

Appendix 5.35: Supply to Belconnen 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 Belconnen
Expenditure type	Capital Expenditure
Business Group	Asset Strategy
Regulatory Period	1 July 2019 to 30 June 2024
Total Project Cost Estimate	\$2,369,200 excluding corporate overheads, excluding contingency, and excluding GST
Five year total spend 2019-24	\$2,369,200 excluding corporate overheads, excluding contingency, and excluding GST
CAPEX category	ENAA Distribution
Primary driver	Load growth in Belconnen
Project Number	PN 20004446

Contents

Reference documents 3

1. Executive Summary 4

2. Strategic Context and Expenditure Need 5

 2.1. Existing infrastructure in the Belconnen area 5

 2.2. Driving need for infrastructure investment 6

3. Objectives 7

 3.1. Corporate, asset management and key project objectives 7

 3.2. Regulatory Compliance 8

 3.2.1. National Electricity Law and National Electricity Rules 8

 3.2.2. Capital Expenditure Objectives and Criteria 8

 3.2.3. Regulatory Investment Test 9

 3.2.4. Utilities Act 2000 (ACT) 9

 3.2.5. Evoenergy’s Distribution Network Augmentation Standards 9

 3.2.6. Cost compliance 10

4. Options Assessment 11

 4.1. Options analysis 11

 4.1.1. Do Nothing Option 11

 4.1.2. Option 1: Construct three new 11 kV cable feeders from Belconnen Zone Substation to Belconnen 11

 4.1.3. Option 2: Construct three new 11 kV cable feeders from Latham Zone Substation to Belconnen 13

 4.1.4. Option 3: Construct new Mitchell Zone Substation 14

 4.1.5. Option 4: Demand management 14

 4.1.6. Option 5: Grid battery to defer Option 1 15

 4.1.7. Option 6: Grid battery only 15

 4.1.8. Summary of Options Analysis 16

 4.2. Recommendation 16

Appendix A – Financial Analysis 17

Appendix B: NPC Analysis 20

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 2017		22.12.17
Australian Power Generation Technology Report, EPRI	2015	2015
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
Evoenergy Mobile Substation Deployment PR1191	1.0	8.5.15
Evoenergy Peak Demand Reduction Strategy	2.0	22.8.17
Evoenergy Electrical Data Manual SM1183	5.0	22.6.17
Augmentation NPC Model Methodology	1.0	29.9.17

1. Executive Summary

This project justification report examines options for supplying forecast load developments in the Belconnen area.

The maximum demand in the Belconnen area is forecast to increase by approximately 9.5 MVA by 2022 with the completion of a number of new residential and commercial developments.

This project proposes three new 11 kV cable feeders to be installed from Belconnen Zone Substation to the Belconnen area. Spare conduits will be installed along the feeder route to provide for future developments and load growth.

The proposed feeders will inter-tie with existing feeders emanating from Gold Creek, Belconnen and Latham zone substations, and thus enable load to be transferred off highly-loaded feeders.

Other options considered and evaluated were the installations of feeders from the Latham zone substation, the installation of a new zone substation in Belconnen, 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 installing three new 11 kV feeders from Belconnen Zone Substation to Belconnen is **\$2,369,200 excluding corporate overheads, excluding contingency, and excluding GST.**

These works will be carried out during the 2019-24 Regulatory Control Period in three stages, ie first cable by June 2021, second cable by June 2022, third cable by 2023.

