.5	5.9	48%	47%	55%	46%	64%	1.45
Quick	CE	3.6	4.8	4.4	5.8	81%	74%	63%	73%	65%	1.28
CSIRO	Civic	4.4	5.8	4.9	6.5	94%	51%	83%	55%	83%	0.76
Hobart Long	Civic	4.4	5.8	4.9	6.5	74%	62%	89%	66%	91%	0.40
Hobart Short	Civic	4.8	6.4	5.3	7.1	38%	61%	87%	62%	96%	0.19
Edmond Barton	TP	3.3	4.5	3.8	5.0	94%	37%	63%	42%	56%	1.47
<b>Dickson</b>											
Braddon	CE	4.9	6.5	5.4	7.2	92%	62%	75%	64%	77%	1.11
Cowper	CE	4.1	5.4	4.9	6.5	105%	100%	103%	109%	80%	0.82
Ebden	CE	5.1	6.9	5.8	7.7	65%	67%	41%	68%	38%	3.21
Ijong	CE	4.1	5.4	5.0	6.7	75%	72%	72%	69%	74%	1.07
Wakefield	CE	4.5	5.9	5.0	6.7	86%	86%	88%	75%	90%	0.46
Wattle	Civic	5.2	7.0	5.9	7.8	72%	58%	64%	48%	98%	0.11

## 2.2. Driving need for infrastructure investment

Forecast additional maximum demand in the Canberra City and Dickson area is indicated in Table 2. This has been based on an assessment of known developments (either at application or Preliminary Network Advice stage) proposed for the area. Some of these developments are either under construction or currently being designed. There is a high degree of certainty (> 80%) that these developments will proceed. In addition there are several potential smaller load increases.

**Table 2: Proposed Developments in Canberra City and Dickson**

<b>Canberra City</b>							
<b>Proposed Development and Net Additional Diversified Load in MVA</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Total</b>
B21, S 63 – London Circuit, commercial development (PN20003048)	0.5	0.5	1	1.5	1.5	1.5	<b>6.5</b>
B4 S19 – London Circuit, commercial development (PN20003048)	0.5	0.5	1				<b>2</b>
B3 S12 - 20 Allara St, residential apartment development (PN20004555)	0.5	0.5	0.5				<b>1.5</b>
B3 S3 – 33 London Circuit, mixed-use development (PN20002983)	0.75						<b>0.75</b>
B27 S26 - 69 Northbourne Ave, mixed-use development (PN20003928)	0.43	0.43	0.43				<b>1.29</b>
S96 - Canberra Centre extension, commercial development (PN20003452)		1	1	2	2.5	1.8	<b>8.3</b>
<b>Additional Load (MVA)</b>	<b>2.7</b>	<b>2.9</b>	<b>3.9</b>	<b>3.5</b>	<b>4.0</b>	<b>3.3</b>	<b>20.3</b>
<b>Cumulative additional forecast load (MVA)</b>	<b>2.7</b>	<b>5.6</b>	<b>9.5</b>	<b>13.0</b>	<b>17.0</b>	<b>20.3</b>	<b>20.3</b>
<b>Dickson</b>							
<b>Proposed Development and Net Additional Diversified Load in MVA</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Total</b>
B5 S30 – Torrens St , mixed use development (PN 20005138)	0.8						
B7 S18 – 92 Northbourne Ave, mixed-use development (PN20003924)	0.8	0.5					<b>1.3</b>
B13 S7 – Lowanna St, mixed-use development (PN20003869)	0.65						<b>0.65</b>
Canberra Metro TPS4 – Wattle St, light rail traction power station	2.6 / 5.2*						<b>2.6</b>
B3 S33 – Challis St, mixed-use development			0.5	0.5			<b>1</b>
B2 S33 – Northbourne Ave / Challis St, mixed-use development			1	1	0.7		<b>2.7</b>
B21 S30 - Mixed development (PN20001119)		0.5	0.5	0.53			<b>1.53</b>
<b>Additional Load (MVA)</b>	<b>4.85</b>	<b>1</b>	<b>2</b>	<b>2.03</b>	<b>0.7</b>	<b>0</b>	<b>10.58</b>
<b>Cumulative additional forecast load (MVA)</b>	<b>4.85</b>	<b>5.85</b>	<b>7.85</b>	<b>9.88</b>	<b>10.58</b>	<b>10.58</b>	<b>10.58</b>

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\* Canberra Metro requires 2.6 MVA under normal operating conditions and 5.2 MVA as peak load during N-1 contingency. 2.6 MVA has been used for planning the network for normal configuration. Short term network reconfiguration will be required to address emergency peak load of 5.2 MVA.

Table 3 shows a summary of the load forecast in Canberra City and Dickson for the next 7 years on the existing 11 kV feeders. These forecast loads make allowance for predicted penetration of rooftop solar PV and battery storage systems. This shows that available capacity will be exceeded by 2021.

