Draft Project Assessment Report

19 March 2021

Version 1.1

Logan Village Zone Substation Limitation

Consultation Period Starts: 19/03/2021

Consultation Period Closes: 08/05/2021

Part of the Energy Queensland Group

EXECUTIVE SUMMARY

ABOUT ENERGEX

Energex is a subsidiary of Energy Queensland Limited, a Queensland Government Owned Corporation. Energex distributes electricity to over 1.5 million residential, commercial and industrial customers across a population base of around 3.4 million in South East Queensland.

IDENTIFIED NEED

Logan Village zone substation (SSLGV) is supplied from Jimboomba bulk supply substation (SSJBB BSP) via a single 33kV radial feeder, F470. There is backup 33kV radial supply from Beenleigh bulk supply substation (SST108), F3620. SSLGV provides electricity supply to approximately 4,400 predominately domestic customers in the Yarrabilba, Buccan, Chambers Flat, Logan Village, Logan Reserve, Park Ridge, Park Ridge South and Waterford area. The Yarrabilba development on the south of SSLGV when fully developed is anticipated to provide approximately 20,000 dwellings to house a population of up to 50,000 people with an ultimate forecast of up to 86MVA load to the network.

The identified need for this Draft Project Assessment Report (DPAR) is that Energex will not meet its Safety Net obligation as outlined in its Distribution Authority at SSLGV in the summer of 2020/21 due to load growth in the area. The requirements of a non-network option to solve the identified need are summarised in Table 1.

Customer Category	Total Limit	Year	Forecast 50 PoE Load (MVA)	Load at risk (MVA)	Days over limit	% Time Above Limit	Hours
Rural	15.2MVA	2021	19.8	4.6	13	0.45%	39
		2022	18.4	3.2	7	0.23%	20.5
		2023	18.9	3.7	8	0.29%	25.5
		2024	19.2	4.0	9	0.33%	29
		2025	19.5	4.3	10	0.37%	32.5
		2026	19.8	4.6	13	0.45%	39
		2027	20.1	4.9	15	0.53%	46.5
		2028	20.6	5.4	22	0.71%	62.5
		2029	21.1	5.9	25	0.86%	75

Table 1: Non-network Option Requirements for SSLGV

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APPROACH

The National Electricity Rules (NER) require that, subject to certain exclusion criteria, network business investments for meeting service standards for a distribution business are subject to a Regulatory Investment Test for Distribution (RIT-D). Energex has determined that investment is essential in this case for it to meet the Safety Net criteria established in its Distribution Authority. Accordingly, this investment is subject to a RIT-D.

Energex published a Non-Network Options Report (NNOR) for the above described network constraint on 10th August 2020.

Three potentially feasible options were identified in the Non-Network Options Report:

- Option 1: Install 2nd 25MVA 33/11kV Transformer and associated modular switchgear at SSLGV
- Option 2: Establish new 25MVA 33/11kV Yarrabilba North zone substation
- Option 3: Upgrade Jimboomba Zone Substation

Following the release of the Non-Network Options Report (NNOR), one submission was received by the closing date of 20th November 2020.The submission received identified the following potentially feasible option:

- Option 4: Establish a Battery Energy Storage System.

This is a DPAR where Energex provides both technical and economic information about possible solutions and has been prepared in accordance with the requirements of clause 5.17.4(i).

Energex's preferred solution to address the identified need is Option 4 – Establish Battery Energy Storage System. The DPAR seeks information from interested parties about possible alternate and cost-effective solutions to address the need for investment.

Submissions in writing in response to this report may be submitted to demandmanagement@energex.com.au and are due by **8 May 2021**.

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1. Introduction

This DPAR has been prepared by Energex in accordance with the requirements of clause 5.17.4(i) of the NER.

This report represents the second stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need that Energex will not meet its Safety Net obligation as outlined in its Distribution Authority at SSLGV in the summer of 2020/21 due to load growth in the area

In preparing this RIT-D, Energex is required to consider reasonable future scenarios. With respect to major customer loads and generation, Energex has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Energex is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1. General Terms and Conditions

1. By issuing this DPAR, Energex is under no obligation whatsoever to review, discuss, select or enter into any agreement with any proponent who may submit a proposal.
2. Proponents will be responsible for all costs associated with the preparation and assessment of providing a proposal in response to this DPAR including but not limited to any site visits and responding to further information requests made by Energex in order to assist Energex in its assessment of the proposal.
3. When evaluating a proposal, Energex will act in accordance with the NER and RIT-D Guidelines (available on the Australian Energy Regulator (AER) website). Further, Energex will follow the process as described in Energex's Demand Side Engagement Strategy (DSES) a copy of which can be found here.
4. Energex may combine all or parts of separate proposals for the purposes of evaluation where this may lead to a more efficient outcome than the separate proposal or option. Proponents should indicate in their proposal whether they wish to have their proposals or options considered in isolation or in combination with other proponents' proposals.
5. Energex will publicly announce the outcome of the evaluation process. This announcement will be published on Energex's website and unless otherwise agreed in writing at the commencement of the assessment process all details of proposals including cost information will be treated as public information.

1.2. Contact Details

Submissions in writing in response to this report may be submitted to demandmanagement@energex.com.au and are due by 8 May 2021.

2. Background

2.1. Existing Network

Logan Village zone substation (SSLGV) provides electricity supply to approximately 4,400 predominately domestic customers in the Yarrabilba, Buccan, Chambers Flat, Logan Village, Logan Reserve, Park Ridge, Park Ridge South and Waterford area.

SSLGV is supplied from Jimboomba bulk supply substation (SSJBB) via a single 33kV feeder, F470, under system normal conditions. Following an outage of F470, an auto-changeover scheme (ACO) operates such that SSLGV is supplied via 33kV feeder F3620 from Beenleigh bulk supply substation (SST108). Geographic and schematic views of the network area under study are provided in Figure 1, Figure 2 and Figure 3.

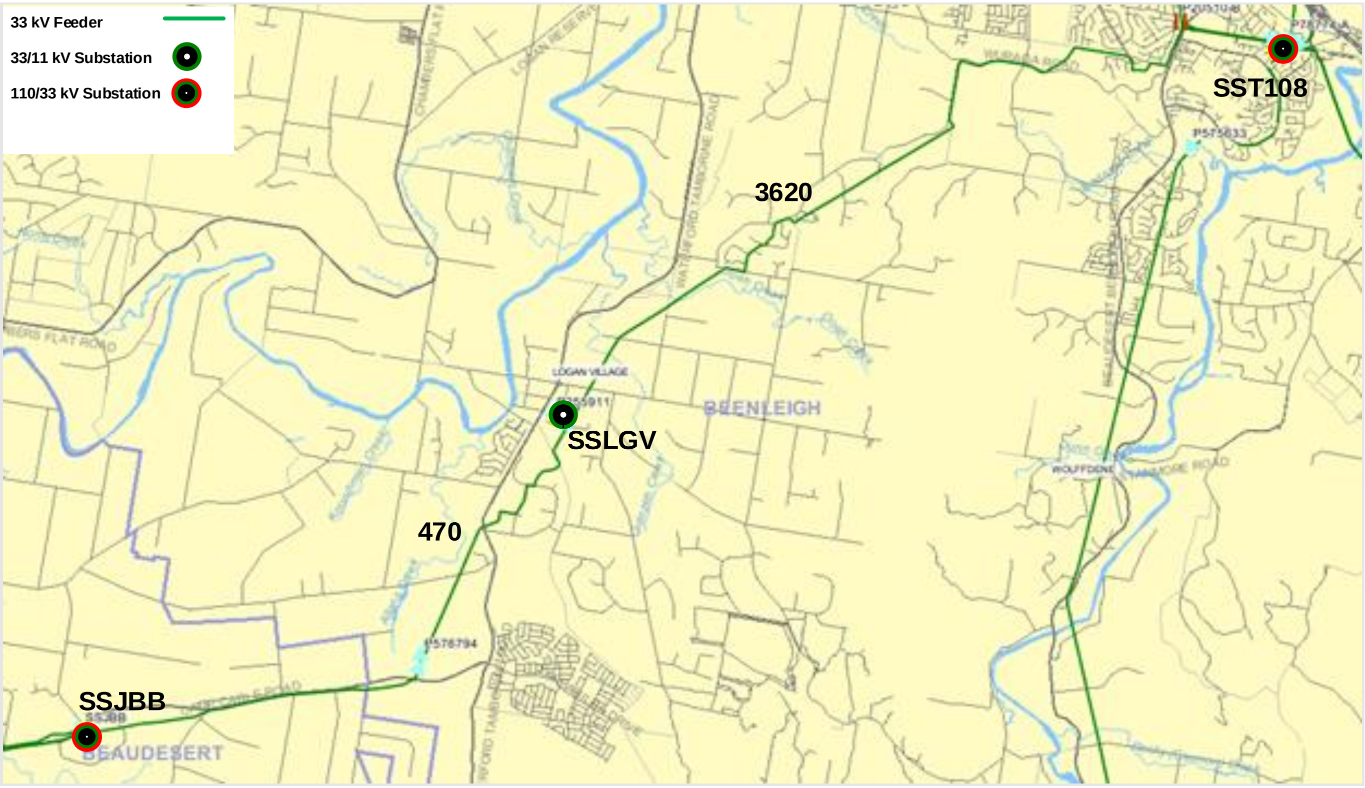


Figure 1: Existing sub-transmission network arrangement (Geographic view)

