

# Demand management opex step change business case

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## Executive summary

The development of Strathnairn represents Stage 1 of the broader Western Belconnen residential development which will ultimately accommodate a population of approximately 30,000 within an estimated 11,500 dwellings plus shopping centres, schools and community facilities. The existing Evoenergy Latham and Belconnen zone substations supplying the area, do not have sufficient capacity to supply the ultimate development. However, there is likely to be sufficient zone substation capacity for the 2019 to 2024 regulatory control period such that the construction of a new zone substation can be deferred at least to the next regulatory control period.

Notwithstanding, the existing 11kV feeder network does not have sufficient capacity to supply the suburb of Strathnairn. To provide for demand in Strathnairn an additional 5.7MVA is required to be in the place by the end of the regulatory control period under the base case and 6.7MVA under the high demand case.

Evoenergy has identified an opportunity to incorporate demand management as a potential alternative to supply side solutions within the suburb of Strathnairn in the 2019-24 regulatory period.

CutlerMerz was engaged by Evoenergy to provide cost estimates for a demand management solution and compare these against the existing network side solutions identified by Evoenergy and, where demand management was cost effective and feasible, propose a step change in associated operational expenditure.

## Comparison of options

Overall, CutlerMerz found that the option of a feeder extension combined with demand management had the lowest net present cost as shown in Table 1 below.

**Table 1 – Comparison of options**

Option	Capex \$2018/19	Opex to 2065 \$2018/19	Total cost	
			\$2018/19	Net present cost
1 Construct zone substation	\$14,012,350	\$5,604,940	\$19,617,290	\$13,393,548
2 Extend feeders and utilise demand management for shortfall	\$15,707,050	\$7,986,660	\$23,693,710	\$13,365,991
3 Demand management only	\$14,192,350	\$10,865,740	\$25,058,090	\$14,573,597

While the benefits estimated above are marginal (in the order of \$30,000 in net present value terms), the cost estimates for the demand management components of Option 2 (and Option 3) are considered an upper limit, with the actual costs to be revealed during the regulatory control period via a market request for demand management solutions.

## Expenditure during the regulatory control period for preferred option

### Opex

Option 2 would require an operational expenditure allowance of **\$1,769,828 excluding corporate overheads, contingency and GST** over the regulatory control period. This consists of the incentive payments to residential customers (\$1,703,840) as well as opex associated with capex investments in the feeder extension and centralised demand management platform (\$50,841) as shown in Table 2.

**Table 2 – Opex associated with preferred option**

FY	Incentive payments opex (direct plus control unit)	Opex associated with capex (@1% of capex)		Total
		Feeder extension	Centralised DM platform	
2020	\$0	\$0	\$0	\$0
2021	\$0	\$15,147	\$0	\$15,147
2022	\$1,398,400	\$15,147	\$1,800	\$1,415,347
2023	\$305,440	\$15,147	\$1,800	\$322,387
2024	\$0	\$15,147	\$1,800	16947
Total	\$1,703,840	\$45,441	\$5,400	\$1,769,828

It may be possible for Evoenergy to procure demand management with lower incentive payments than estimated for the purpose of this business case. The actual costs would be determined via a request for demand management solutions in accordance with the minimum project evaluation requirements as prescribed by Clause 2.2.1 of the Demand Management Incentive Scheme. Where the costs of demand management are lower than estimated, the reduced opex would be subject to the Efficiency Benefits Sharing Scheme.

#### Capex

The supply side component of the preferred option would require a capex allowance of is **\$1,694,700 excluding corporate overheads, contingency and GST**. This includes the feeder extension as augmentation expenditure (\$1,514,700) as well as the establishment of a demand management platform and communications receiver as IT/OT expenditure (\$180,000).

### **Application of Demand Management Incentive Scheme and Incentive Allowance**

It is considered that components of the expenditure outlined above may be eligible for incentives under the Australian Energy Regulator's Demand Management Incentive Scheme and the Demand Management Innovation Allowance.

The incentive payments may be considered eligible for the Demand Management Incentive Scheme with an incentive payment equal to up to 50% of the total revealed costs once the demand management projects are committed (depending on the economic value of the demand management solution).

The opex and capex components related to the demand management platform may potentially be eligible under the Demand Management Innovation Allowance given the solution involves technology or a technique not previously implemented by any DNSP.

## 1 Introduction

Evoenergy has identified an opportunity to incorporate demand management as a potential alternative to supply side solutions within the suburb of Strathnairn in the 2019-24 regulatory period. The development of Strathnairn represents Stage 1 of the broader Western Belconnen residential development. Demand management requires operational expenditure (opex) to allow Evoenergy to procure solutions from the market as opposed to traditional capital intensive supply side solutions.

### 1.1 Purpose of this document

This document therefore outlines the business case for a demand management solution at Strathnairn and the associated opex required to deliver this solution. It is envisaged that this opex will be incorporated within Evoenergy's regulatory proposal as a step change to the base opex forecast for the 2019-24 regulatory period.