**Table 3: Forecast load growth by feeder in Canberra City and Dickson**

Forecast Load Growth - Canberra City								
Feeder / Year	Feeder rating MVA	2017 existing load	2018	2019	2020	2021	2022	2023
Edmund Barton load growth MVA	3.3	1.83	0.5	0.5				
Edmund Barton spare capacity MVA		1.47	0.97	0.47				
Binara load growth MVA	4.9	3.39	1	1	1.5			
Binara spare capacity MVA		1.51	0.51	-0.49	-1.99			
Elec House load growth MVA	4.8	2.34			1	1.5	1.6	1.5
Elec House spare capacity MVA		2.46	2.46	2.46	1.46	-0.04	-1.54	-3.04
CSIRO load growth MVA	4.4	3.64	0.75					
CSIRO capacity MVA		0.76	0.01					
Northbourne load growth MVA	4.0	2.55	0.43	0.43	0.43			
Northbourne capacity MVA		1.45	1.02	0.59	0.16			
Bunda load growth MVA	4.5	2.31		1	1	2	2.5	1.8
Bunda capacity MVA		2.19	2.19	1.19	0.19	-1.81	-4.31	-6.1
<b>Total load growth MVA pa</b>	<b>25.9</b>	<b>16.06</b>	<b>2.68</b>	<b>2.93</b>	<b>3.93</b>	<b>3.5</b>	<b>4.1</b>	<b>3.3</b>
<b>Total spare capacity available MVA</b>		<b>9.84</b>	<b>7.16</b>	<b>4.23</b>	<b>0.3</b>	<b>-3.2</b>	<b>-7.3</b>	<b>-10.6</b>
Forecast Load Growth - Dickson								
Feeder / Year	Feeder rating MVA	2017 existing load	2018	2019	2020	2021	2022	2023
Braddon load growth MVA	4.9	3.79	0.8	0.5				
Braddon spare capacity MVA		1.11	0.3	-0.2	-0.2	-0.2	-0.2	-0.2
Ijong load growth MVA	4.1	3.03	0.65					
Ijong spare capacity MVA		1.07	0.42	0.42	0.42	0.42	0.42	0.42
Wattle load growth MVA	5.2	5.09	2.6					
Wattle spare capacity MVA		0.11	0.11	0.11	0.11	0.11	0.11	0.11
Load transfer from Cowper to Wattle			2.6					
Wakefield load growth MVA	4.5	4.0			0.5	0.5		
Wakefield spare capacity MVA		0.5	0.5	0.5	0	-0.5	-0.5	-0.5
Cowper load growth MVA	4.1	3.28	2.6		1	1	0.7	
Cowper spare capacity MVA		0.82	0.82	0.82	-0.18	-1.18	-1.88	-1.88
Load Transfer from Cowper to Wattle			2.6					
Ebden load growth MVA	5.1	1.89	2.6					
Ebden spare capacity MVA		3.21	0.61	0.61	0.61	0.61	0.61	0.61
Load Transfer from Ebden to Cowper			2.6					
<b>Total load growth MVA pa</b>	<b>27.9</b>	<b>21.08</b>	<b>4.05</b>	<b>0.5</b>	<b>1.5</b>	<b>1.5</b>	<b>0.7</b>	<b>0</b>
<b>Total spare capacity available MVA</b>		<b>6.82</b>	<b>2.77</b>	<b>2.27</b>	<b>0.77</b>	<b>-0.73</b>	<b>-1.43</b>	<b>-1.43</b>

### 3. Objectives

#### 3.1. Corporate, asset management and key project objectives

The corporate, asset management and related key project objectives are shown in Table 4 below. These objectives are used to assess the relative risk of options.

**Table 4: Corporate, asset management and key project objectives**

Corporate objectives	Asset management objectives	Key project objectives
<b>Responsible</b>	<ul style="list-style-type: none"> <li>Achieve zero deaths or injuries to employees or the public.</li> <li>Maintain a good reputation within the community.</li> <li>Minimise environmental impacts, for example bushfire mitigation.</li> <li>Meet all requirements of regulatory authorities, such as the AER as outlined in the NER, and the ACT Utilities (Technical Regulations) Act 2014.</li> </ul>	The selected option must ensure environment and safety standards will be met.
<b>Reliable</b>	<ul style="list-style-type: none"> <li>Tailor maintenance and renewal programs for each asset class based on real time modelling of asset health and risk.</li> <li>Meet network SAIDI and SAIFI KPIs.</li> <li>Record failure modes of the most common asset failures in the network.</li> <li>Successfully deliver the asset class Program of Work (PoW) to ensure that the protection operates correctly to disconnect faulty sections in accordance with the NER.</li> </ul>	Options evaluations to consider the value of customer reliability (VCR).  In accordance with regulated requirements, the selected option must ensure access to an electricity supply.
<b>Sustainable</b>	<ul style="list-style-type: none"> <li>Enhance asset condition and risk modelling to optimise and implement maintenance and renewal programs tailored to the assets' needs.</li> <li>Make prudent commercial investment decisions to manage assets at the lowest lifecycle cost.</li> <li>Integrate primary assets with protection and automation systems in accordance with current and future best practice industry standards</li> <li>Deliver the asset class PoW within budget.</li> </ul>	Options evaluations to consider the cost effectiveness of the solution.  In accordance with regulated requirements, the selected option must be the most prudent and efficient.  Non-network options will be evaluated on equal merit with network solutions.
<b>People</b>	<ul style="list-style-type: none"> <li>Proactively seek continual improvement in asset management capability and competencies of maintenance personnel.</li> </ul>	A post implementation review to incorporate learnings through the asset management system.

The project objectives are consistent with Evoenergy's regulatory requirements described below.

## 3.2. Regulatory Compliance

### 3.2.1. National Electricity Law and National Electricity Rules

Evoenergy is subject to the National Electricity Law (NEL) and the National Electricity Regulations (NER) which regulate the National Electricity Market (NEM). Evoenergy operates in the NEM as both a Transmission Network Service Provider (TNSP) and a Distribution Network Service Provider (DNSP).

The National Electricity Objective (NEO), as stated in the NEL is to:

*“...promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*

- a) price, quality, safety, reliability and security of supply of electricity; and*
- b) the reliability, safety and security of the national electricity system.”*

This objective requires Registered NEM participants to balance the costs and risks associated with electricity supply.

The planning and development process for distribution and transmission networks is carried out in accordance with the National Electricity Rules (NER) Chapter 5 Part B Network Planning and Expansion.

The primary objective of planning is to ensure that customers are able to receive a sufficient and reliable supply of electricity now and into the future.

