

Appendix 5.31: Supply to Canberra CBD 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

Project name	Supply to Canberra CBD
Expenditure type	Capital Expenditure
Business Group	Asset Strategy
Regulatory Period	1 July 2019 to 30 June 2024
Total Project Cost Estimate	\$892,600 excluding corporate overheads, excluding contingency, and excluding GST
Five year total spend 2019-24	\$892,600 excluding corporate overheads, excluding contingency, and excluding GST
CAPEX category	ENAA Distribution
Primary driver	Load growth in Canberra City CBD
Project Number	20004673

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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
Electricity Distribution Supply Standards Code		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
Suburban Land Agency Indicative Land Release Program 2017-21		2017
Evoenergy Peak Demand Reduction Strategy	2.0	22.8.17
CutlerMerz Augex Uncertainty Risk Appraisal (AURA) Model Methodology	1.0	Nov 2017

1. Executive Summary

This Project Justification Report addresses the growth of electricity demand in the Canberra Central Business District (CBD) area and evaluates options re how Evoenergy can meet these needs.

The maximum demand in the Canberra Central Business District (CBD) is forecast to increase steadily over the next five years with major residential and commercial developments along with the ACT Government's City to the Lake long term urban renewal plan. The load in this area is typically summer peaking. The new development is likely to incorporate high energy efficiency and solar PV, incorporated within the demand forecast.

The existing combined summer firm rating of the four 11 kV feeders in the vicinity of the proposed developments around Canberra CBD is approximately 17.8 MVA with a combined available spare capacity is 5.6 MVA. The forecast load growth in these areas indicates the available spare capacity will be fully utilised by 2021 and approximately 8.6 MVA supply capacity will be non-firm by 2023.

The preferred option to meet the new demand is a new 11 kV feeder from Civic Zone Substation to London Circuit to supply growing load demand as existing feeders supplying the CBD near firm capacity loading.

The proposed new 11 kV feeder from Civic Zone Substation will inter-tie with 11 kV feeders from City East and Telopea Park Zone Substations to provide backup security of supply in the event of an outage at Civic.

Other options considered include an additional feeder from City East Zone Substation, demand management, and a grid battery. The additional feeder was excluded due to its high net present cost (compared with the preferred option). Demand management was not considered feasible due to the insufficient existing capacity such that there is a requirement for greater than 40% of new demand to be offset. The grid battery was excluded due to a higher net present cost and the relative certainty of the demand increase (noting grid batteries and other modular solutions deliver a higher options value in the context of uncertain demand).

A preliminary cost estimate for the preferred option is **\$892,600 excluding corporate overheads, contingency and GST**. These works will be carried out during the 2019-24 Regulatory Control Period, with proposed project completion by June 2020.

2. Strategic Context and Expenditure Need

There is significant development proposed for the Canberra CBD, in particular the existing carparks around London Circuit are to be redeveloped as multi-storey commercial and residential apartment buildings.

2.1. Existing infrastructure in the Canberra CBD (London Circuit) area

There are four 11 kV feeders supplying the London Circuit area in Canberra’s CBD. These are Binara and Electricity House feeders from City East Zone Substation, Hobart Short from Civic Zone substation, and Edmond Barton from Telopea Park Zone Substation.

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 the London Circuit area, Canberra CBD

Feeder Name	Zone Sub	MVA				2015		2016		2017	Spare 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	
Canberra CBD											
Binara	CE	4.9	6.5	5.4	7.2	68%	72%	68%	47%	69%	1.51
Elec House	CE	4.8	6.3	5.3	7.0	49%	26%	48%	27%	48%	2.46
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
Total											5.63

2.2. Driving need for infrastructure investment

Forecast additional maximum demand in the Canberra CBD 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 CBD

Proposed Development and Net Additional Diversified Load in MVA	2018	2019	2020	2021	2022	2023	Total
B21, S 63 – London Circuit, commercial development (PN 20003048)	0.5	0.5	1	1.5	1.5	1.5	6.5
B4 S19 – London Circuit, commercial development (PN 20003048)	0.5	0.5	1				2
B3 S12 - 20 Allara St, residential apartment development (PN 20004555)	0.5	0.5	0.5				1.5
B3 S3 – 33 London Circuit, mixed-use development (PN 20002983)	0.75						0.75
B27 S26 - 69 Northbourne Ave, mixed-use development (PN 20003928)	0.45	0.4	0.4				1.25
S96 - Canberra Centre extension, Cooyong & Genge Sts, commercial development (PN 20003452)		1	1	2	2.5	1.8	8.3
B20, S 63 – London Circuit, mixed-use development				1.5	1.5	1.5	4.5
Additional Load (MVA)	2.7	2.9	3.9	5.0	5.5	4.8	14.8
Cumulative additional forecast load (MVA)	2.7	5.6	9.5	14.5	20.0	24.8	24.8

Table 2 shows that cumulative additional load in the area will exceed the available spare firm capacity by winter 2020.