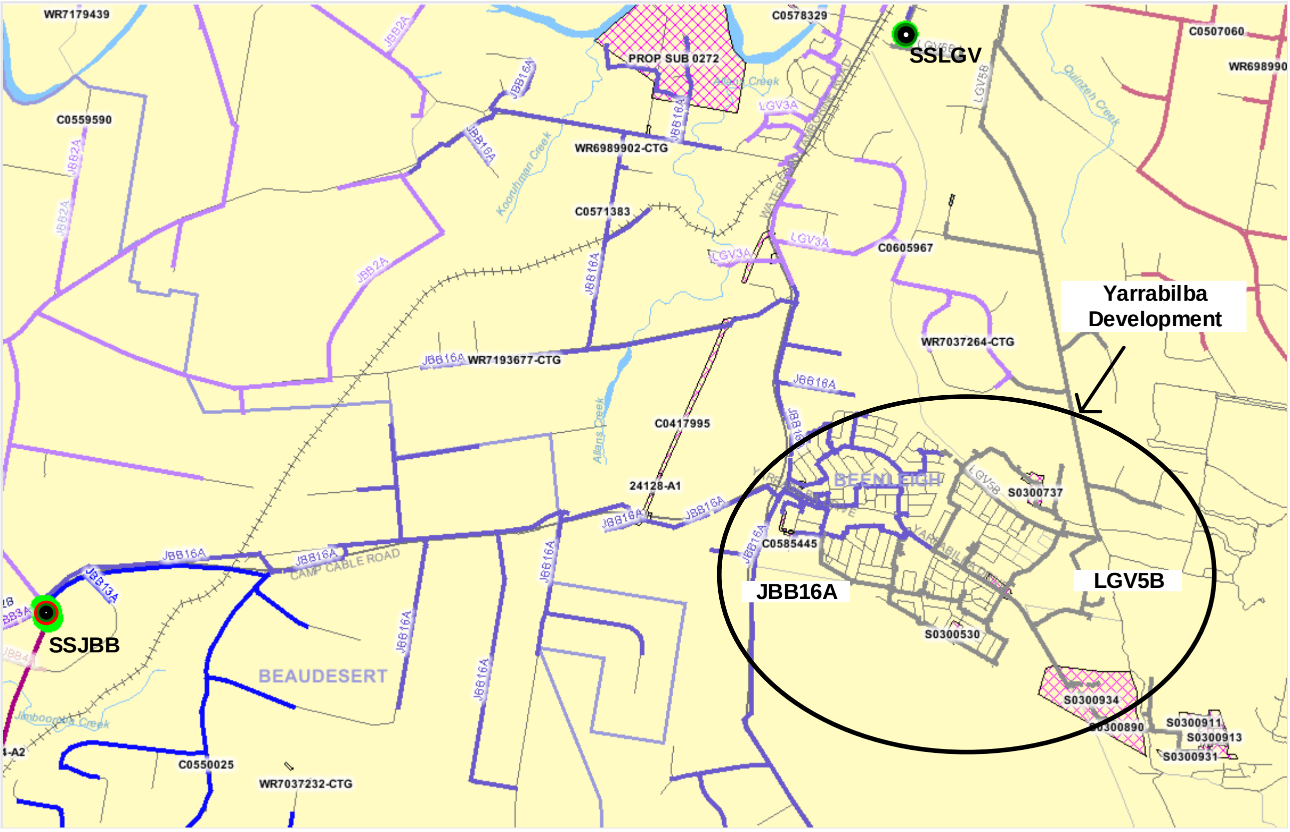


Figure 2: Existing 11kV network arrangement (Geographic view)

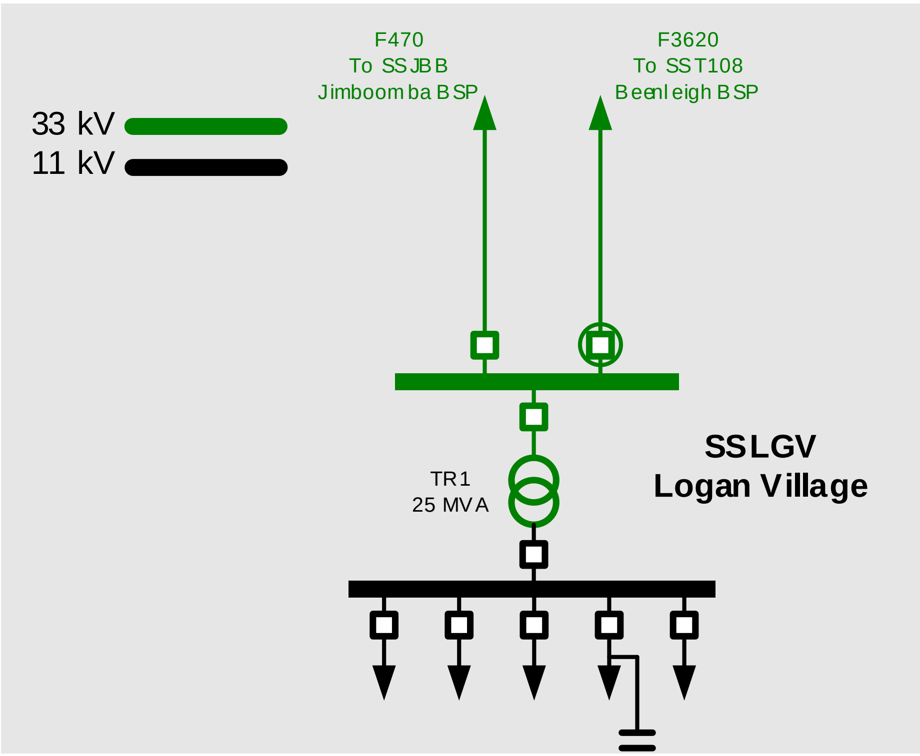


Figure 3: Existing Network Arrangement (Schematic View)

2.2. Load Profiles

The annual load profile for SSLGV is shown in Figure 4 below.