### 3.2.2. Capital Expenditure Objectives and Criteria

The NER provides further guidance in terms of allowable capital expenditure via the capital expenditure objectives and criteria for standard control services. These capital 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 expenditure criteria, set out in Section 6.5.6(c) and Section 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 expenditure objectives*
- 2) The costs that a prudent operator would require to achieve the expenditure objectives; and*
- 3) A realistic expectation of the demand forecast and cost inputs required to achieve the expenditure objectives.*

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

### 3.2.3. Regulatory Investment Test

Section 5.16 of the NER 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.

The regulatory investment tests provide the opportunity for external parties to submit alternative proposals to the Network Service Provider, who is obliged to consider any credible proposal objectively.

Since the required investment is greater than \$5million the project is subject to the RIT-D. Evoenergy commenced RIT-D process in 2014 with publication of a Project Specification Consultation Report, but has yet to complete the RIT-D process (ie publication of Draft Project Assessment Report and Final Project Assessment Report). These reports will need to be prepared as part of the development of this project. The initial RIT-D consultation paper published in 2014 recommended establishing a new zone substation at the Arboretum site (comprising two transformers and two switchboards) by 2017-18, but lower load growth rate has enabled this to be deferred to 2021-22.

### 3.2.4. Utilities Act 2000 (ACT)

Evoenergy has an obligation to comply with the Utilities Act 2000 (ACT) which imposes specific technical, safety and reliability obligations via the Management of Electricity Network Assets Code and the Electricity Distribution Supply Standards Code.

The Electricity Distribution Supply Standards Code (August 2013) sets out performance standards for Evoenergy’s distribution network. Evoenergy is required to take all reasonable steps to ensure that its Electricity Network will have sufficient capacity to make an agreed level of supply available.

This local jurisdictional code specifies reliability standards that Evoenergy must endeavour to meet when planning, operating and maintaining the distribution network. It also specifies power quality parameters that must be met including limits on voltage flicker, voltage dips, switching transients, earth potential rise voltage unbalance, harmonics and direct current content.

The Management of Electricity Network Assets Code requires electricity distributors to protect integrity and reliability of the electricity network and to ensure the safe management of the electricity network without injury to any person or damage to property and the environment.

### 3.2.5. Evoenergy’s Distribution Network Augmentation Standards

Evoenergy’s distribution network augmentation standards are set to ensure compliance with the relevant regulatory instruments as described above.

Evoenergy’s planning standards are determined on an economic basis but expressed deterministically so that peak demand can be met with an appropriate level of backup should a credible contingency event occur. A credible contingency event is the loss of a single network element, which occurs sufficiently frequently, and has such consequences, as to justify Evoenergy to take prudent precautions to mitigate. This is commonly referred to as an N-1 event.

Zone substation capacity must be augmented if the forecast zone substation maximum demand based on 50% PoE under N-1 conditions exceeds the two-hour emergency rating.

Major zone substation augmentation such as the installation of an additional transformer will not be considered until all other options such as load transfer to adjacent zone substations and non-network options have been fully explored and implemented.

For high voltage (11kV) distribution feeders in urban areas Evoenergy specifies that there should be a minimum of two effective feeder ties to meet two-for-three arrangement where it is economically viable, i.e. two feeders able to supply the load normally supplied by three feeders. A firm rating is assigned to each feeder based on its thermal rating and the number of feeder ties available.

Distribution high voltage feeder capacity must be augmented or demand management solutions provided if the forecast 50% PoE feeder maximum demand exceeds the firm ratings as given in Table 5.

**Table 5: Feeder Firm Rating standard**

Feeder configuration	Firm rating as percentage of thermal capacity
Two or more feeder ties	75%
One feeder tie	50%
Feeders operating in parallel	$\{(N-1)/N\}\%$ <sup>1</sup>
Partial feeder tie	100% or less <sup>2</sup>
No feeder tie	100%

### 3.2.6. Cost compliance

Cost compliance is achieved by proactively pursuing the philosophy of compliance with the national electricity objective by fully exploring and evaluating all options technically and commercially so as to seek approval for a solution that provides sound grounds for an efficient investment while meeting the long term interests of the consumers.

The investment value has been determined using 2016-17 market prices. The methodology and estimated costs used for this project are developed through the application of industry knowledge and Good Engineering Operating Practices based on historical similar projects. This approach complies with paragraphs 6 & 7 of the National Electricity Law (NEL).

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<sup>1</sup> “N” represents the number of feeders operating in parallel.

<sup>2</sup> A partial feeder tie refers to a tie with limited back feeding capacity. The firm capacity of a feeder with a partial feeder tie may be set below 100% its thermal capacity.

## 4. Options Assessment

Evoenergy has considered five options to provide additional capacity to the Canberra City and Dickson areas as listed in Table 6.

**Table 6: Options considered for provision of additional capacity to Canberra City and Dickson**

Option	Option type	Description	Evaluation
0	Network	Do nothing	Not selected as does not meet minimum requirements
1	<b>Network</b>	<b>Construct new 11 kV cable feeder from City East Zone Substation to Canberra City and extend Haig feeder to Dickson area in two stages during 2019-20 and 2020-21 financial years.</b>	<b>Selected as higher NPC</b>
2	Network	Construct new 11 kV cable feeder from Civic Zone Substation to Canberra City and extend Haig feeder to Dickson area in two stages during 2019-20 and 2020-21 financial years.	Not selected due to lower NPC
3	Non-network	Demand side management and embedded generation	Not selected as does not meet minimum requirements and lower NPC
4	Mixed	Delay preferred network option using a grid battery	Not selected as cost of delay exceeded benefits
5	Non-network	Grid battery only	Not selected due to lower NPC

### 4.1. Options analysis

#### 4.1.1. Do Nothing Option

The 'Do Nothing' option would result in insufficient network capacity in the area to meet demand during a contingency event.