The proposed residential developments in Canberra City and Dickson are primarily multi-storey apartment buildings. To date these have tended to be all-electric and built without solar PV or battery energy storage facilities. Although the buildings themselves and installed appliances (reverse cycle heat pumps, lighting etc) are energy efficient, an after diversity maximum demand (ADMD) figure of 2.5 kVA per unit has been assumed. This allows for current energy efficiency measures and will allow for the expected uptake of electric vehicle charging facilities and instantaneous hot-water heating systems in the future. A concerted effort is proposed by Evoenergy as part of its Demand Side Management initiative, to work with developers and their designers at an early stage, to consider alternative energy sources such as gas, and to increase electrical energy efficiency (building management systems, centralised gas hot-water heating systems etc).

The *Electricity Distribution (Supply Standards) Code* issued by the ACT Independent Competition and Regulatory Commission (ICRC) sets out certain performance standards for the distribution network in the ACT. A Distribution Network Service Provider (DNSP) 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”. The processes defined in these criteria serve to limit network augmentation expenditure to instances where the increase in demand is clear and above the secure or firm capacity.

3. Objectives

3.1. Corporate, asset management and key project objectives

The corporate, asset management and related key project objectives are shown in Table 3 below. These objectives are used to assess the relative risk of options.

Table 3: Corporate, asset management and key project objectives

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

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.

For high voltage (11 kV) 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 4.

Table 4: 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	$\{(N-1)/N\}\%1$
Partial feeder tie	100% or less ²
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).

¹ “N” represents the number of feeders operating in parallel.

² 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 (plus a do nothing option) to provide additional capacity to London Circuit, Canberra CBD as listed in Table 5.

Table 5: Options considered for provision of additional capacity to London Circuit

Option	Option type	Description	Evaluation
0	Network	Do nothing	Not selected as does not meet minimum requirements
1	Network	Construct new 11 kV cable feeder from Civic Zone Substation to London Circuit	Selected as higher NPC
2	Network	Construct new 11 kV cable feeder from City East Zone Substation to London Circuit	Not selected due to lower NPC
3	Non-network	Demand side management	Not selected as does not meet minimum requirements and lower NPC
4	Non-network	Grid battery	Not selected due to lower NPC
5	Mixed	Delayed preferred network option using grid battery	Not selected as cost of delay exceeds benefits

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 \$1,361 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 feeder from Civic Zone Substation to Canberra CBD

Option 1 considers the installation of a new 11 kV cable feeder from Civic Zone Substation to London Circuit to meet the growing load demand.

Civic Zone Substation is nearest to the proposed development on the corner of London Circuit and Edinburgh Ave. The route length of the 11 kV feeder from Civic Zone Substation to this development is approximately 3.6 km. There will be a spare conduit available for 3.2 km from Civic Zone Substation to Edinburgh Ave (to be installed under a separate project). It is proposed two conduits (one spare) are installed from Edinburgh Ave to the development at B21 S63 on London Circuit.

A preliminary estimated cost for Option 1, for the installation of a new feeder from Civic Zone Substation to the London Circuit is **\$892,600 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B. Proposed project completion is June 2020.

4.1.3. Option 2: Construct new 11 kV feeder from City East Zone Substation to Canberra CBD

Option 2 considers the installation of a new 11 kV cable feeder from City East Zone Substation to London Circuit to meet the growing load demand.

City East Zone Substation is not the closest to the proposed development on the corner of London Circuit and Edinburgh Ave. The route length of an 11 kV feeder from City East Zone Substation to this development is approx. 4.0 km. There are no spare conduits available along this route.

A preliminary cost estimate for Option 2, the installation of a new feeder from City East Zone Substation, is **\$2,567,000 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPV 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 CBD 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 3.9 MVA pa.

Latent demand management within the existing customer base was investigated, with a maximum estimated capacity of 1.017 MVA. This does not meet the minimum capacity required of 3.9 MVA by 2020 to enable the new feeder to be deferred.