2. Strategic Context and Expenditure Need

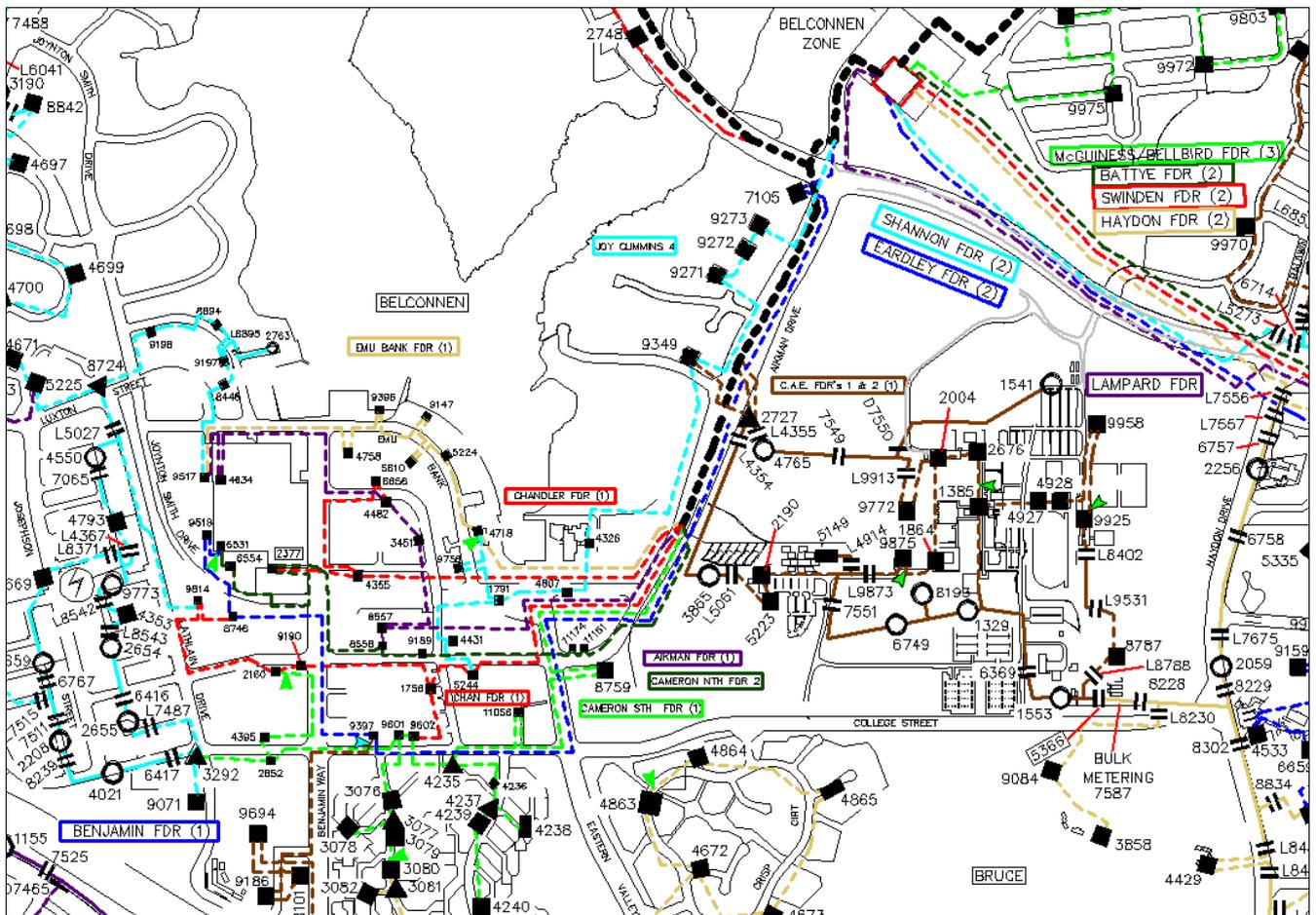
There is significant development planned for the Belconnen area. Existing infrastructure has insufficient capacity to cater for the additional demand associated with these developments.

2.1. Existing infrastructure in the Belconnen area

There are currently five 11 kV feeders supplying the Belconnen area. These are Emu Bank, Chandler, Joy Cummins, Aikman, Chan, Cameron North, Cameron South and Benjamin feeders from Belconnen Zone Substation, and Fielder feeder from Latham Zone Substation.

The existing feeder network is illustrated in Figure 1.

Figure 1: Belconnen 11 kV Feeders.



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: Belconnen Area Feeder Loadings

Feeder 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	
Aikman	BN	4.2	5.5	4.7	6.2	66%	43%	73%	50%	70%	1.2
Benjamin	BN	4.2	5.5	4.7	6.2	66%	41%	78%	54%	83%	0.7
Cameron North	BN	4.9	6.5	5.4	7.2	85%	38%	76%	45%	85%	0.7
Cameron South	BN	4.2	5.5	4.7	6.2	101%	61%	59%	63%	100%	0.0
Chan	BN	4.3	5.7	4.8	6.4	89%	40%	79%	50%	96%	0.2
Chandler	BN	4.2	5.5	4.7	6.2	57%	47%	61%	47%	57%	1.8
Emu Bank	BN	4.8	6.3	5.3	7.0	59%	40%	59%	43%	62%	1.9
Joy Cummins	BN	5.1	7.0	5.8	7.8	42%	30%	34%	47%	41%	3.0
Fielder	LA	4.8	6.4	5.9	7.8	96%	94%	108%	94%	105%	-0.2
Total											9.3

2.2. Driving need for infrastructure investment

Forecast additional maximum demand in the Belconnen 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 currently being designed. There is a high degree of certainty (> 80%) that these developments will proceed. There will be other smaller load increases.

Table 2: Proposed Developments in the Belconnen area.

Proposed Development and Net Additional Diversified Load in MVA	2018	2019	2020	2021	2022
PN 20002104 Calvary Hospital expansion	1.5				
PN 20000938 University of Canberra Hospital	1.4				
PN 20002574 University of Canberra student accommodation	0.8				
PN 20003016 Mixed development S52 B34		1.5			
PN 20003743 Mixed development S48 B8	0.5				
PN 20003008 Mixed development S200 B2			2.0		
PN 20004977 Supply to Cancer Clinic		0.7			
Peet / University of Canberra residential development			3.0	3.0	3.0
Belconnen Trades Centre mixed development			1.0	1.0	1.0
Additional Load (MVA)	4.2	2.2	6.0	4.0	4.0
Cumulative Additional Forecast Load (MVA)	4.2	6.4	12.4	16.4	20.4
Spare capacity of existing feeders to Belconnen area	4.7	2.5	-3.5	-7.5	-9.5

The proposed developments shown in Table 2 indicate there will be a shortfall of approximately 9.5 MVA firm capacity by summer 2022 onwards so additional feeders will be required unless significant demand side management initiatives can avoid this.