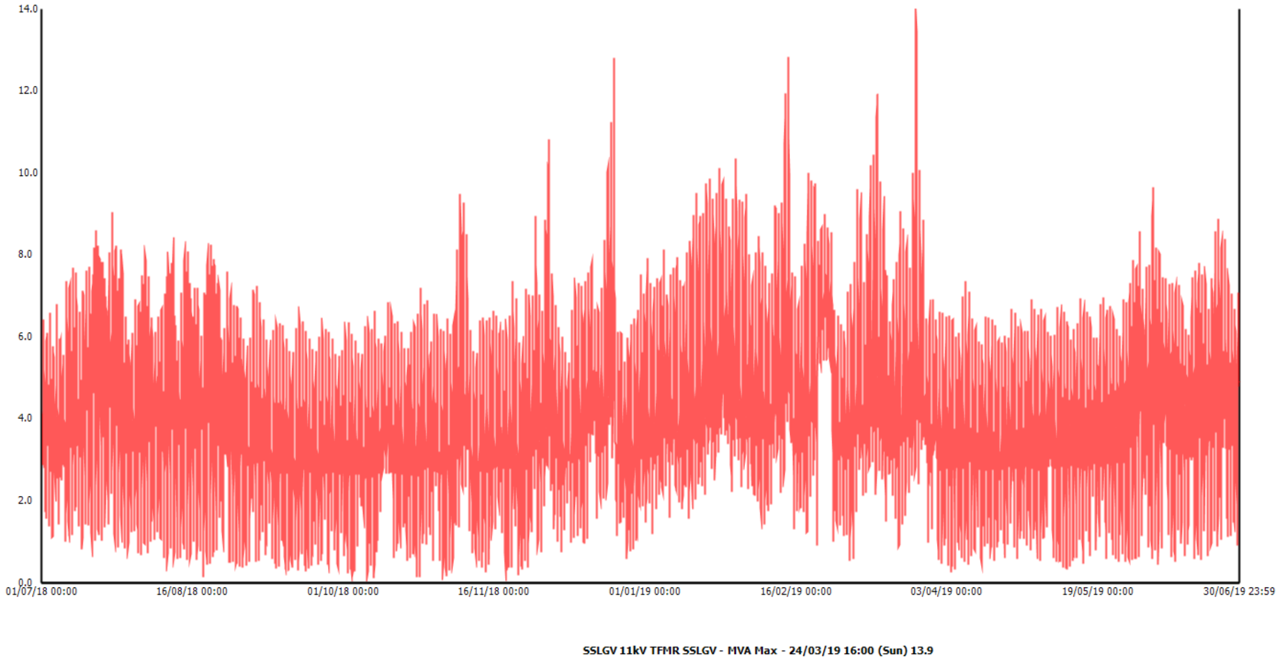
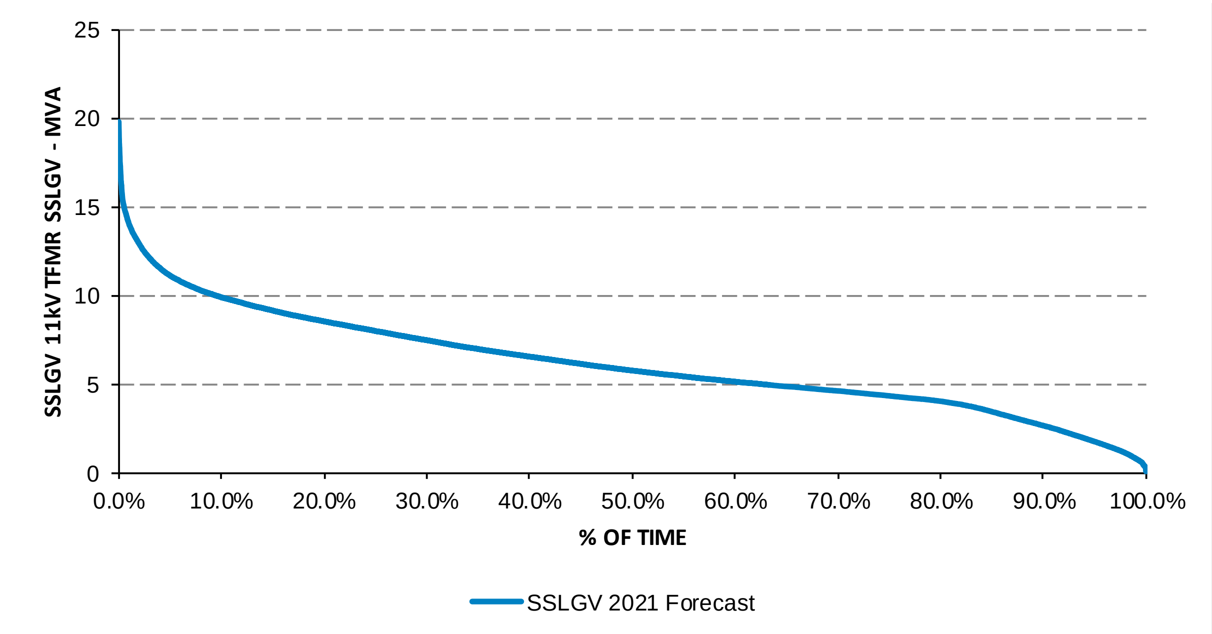


Figure 4: Annual Load Profile (MVA) for SSLGV

Figure 5 shows the load duration curve for SSLGV. This is based on the previous 3 years of data and is scaled to its 50% Probability of Exceedance (50PoE) forecast.



*The values for SSLGV have been scaled to the 2021 peak forecast load of 19.8MVA

Figure 5: Load duration curve for SSLGV

3. Identified Need

3.1. Applied Service Standards

Under its Distribution Authority, Energex must adhere to the Safety Net which identifies the principles that apply to the operation of network assets under network contingency conditions. System contingency related capability is assessed against a 50% probability of exceedance (PoE) forecast load, available load transfers, emergency cyclic capacity (ECC) ratings, non-network response, mobile plant, mobile generators, and short-term ratings of plant and equipment where available. This process allows load at risk under system normal and contingency conditions to be identified and assessed. Energex's Distribution Authority can be accessed by the following link:

https://www.dnrme.qld.gov.au/__data/assets/pdf_file/0003/219486/distribution-authority-d0798-energex.pdf

SSLGV is classified as a Rural zone substation, and as such, the following Safety Net criteria apply:

- For a rural zone substation, during a single contingency event, interruption of supply up to 40MVA is permissible for the first 30 minutes, followed by a maximum interruption of up to 15MVA is permissible, provided all load except for up to 10MVA can be restored within 4 hours, and the remaining load fully restored within 12 hours.

Table 2 below outlines the Safety Net criteria.

Category	Demand Range	Allowed Outage to be OK
Rural	>40MVA	No outage OK
	15-40MVA	30 minutes OK
	10-15MVA	4 hours OK
	<10MVA	12 hours OK

Table 2: Summary of Safety Net Criteria

Further to an assessment against its Safety Net obligations, Energex also undertake analysis of system capacity under normal conditions with all plant in service against the 10PoE load.

3.2. Description of the Identified Need

3.2.1. Safety Net Non-Compliance

The existing supply to the Logan Village and Yarrabilba areas does not meet the Safety Net for an unplanned outage of a transformer at SSLGV. The following section outlines the substation and feeder limitations of the existing network. The system normal condition is assessed against the 10%PoE load forecast for SSJBB bulk supply substation and SSLGV and SSJBB zone substations. The 50%POE load forecast is used for N-1 contingency analysis.

3.3. Quantification of the Identified Need

3.3.1. Safety Net Non-Compliance

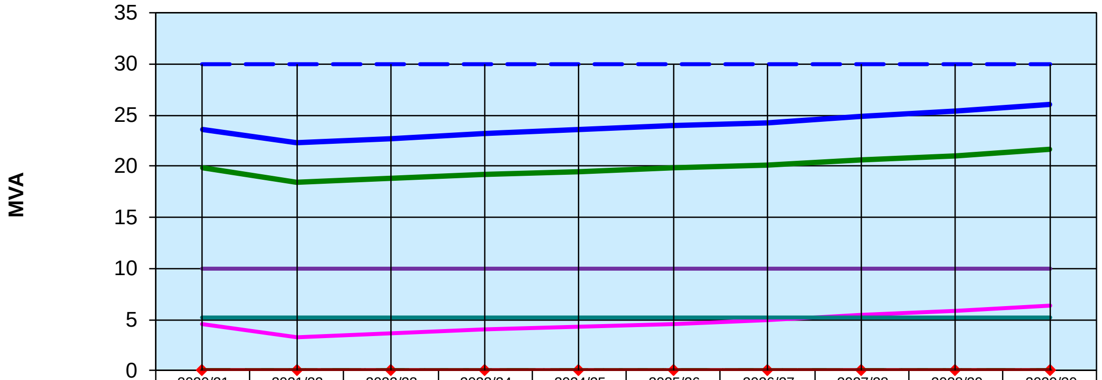
SSLGV Limitations

SSLGV is equipped with 1 x 25MVA 33/11kV transformer. The substation capacity is limited by transformer itself and provides an NCC, ECC and 2HEC as below:

- NCC – 30MVA
- ECC – 0MVA
- 2HEC – 0MVA

Figure 6 shows the network limitations at SSLGV. Note that there are permanent load transfers from SSLGV to SSJBB and from SSLGV to Crestmead zone substation (SSCRM) which results in a slight reduction in load between 2020/21 and 2021/22.