### 1.2 Structure of this document

The document is structured as follows:

- Section 1 provides a brief background and purpose of this document;
- Section 2 outlines the need for investment in the Strathnairn area to meet the forecast increase in demand;
- Section 3 outlines the regulatory arrangements for allowance of demand management in the context of the regulatory proposal;
- Section 4 details potential options to meet the forecast increase in demand including both supply side, demand management and hybrid options; and
- Section 5 summarises the preferred option and the associated opex and capex requirements

### 1.3 Limitations

This document compares various options to supply the demand for energy within the Strathnairn development including both traditional network and non-network alternatives. The engineering solutions for network options and associated cost estimates have been developed by Evoenergy network planners and are further detailed in the Evoenergy Project Justification Report. For the purposes of this business case, only the most cost effective network options have been considered and are summarised in this report.

It is assumed that the network options identified by Evoenergy are exhaustive and have been accurately scoped and estimated. That is, CutlerMerz has not verified whether further network options other than those discussed within the Project Justification Report could be deployed at lower cost and still meet the project need.

The non-network options including demand management and grid battery have been scoped and estimated by CutlerMerz. The cost estimates for these solutions are based upon both publicly and non-publicly available estimates of forward looking technology prices. In some cases, the requisite technology is not currently available on the market and in this case, indicative costs and timing have been sought from technology suppliers. These costs are commercial in confidence.

Both the network and non-network options have been developed to meet Evoenergy Distribution Augmentation Standards. Options which do not comply with this standard (ie options which provide a lower level of reliability) have not been further considered.

Further, the demand forecasts were provided to CutlerMerz for both a base case and high demand scenario. The demand forecasts have not been independently verified by CutlerMerz.

## 2 Project need

### 2.1 Proposed development

The West Belconnen District, situated approximately 15 km northwest of the Canberra Central Business District, is being developed by a joint venture of the ACT Government's Suburban Land Agency (SLA) and Riverview Developments Pty Ltd known as Ginninderry Group Ltd. The SLA has published an indicative land release programme that indicates development will proceed at approximately 300 dwellings per annum with an ultimate population of approximately 30,000 within an estimated 11,500 dwellings plus shopping centres, schools and community facilities. Subsequent to the publication of the land release programme, it is understood that Ginninderry Group Ltd has stated they intend to develop the district at a more ambitious rate of 380 dwellings per annum.

The first stage of development of West Belconnen, comprising Stage 1 of the suburb of Strathnairn is currently under construction. The location of Strathnairn in the context of West Belconnen is shown in Figure 1.

### 2.2 Existing infrastructure

The West Belconnen District is supplied by the Latham zone substation (approximately 7km away) and the Belconnen zone substation (approximately 10km away). The Latham substation has a firm capacity of 100 MVA while Belconnen has a firm capacity of 55 MVA.

There are currently two 11 kV feeders supplying the Strathnairn area. These are Macrossan and Latham feeders extending from Latham Zone Substation with a combined firm rating of 9 MVA and emergency rating 11.8 MVA

### 2.3 Demand forecasts

The development of West Belconnen has a mandate to install rooftop PV generation (ranging in size from 1.5 kW to 4.0 kW) on all detached dwellings and terraced townhouses. Battery storage systems are voluntary. Evoenergy anticipates that the after diversity maximum demand (ADMD) levels for this area will be lower than elsewhere and have been assumed to be 2.0 kVA per dwelling. At a rate of 300 to 380 new dwellings per annum, this will add approximately 0.6 MVA to 0.8 MVA load growth annually.

Accordingly, the maximum demand at Latham is forecast to rise to approximately 83 MVA over the next ten years, with expansion of the Lower Molonglo Water Quality Control Centre and residential developments in the area (e.g. Ginninderra Estate – adjacent to West Belconnen) being within the firm capacity of the existing zone substation. However, the maximum demand at Belconnen is forecast to rise to approximately 63 MVA over the next 10 years, implying an additional need for capacity within 10 years (but not within the 2019 to 2024 regulatory control period).

Table 3 and Table 4 show a summary of the demand forecast in the Strathnairn suburb to 2026 for both a base case and a high demand forecast (where the ADMD values above are not achieved). These forecast loads make allowance for predicted penetration of rooftop solar PV and energy efficiency.

This shows that available firm summer capacity will be exceeded by 2019 and the emergency rating capacity by 2023 in the base case (or 2022 under the high demand forecast). By 2026, there is estimated to be between 5.7 and 6.7MVA above the firm rating.