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.

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 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 six options to provide additional capacity and security of supply to the Belconnen area as listed in Table 5.

Table 5: Options considered for provision of additional capacity and security to Belconnen.

Option	Option type	Description	Evaluation
0	Network	Do nothing	Not selected as does not meet minimum requirements
1	Network	Three 11 kV feeders Belconnen Zone Substation to Belconnen	Selected due to higher NPC
2	Network	Three 11 kV feeders Latham Zone Substation to Belconnen	Not selected due to lower NPC
3	Network	Construct new Belconnen Zone Substation	Not selected due to lower NPC
4	Non-network	Demand side management	Not selected as does not meet minimum requirements and lower NPC
5	Mixed	Delayed preferred network option using grid battery	Not selected as cost of delay exceeded benefits
6	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 \$4,041 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 three new 11 kV cable feeders from Belconnen Zone Substation to Belconnen

Option 1 proposes to install three new underground 11 kV cable feeders to the Belconnen area from Belconnen Zone Substation to meet the growing load demand. Each new feeder would provide up to 5.5 MVA firm capacity (summer).

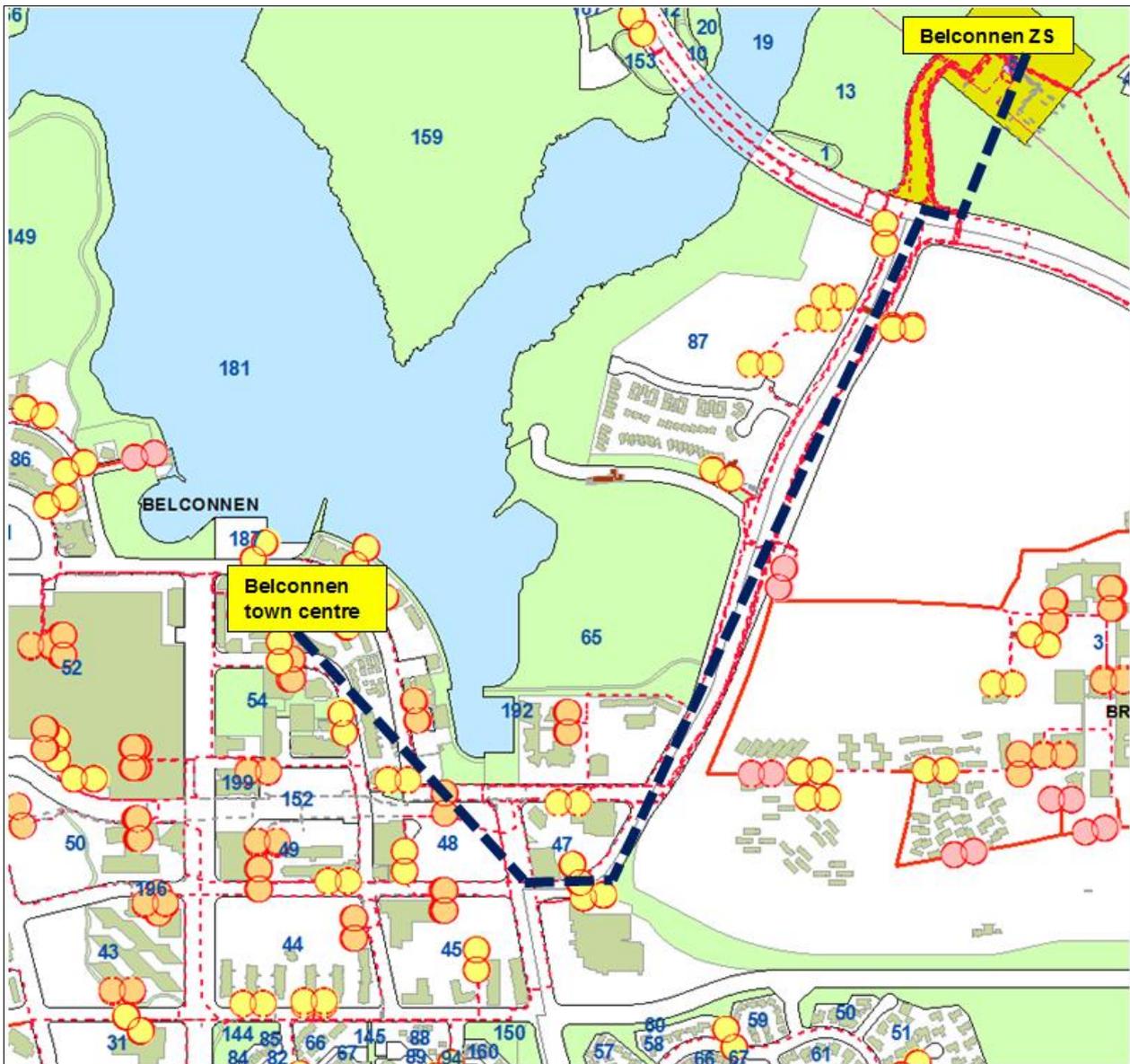
The works proposed under this option are:

- Civil works including trenching and directional drilling approximately 2.6 km from Belconnen Zone Substation to Belconnen.
- Installation of three 11 kV 3c/400mm² AL XLPE cable feeders in three stages, ie first cable by June 2021, second cable by June 2022, third cable by 2023.
- Installation of feeder protection, SCADA and commissioning.