These non-network options are summarised in Table 6.

Table 6: Summary of latent demand management

Non-network Option	Electricity House Feeder	Binara Feeder	Total
Customer – owned embedded generation	0.2 MVA	0.3 MVA	0.5 MVA
Customer – owned energy storage	0.02 MVA	0.03 MVA	0.05 MVA
Load curtailment	0.007 MVA	0.010 MVA	0.017 MVA
Totals	0.447 MVA	0.57 MVA	0.567 MVA

In summary, a maximum demand reduction of 0.567 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 will be requested in Evoenergy’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, 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.

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For Canberra CBD it was determined that more than 40% 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

A further option to adopt a grid battery to defer Option 1 was also explored. 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 **\$1,485,677 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPV comparison in Appendices A and B.

4.1.6. Option 5: Grid battery only

The final option explored the use of 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 network battery is modular and also 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 CBD however, the grid battery was not economic due to the relative certainty of demand with a preliminary cost estimate of **\$15,816,300 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPV comparison in Appendices A and B.

4.1.7. Summary of Options Analysis

Table 7: 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 Civic Zone Substation to London Circuit	\$892,600	\$892,600	-\$882,010	Selected due to higher NPC
2	Construct new 11 kV cable feeder from City East Zone Substation to London Circuit	\$2,567,000	\$2,567,000	-\$2,536,545	Not selected due to lower NPC
3	Demand management	N/A	N/A	N/A	Not selected as does not meet need
4	Grid battery to defer Option 1	\$1,485,677	\$1,485,677	-\$1,438,050	Not selected as deferral not economic
5	Grid battery only	\$15,816,300	\$3,462,235	-\$8,039,260	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 Civic Zone Substation to the proposed developments on London Circuit.

Financial analysis (refer Appendix B) shows Option 1 to be the best option due to its higher (i.e. 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 new developments at London Circuit, Canberra CBD.

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Timing is scheduled for completion by June 2020. Future additional feeder cables will be installed as the load growth and demand increases with further development of Canberra CBD.

The preliminary cost estimate of the selected option is **\$892,600 excluding overheads, contingency and GST**.

The proposed 11 kV feeder will provide ties to existing feeders from City East 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

Installation of 11 kV feeder from Civic Zone Substation to London Circuit. One Spare conduit will be installed from Civic zone substation to Nishi Building on Edinburgh Ave under project 1752000 & 17519152. Total route length for new feeder is approx 3.6 km. Spare Conduit available for 3.2 km. For remaining 400m from Nishi building to London Circuit, assume one trench with 2 conduits (1 spare) and one directional drill with 2 conduits.					
Preliminary Estimate ± 30% Accuracy					
Description	Notes	Unit	\$/Unit	Quantity	Cost
Trenching and drilling					\$386,000
Clearing of route where required	Allowance	m2	\$10	2000	\$20,000
Directional drilling	Assume drilling with no rock. Assume two conduits per drill. Assume 50% of 400 m to be drilled, ie 200m.	m	\$600	200	\$120,000
Open trenching and backfilling	Assume drilling with no rock. Assume two conduits per trench. Assume 50% of 400 m to be trenched, ie 200m.	m	\$300	200	\$60,000
Cable jointing and haulage pits	Assume every 500m	ea	\$3,000	8	\$24,000
Traffic management		m	\$5	3600	\$18,000
Reinstatement incl revegetation as required	Allowance	m3	\$40	3600	\$144,000
Cabling works					\$340,600
11 kV 3c/400mm2 Al XLPE cable		m	\$56	3600	\$201,600
Throughjoints	Assume every 500m	ea	\$1,000	8	\$8,000
Terminations	Terminations at City East CB and distribution substation switchgear	ea	\$1,500	2	\$3,000
Conduit and marker tape	(3x150mm plus 2x63mm) + (1x150mm plus 1x63mm)	m	\$15	3600	\$54,000
HV Cables Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000
Cable installation labour and plant		m	\$20	3600	\$72,000
Electrical (Secondary System)					\$12,000
Protection & Control					\$5,000
P&C Secondary Cabling	per feeder panel	ea	\$2,500	1	\$2,500
P&C Test & Commission	Allowance	ea	\$2,500	1	\$2,500
Protection upgrade if required	Allowance	ea	\$40,000	1	\$40,000
DC Supply System					\$7,000
DC Cabling	per switchgear panel/bay	ea	\$5,000	1	\$5,000
DC Test & Commission	Allowance	ea	\$2,000	1	\$2,000
Other Required Works					\$0
	Allowance	ea		1	\$0
	Allowance	ea		1	\$0
SCADA					\$4,000
SCADA connections for new feeder panels		ea	\$2,000	1	\$2,000
Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000
Indirect Costs					\$150,000
Development Application	Allowance	ea	\$100,000	1	\$100,000
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea		1	\$0
Project management and administration	Allowance	ea	\$50,000	1	\$50,000
Project Sub Total without overheads					\$892,600
Overheads					
Overall average overhead rate	Allowance	27%		1	\$241,002
Project Sub Total with overheads					\$1,133,602
Contingency					
All project works	Preliminary allowance	10%		1	\$113,360
Project total with all overheads and contingency					\$1,246,962