**Table 3 – Strathnairn demand forecast (base case)**

Year	2019	2020	2021	2022	2023	2024	2025	2026
Demand Forecast (MVA)	9.1	9.9	10.7	11.5	12.3	13.1	13.9	14.7
Feeder capacity (firm) (MVA)	9	9	9	9	9	9	9	9
Feeder capacity (emergency) (MVA)	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Spare capacity above firm rating (MVA)	<b>-0.1</b>	<b>-0.9</b>	<b>-1.7</b>	<b>-2.5</b>	<b>-3.3</b>	<b>-4.1</b>	<b>-4.9</b>	<b>-5.7</b>
Spare capacity above emergency rating (MVA)	<b>2.7</b>	<b>1.9</b>	<b>1.1</b>	<b>0.3</b>	<b>-0.5</b>	<b>-1.3</b>	<b>-2.1</b>	<b>-2.9</b>

**Table 4 – Strathnairn demand forecast (high case)**

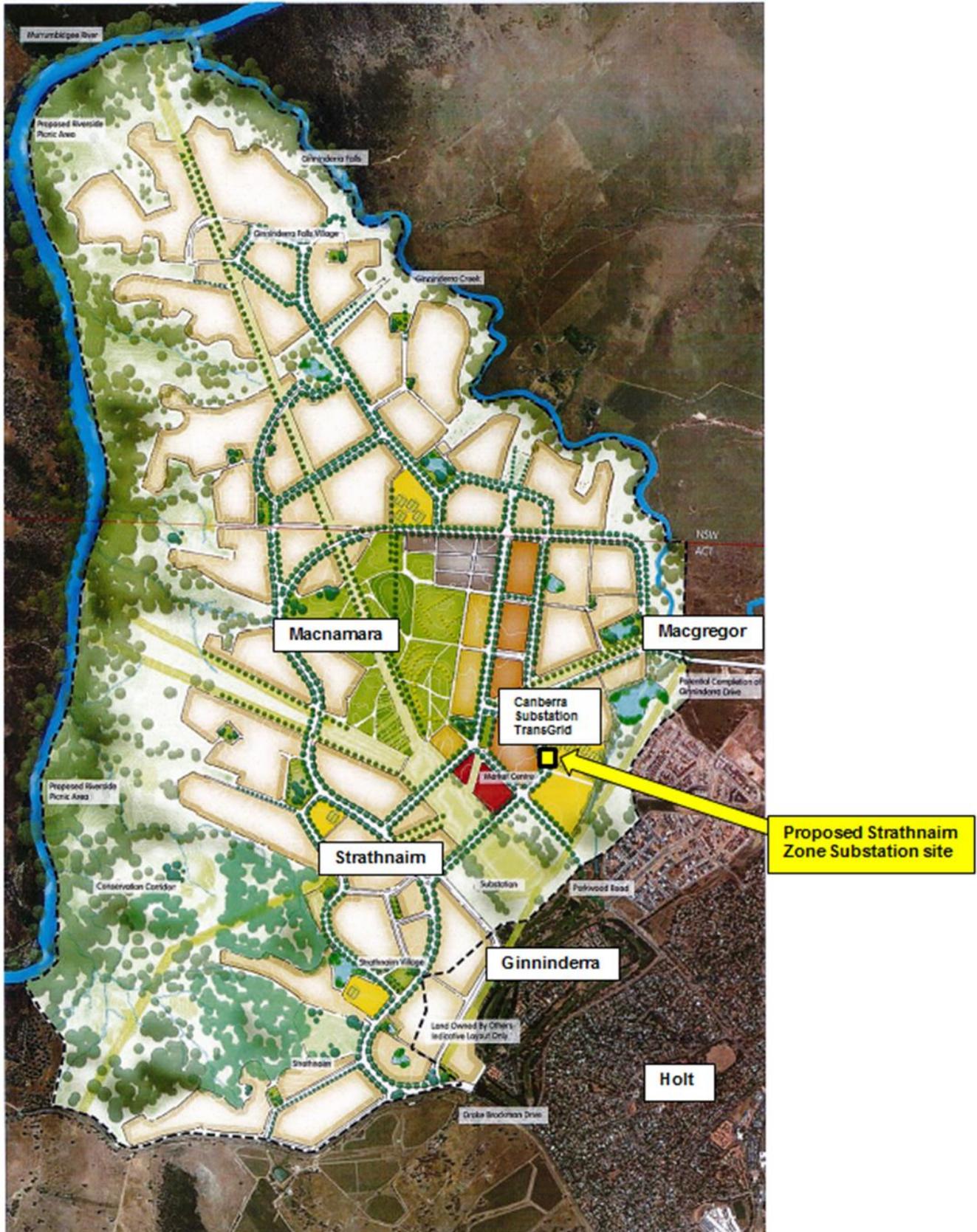
Year	2019	2020	2021	2022	2023	2024	2025	2026
Demand Forecast (MVA)	9.3	10.2	11.1	12	12.9	13.8	14.7	15.7
Feeder capacity (firm) (MVA)	9	9	9	9	9	9	9	9
Feeder capacity (emergency) (MVA)	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Spare capacity above firm rating (MVA)	<b>-0.3</b>	<b>-1.2</b>	<b>-2.1</b>	<b>-3</b>	<b>-3.9</b>	<b>-4.8</b>	<b>-5.7</b>	<b>-6.7</b>
Spare capacity above emergency rating (MVA)	<b>2.5</b>	<b>1.6</b>	<b>0.7</b>	<b>-0.2</b>	<b>-1.1</b>	<b>-2</b>	<b>-2.9</b>	<b>-3.9</b>

## 2.4 Summary of project need

The existing Latham and Belconnen zone substations do not have sufficient capacity to supply the ultimate West Belconnen district. However, there is likely to be sufficient capacity for the 2019 to 2024 regulatory control period such that the construction of a new zone substation can be deferred at least to the next regulatory control period.