SSLGV Load Forecast - Existing

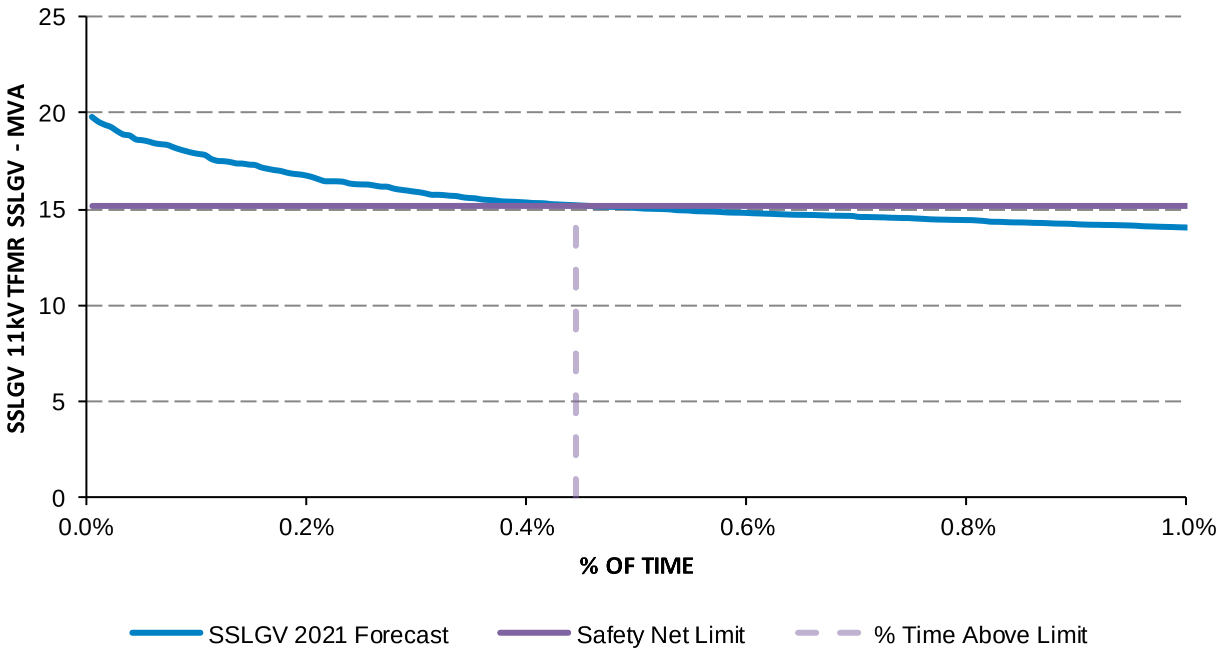


	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	23.56	22.25	22.76	23.18	23.56	23.94	24.29	24.93	25.44	26.11
Summer NCC	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Load > NCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50 PoE Load	19.81	18.43	18.85	19.19	19.51	19.82	20.12	20.64	21.07	21.62
Summer ECC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Summer 2HEC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LAR	4.61	3.23	3.65	3.99	4.31	4.62	4.92	5.44	5.87	6.42
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20
Avail Mobile Eqpt	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00

Figure 6: Load Forecast and Load at Risk for SSLGV

Figure 6 above illustrates that there is Safety Net load at risk associated with an outage of TR1 at SSLGV, increasing from 4.61MVA to 6.42MVA.

To meet Energex's Safety Net obligations, SSLGV can supply up to 15.2MVA. This incorporates 5.2MVA of available load transfers and 10MVA of mobile generation support. Figure 7 shows the portion of the load duration curve for the forecast 11kV load of SSLGV and available capacity at SSLGV.



*The values for SSLGV have been scaled to the 2021 peak forecast load of 19.81MVA.

Figure 7: Load Duration Curve SSLGV

Figure 7 shows that approximately 0.45% of the time in 2020/21 the load is above the 15.2MVA limit.

Figure 8 shows that as the load increases each year, the limit is surpassed for a longer duration per year. For ease of presentation, only every second year is shown.

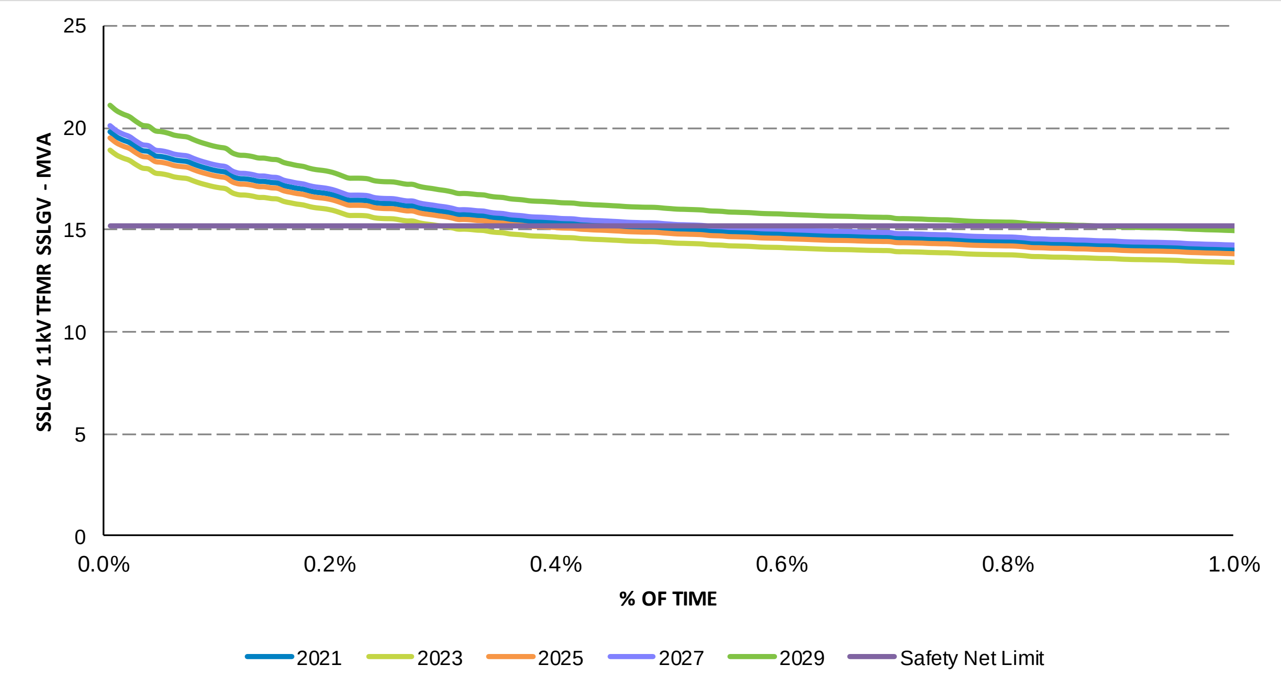


Figure 8: Load duration curve for 2021 - 2029

Figure 8 above shows that the duration in which the load is at risk rises from 0.45% to 0.86% of the year.

Table 3 illustrates that the amount of time support would be required is forecast to start with 13 days in 2020/21 and increases significantly to 25 days by 2028/29.

Customer Category	Total Limit	Year	Forecast 50 PoE Load (MVA)	Load at risk (MVA)	Days over limit	% Time Above Limit	Hours
Rural	15.2MVA	2021	19.8	4.6	13	0.45%	39
		2022	18.4	3.2	7	0.23%	20.5
		2023	18.9	3.7	8	0.29%	25.5
		2024	19.2	4.0	9	0.33%	29
		2025	19.5	4.3	10	0.37%	32.5
		2026	19.8	4.6	13	0.45%	39
		2027	20.1	4.9	15	0.53%	46.5
		2028	20.6	5.4	22	0.71%	62.5
		2029	21.1	5.9	25	0.86%	75

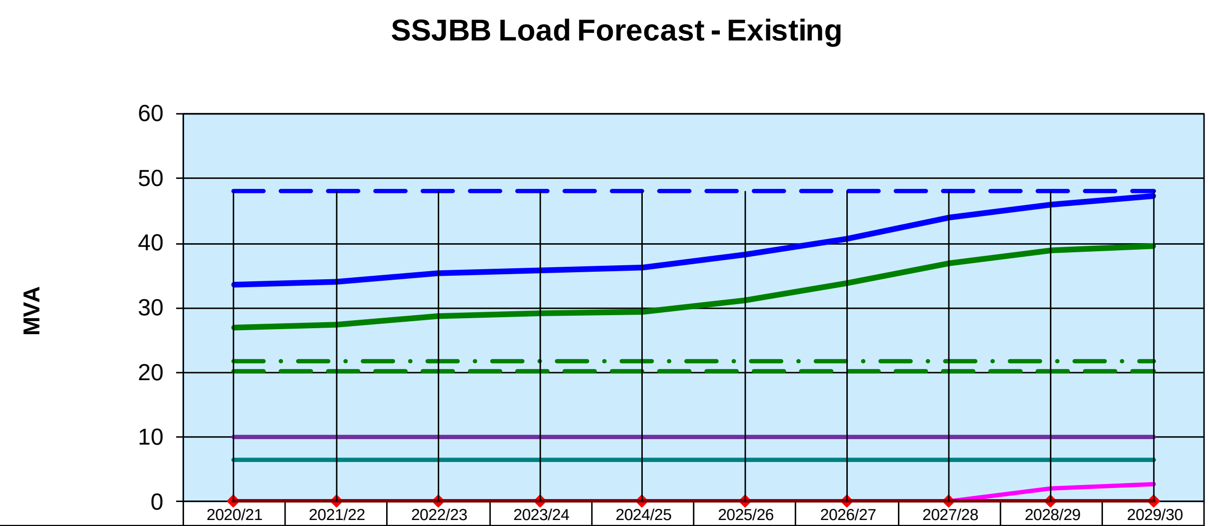
Table 3: Forecast duration load will be at risk

SSJBB Zone Substation

SSJBB is equipped with 1 x 15MVA and 1x 25MVA 33/11kV transformers. The substation capacity is limited by the 15MVA transformer and provides an NCC, ECC and 2HEC as below:

- NCC – 48MVA
- ECC – 20.25MVA
- 2HEC – 21.7MVA

Figure 9 shows the limitations at SSJBB:



	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	33.51	34.09	35.39	35.90	36.33	38.19	40.65	43.92	45.97	47.30
Summer NCC	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00
Load > NCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50 PoE Load	27.04	27.50	28.68	29.09	29.45	31.16	33.87	36.94	38.83	39.53
Summer ECC	20.30	20.30	20.30	20.30	20.30	20.30	20.30	20.30	20.30	20.30
Summer 2HEC	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80
LAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	2.03	2.73
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Avail Mobile Eqpt	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00

Figure 9: Load Forecast and Load at Risk for SSJBB

Figure 9 shows a network limitation at SSJBB in 2027/28 of 0.5MVA, increasing to 2.73MVA in 2029/30. It should be noted that SSJBB is currently sharing the load growth from the Yarrabilba development area with SSLGV. It is anticipated that if either substation was upgraded to supply load in this area, that substation would see most of the load growth.