Project Justification Report – Supply to Belconnen

Figure 2 illustrates the proposed cable route.

Figure 2: Proposed 11 kV feeder cables route Belconnen Zone Substation to Belconnen



A preliminary cost estimate for Option 1 is **\$2,369,200 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

Costs for each stage are estimated at: Stage 1 (2021) \$1,806,400; Stage 2 (2022) \$281,400; Stage 3 (2023) \$281,400 excluding corporate overheads, contingency and GST.

Option 1 is selected due to its higher (ie least negative) net present cost (NPC).

4.1.3. Option 2: Construct three new 11 kV cable feeders from Latham Zone Substation to Belconnen

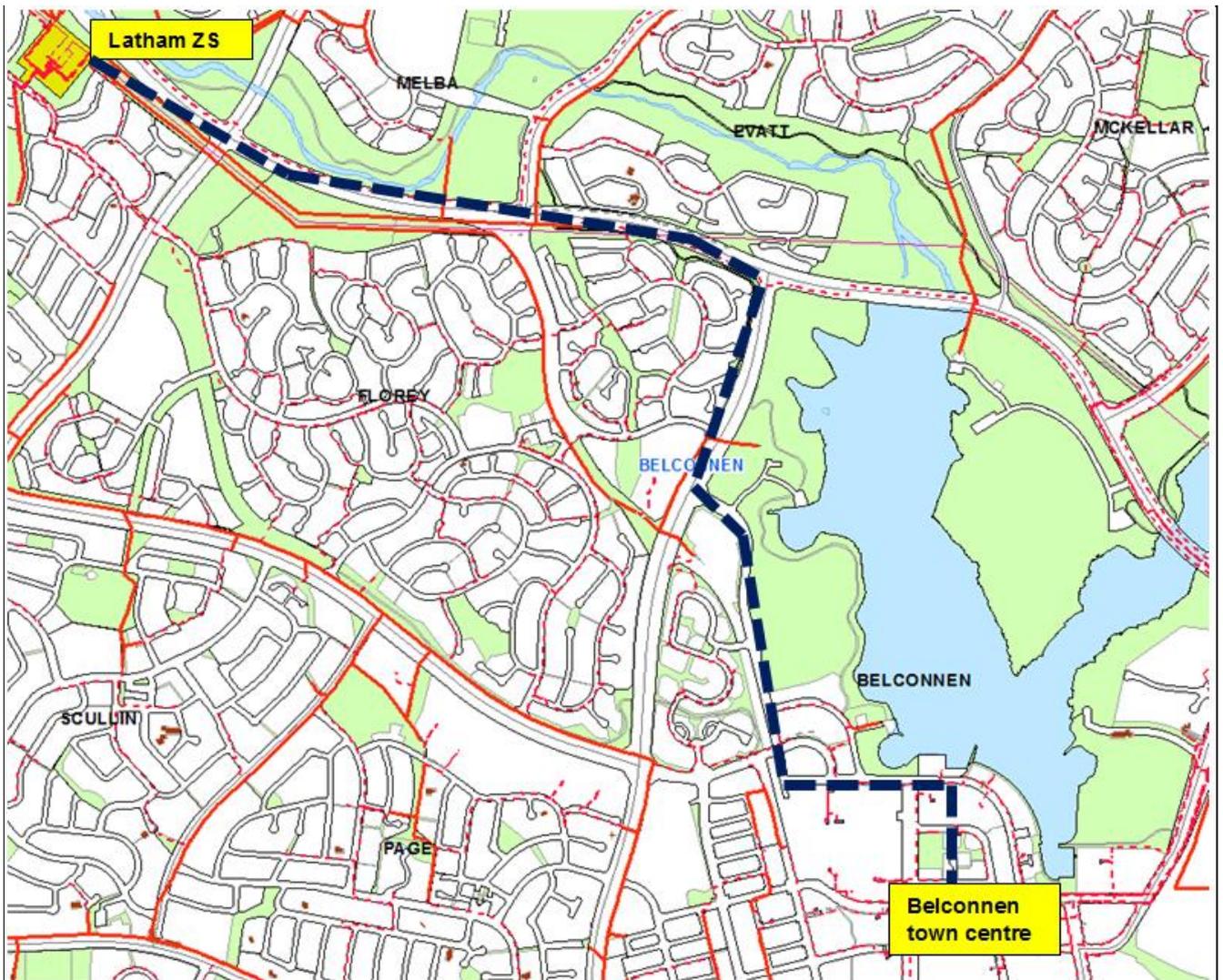
Option 2 proposes to install three new underground 11 kV cable feeders to the Belconnen area from Latham Zone Substation to meet the growing load demand. Each new feeder would provide up to 5.5 MVA firm capacity (summer).

The works proposed under this option are:

- Civil works including trenching and directional drilling approximately 4.8 km from Latham Zone Substation to Belconnen
- Installation of three 11 kV 3c/400mm² AL XLPE cable feeders in three stages, ie first cable by June 2021, second cable by June 2022, third cable by 2023.
- Installation of feeder protection, SCADA and commissioning.