Notwithstanding, the existing 11kV feeder network does not have sufficient capacity to supply the suburb of Strathnairn, as the first stage of the West Belconnen development. It is estimated that an additional 4.1 MVA of feeder capacity is required within the 2019 to 2024 regulatory control period under the base case and 4.8 MVA under the high demand case to ensure that demand is less than the firm rating of the feeder network. To provide for 2026 demand (which must be in place by the end of this regulatory control period) an additional 5.7MVA is required under the base case and 6.7MVA under the high demand case.

Figure 1 – West Belconnen District Development



### 3 Regulatory context

As required by the National Electricity Rules (NER), the Australian Energy Regulator (AER) approves proposed capital and operating expenditure where it is satisfied that the capital and operating expenditure for the regulatory control period reasonably reflects the capital and operating expenditure criteria specified in Chapter 6.5.6 (c) and 6.5.7(c) which include:

- The efficient costs of achieving the capital expenditure objectives<sup>1</sup>;
- The costs that a prudent operator would require to achieve the capital expenditure objectives; and
- A realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

In determining capital expenditure allowances, the AER has regard to the substitution possibilities between operating and capital expenditure.

The NER therefore sets out an expectation for Evoenergy to set its expenditure at levels which are prudent and efficient, considering potential trade-offs between operating and capital expenditure. In this sense, the lowest cost option to meeting the realistic expectation of demand should be selected regardless as to whether this represents opex or capex. In other words, the regulatory framework should provide for demand management where this represents the lowest cost solution.

Despite this, and in the AER's view<sup>2</sup>, the current regulatory framework may provide incentives for DNSPs to preference capital intensive network options over non-network options due to:

- The ability to achieve a return on capex included in the regulatory asset base over the asset lifetime, which is typically decades long, and the associated relatively stable long-term cash flows;
- The ability to receive an allowed rate of return on regulated capex that is above its actual cost of capital, which would produce an opportunity for it to profit from its capex; and
- Limited down-side risk from overinvestment in capex (where the risk is transferred to customers) compared to down-side risk of underinvestment.

Accordingly, the AER has introduced a number of incentive schemes for DNSPs to invest in demand management as an alternative to capex including:

- The Capital Efficiency Sharing Scheme (CESS) which enables DNSPs to share the benefits of any savings in capex achieved during the regulatory period (including those driven by demand management); and
- The Demand Management Incentive Scheme (DMIS) which provides a direct incentive to the DNSP to adopt demand management in lieu of a capital intensive option.

Both these schemes enable DNSPs to provide for supply side capital intensive solutions within their regulatory proposals but then provide incentives to manage demand during the regulatory control period.

Notwithstanding the availability of these mechanisms, Evoenergy has elected to pursue demand management as a response to capacity constraints *within* its regulatory proposal where demand management is considered

<sup>1</sup> Where the relevant objectives relate to meeting or managing demand for standard control services

<sup>2</sup> Australian Energy Regulator, Explanatory statement: Demand management incentive scheme - Electricity distribution network service providers, December 2017 < <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism>>

feasible and represents the lowest cost option. Evoenergy is therefore, under these circumstances, seeking a step change in its opex allowance to enable demand management rather than a capex allowance.

## 4 Options considered

The potential options to providing additional capacity are outlined below with the total cost for each option expressed in \$2018/19.

### 4.1 Do Nothing

If no solution is implemented within the 2019 to 2024 regulatory control period, demand within Strathnairn will exceed the firm capacity of the existing feeders in 2019 (based on both the base case demand forecast and the high demand forecast) and the emergency capacity by the end of the regulatory control period.

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

- The total amount of energy per year which exceeds the firm rating;
- The probability that a contingency event will occur in any given hour (estimated at 6% per annum);
- The time taken to restore service following the contingency event (usually within 24 hours); and
- The value of customer reliability (set equal to \$26.93 per MWh in accordance with AEMO value of customer reliability for NSW residential customers adjusted for inflation)

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

Table 5 below shows the energy at risk and associated value for each year.