The value of energy at risk is estimated to be approximately \$2,169 over a five year period based on the probability of a contingency event at the same time as demand exceeding firm capacity.

Despite the relatively low value of energy at risk, the Do Nothing option would result in Evoenergy breaching its Distribution Network Augmentation Standards and thus its obligation to provide a reliable and secure power supply.

#### 4.1.2. Option 1: Construct new 11 kV cable feeder from City East Zone Substation to Canberra City and extend Haig feeder to Dickson area

Option 1 considers the installation of a new 11 kV cable feeder from City East Zone Substation to Canberra City and extension of the Haig feeder to the Dickson area to meet the growing load demand.

City East Zone Substation is nearest to the proposed major extension of the Canberra Centre at the corner of Cooyong St and Donaldson St. The route length of the 11 kV feeder from City East Zone Substation to this development is approximately 2.4 km. There are no spare conduits available along this route. It is proposed to install three conduits (two spare) from City East Zone Substation along Chisholm and Donaldson Streets to this site.

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The Haig feeder emanates from City East Zone Substation. It is lightly loaded and it is proposed to extend it to the proposed developments in the Dickson area. The route length for the extension of the Haig feeder from distribution substation S 9225 to the corner of Northbourne Ave / Morphett is approx 1.5 km. There are no spare conduits available along this route. The Wattle feeder cable will be disconnected from S874 and through-jointed to the extended Haig feeder.

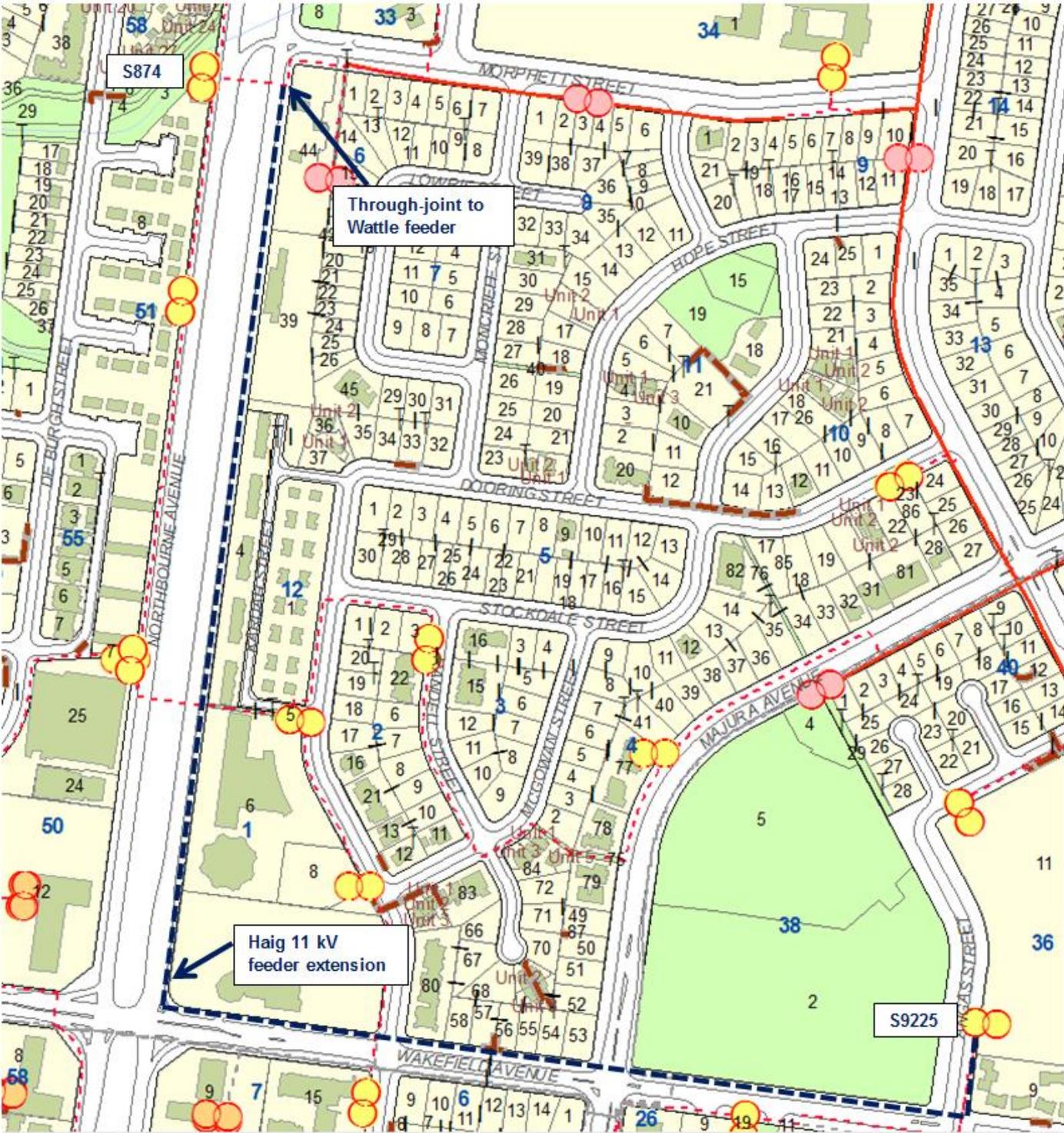
Figure 1 illustrates the proposed cable route of the new feeder from City East Zone Substation.

**Figure 1: Proposed 11 kV feeder cable route City East Zone Substation to Canberra City**



Figure 2 illustrates the proposed Haig feeder extension.

Figure 2: Proposed 11 kV Haig feeder cable extension to Dickson



A preliminary cost estimate for Option 1 is **\$2,914,000 excluding overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

Option 1 is selected due to its higher (ie least negative) net present cost (NPC). Proposed project completion is by June 2022.