Figure 3 illustrates the proposed cable route.

Figure 3: Proposed 11 kV feeder cables route Latham Zone Substation to Belconnen



A preliminary cost estimate for Option 2 is **\$5,710,950 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

Costs for each stage are estimated at: Stage 1 (2021) \$4,293,650; Stage 2 (2022) \$708,650; Stage 3 (2023) \$708,650 excluding corporate overheads, contingency and GST.

Option 2 is not selected due to its lower present cost (NPC).

4.1.4. Option 3: Construct new Mitchell Zone Substation

A new zone substation has previously been proposed to supply the Mitchell and South Gungahlin area. This would reduce the load on both Belconnen and Gold Creek zone substations. A suitable site has been identified at the corner of Well Station Drive and Hoskins Street. A standard outdoor air-insulated 132 kV substation with indoor 11 kV switchboards would be constructed.

The works proposed under this option are:

- Construction of new 132/11 kV H-scheme zone substation. Switchyard to allow for three transformers, two 132 kV line connection bays and two bus zones.
- Construction of control building, switchyard and structures.
- Construction of two 132 kV underground cable circuits from substation to Bruce–Gold Creek line (to allow loop-in-loop-out connection).
- Installation of two 132 kV underground to overhead connections to Bruce–Gold Creek line.
- Installation of two 132/11 kV 30/55 MVA power transformers and neutral earthing transformers.
- Installation of auxiliary transformers.
- Installation of two 11 kV duplicate selectable bus switchboards in new building.
- Protection and control equipment associated with the above new assets.
- Construction would be carried out in two stages: Stage 1 (2021) Construction of zone substation with one 132/11 kV 30/55 MVA transformer and one 11 kV switchboard; Stage 2 (2030) installation of second 132/11 kV 30/55 MVA transformer and second 11 kV switchboard.

This would provide 55 MVA continuous firm capacity at Belconnen Zone Substation.

A preliminary cost estimate for Option 3 is **\$15,739,350 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

Costs for each stage are estimated at: Stage 1 (2021) \$12,226,350 and Stage 2 (2030) \$3,513,000 excluding corporate overheads, contingency and GST.

Option 3 is not selected due to its lower present cost (NPC).

4.1.5. Option 4: Demand management

Option 4 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 Belconnen feeders to the next regulatory control period (beyond 2024), it is estimated that non-network solutions would need to provide a maximum demand of approximately 11.1 MVA pa.

Latent demand management within the existing customer base was investigated, with a maximum estimated capacity of 0.3 MVA. This does not meet the minimum capacity required of 3.9 MVA by 2020 to enable the first new feeder to be deferred.

These non-network options are summarised in Table 6.

Table 6: Summary of latent demand management

Non-network Option	Total
Customer – owned embedded generation	0 MVA
Customer – owned energy storage	0.1 MVA
Load curtailment	0.2 MVA
Totals	0.3 MVA

In summary, a maximum demand reduction of 0.3 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, 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 Belconnen it was determined that more than 50% 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.

4.1.6. Option 5: 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 **\$4,038,884 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

4.1.7. Option 6: 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 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 Belconnen however, the grid battery is not economic due to the relative certainty of demand with a preliminary cost estimate of **\$75,923,272 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

4.1.8. Summary of Options Analysis

A summary of the options considered is presented in the Table 7.

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	Three 11 kV feeders Belconnen Zone Substation to Belconnen	\$2,369,200	\$2,369,200	-\$2,348,549	Selected due to higher NPC
2	Three 11 kV feeders Latham Zone Substation to Belconnen	\$5,710,950	\$5,710,950	-\$5,655,602	Not selected due to lower NPC
3	New Belconnen Zone Substation	\$15,739,350	\$12,226,350	-\$14,238,878	Not selected due to lower NPC
4	Demand side management	N/A	N/A	N/A	Not selected as does not meet need
5	Grid battery to defer Option 1	\$4,033,635	\$4,033,635	-\$3,705,660	Not selected due to lower NPC
6	Grid battery only	\$71,737,028	\$16,533,453	-\$36,832,916	Not selected as does not meet need

4.2. Recommendation

The selected option is Option 1, the construction of a three new 11 kV underground cable feeders from Belconnen Zone Substation to the Belconnen area. Cables to be 11 kV 3c/400mm² AL XLPE.

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 feeders will provide capacity and security of supply to the new developments proposed for the Belconnen area. Additional spare conduits will be installed for future feeders to meet future load growth.

Timing is scheduled for completion by June 2023.

The preliminary cost estimate for the selected option is **\$2,369,200 excluding overheads, contingency and GST.**

The proposed 11 kV feeders will provide ties to existing feeders from Belconnen and Latham zone substations, and thus provide some backup supply capability and load transfer capability in the future.