4. Network Options Considered

4.1. Do Nothing (Base Case)

The identified need is a non-compliance of Energex's Safety Net obligations outlined in Energex's Distribution Authority. As such, the 'Do Nothing' option is not an acceptable outcome.

4.2. Option 1: Install 2nd 25MVA 33/11kV Transformer and associated modular switchgear at SSLGV

This option involves installing a second 25MVA 33/11kV transformer and 2nd modular substation in October 2023.

The works required to implement this option are:

- Install 2nd 25MVA 33/11kV modular substation.
- Cut over existing 33kV feeder F3620 to the new modular substation.
- Cut over 2 x 11kV feeders to the new modular substation.
- Reconfigure 11kV feeders to de-load SSJBB
- Estimated capital expenditure: $8.57 million ± 40%
- Estimated operating expenditure: $3,300 / annum

A schematic diagram of the proposed solution is shown in Figure 10 below.

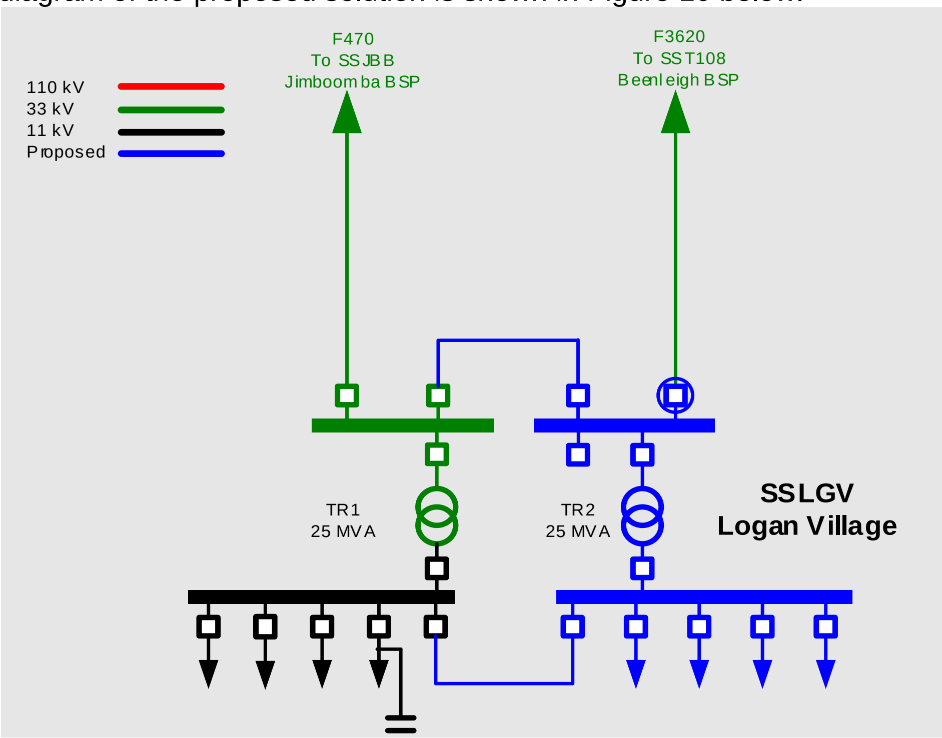


Figure 10: Proposed Network Arrangement under Option 1

4.3. Option 2: Establish new 25MVA 33/11kV Yarrabilba North zone substation

This option involves building Yarrabilba North zone substation (356) as a single 25MVA modular substation by cutting-in-and-out of F470 between SSJBB and SSLGV.

The works required to implement this option are:

- Establish 1x 25MVA 33/11kV modular substation at Yarrabilba North zone substation
- Establish approximately 4 km of 33kV DCCT feeders to Yarrabilba North zone substation by cutting in-and-out of existing 33kV feeder F470 between SSJBB and SSLGV.
- Reconductor, uprate and reconfigure existing 11kV network to provide optimum 11kV supply capacity to Yarrabilba development and provide relief to existing 11kV feeders and adjacent zone substations (SSLGV and SSJBB).
- Estimated capital expenditure: \$21.60 million ± 40%
- Estimated operating expenditure: \$50,200 / annum

A schematic diagram of the proposed solution is shown in Figure 11 below.

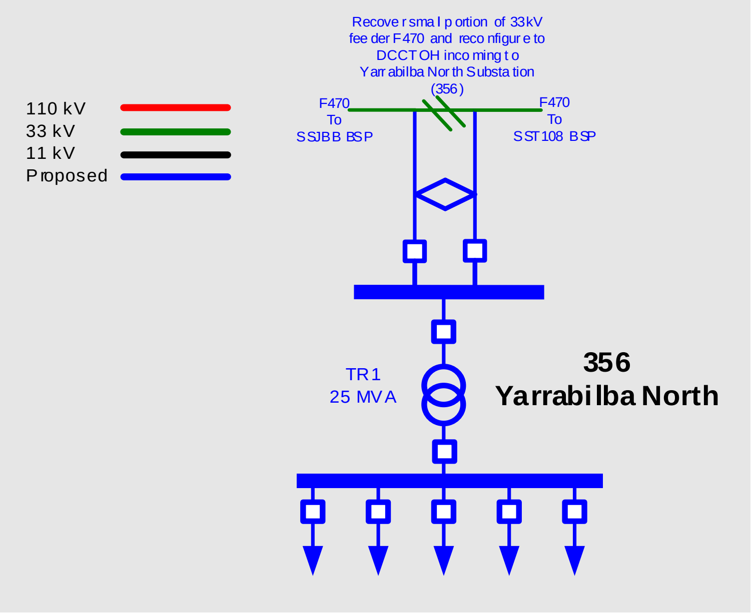


Figure 11: Proposed Network Arrangement under Option 2

4.4. Option 3: Upgrade Jimboomba Zone Substation

This option involves upgrading Jimboomba zone supply by installing a 3rd 25MVA 33/11kV modular substation by October 2023.

The works required to implement this option are:

- Install 3rd 25MVA 33/11kV modular substation.
- Cut over the "A" (JBBTR7A) leg of TR7 to the new 3rd modular substation.
- Cut over 2 x 11kV feeders to the new 3rd modular substation.
- Reconfigure and uprate existing 11kV feeders to de-load SSLGV.
- Establish new 11kV feeders to the east with spare conduits to support future Yarrabilba development as part of distribution project.
- Split 11kV bus (BB11) supplied from TR1 and modify existing ACO scheme for the loss of TR1.
- Estimated capital expenditure: $ 8.48million ± 40%
- Estimated operating expenditure per annum: $7,300 / annum

This option has the disadvantage of requiring longer 11kV feeders to supply the load at Yarrabilba over both SSLGV and a new Yarrabilba zone substation. Furthermore, a second transformer and modular building is still likely to be required at a future stage under this option. A schematic diagram of the proposed solution is shown in Figure 12 below.

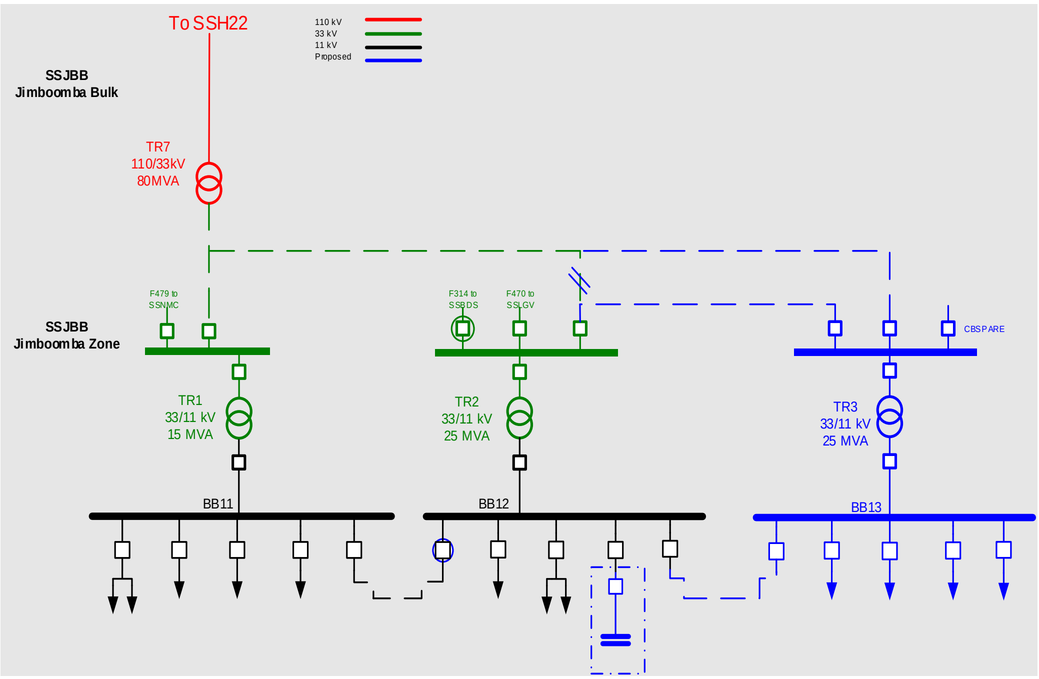


Figure 12: Proposed Network Arrangement under Option 3

4.5. Preferred Network Option

Of the network options considered above, Option 1 was considered the preferred network option[1]. SSLGV is closer to most of the new developments, meaning it is less costly to construct 11kV feeder to supply the new forecast loads. The scope of the preferred network option includes:

- Establish a second 33/11kV transformer
- Establish a second modular 33kV and 11kV substation building

The preferred network option has an estimated capital project cost of $8.57M, and an annual operating cost of approximately $3,300 / annum.

4.6. Potential Deferred Augmentation Charge

Energex have estimated the capital cost of the network options to within ± 40% of estimation accuracy. Using these costs as a guide, a deferral of the preferred network option by a year represents a deferral saving of approximately $230,000 per annum, assuming the same reliability outcomes are maintained as with the preferred network option. While this should not be considered as the precise deferral cost available to a non-network proponent, it serves as a guide for interested parties to determine the viability of their proposal. Energex will work with non-network proponents based on the specifics of what the proponents offer and any necessary further works that Energex may have to undertake to ensure the reliability, security and safety of the network are maintained.

[1] Refer section 8.5 for selection of preferred option

5. Summary of Submission/s Received

On 10th August 2020 Energex published the NNOR providing details on the identified need at SSLGV. This report sought information from Registered Participants, AEMO and Interested Parties regarding alternative potential credible options or variants to the potential credible option presented by Energex.

In response to the NNOR, Energex received one submission by 20th November. This response identified a credible option to establish 5MW/15MWh battery system to meet the required load at risk at SSLGV in 2022 and add a further 3MW/9MWh battery capacity to the system in 2028.

5.1. Option 4: Contract a Battery Energy Storage System

This option involves contracting a proponent to provide a 5MW/15MWh Battery Energy Storage System in the vicinity of SSLGV in 2022, with an additional 3MW/9MWh in 2028. For an outage of the 33/11kV transformer at SSLGV, the battery system will be utilised by Energex to restore load in accordance with the Safety Net thresholds. As load continues to grow, the battery system size will be required to increase for Energex to be able to continue to meet its Safety Net criteria.

Future Stages

Contracting a Battery Energy Storage System enables Energex to continue to supply customers from SSLGV without having to increase capacity at the substation during the contracted term/s. Beyond this contracted term Energex may then consider implementing the following network options:

- Option 1: Install 2nd 25MVA 33/11kV Transformer and associated modular switchgear at SSLGV
- Option 2: Establish new 25MVA 33/11kV Yarrabilba North zone substation

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6. Non-Network Options Requirements

6.1. Assessment of Non-Network Solutions

To reduce, defer or eliminate network expenditure as part of the identified Non-Network Options, a proponent would need to provide a 5MW/15MWh battery systems in 2022, with an additional 3MW/9MWh in 2028.

6.2. Feasible vs Non-Feasible Options

6.2.1. Potentially Feasible Options

The identified need presented in this DPAR is driven by Energex not meeting its Safety Net obligations. Specifically, an outage of the existing transformer at SSLGV leads to a Safety Net load at risk of 4.6MVA in 2021/22 which increases in future years. Figure 7, Figure 8 and Table 3 in Section 3.3 outlines the load reduction and operating profile required to reduce or eliminate the Identified Need.

With regard to the requirements of clause 5.17.4(e)(4) of the NER, any non-network option will contribute to power system security and reliability to the extent that the solution solves the Safety Net limitation. The contribution to power system fault levels is not an issue for this limitation.

Any solutions that prudently and efficiently address these constraints will be considered. A non-exhaustive list of potentially feasible options includes:

- Embedded dispatchable network generation
- Embedded energy storage systems
- Embedded energy storage systems combined with Generation (possibly dispatchable or non-dispatchable)
- Load curtailment agreements with customers to disconnect from the network following a contingency.

It should be noted that the above options may be aggregated across several substations in the network. For example, embedded solutions or load curtailment options could be implemented in the supply areas of Jimboomba and Logan Village to provide the required network support.

6.2.2. Options That Are Unlikely to Be Feasible

Without attempting to limit a potential proponent’s ability to innovate, unproven, experimental or undemonstrated technologies are unlikely to be considered as feasible options to address the identified limitation.

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7. Market Benefit Assessment Methodology

The identified need outlined in the NNOR and the DPAR is a regulatory obligation to meet the Safety Net requirements outlined in the Distribution Authority. Because of this, the assessment methodology is a lowest cost process, rather than a cost/benefit analysis based on market benefits. There is no material difference in specific market benefits, such as Value of Customer Reliability, between identified Network and Non-Network Options . As such, no Market Benefits have been calculated for use in the economic analysis to identify the preferred option.

8. Detailed Economic Assessment

8.1. Methodology

Where there is a regulatory obligation to comply with the Safety Net criteria, Energex apply a lowest cost Net Present Value (NPV) assessment to determine the preferred network option. For the identified need presented in this DPAR, a Weighted Average NPV, based on a sensitivity analysis, was conducted to establish the option that remained the lowest cost option in the scenarios considered. In effect, this means that Energex create a separate NPV for each scenario, assign a weighting to each, with the outcome a Weighted Average NPV to inform the lowest cost option in a range of scenarios to proceed with.

The preferred option for this DPAR is Option 4, which was based on the submission received in response to the NNOR. To protect Commercial-in-Confidence information, Energex has not published the economic analysis associated with the costs provided in this submission. Energex however can detail that the costs associated with this option are enough to meet the deferral value required to be the preferred option (as identified in section 4.6 of this report). In addition, the Weighted Average NPV is the lowest cost when comparing the non-network option to the alternative feasible Network options.

Any future submission must also meet this deferral value threshold. For completeness, the project identified as Option 4 does not disclose costing detail as part of this Draft Project Assessment Report.

Proponents are still encouraged to put forward submissions in response to this Draft Project Assessment Report (DPAR) and feasible options will be evaluated against selection criteria.

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8.2. Key Variables and Assumptions

8.2.1. Discount Rate

Calculations for annual deferral values of projects are based on Energex's regulated pre-tax real Weighted Average Cost of Capital (WACC). This value is prescribed by the AER for a specific regulatory control period. The identified need described in this DPAR occurs in the 2020-2025 regulatory control period, where the WACC is 2.62%. (Note that this is lower than the WACC in the previous regulatory control period.)

8.2.2. Cost Estimates

Project costs are calculated using standard estimate components which are developed and evaluated by estimation teams in Energex. The costs are split into 2 components: direct cost, which is the costs which are directly costed to the project; and indirect costs which cover overheads associated with the business. All costs provided in this report are estimated to fall within ± 40% accuracy of the stated cost.

8.2.3. Evaluation Test Period

Consideration of network options is assessed over an evaluation period of 60 years.

8.3. Scenarios Adopted for Sensitivity Analysis

The scenarios that have been considered are:

- **Medium demand (base case)** – under this scenario the load forecast presented in Section 3.3 is utilised to set the timing of the future stages in each option. In effect, this means that a new 11kV feeder has been assumed to be required to supply the new load at Yarrabilba every 4 years, whether this is from SSLGV, SSJBB or a new Yarrabilba zone substation. For Option 4, this means that the initial battery solution will be able to support the load for 10 years. This scenario has been assigned a likelihood of 60% in the weighted average NPV.
- **High demand** – under this scenario the only change from the Medium Demand scenario is a new 11kV feeder is assumed to be required every two years, with any future stages for each option assumed to be earlier than for the case of Medium Demand. For Option 4, this means that the initial battery solution can only support the load for five years, with subsequent network development occurring at this point. This scenario has been assigned a likelihood of 20% in the weighted average NPV.
- **Low demand** – under this scenario the assumption is that new 11kV feeders are required every six years and any subsequent stages for each option shifted out accordingly. For Option 4, this means that the initial battery solution will be able to support the load for a further 10 years. This scenario has been assigned a likelihood of 20% in the weighted average NPV.