### 4.1.3. Option 2: Construct new 11 kV cable feeder from Civic Zone Substation to Canberra City and extend Haig feeder to Dickson area

Option 2 considers the installation of a new 11 kV cable feeder from Civic Zone Substation to Canberra City and extension of the Haig feeder to the Dickson area to meet the growing load demand.

Civic Zone Substation is not the closest to the proposed major extension of the Canberra Centre at the corner of Cooyong St and Donaldson St. The route length of an 11 kV feeder from Civic Zone Substation to this development is approximately 6.0 km. There are no spare conduits available along this route.

The Haig feeder emanates from City East Zone Substation. It is lightly loaded and it is proposed to extend it to the propose developments in the Dickson area. The route length for the extension of the Haig feeder from distribution substation S 6629 to S 623 is approx. 2.1 km. There are no spare conduits available along this route.

A preliminary cost estimate for Option 2, the installation of a new feeder from Civic Zone Substation and extension of the Haig feeder, is **\$5,051,600 excluding overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

Option 2 is not selected due to its lower NPC.

### 4.1.4. Option 3: Demand management

Option 3 considers non-network initiatives including:

- Incentives to realise the potential of latent demand management within the customer base
- Incentives to encourage the uptake of additional demand management within the customer base

These options are further discussed within the Demand Management Paper.

To defer the Canberra City and Dickson feeder to the next regulatory control period (beyond 2024), it is estimated that non-network solutions would need to provide a maximum demand of approximately 12 MVA pa.

Latent demand management within the existing customer base was investigated, with a maximum estimated capacity of 1.14 MVA. This does not meet the minimum capacity to enable the new feeder to be deferred.

These non-network options are summarised in Table 7.

**Table 7: Summary of latent demand management**

Non-network Option	Electricity House feeder	Bunda feeder	Binara feeder	Cowper feeder	Total
Customer – owned embedded generation	0.2 MVA	0.2 MVA	0.3 MVA	0.2 MVA	<b>1.0 MVA</b>
Customer – owned energy storage	0.02 MVA	0.02 MVA	0.03 MVA	0.03 MVA	<b>0.1 MVA</b>
Load curtailment	0.01 MVA	0.01 MVA	0.01 MVA	0.01 MVA	<b>0.04 MVA</b>
<b>Totals</b>	<b>0.23 MVA</b>	<b>0.23 MVA</b>	<b>0.34 MVA</b>	<b>0.24 MVA</b>	<b>1.14 MVA</b>

In summary, a maximum demand reduction of 1.14 MVA could be achieved if all the above non-network options were implemented. This is not sufficient to defer the new feeder.

Third party non-network proposals have been requested in ActewAGL’s 2017 Annual Planning Report and via Evoenergy’s website demand management portal and may identify additional opportunities.

Where there is insufficient latent demand management within the customer base, there is further opportunity to incentivise customers to adopt additional technologies to reduce demand. This includes opportunities to permanently reduce demand (such as energy efficiency technology or power factor correction) as well as opportunities to adopt technology to enable participation in demand response markets (such as embedded generation, battery storage,

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building management systems). For the purposes of the evaluation, it is assumed that no more than 30% of demand growth can be offset using additional demand management.

For Canberra City and Dickson it was determined that more than 55% of demand growth would need to be offset by demand management to enable the project to be deferred, implying that new demand management is unlikely to defer investment.

### 4.1.5. Option 4: Grid battery to defer Option 1

This option utilises a grid battery to enable Option 1 to be deferred. This option has the advantage of deferring the investment until greater certainty in future demand is known. However, given the relatively high certainty of future demand for this project and the relatively high cost of the grid battery, this option was assessed as higher cost than the network Option 1 with a preliminary cost estimate of **\$5,391,139 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

### 4.1.6. Option 5: Grid battery only

This option utilises a grid battery only. A grid battery, although more expensive than a traditional network solution on a per MVA basis, has advantages over a traditional network solution. A grid battery is modular and is able to be redeployed, meaning it can represent a more economic option in an environment of demand uncertainty or where demand is expected to increase for a short period and then decline.

In the case of Canberra City and Dickson however, the grid battery was not economic due to the relative certainty of demand with a preliminary cost estimate of **\$84,837,579 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

### 4.1.7. Summary of Options Analysis

Table 8: Summary of Options

Option	Description	Total Capital Cost 2019-2039	Capital Cost 2019-24	20 year Net Present Cost	Outcome
0	Do nothing	\$0	\$0	\$0	Not selected as does not meet need
1	Construct new 11 kV cable feeder from City East Zone Substation to Canberra City and extend Haig feeder to Dickson	\$2,914,000	\$2,914,000	-\$2,770,375	Selected due to higher NPC
2	Construct new 11 kV cable feeder from Civic Zone Substation to Canberra City and extend Haig feeder to Dickson	\$5,051,600	\$5,051,600	-\$4,802,617	Not selected due to lower NPC
3	Demand side management	N/A	N/A	N/A	Not selected as does not meet need
4	Grid battery to defer Option 1	\$5,391,139	\$5,391,139	-\$4,656,651	Not selected as deferral not economic
5	Grid battery only	\$84,837,579	\$16,203,879	-\$42,061,231	Not selected due to lower NPC

## 4.2. Recommendation

The selected option is Option 1, the installation of a new 11 kV cable feeder from City East Zone Substation to Canberra City (Canberra Centre) and extension of the Haig feeder to the Dickson area.

Financial analysis shows Option 1 to be the best option due to its higher (ie least negative) NPC. It also has the lowest capital cost. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B. It can be implemented in time to meet the project needs as identified and will add to Evoenergy's regulated asset base. The major assets will have an economic life of 50 years.

The new feeder will provide capacity and security of supply to the proposed developments in Canberra City and Dickson areas.

Timing is scheduled for completion by June 2022. Future additional feeder cables will be installed as the load growth and demand increases with further development of Canberra City.