**Table 5 – Energy at risk**

Energy at risk		2019	2020	2021	2022	2023	2024	Total
Base case demand forecast	kWh	208	9,025	64,961	193,833	409,997	717,078	1,395,102
	\$(2018/19)	2	39	205	490	1,410,770	8,915,893	10,327,398
High demand forecast	kWh	667	19,836	114,499	311,651	630,187	1,067,444	2,144,284
	\$(2018/19)	5	78	314	466,400	6,336,796	28,855,833	35,659,425

It is therefore estimated that the Do Nothing option has an economic cost of between \$10 million and \$36 million over the regulatory control period, but that significant economic costs do not accrue until 2022 or later where the emergency rating is exceeded.

### 4.2 Option 1 – Strathnairn zone substation

Option 1 proposes to meet future demand in the Strathnairn area as well as future development within West Belconnen via the construction of a new 132/11 kV zone substation in Strathnairn. The new zone substation site would be established and developed with all earthworks, earthing, fencing, and 132 kV structure and busbar plus the installation of one 132/11 kV 30/55 MVA transformer and one 11 kV switchboard. Space will also be provided for a future two additional transformers and two additional 11 kV switchboards.

Stage 2 of the project would then involve installation of a second 132/11 kV 30/55 MVA transformer and a second 11 kV switchboard around 2040. Stage 2 is not considered in the option evaluation due to lack of certainty with respect to demand to 2040.

Stage 1, comprising development of the site and installation of the substation is estimated to require a capital expenditure of **\$14,012,350 excluding corporate overheads, contingency and GST** with an annual operational expenditure assumed at 1% of this cost. The project is proposed to be completed by the end of the 2022-23 financial year to provide the capacity required by the growing residential suburb of Strathnairn.

Overall, Option 1 has a total net present value of **\$13,393,548 excluding corporate overheads, contingency and GST** assuming a 6.42% discount rate.

Table 6 below shows the associated impact of Option 1 on the revenue building blocks.

**Table 6 - Option 1 Revenue Building Blocks**

FY	Opex	Capex	Revenue
2020	\$0	\$0	\$0
2021	\$0	\$0	\$0
2022	\$140,124	\$14,012,350	\$1,390,025
2023	\$140,124	\$0	\$1,390,025
2024	\$140,124	\$0	\$1,390,025
2025	\$140,124	\$0	\$1,390,025
2026	\$140,124	\$0	\$1,390,025
2027	\$140,124	\$0	\$1,390,025
2028	\$140,124	\$0	\$1,390,025
2029	\$140,124	\$0	\$1,390,025
2030	\$140,124	\$0	\$1,390,025
2031	\$140,124	\$0	\$1,390,025
2032	\$140,124	\$0	\$1,390,025
2033	\$140,124	\$0	\$1,390,025
2034	\$140,124	\$0	\$1,390,025
2035	\$140,124	\$0	\$1,390,025
2036	\$140,124	\$0	\$1,390,025
2037	\$140,124	\$0	\$1,390,025
2038	\$140,124	\$0	\$1,390,025
2039	\$140,124	\$0	\$1,390,025
2040	\$140,124	\$0	\$1,390,025
2041	\$140,124	\$0	\$1,390,025
2042	\$140,124	\$0	\$1,390,025
2043	\$140,124	\$0	\$1,390,025
2044	\$140,124	\$0	\$1,390,025
2045	\$140,124	\$0	\$1,390,025
2046	\$140,124	\$0	\$1,390,025
2047	\$140,124	\$0	\$1,390,025
2048	\$140,124	\$0	\$1,390,025
2049	\$140,124	\$0	\$1,390,025

FY	Opex	Capex	Revenue
2050	\$140,124	\$0	\$1,390,025
2051	\$140,124	\$0	\$1,390,025
2052	\$140,124	\$0	\$1,390,025
2053	\$140,124	\$0	\$1,390,025
2054	\$140,124	\$0	\$1,390,025
2055	\$140,124	\$0	\$1,390,025
2056	\$140,124	\$0	\$1,390,025
2057	\$140,124	\$0	\$1,390,025
2058	\$140,124	\$0	\$1,390,025
2059	\$140,124	\$0	\$1,390,025
2060	\$140,124	\$0	\$1,390,025
2061	\$140,124	\$0	\$1,390,025
2062	\$0	\$0	\$0
2063	\$0	\$0	\$0
2064	\$0	\$0	\$0
2065	\$0	\$0	\$0

### 4.3 Option 2 – Extension of existing feeders and demand management

Option 2 proposes to extend an existing 11 kV O’Loughlen cable feeder from the intersection of O’Loughlen Street and Southern Cross Drive to supply the first stage of Strathnairn. The existing load on the O’Loughlen feeder (approximately 1.9 MVA) would be transferred to adjacent feeders. This would free up almost the full firm capacity of the O’Loughlen feeder (4.5 MVA) to supply Strathnairn Stage 1.

The O’Loughlen feeder extension, coupled with extensions of Macrossan and Latham feeders, will be capable of meeting the Strathnairn demand under the base case until 2025-26 at which stage the option of a permanent zone substation (as described in Option 1 would be considered).