A.2 Cost Estimate – Option 2

Installation of 11 kV feeder from City East Zone Substation to London Circuit. Total route length for new feeder is approx 4 km. Assume one trench with 2 conduits (1 spare) and one directional drill with 2 conduits.					
Preliminary Estimate ± 30% Accuracy					
Description	Notes	Unit	\$/Unit	Quantity	Cost
Trenching and drilling					\$2,024,000
Clearing of route where required	Allowance	m2	\$10	2000	\$20,000
Directional drilling	Assume drilling with no rock. Assume two conduits per drill. Assume 50% of 4 km to be drilled, ie 2 km.	m	\$600	2000	\$1,200,000
Open trenching and backfilling	Assume drilling with no rock. Assume two conduits per trench. Assume 50% of 4 km to be trenched, ie 2 km.	m	\$300	2000	\$600,000
Cable jointing and haulage pits	Assume every 500m	ea	\$3,000	8	\$24,000
Traffic management		m	\$5	4000	\$20,000
Reinstatement incl revegetation as required	Allowance	m3	\$40	4000	\$160,000
Cabling works					\$377,000
11 kV 3c/400mm2 Al XLPE cable		m	\$56	4000	\$224,000
Throughjoints	Assume every 500m	ea	\$1,000	8	\$8,000
Terminations	Terminations at City East CB and D Sub switchgear	ea	\$1,500	2	\$3,000
Conduit and marker tape	(3x150mm plus 2x63mm) + (1x150mm plus 1x63mm)	m	\$15	4000	\$60,000
HV Cables Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000
Cable installation labour and plant		m	\$20	4000	\$80,000
Electrical (Secondary System)					\$12,000
Protection & Control					\$5,000
P&C Secondary Cabling	per feeder panel	ea	\$2,500	1	\$2,500
P&C Test & Commission	Allowance	ea	\$2,500	1	\$2,500
Protection upgrade if required	Allowance	ea	\$40,000	1	\$40,000
DC Supply System					\$7,000
DC Cabling	per switchgear panel/bay	ea	\$5,000	1	\$5,000
DC Test & Commission	Allowance	ea	\$2,000	1	\$2,000
Other Required Works					\$0
	Allowance	ea		1	\$0
	Allowance	ea		1	\$0
SCADA					\$4,000
SCADA connections for new feeder panels		ea	\$2,000	1	\$2,000
Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000
Indirect Costs					\$150,000
Development Application	Allowance	ea	\$100,000	1	\$100,000
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea		1	\$0
Project management and administration	Allowance	ea	\$50,000	1	\$50,000
Project Sub Total without overheads					\$2,567,000
Overheads					
Overall average overhead rate	Allowance	27%		1	\$693,090
Project Sub Total with overheads					\$3,260,090
Contingency					
All project works	Preliminary allowance	10%		1	\$326,009
Project total with all overheads and contingency					\$3,586,099

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	\$892,600	\$2,567,000	N/A	\$593,077	\$593,077
2020-21				\$892,600	\$538,304
2021-22					\$807,455
2022-23					\$807,455
2023-24					\$807,455
2024-25					\$807,455
2025-26					\$807,455
2026-27					\$807,455
2027-28					\$807,455
2028-29					\$807,455
2029-30					\$807,455
2030-31					\$807,455
2031-32					\$807,455
2032-33					\$807,455
2033-34					\$807,455
2034-35					\$807,455
2035-36					\$807,455
2036-37					\$807,455
2037-38					\$807,455
2038-39					\$807,455
Total Cost (20 years)	\$892,600	\$2,567,000	N/A	\$1,485,677	\$3,553,746
2019-24 Regulatory Control Period Cost	\$892,600	\$2,567,000	N/A	\$1,485,677	\$15,665,571