The preliminary cost estimate for the selected option is **\$2,914,000 excluding overheads, contingency and GST.**

Proposed 11 kV feeders will provide ties to existing feeders from Civic and Telopea Park zone substations, and thus provide some backup supply capability and load transfer capability in the future.

## Appendix A – Preliminary Cost Estimates

### A.1 Cost Estimate – Option 1: 11 kV cable feeder from City East Zone Substation to Canberra City and extend Haig feeder to Dickson

Installation of 11 kV feeder from City East Zone Substation to Canberra City (Stage 1) and extension of Haig feeder to Dickson (Stage 2). Assume one trench with 3 conduits (1 spare) and one directional drill with 3 conduits. Total route length for new feeder is approx 2.4 km. Total route length for Haig feeder extension approx 1.5 km.							
Preliminary Estimate ± 30% Accuracy							
Description	Notes	Unit	\$/Unit	Stage 1 Quantity	Stage 1 Cost	Stage 2 Quantity	Stage 2 Cost
Trenching and drilling					\$1,223,000		\$997,100
Clearing of route where required	Allowance	m2	\$10	2000	\$20,000	1160	\$11,600
Directional drilling	Assume drilling with no rock. Assume three conduits per drill. Assume 50% of 2.4 km and 2.1 km total route length to be drilled for stage 1 & 2 respectively, ie 1.2 km for stage 1 and 1.05 km for stage 2.	m	\$600	1200	\$720,000	1500	\$900,000
Open trenching and backfilling	Assume excavation with no rock. Backfill with bedding sand and native soil. Assume three conduits per trench. Assume 50% of 2.4 km and 2.1 km total route length can be trenched, ie 1.2 km for stage 1 and 1.05 km	m	\$300	1200	\$360,000	30	\$9,000
Cable jointing and haulage pits	Assume every 500m	ea	\$3,000	5	\$15,000	3	\$9,000
Traffic management required	Allowance	m3	\$40	2400	\$96,000	1500	\$60,000
<b>Cabling works</b>					<b>\$228,400</b>		<b>\$143,000</b>
11 kV 3c/400mm2 Al XLPE cable		m	\$56	2400	\$134,400	1500	\$84,000
Throughjoints	Assume every 500m	ea	\$1,000	5	\$5,000	3	\$3,000
Terminations	switchgear	ea	\$1,500	2	\$3,000	1	\$1,500
Conduit and marker tape	1x63mm)	m	\$15	2400	\$36,000	1500	\$22,500
HV Cables Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000	1	\$2,000
Cable installation labour and plant		m	\$20	2400	\$48,000	1500	\$30,000
<b>Electrical (Secondary System)</b>					<b>\$12,000</b>		<b>\$2,500</b>
Protection & Control					\$5,000		\$2,500
P&C Secondary Cabling	per feeder panel	ea	\$2,500	1	\$2,500	0	\$0
P&C Test & Commission	Allowance	ea	\$2,500	1	\$2,500	1	\$2,500
Protection upgrade if required	Allowance	ea	\$40,000	1	\$40,000	0.5	\$20,000
<b>DC Supply System</b>					<b>\$7,000</b>		<b>\$0</b>
DC Cabling	per switchgear panel/bay	ea	\$5,000	1	\$5,000	0	\$0
DC Test & Commission	Allowance	ea	\$2,000	1	\$2,000	0	\$0
<b>Other Required Works</b>					<b>\$0</b>		<b>\$0</b>
	Allowance	ea		1	\$0	1	\$0
	Allowance	ea		1	\$0	1	\$0
<b>SCADA</b>					<b>\$4,000</b>		<b>\$4,000</b>
panels		ea	\$2,000	1	\$2,000	1	\$2,000
Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000	1	\$2,000
<b>Indirect Costs</b>					<b>\$150,000</b>		<b>\$150,000</b>
Development Application	Allowance	ea	\$75,000	1	\$75,000	1	\$75,000
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea	\$25,000	1	\$25,000	1	\$25,000
administration	Allowance	ea	\$50,000	1	\$50,000	1.0	\$50,000
<b>Stage Sub Total without overheads</b>					<b>\$1,617,400</b>		<b>\$1,296,600</b>
<b>Project Sub Total without overheads</b>							<b>\$2,914,000</b>
<b>Overheads</b>							
Overall average overhead rate	Allowance	27%		1	\$436,698	1	\$350,082
<b>Stage Sub Total with overheads</b>					<b>\$2,054,098</b>		<b>\$1,646,682</b>
<b>Project Sub Total with overheads</b>							<b>\$3,700,780</b>
<b>Contingency</b>							
All project works	Preliminary allowance	10%		1	\$205,409.80	1	\$164,668.20
<b>Stage total with all overheads and contingency</b>					<b>\$2,259,508</b>		<b>\$1,811,350</b>
<b>Project total with all overheads and contingency</b>							<b>\$4,070,858</b>

## A.2 Cost Estimate – Option 2: 11 kV cable feeder from Civic Zone Substation to Canberra City and extend Haig feeder to Dickson