Appendix A – Financial Analysis

A.1 Cost Estimate – Option 1: 11 kV Feeders from Belconnen ZS to Belconnen

Belconnen Zone Substation to Belconnen area: three new 11 kV feeders - route length approx 2.6 km. Assume spare conduits available from Belconnen to Ginninderra Drive (approx 0.25 km). Stage 1 first cable (2020), Stage 2 second cable (2021), Stage 3 third cable (2022).									
Preliminary Estimate ± 30% Accuracy									
Description	Notes	Unit	\$/Unit	Stage 1 Quantity	Stage 1 Cost	Stage 2 Quantity	Stage 2 Cost	Stage 3 Quantity	Stage 3 Cost
Trenching and drilling					\$1,508,900		\$8,900		\$8,900
Clearing of route where required	Allowance	m2	\$10	5000	\$50,000	0	\$0	0	\$0
Directional drilling	Assume drilling with no rock. Assume three 150mm conduits and one 63mm conduit per drill. Assume drill 3.0 km.	m	\$600	2350	\$1,410,000	0	\$0	0	\$0
Open trenching and backfilling	Assume excavation with no rock. Backfill with bedding sand and native soil. Assume two 150mm conduits and one 63mm conduit per trench. Assume trench 1.4 km.	m	\$250	0	\$0	0	\$0	0	\$0
Cable jointing and haulage pits	Assume every 500m	ea	\$1,000	5	\$5,000	5	\$5,000	5	\$5,000
Traffic management		m	\$2	2600	\$3,900	2600	\$3,900	2600	\$3,900
Reinstatement incl revegetation as required	Excavation, no rock (minor boulders only). Route is mostly flat.	m3	\$40	1000	\$40,000		\$0		\$0
Cabling works					\$199,000		\$199,000		\$199,000
11 kV 3c/400mm2 AI XLPE cable		m	\$55	2600	\$143,000	2600	\$143,000	2600	\$143,000
11 kV 3c/300mm2 AI XLPE cable		m	\$45	0	\$0		\$0		\$0
11 kV 3c/185mm2 AL XLPE cable		m	\$30	0	\$0		\$0		\$0
Throughjoints	Assume every 500m	ea	\$1,000	4	\$4,000	4	\$4,000	4	\$4,000
Terminations		ea	\$1,500	2	\$3,000	2	\$3,000	2	\$3,000
Conduit and marker tape	Assume conduit included in trenching and drilling rates	m	\$15	0	\$0	0	\$0		\$0
Cable installation labour and plant		m	\$15	2600	\$39,000	2600	\$39,000	2600	\$39,000
Cable jointing labour and plant		ea	\$1,000	7	\$7,000	7	\$7,000	7	\$7,000
HV Cables and connections Test & Commissioning	Allowance	ea	\$3,000	1	\$3,000	1	\$3,000	1	\$3,000
Zone Substation Connection					\$16,500	1	\$16,500		\$16,500
11 kV feeder CB at Belconnen	Assume spare CBs available	ea	\$100,000	0	\$0	0	\$0	0	\$0
11 kV Test & Commissioning	per CB	lot	\$2,000	1	\$2,000	1	\$2,000	1	\$2,000
P&C equipment and cabling	per feeder panel	ea	\$5,000	1	\$5,000	1	\$5,000	1	\$5,000
P&C Test & Commission	Allowance	ea	\$2,500	1	\$2,500	1	\$2,500	1	\$2,500
DC Cabling	per switchgear panel/bay	ea	\$5,000	1	\$5,000	1	\$5,000	1	\$5,000
DC Test & Commission	Allowance	ea	\$2,000	1	\$2,000	1	\$2,000	1	\$2,000
SCADA					\$17,000		\$2,000		\$2,000
SCADA connections	per feeder CB and TPS	ea	\$2,000	1	\$2,000	1	\$2,000	1	\$2,000
Fibre optic cable		m	\$5	2600	\$13,000	0	\$0	0	\$0
SCADA Test & Commission	Allowance	ea	\$2,000	1	\$2,000	0	\$0	0	\$0
Indirect Costs					\$65,000		\$55,000		\$55,000
Development Application	Allowance	ea	\$10,000	1	\$10,000	0	\$0	0	\$0
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea	\$5,000	1	\$5,000	1	\$5,000	1	\$5,000
Project management and administration	Allowance	ea	\$50,000	1	\$50,000	1	\$50,000	1	\$50,000
Stage Sub Total without overheads					\$1,806,400		\$281,400		\$281,400
Project Sub Total without overheads									\$2,369,200
Overheads									
Overheads at average rate 33%	Allowance	27%			\$487,728		\$75,978		\$75,978
Stage Sub Total with overheads					\$2,294,128		\$357,378		\$357,378
Project Sub Total with overheads									\$3,008,884
Contingency									
Contingency at 10%	Allowance	10%			\$229,413		\$35,738		\$35,738
Stage total with all overheads and contingency					\$2,523,541		\$393,116		\$393,116
Project total with all overheads and contingency									\$3,309,772