The preliminary estimated cost of this option is **\$1,514,700 excluding corporate overheads, contingency and GST** plus an additional opex component assumed to be equal to 1% of capital expenditure.

However, under the high demand forecast it is unlikely that the feeder extension would be able to meet the required demand for 2026 such that an additional 2.2 MVA of demand management would be required.

Under Option 2, Evoenergy would procure this additional demand management from the market during the regulatory control period via request for demand management solutions in accordance with the minimum project evaluation requirements as prescribed by Clause 2.2.1 of the Demand Management Incentive Scheme.

The cost of this demand management is assumed to include the following:

1. Subsidy required to incentivise customers who have already deployed demand management technology (such as existing battery storage, existing building management systems and existing embedded generation) to provide prescribed demand management at relevant times;
2. Subsidy required to incentivise customers to deploy new demand management technology to provide prescribed demand management services at relevant times; and
3. Cost to establish a centralised demand management platform.

For the purposes of this regulatory proposal 1) and 2) above are estimated to be equal to the subsidy that must be provided to promote an NPV positive business case for deployment of behind the meter battery storage systems at residential premises (assuming a time of use tariff). In practice, it may be that existing demand management may be procured at a reduced cost.

It is assumed that the incentive would be a one off payment to the individual customer and requires the customer to provide demand management until such time as the new zone substation is built. The incentive would require that the customer is provisioned with a battery storage system at the time of completion of construction of their dwelling such that the demand management is available from the point that the connection is energised.

The costs for the demand management platform are less certain due to the immature market and lack of existing available products. However, it is understood that several smart grid equipment providers are seeking to launch applicable products in early 2018. The costs of these services include a centralised communications receiver and distributed controls for each distributed unit providing demand management services. The estimated costs associated with the demand management solution are shown in Table 7 below.

**Table 7 – Demand management costs for Option 2**

Item	Expenditure Type	Cost per unit	Estimated number of units required	Total cost (over regulatory control period)
Incentive payment	Opex	■	■	\$1,472,340
DM Platform distributed equipment <sup>3</sup>	Opex	■	■	\$231,500
DM platform centralised equipment <sup>4</sup>	Capex	\$180,000	1	\$180,000
Total				\$1,883,840

The total cost of Option 2, including the feeder extension and demand management is therefore **\$3,398,540 excluding corporate overheads, contingency and GST**, made up of capital expenditure of \$1,694,700 and once-off opex of \$1,703,840. In addition to this is an ongoing additional opex component assumed to be equal to 1% of capital expenditure.

Incentives and DM platform distributed equipment costs are incurred at a rate of ■ units per year from 2023 until all ■ units are installed as shown in Table 8.

**Table 8 – Incentive payments for Option 2 for regulatory control period (\$2018/19)**

	2020	2021	2022	2023	2024	2025
Number of units deployed	-	-	-	■	■	-
Incentive payments including distributed control systems	-	-	-	\$1,398,400	\$305,440	-

<sup>3</sup> The cost of the distributed control system may be added to the incentive under the condition that the units deployed include the requisite controls and communications

<sup>4</sup> The platform may either be established by Evoenergy or a licensing fee could be paid to a supplier. For the purpose of the business case it is assumed that the platform is established by Evoenergy via capital expenditure. Where the alternative licensing arrangement was adopted approximately \$30,000 would be required in capital expenditure for the communications receiver and \$150,000 available for licensing fees. This is considered sufficient due to the relatively small scale of the demand management, but further investment may be required in the future (next regulatory control period) where centrally controlled demand management is deployed more widely.

Option 2 would defer the development of a permanent zone substation to 2026. As with Option 1, the substation will require a capital expenditure of **\$14,012,350 excluding corporate overheads, contingency and GST** with an annual operational expenditure assumed at 1% of this cost.

Overall, Option 2 has a total net present value of **\$13,365,991 excluding corporate overheads, contingency and GST** assuming a 6.42% discount rate.

Table 9 below shows the associated impact of Option 2 on the revenue building blocks.