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 the Canberra CBD. 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 Canberra CBD

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

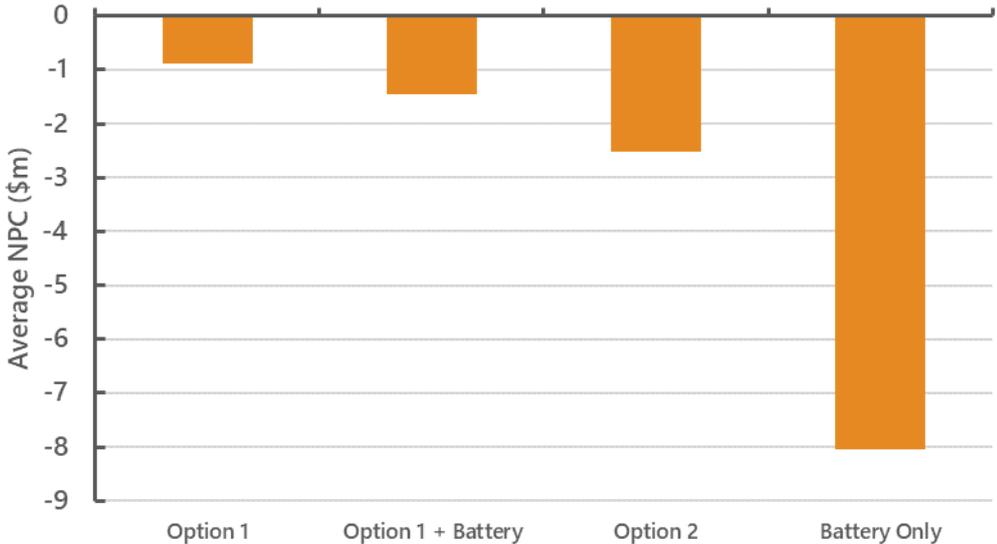
Options:

- One – one new 11 kV feeders from Civic Zone Substation
- Two – one new 11 kV feeders from City East Zone Substation
- Three – best non-network option (grid battery)
- Four – best mixed network and non-network combination (Option one plus grid battery)

RESULTS (Average over 50 simulations):

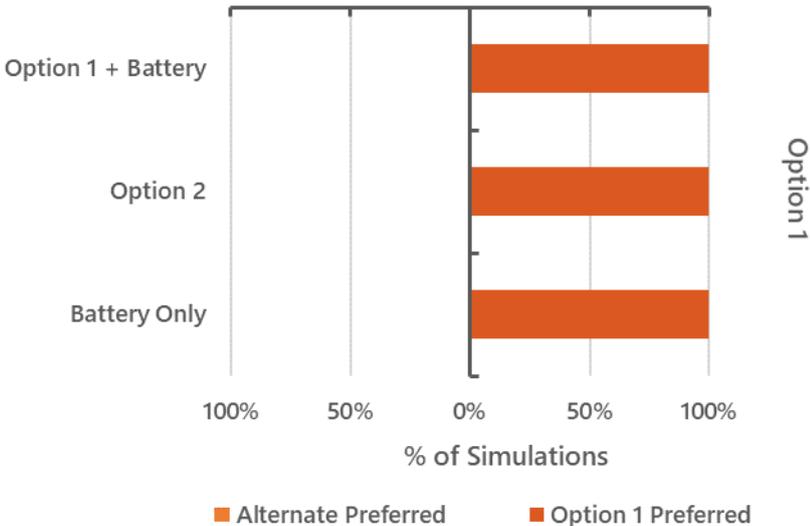
Option:	One	Two	Three	Four
NPC (2019-2024)	-\$805,020	-\$2,315,131	-\$2,754,515	-\$1,361,060
NPC (2019-2039)	-\$882,010	-\$2,536,545	-\$8,315,225	-\$1,438,050
Network Option total Capital Cost	\$892,600	\$2,567,000	-	\$892,600
Option Capital Cost (2019-2024)	\$892,600	\$2,567,000	\$3,553,746	\$1,485,677
Option Capital Cost (2019-2039)	\$892,600	\$2,567,000	\$15,665,571	\$1,485,677

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	35	0
2021	8,763	28
2022	85,811	203
2023	283,749	565
2024	283,749	565

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.