A.2 Cost Estimate – Option 2: 11 kV Feeders from Latham ZS to Belconnen

Latham Zone Substation to Belconnen area: three new 11 kV feeders - route length approx 4.8 km. Assume 50-50 directional drilling and trenching. Stage 1 first cable (2020), Stage 2 second cable (2021), Stage 3 third cable (2022).									
Preliminary Estimate ± 30% Accuracy									
Description	Notes	Unit	\$/Unit	Stage 1 Quantity	Stage 1 Cost	Stage 2 Quantity	Stage 2 Cost	Stage 3 Quantity	Stage 3 Cost
Trenching and drilling					\$2,146,200		\$16,200		\$16,200
Clearing of route where required	Allowance	m2	\$10	5000	\$50,000	0	\$0	0	\$0
Directional drilling	Assume drilling with no rock. Assume three 150mm conduits and one 63mm conduit per drill. Assume drill 3.0 km.	m	\$600	2400	\$1,440,000	0	\$0	0	\$0
Open trenching and backfilling	Assume excavation with no rock. Backfill with bedding sand and native soil. Assume two 150mm conduits and one 63mm conduit per trench. Assume trench 1.4 km.	m	\$250	2400	\$600,000	0	\$0	0	\$0
Cable jointing and haulage pits	Assume every 500m	ea	\$1,000	9	\$9,000	9	\$9,000	9	\$9,000
Traffic management		m	\$2	4800	\$7,200	4800	\$7,200	4800	\$7,200
Reinstatement incl revegetation as required	Excavation, no rock (minor boulders only). Route is mostly flat.	m3	\$40	1000	\$40,000		\$0		\$0
Cabling works					\$362,000		\$362,000		\$362,000
11 kV 3c/400mm2 AI XLPE cable		m	\$55	4800	\$264,000	4800	\$264,000	4800	\$264,000
11 kV 3c/300mm2 AI XLPE cable		m	\$45	0	\$0		\$0		\$0
11 kV 3c/185mm2 AL XLPE cable		m	\$30	0	\$0		\$0		\$0
Throughjoints	Assume every 500m	ea	\$1,000	9	\$9,000	9	\$9,000	9	\$9,000
Terminations		ea	\$1,500	2	\$3,000	2	\$3,000	2	\$3,000
Conduit and marker tape	Assume conduit included in trenching and drilling rates	m	\$15	0	\$0	0	\$0		\$0
Cable installation labour and plant		m	\$15	4800	\$72,000	4800	\$72,000	4800	\$72,000
Cable jointing labour and plant		ea	\$1,000	11	\$11,000	11	\$11,000	11	\$11,000
HV Cables and connections Test & Commissioning	Allowance	ea	\$3,000	1	\$3,000	1	\$3,000	1	\$3,000
Zone Substation Connection					\$16,500	1	\$16,500		\$16,500
11 kV feeder CB at Belconnen	Assume spare CBs available	ea	\$100,000	0	\$0	0	\$0	0	\$0
11 kV Test & Commissioning	per CB	lot	\$2,000	1	\$2,000	1	\$2,000	1	\$2,000
P&C equipment and cabling	per feeder panel	ea	\$5,000	1	\$5,000	1	\$5,000	1	\$5,000
P&C Test & Commission	Allowance	ea	\$2,500	1	\$2,500	1	\$2,500	1	\$2,500
DC Cabling	per switchgear panel/bay	ea	\$5,000	1	\$5,000	1	\$5,000	1	\$5,000
DC Test & Commission	Allowance	ea	\$2,000	1	\$2,000	1	\$2,000	1	\$2,000
SCADA					\$28,000		\$2,000		\$2,000
SCADA connections	per feeder CB and TPS	ea	\$2,000	1	\$2,000	1	\$2,000	1	\$2,000
Fibre optic cable		m	\$5	4800	\$24,000	0	\$0	0	\$0
SCADA Test & Commission	Allowance	ea	\$2,000	1	\$2,000	0	\$0	0	\$0
Indirect Costs					\$65,000		\$55,000		\$55,000
Development Application	Allowance	ea	\$10,000	1	\$10,000	0	\$0	0	\$0
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea	\$5,000	1	\$5,000	1	\$5,000	1	\$5,000
Project management and administration	Allowance	ea	\$50,000	1	\$50,000	1	\$50,000	1	\$50,000
Stage Sub Total without overheads					\$2,617,700		\$451,700		\$451,700
Project Sub Total without overheads									\$3,521,100
Overheads									
Overheads at average rate 33%	Allowance	27%			\$706,779		\$121,959		\$121,959
Stage Sub Total with overheads					\$3,324,479		\$573,659		\$573,659
Project Sub Total with overheads									\$4,471,797
Contingency									
Contingency at 10%	Allowance	10%			\$332,448		\$57,366		\$57,366
Stage total with all overheads and contingency					\$3,656,927		\$631,025		\$631,025
Project total with all overheads and contingency									\$4,918,977

A.3 Capital Expenditure Cash Flow for Each Credible Option

Financial Year	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6
2019/20	\$1,806,400	\$4,293,650	\$12,226,350		\$1,669,684	\$1,669,684
2020/21	\$281,400	\$708,650			\$2,087,800	\$3,768,125
2021/22	\$281,400	\$708,650			\$281,400	\$3,768,125
2022/23						\$3,768,125
2023/24						\$3,768,125
2024/25						\$3,768,125
2025/26						\$3,768,125
2026/27						\$3,768,125
2027/28						\$3,768,125
2028/29						\$3,768,125
2029/30			\$3,513,000			\$3,768,125
2030/31						\$3,768,125
2031/32						\$3,768,125
2032/33						\$3,768,125
2033/34						\$3,768,125
2034/35						\$3,768,125
2035/36						\$3,768,125
2036/37						\$3,768,125
2037/38						\$3,768,125
2038/39						\$3,768,125
Total Cost (20 yr)	\$2,369,200	\$5,710,950	\$12,226,350	N/A	\$4,038,884	\$16,742,183
2019-24 Regulatory Control Period Cost	\$2,369,200	\$5,710,950	\$15,739,350	N/A	\$4,038,884	\$73,264,053

Appendix B: 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 Belconnen. 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 Belconnen

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

Options:

One – Three 11 kV feeders Belconnen Zone Substation to Belconnen.