**Table 9 - Option 2 Revenue Building Blocks**

FY	Opex	Capex	Revenue
2020	\$0	\$0	\$0
2021	\$0	\$0	\$0
2022	\$15,147	\$1,514,700	\$150,258
2023	\$1,415,347	\$180,000	\$1,566,514
2024	\$322,387	\$0	\$473,554
2025	\$16,947	\$0	\$168,114
2026	\$157,071	\$14,012,350	\$1,558,139
2027	\$157,071	\$0	\$1,558,139
2028	\$157,071	\$0	\$1,558,139
2029	\$157,071	\$0	\$1,558,139
2030	\$157,071	\$0	\$1,558,139
2031	\$157,071	\$0	\$1,558,139
2032	\$157,071	\$0	\$1,558,139
2033	\$157,071	\$0	\$1,558,139
2034	\$157,071	\$0	\$1,558,139
2035	\$157,071	\$0	\$1,558,139
2036	\$157,071	\$0	\$1,558,139
2037	\$157,071	\$0	\$1,558,139
2038	\$157,071	\$0	\$1,558,139
2039	\$157,071	\$0	\$1,558,139
2040	\$157,071	\$0	\$1,558,139
2041	\$157,071	\$0	\$1,558,139
2042	\$157,071	\$0	\$1,558,139
2043	\$157,071	\$0	\$1,558,139
2044	\$157,071	\$0	\$1,558,139
2045	\$157,071	\$0	\$1,558,139
2046	\$157,071	\$0	\$1,558,139
2047	\$157,071	\$0	\$1,558,139
2048	\$157,071	\$0	\$1,558,139
2049	\$157,071	\$0	\$1,558,139
2050	\$157,071	\$0	\$1,558,139

FY	Opex	Capex	Revenue
2051	\$157,071	\$0	\$1,558,139
2052	\$157,071	\$0	\$1,558,139
2053	\$157,071	\$0	\$1,558,139
2054	\$157,071	\$0	\$1,558,139
2055	\$157,071	\$0	\$1,558,139
2056	\$157,071	\$0	\$1,558,139
2057	\$157,071	\$0	\$1,558,139
2058	\$157,071	\$0	\$1,558,139
2059	\$157,071	\$0	\$1,558,139
2060	\$157,071	\$0	\$1,558,139
2061	\$157,071	\$0	\$1,558,139
2062	\$141,924	\$0	\$1,407,881
2063	\$140,124	\$0	\$1,390,025
2064	\$140,124	\$0	\$1,390,025
2065	\$140,124	\$0	\$1,390,025

#### 4.4 Option 3 – Demand management only

Option 3 proposes to utilise demand management to reduce demand within Strathnairn such that no supply side solution is required until 2025-26, when it is anticipated that the new substation is required. It is estimated that a total of up to 6.7 MVA of demand reduction will be required to be contracted by the end of the regulatory control period to meet this demand.

As per Option 2, Evoenergy would procure the demand management from the market during the regulatory control period via a request for demand management solutions in accordance with the minimum project evaluation requirements as prescribed by Clause 2.2.1 of the Demand Management Incentive Scheme.

For the purposes of the regulatory proposal, the estimated cost of the demand management solution is shown in Table 10 below.

**Table 10 – Demand management costs for Option 3**

Item	Expenditure Type	Cost per unit	Number of units required	Total cost (over regulatory control period)
Incentive payment	Opex	█	█	\$4,483,800
DM Platform distributed equipment	Opex	█	█	\$705,000
DM platform centralised equipment	Capex	\$180,000	1	\$180,000
Total				\$5,368,800

This indicates that of the █ dwellings constructed per year and provisioned with solar, approximately 70% would require battery storage with a total cost of **\$5,368,800 excluding corporate overheads, contingency and GST**, made up of capital expenditure of \$180,000 and once-off opex of \$5,188,800 spread over four years. In addition to this is an ongoing additional opex component assumed to be equal to 1% of capital expenditure.

Incentives and DM platform distributed equipment costs are incurred at a rate of [REDACTED] units per year from 2022 until all [REDACTED] units are installed as shown in Table 11.

**Table 11 – Incentive payments for Option 3 (\$2018/19)**

	2020	2021	2022	2023	2024	2025
Number of units deployed	-	-	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Incentive payments (\$2018/19)	-	-	\$1,398,400	\$1,398,400	\$1,398,400	\$993,600

Option 3 would then defer a permanent zone substation until 2026. As with Option 1, the substation will require a capital expenditure of **\$14,012,350 excluding corporate overheads, contingency and GST** with an annual operational expenditure assumed at 1% of this cost.

Overall, Option 3 has a total net present value of **\$14,573,597 excluding corporate overheads, contingency and GST** assuming a 6.42% discount rate.

Table 12 below shows the associated impact of Option 2 on the revenue building blocks.

**Table 12 - Option 3 Revenue Building Blocks**

FY	Opex	Capex	Revenue
2020	\$0	\$0	\$0
2021	\$0	\$0	\$0
2022	\$1,400,200	\$180,000	\$1,416,256
2023	\$1,400,200	\$0	\$1,416,256
2024	\$1,400,200	\$0	\$1,416,256
2025	\$995,400	\$0	\$1,011,456
2026	\$141,924	\$14,012,350	\$1,407,881
2027	\$141,924	\$0	\$1,407,881
2028	\$141,924	\$0	\$1,407,881
2029	\$141,924	\$0	\$1,407,881
2030	\$141,924	\$0	\$1,407,881
2031	\$141,924	\$0	\$1,407,881
2032	\$141,924	\$0	\$1,407,881
2033	\$141,924	\$0	\$1,407,881
2034	\$141,924	\$0	\$1,407,881
2035	\$141,924	\$0	\$1,407,881
2036	\$141,924	\$0	\$1,407,881
2037	\$141,924	\$0	\$1,407,881
2038	\$141,924	\$0	\$1,407,881
2039	\$141,924	\$0	\$1,407,881
2040	\$141,924	\$0	\$1,407,881
2041	\$141,924	\$0	\$1,407,881