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8.4. NPV Results

Table 4 shows the Weighted Average NPV results for the identified options. As discussed earlier, the NPV costs results have been withheld for Options 4 and 5 as they are based on the submission to the NNOR that was received, which Energex and the proponent considers to be Commercial-in-Confidence. The costs associated with these two options are such that Option 4 is the preferred option in the Weighted Average NPV results.

Option Number	Option Name	Rank	Net Economic Benefit ($M)	PV of CAPEX ($M)	PV of OPEX (SM)
1	2nd Transformer at SSLGV	2	-29,439	-27,801	-1,638
2	New Substation at Yarrabilba North	4	-33,844	-32,016	-1,829
3	Upgrade SSJBB	3	-30,316	-28,432	-1,884
4	5MW Battery followed by Yarrabilba Central	1	Withheld	Withheld	Withheld

Table 4: Weighted Average NPV Results

Further details such as project staging and the NPV results for each scenario can be found in Appendix C.

8.5. Selection of Preferred Option

Option 4 is currently the preferred option overall. Contracting a battery system for 5MW defers the investment in a 2nd transformer at SSLGV and enables Energex to monitor load growth in the Yarrabilba area and move to establishing a new substation in the Yarrabilba development, closer to the load centre. The scope of the preferred network option includes:

- Contract 5MW/15MWh battery system to allow for generation support under a contingency at SSLGV in 2022
- Contract a further 3MV/9MWh battery system as load grows in the area in 2028

As previously described, Energex view the information provided as part of the submission to the NNOR as Commercial-in-Confidence and as such won't publish the capital and operating costs associated with this option. The costs are equivalent or better than the deferral value outlined in Section 4.6.

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9. Submission and Next Steps

9.1. Submissions from Solution Providers

Energex invites written submissions to address the identified need in this report from registered participants and interested parties.

Energex will not be legally bound in any way or otherwise obligated to any person who may receive this RIT-D report or to any person who may submit a proposal. At no time will Energex be liable for any costs incurred by a proponent in the assessment of this RIT-D report, any site visits, obtainment of further information from Energex or the preparation by a proponent of a proposal to address the identified need specified in this RIT-D report.

The RIT-D process is aimed at identifying a technically feasible non-network alternative to the internal option that has greater net economic benefits. However, the selection of the solution provider to implement the preferred option will be done after the conclusion of the Final Project Assessment Report (FPAR) and in accordance with Energex standards for procurement.

Submissions in response to the report may be submitted to demandmanagement@energex.com.au and are due by **8th May 2021.**

9.2. Next Steps

Following Energex's consideration of submissions received in response to this report, the preferred option, and a summary of and commentary on any submissions received will be included as part of the Final Project Assessment Report (FPAR). The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Energex intends to publish the FPAR no later than 14 June 2021. Energex will use its reasonable endeavours to publish the FPAR by the above date. This may however not be achievable due to changing power system conditions or other circumstances beyond the control of Energex.

At the conclusion of the consultation process, Energex intends to take steps to progress the recommended solution(s) to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvement(s), as necessary.

Please note: At the conclusion of the Final Project Assessment Report (FPAR), for Energex to act on a submission from a non-network proponent, Energex will need to enter into a legally binding contract with that non-network proponent for delivery of the non-network solution within a timeframe satisfactory to Energex to ensure timely completion of the project. Failure to enter into a contract within a satisfactory timeframe will result in Energex reverting to the next preferred credible option identified as part of the preferred option published in the FPAR.

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Step 1	Publish Non-Network Options Report inviting non-network options from interested participants	Date Released: **10 August 2020**
Step 2	Submissions in response to the Non-Network Options Report	Concluded: **20 November 2020**
Step 3	Review and analysis of proposals by Energex This is likely to involve further consultation with proponents and additional data may be requested.	Concluded: **18 December 2020**
Step 4	Release of Draft Project Assessment Report (DPAR) (this report)	Date Released: **19 March 2021**
Step 5	Submissions in response to the Draft Project Assessment Report.	Due Date: **8 May 2021**
Step 6	Review and analysis by Energex. This is likely to involve further consultation with proponents and additional data may be requested.	Anticipated to be completed by: **21 May 2021**
Step 7	Release of Final Project Assessment Report (FPAR) including summary of submissions received	Anticipated to be released by: **14 June 2021**
Energex reserves the right to revise this timetable at any time. The revised timetable will be made available on the Energex website.		

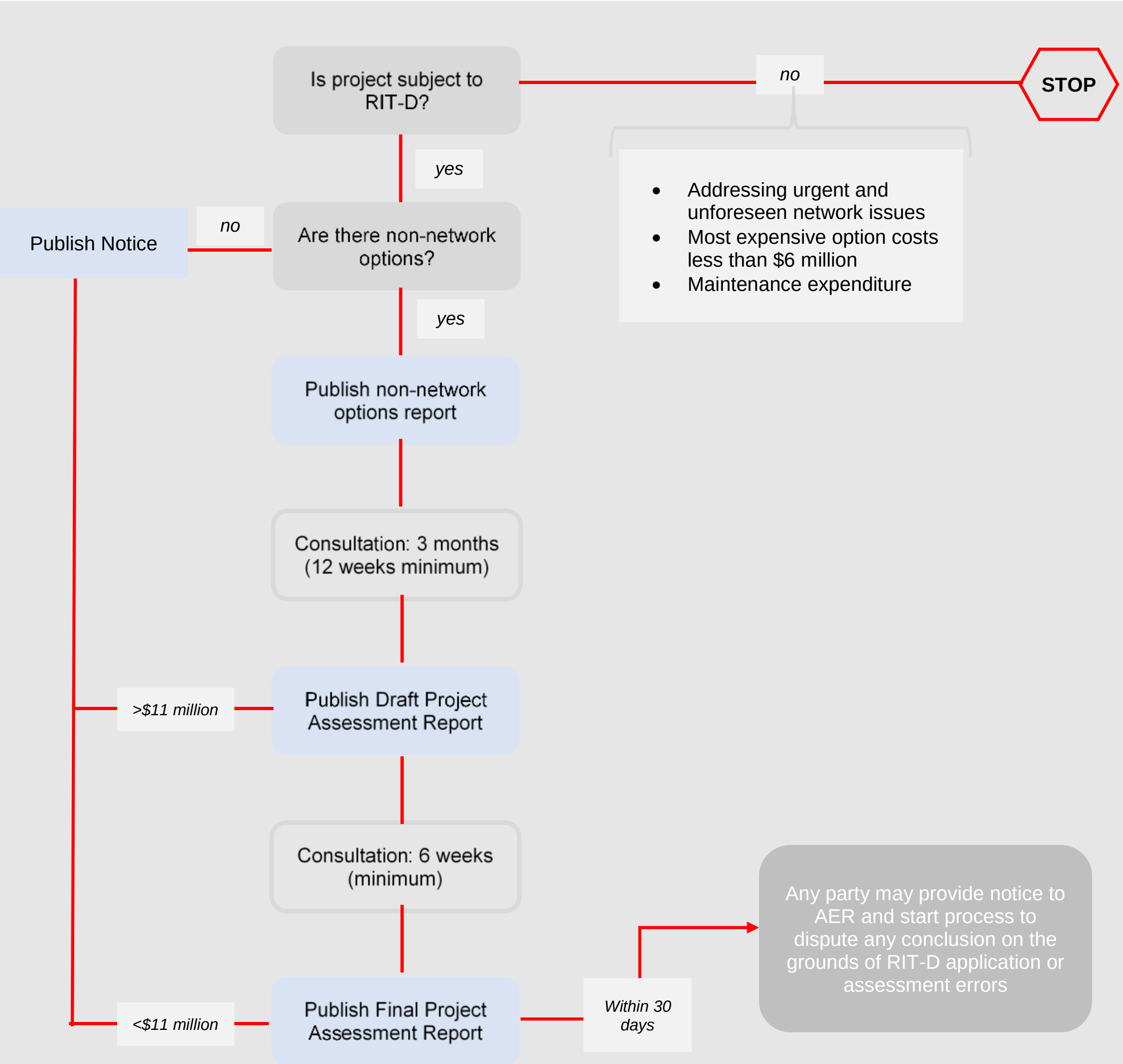
During the consultation period, Energex will review, compare and analyse all internal and external solutions. Detailed economic options analysis and comparisons of expected market benefits will be undertaken during this time. At the end of the consultation and review process Energex will publish a final report which will detail the most feasible option and proceed to implement that option.

10. Compliance Statement

This DPAR complies with the requirements of NER section 5.17.4(e) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.1
(3) if available, the relevant annual deferred *augmentation* charge associated with the identified need;	4.6
(4) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of *load* reduction or additional *supply*; (ii) location; (iii) contribution to *power system security* or *reliability*; (iv) contribution to *power system* fault levels as determined under clause 4.6.1; and (v) the operating profile;	3 & 0
(5) a summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options and non-network options;	4 & 0
(6) for each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on: (i) a technical definition or characteristics of the option; (ii) the estimated construction timetable and commissioning date (where relevant); and (iii) the total indicative cost (including capital and operating costs);	4, 0 & 0
(7) information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a non-network proposal for consideration by the RIT-D proponent.	9

Appendix A – The RIT-D Process



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.