Two – Three 11 kV feeders Latham Zone Substation to Belconnen.

Three – New Mitchell Zone Substation

Four – Demand management

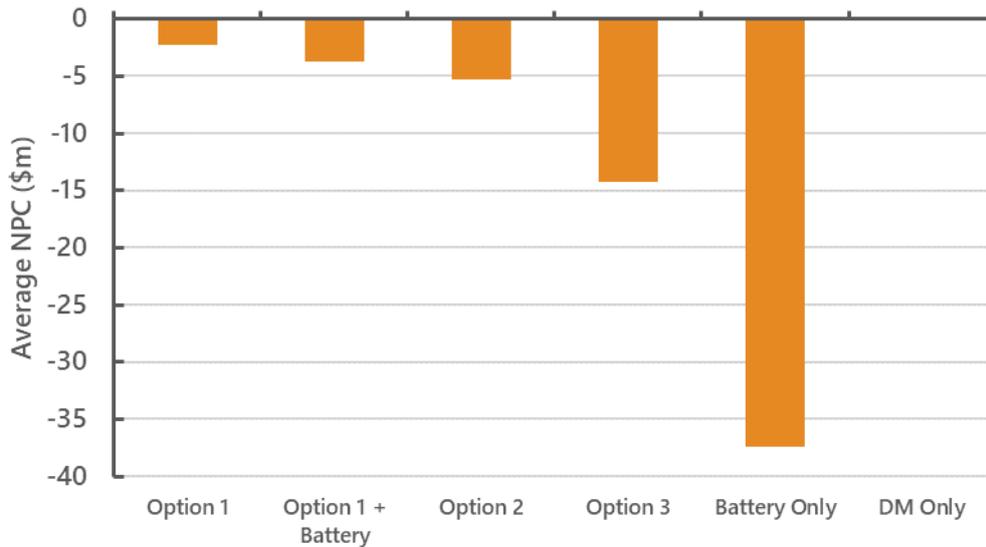
Five – Defer option one with grid battery

Six – Grid battery only

RESULTS (Average over 50 simulations):

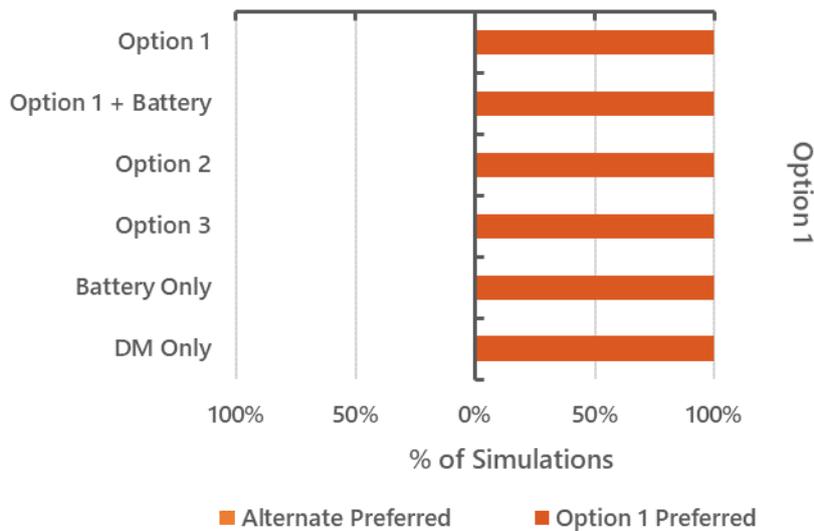
Option:	One	Two	Three	Four	Five	Six
NPC (2019-2024)	-\$2,030,841	-\$4,877,548	-\$11,331,761	N/A	-\$3,502,990	-\$12,954,611
NPC (2019-2039)	-\$2,223,058	-\$5,339,579	-\$14,238,878	N/A	-\$3,695,207	-\$37,414,699
Network Option total Capital Cost	\$2,369,200	\$5,710,950	\$15,739,350	N/A	\$2,369,200	-
Option Capital Cost (2019-2024)	\$2,228,500	\$5,356,625	\$12,226,350	N/A	\$4,021,994	\$16,774,481
Option Capital Cost (2019-2039)	\$2,228,500	\$5,356,625	\$15,739,350	N/A	\$4,021,994	\$72,892,623

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	12,973	29
2021	183,251	343
2022	725,450	1,223
2023	725,450	1,223
2024	725,450	1,223

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.