FY	Opex	Capex	Revenue
2042	\$141,924	\$0	\$1,407,881
2043	\$141,924	\$0	\$1,407,881
2044	\$141,924	\$0	\$1,407,881
2045	\$141,924	\$0	\$1,407,881
2046	\$141,924	\$0	\$1,407,881
2047	\$141,924	\$0	\$1,407,881
2048	\$141,924	\$0	\$1,407,881
2049	\$141,924	\$0	\$1,407,881
2050	\$141,924	\$0	\$1,407,881
2051	\$141,924	\$0	\$1,407,881
2052	\$141,924	\$0	\$1,407,881
2053	\$141,924	\$0	\$1,407,881
2054	\$141,924	\$0	\$1,407,881
2055	\$141,924	\$0	\$1,407,881
2056	\$141,924	\$0	\$1,407,881
2057	\$141,924	\$0	\$1,407,881
2058	\$141,924	\$0	\$1,407,881
2059	\$141,924	\$0	\$1,407,881
2060	\$141,924	\$0	\$1,407,881
2061	\$141,924	\$0	\$1,407,881
2062	\$140,124	\$0	\$1,390,025
2063	\$140,124	\$0	\$1,390,025
2064	\$140,124	\$0	\$1,390,025
2065	\$140,124	\$0	\$1,390,025

## 5 Preferred option

Summary of the costs of each option are presented in Table 13 below.

**Table 13 – Comparison of options**

Option	Capex	Opex to 2065	Total cost	
	\$2018/19	\$2018/19	\$2018/19	Net present cost
1	\$14,012,350	\$5,604,940	\$19,617,290	\$13,393,548
2	\$15,707,050	\$7,986,660	\$23,693,710	\$13,365,991
3	\$14,192,350	\$10,865,740	\$25,058,090	\$14,573,597

Based on the lowest net present cost, Option 2 is preferred, involving extending the existing feeders and procuring demand management services from customers.

While the benefits estimated above are marginal (in the order of \$30,000), the cost estimates for the demand management components of Option 2 (and Option 3) are considered an upper limit with the actual costs to be revealed during the regulatory control period via a market request for demand management solutions in accordance with the minimum project evaluation requirements as prescribed by Clause 2.2.1 of the Demand Management Incentive Scheme.

Option 2 requires capex and opex allowances for the 2019 to 2024 regulatory control period as described below.

### 5.1 Expenditure during the regulatory control period

#### 5.1.1 Opex

The demand management component of Option 2 would require an operational expenditure allowance of **\$1,703,840 excluding corporate overheads, contingency and GST** over the regulatory control period. This consists of the incentive payments to residential customers (\$1,472,340) as well as additional costs to provision the distributed demand management technology with controls to enable the centralised demand management platform to operate the units during peak periods (\$231,500).

FY	Incentive payments opex (direct plus control unit)	Opex associated with capex (@1% of capex)		Total
		Feeder extension	Centralised DM platform	
2020	\$0	\$0	\$0	\$0
2021	\$0	\$15,147	\$0	\$15,147
2022	\$1,398,400	\$15,147	\$1,800	\$1,415,347
2023	\$305,440	\$15,147	\$1,800	\$322,387
2024	\$0	\$15,147	\$1,800	16947
Total	\$1,703,840	\$45,441	\$5,400	\$1,769,828

It may be possible for Evoenergy to procure demand management with lower incentive payments than estimated for the purpose of this business case. The actual costs would be determined via a request for demand management solutions in accordance with the minimum project evaluation requirements as prescribed by Clause 2.2.1 of the Demand Management Incentive Scheme. Where the costs of demand management are lower than estimated, the reduced opex would be subject to the Efficiency Benefits Sharing Scheme.

### 5.1.2 Capex

The supply side component of the preferred option would require a capex allowance of is **\$1,694,700 excluding corporate overheads, contingency and GST**. This includes the feeder extension as augmentation expenditure (\$1,514,700) as well as the establishment of a demand management platform and communications receiver as IT/OT expenditure (\$180,000).

## 5.2 Application of DMIS/DMIA

It is considered that components of the expenditure outlined above may be eligible for incentives under the Demand Management Incentive Scheme and the Demand Management Innovation Allowance which will be further considered by Evoenergy.

The incentive payments may be considered eligible for the Demand Management Incentive Scheme with an incentive payment equal to the 50% of the total revealed costs once the demand management projects are committed (up to the economic value of the demand management solution).

The opex and capex components related to the demand management platform may potentially be eligible under the Demand Management Innovation Allowance given that it involves technology or a technique not previously implemented by any DNSP.