Installation of 11 kV feeder from Civic Substation to Canberra City (Stage 1) and extension of Haig feeder to Dickson (Stage 2). Assume one trench with 3 conduits (1 spare) and one directional drill with 3 conduits. Total route length for new feeder is approx 6.0 km. Total route length for Haig feeder extension approx 2.1 km.							
Preliminary Estimate ± 30% Accuracy							
Description	Notes	Unit	\$/Unit	Stage 1 Quantity	Stage 1 Cost	Stage 2 Quantity	Stage 2 Cost
<b>Trenching and drilling</b>					\$3,026,000		\$1,054,500
Clearing of route where required	Allowance	m2	\$10	2000	\$20,000		\$0
Directional drilling	Assume drilling with no rock. Assume three conduits per drill. Assume 50% of 6 km and 2.1 km total route length to be drilled for stage 1 & 2 respectively, ie 3 km for stage 1 and 1.05 km for stage 2.	m	\$600	3000	\$1,800,000	1050	\$630,000
Open trenching and backfilling	Assume excavation with no rock. Backfill with bedding sand and native soil. Assume three conduits per trench. Assume 50% of 6 km and 2.1 km total route length can be trenched, ie 3 km for stage 1 and 1.05 km for stage 2.	m	\$300	3000	\$900,000	1050	\$315,000
Cable jointing and haulage pits	Assume every 500m	ea	\$3,000	12	\$36,000	5	\$15,000
Traffic management		m	\$5	6000	\$30,000	2100	\$10,500
Reinstatement incl revegetation as required	Allowance	m3	\$40	6000	\$240,000	2100	\$84,000
<b>Cabling works</b>					\$563,000		\$201,100
11 kV 3c/400mm2 Al XLPE cable		m	\$56	6000	\$336,000	2100	\$117,600
Throughjoints	Assume every 500m	ea	\$1,000	12	\$12,000	5	\$5,000
Terminations	Terminations at City East CB and D Sub switchgear	ea	\$1,500	2	\$3,000	2	\$3,000
Conduit and marker tape	(3x150mm plus 2x63mm) + (1x150mm plus 1x63mm)	m	\$15	6000	\$90,000	2100	\$31,500
HV Cables Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000	1	\$2,000
Cable installation labour and plant		m	\$20	6000	\$120,000	2100	\$42,000
<b>Electrical (Secondary System)</b>					\$12,000		\$12,000
Protection & Control					\$5,000		\$5,000
P&C Secondary Cabling	per feeder panel	ea	\$2,500	1	\$2,500	1	\$2,500
P&C Test & Commission	Allowance	ea	\$2,500	1	\$2,500	1	\$2,500
Protection upgrade if required	Allowance	ea	\$40,000	1	\$40,000	0.5	\$20,000
DC Supply System					\$7,000		\$7,000
DC Cabling	per switchgear panel/bay	ea	\$5,000	1	\$5,000	1	\$5,000
DC Test & Commission	Allowance	ea	\$2,000	1	\$2,000	1	\$2,000
<b>Other Required Works</b>					\$0		\$0
	Allowance	ea		1	\$0	1	\$0
	Allowance	ea		1	\$0	1	\$0
<b>SCADA</b>					\$4,000		\$4,000
SCADA connections for new feeder panels		ea	\$2,000	1	\$2,000	1	\$2,000
Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000	1	\$2,000
<b>Indirect Costs</b>					\$150,000		\$25,000
Development Application	Allowance	ea	\$100,000	1	\$100,000	0	\$0
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea		1	\$0	1	\$0
Project management and administration	Allowance	ea	\$50,000	1	\$50,000	0.5	\$25,000
<b>Stage Sub Total without overheads</b>					\$3,755,000		\$1,296,600
<b>Project Sub Total without overheads</b>							\$5,051,600
<b>Overheads</b>							
Overall average overhead rate	Allowance	27%		1	\$1,013,850	1	\$350,082
<b>Stage Sub Total with overheads</b>					\$4,768,850		\$1,646,682
<b>Project Sub Total with overheads</b>							\$6,415,532
<b>Contingency</b>							
All project works	Preliminary allowance	10%		1	\$476,885.00	1	\$164,668.20
<b>Stage total with all overheads and contingency</b>					\$5,245,735		\$1,811,350
<b>Project total with all overheads and contingency</b>							\$7,057,085

## Appendix B – Financial Analysis

### B.1 Capital Expenditure Cash Flow for Each Option

Financial Year	Option 1	Option 2	Option 3	Option 4 *	Option 5 *
2019/20					
2020/21	\$2,914,000	\$5,051,600		\$2,477,139	\$2,477,139
2021/22				\$2,914,000	\$4,575,580
2022/23					\$4,575,580
2023/24					\$4,575,580
2024/25					\$4,575,580
2025/26					\$4,575,580
2026/27					\$4,575,580
2027/28					\$4,575,580
2028/29					\$4,575,580
2029/30					\$4,575,580
2030/31					\$4,575,580
2031/32					\$4,575,580
2032/33					\$4,575,580
2033/34					\$4,575,580
2034/35					\$4,575,580
2035/36					\$4,575,580
2036/37					\$4,575,580
2037/38					\$4,575,580
2038/39					\$4,575,580
<b>Total Cost (20 yr)</b>	<b>\$2,914,000</b>	<b>\$5,051,600</b>	<b>N/A</b>	<b>\$5,391,139</b>	<b>\$16,203,879</b>
<b>2019-24 Regulatory Control Period Cost</b>	<b>\$2,914,000</b>	<b>\$5,051,600</b>	<b>N/A</b>	<b>\$5,391,139</b>	<b>\$84,837,579</b>

\* Options 4 and 5 utilise a network owned battery which is modular and redeployable and has a 10 year lifetime. The battery is costed on a lease-like basis.

## B.2 NPC Analysis

The Net Present Cost (NPC) was calculated using a Monte-Carlo simulation model. The simulation randomly selects a peak demand growth rate for each year that is within  $\pm 10\%$  of the forecasted spot loads expected in Kingston. The use of a Monte-Carlo simulation results in selection of the best option that is robust to uncertain peak demand growth forecasts.

Investment within the simulation is dynamic – investment decisions change based on the randomly selected growth rates from previous years. Investment occurs automatically when the firm rating is breached so the value of energy at risk is always zero. In options where multiple investments are available the cheapest is selected.

### Summary Financial Analysis Results for Supply to Kingston Foreshore

The summary below shows the average values for the selected characteristics after 50 simulations.

#### Options:

One – new 11 kV feeder from City East Zone Substation

Two – new 11 kV feeder from Civic Zone Substation

Three – Demand management

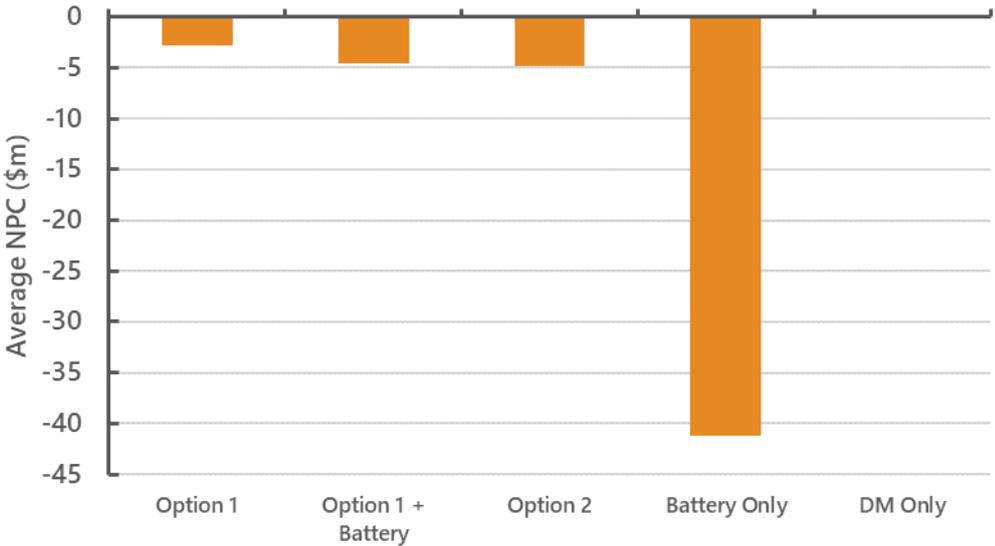
Four – Grid battery to defer option 1

Five – Grid battery only

#### RESULTS (Average over 50 simulations):

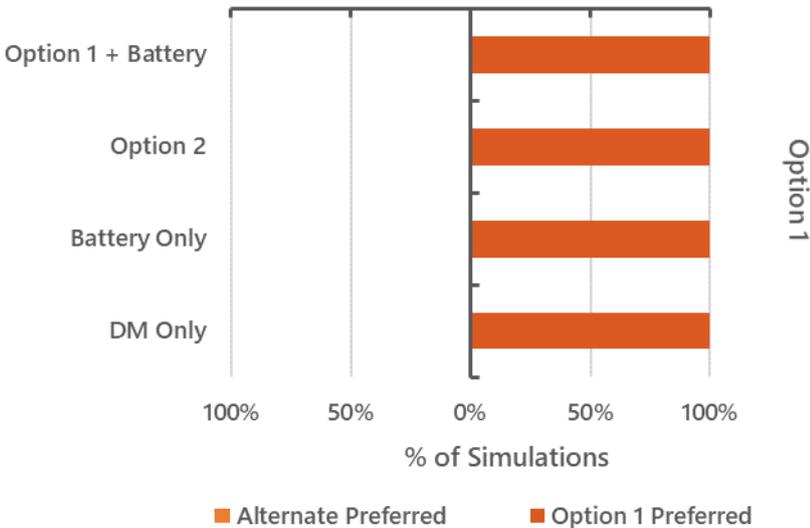
Option:	One	Two	Three	Four	Five
NPC (2019-2024)	-\$2,519,533	-\$4,370,120	N/A	-\$4,282,564	-\$11,888,028
NPC (2019-2039)	-\$2,770,878	-\$4,805,841	N/A	-\$4,533,908	-\$41,264,554
Network Option total Capital Cost	\$2,914,000	\$5,051,600	N/A	\$2,914,000	-
Option Capital Cost (2019-2024)	\$2,914,000	\$5,051,600	N/A	\$5,237,338	\$15,863,320
Option Capital Cost (2019-2039)	\$2,914,000	\$5,051,600	N/A	\$5,237,338	\$83,261,118

**Average Net Present Cost for Each Network / Non-Network Combination:**



Multiple combinations of network options, demand management and network batteries were tested using the Monte-Carlo model. The preferred option was selected on the basis of minimising the Net Present Cost.

**Percentage of Simulations where the Selected Option had a Lower Cost than Other Options:**



The random variation in peak demand growth in the Monte-Carlo model means that different options may be preferred in some simulations. The above chart shows that Option 1 was the preferred option in 100% of simulations.

**Value of Risk:**

Year	Volume of Energy at Risk (kWh)	Value of Energy at Risk (\$)
2020	-	-
2021	15,320	31
2022	190,659	343
2023	537,020	897
2024	537,020	897

**Notes:**

Energy at risk is the volume of energy served above the firm rating each year. An indicative load duration curve has been used to determine the relationship between peak demand, firm rating and volume of energy in kWh.

Value at risk assumes:

Value of Customer Reliability = \$26.93/kWh

Probability of Failure = 6% (3% annual probability of transformer failure + 3% probability of feeder failure)

Outage duration = 8 hours

Probability of failure in any given hour:  $6\% * 8 / 24 / 365$

Value above firm rating = VCR \* probability \* volume of energy

All energy above the emergency rating is not served. This is equivalent to assuming a 100% outage probability for energy above this level.

In addition to the VCR cost, there are litigation, reputational and other financial risks that are included in the total:

Litigation costs = \$100,000 / event

Reputational risk cost = external consultations and communications costs = \$10,000 / event.

Financial risk cost = internal investigation costs = \$10,000 / event.

**Total risk cost** = Reliability risk cost + Litigation + Reputational risk cost + Financial risk cost  
 = VCR / kWh + \$120,000 / event.