Appendix B – Glossary of Terms

Term	Definition
Peak Risk Period	The time period over which the load is highest (Day/Night).
NCC Rating (MVA)	Normal Cyclic Capacity – the total capacity with all network components and equipment in service. The maximum permissible peak daily loading for a given load cycle that plant can supply each day of its life. Taking impedance mismatch into consideration, it is considered the maximum rating for a transformer to be loaded under normal load conditions.
10 PoE Load (MVA)	Peak load forecast with 10% probability of being exceeded (one in every 10 years will be exceeded). Based on normal expected growth rates & weather corrected starting loads.
LARn (MVA)	Security standard load at risk under system normal condition, expressed in MVA.
LARn (MW)	Security standard load at risk under system normal condition, expressed in MW.
Power Factor at Peak Load	Compensated power factor at 50 PoE Load. Capacitive compensation is switched according to the size of the capacitor banks installed at the substation, compensation is generally limited to prevent a substation from going into leading power factor.
ECC Rating (MVA)	Emergency Cyclic Capacity – the long term firm delivery capacity under a single contingent condition. The maximum permissible peak emergency loading for a given load cycle that an item of plant can supply for an extended period of time without unacceptable damage. For substations with multiple transformers, the ECC is the minimum emergency cyclic capacity of all transformer combinations taking impedance mismatches into consideration, with one transformer off-line.
50 PoE Load (MVA)	Peak load forecast with 50% probability of being exceeded (one in every two years will be exceeded). Based on normal expected growth rates and weather corrected starting loads.
Raw LAR (MVA)	The amount of load exceeding ECC rating. (50 PoE Load – ECC Rating)
2-Hour Rating (MVA)	Two-Hour Emergency Capacity (2HEC) – the short term or firm delivery capacity under a single contingent condition. The maximum permissible peak emergency loading for a given load cycle that an item of plant can supply up to two hours without causing unacceptable damage. For substations with multiple transformers, the 2HEC is the minimum two hour emergency rating of all transformer combinations taking impedance mismatches into consideration, with one transformer off line.

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Term	Definition
Auto Trans Avail (MVA)	SCADA or automatically controlled load transfers that can be implemented within one minute.
Remote Trans Avail (MVA)	Load transfers that can be implemented through SCADA switching procedures by the network control officer. It is assumed that this can generally be achieved within 30 minutes excluding complex or time –consuming restoration procedures.
Manual Trans Avail (MVA)	Load transfers can also be deployed via manually controlled switchgear locally by field staff. It is assumed that the implementation of manual switching procedures to isolate the faulted portion of the network to restore supply to healthy parts of the network can be fully implemented within three hours (urban) or four hours (rural). Manual transfers are obtained from load flow studies performed on each 11kV distribution feeder based on the forecast 2016/17 load, the sum of all available 11kV transfers at a substation is multiplied by a 0.75 factor to account for diversity and to provide a margin of error to avoid voltage collapse. The same approach applies throughout the forward planning period.
LARc (MVA)	Security standard load at risk for single contingent conditions.
LARc (MW)	Estimated generation / load reduction required to defer the forecast system limitation. This is the security standard load at risk for a single contingency, expressed in MW.
Customer Category	For security standard application, the general type of customer a substation or feeder supplying the area.

Appendix C – NPV Details

Component Title Selection	Stage Timing Option 1	Stage Timing Option 2	Stage Timing Option 3	Stage Timing Option 4
Install 2nd 25MVA 33/11kV Transformer and associated modular switchgear at SSLGV	2023			
Establish new 25MVA 33/11kV Yarrabilba North zone substation		2023		
Upgrade Jimboomba Zone Substation			2023	
Establish new 11kV Feeder from Logan Village to Yarabilba development (approx. 5km)	2025			2025
Establish new 11kV Feeder from Logan Village to Yarabilba development (approx. 5km)	2029			2029
Establish new 33kV feeder from Yarabilba zone substation, energised at 11kV (approx. 8km)	2033			2043
Establish new 33kV feeder from Jimboomba zone subtation, energise at 11kV (approx. 10km)	2037			2047
Establish new zone substation at Yarabilba Central	2040		2040	2033
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)		2025		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)		2029		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)		2033		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)		2037		
Establish 2nd 25MVA 33/11kV Transformer and associated modular switchgear at Yarabilba North Substation		2033		
Establish new 33kV feeder from Jimboomba zone substation to Yarabilba Central		2033		
Establish new 11kV Feeder from Jimboomba zone substation (approx. 8km)			2025	
Establish new 11kV Feeder from Jimboomba zone substation (approx. 8km)			2029	
Establish new 33kV feeder from Yarabilba zone substation, energised at 11kV (approx. 8km)			2033	
Establish new 33kV feeder from Jimboomba zone subtation, energise at 11kV (approx. 10km)			2037	
Establish 2nd 25MVA 33/11kV Transformer and associated modular switchgear at Yarabilba Central Substation	2050		2050	2043
Establish battery solution				2023
Incremental maintenance cost associated with single transformer site				2023

Table 5: Project Staging for the Medium Demand Scenario

Option Number	Option Name	Rank	Net Economic Benefit ($M)	PV of CAPEX ($M)	PV of OPEX (SM)
1	2nd Transformer at SSLGV	2	-30,116	-28,425	-1,691
2	New Substation at Yarrabilba North	4	-34,835	-32,961	-1,874
3	Upgrade SSJBB	3	-30,669	-28,746	-1,922
4	5MW Battery followed by Yarrabilba Central	1	Withheld	Withheld	Withheld

Table 6 – NPV Results for Medium Demand Scenario

Component Title Selection	Recovery Date	Recovery Value $ Real	Stage Timing Option 1	Stage Timing Option 2	Stage Timing Option 3	Stage Timing Option 4
Install 2nd 25MVA 33/11kV Transformer and associated modular switchgear at SSLGV			2023			
Establish new 25MVA 33/11kV Yarrabilba North zone substation				2023		
Upgrade Jimboomba Zone Substation					2023	
Establish new 11kV Feeder from Logan Village to Yarabilba development (approx. 5km)			2025			2025
Establish new 11kV Feeder from Logan Village to Yarabilba development (approx. 5km)						
Establish new 33kV feeder from Yarabilba zone substation, energised at 11kV (approx. 8km)			2029			2027
Establish new 33kV feeder from Jimboomba zone subtation, energise at 11kV (approx. 10km)			2033			2033
Establish new zone substation at Yarabilba Central			2035		2033	2033
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)				2025		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)				2029		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)				2033		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)				2037		
Establish 2nd 25MVA 33/11kV Transformer and associated modular switchgear at Yarabilba North Substation				2025		
Establish new 33kV feeder from Jimboomba zone substation to Yarabilba Central				2028		
Establish new 11kV Feeder from Jimboomba zone substation (approx. 8km)					2025	
Establish new 11kV Feeder from Jimboomba zone substation (approx. 8km)						
Establish new 33kV feeder from Yarabilba zone substation, energised at 11kV (approx. 8km)					2027	
Establish new 33kV feeder from Jimboomba zone subtation, energise at 11kV (approx. 10km)					2030	
Establish 2nd 25MVA 33/11kV Transformer and associated modular switchgear at Yarabilba Central Substation			2045		2043	2038
Establish battery solution						2023
Incremental maintenance cost associated with single transformer site						2023

Table 7 – Project Staging for the High Demand Scenario

Option Number	Option Name	Rank	Net Economic Benefit ($M)	PV of CAPEX ($M)	PV of OPEX (SM)
1	2nd Transformer at SSLGV	2	-32,816	-30,965	-1,852
2	New Substation at Yarrabilba North	4	-37,750	-35,775	-1,975
3	Upgrade SSJBB	3	-35,039	-32,868	-2,171
4	5MW Battery followed by Yarrabilba Central	1	Withheld	Withheld	Withheld

Table 8 – NPV Results for High Demand Scenario

Component Title Selection	Stage Timing Option 1	Stage Timing Option 2	Stage Timing Option 3	Stage Timing Option 4
Install 2nd 25MVA 33/11kV Transformer and associated modular switchgear at SSLGV	2023			
Establish new 25MVA 33/11kV Yarrabilba North zone substation		2023		
Upgrade Jimboomba Zone Substation			2023	
Establish new 11kV Feeder from Logan Village to Yarabilba development (approx. 5km)	2027			2027
Establish new 11kV Feeder from Logan Village to Yarabilba development (approx. 5km)	2033			2033
Establish new 33kV feeder from Yarabilba zone substation, energised at 11kV (approx. 8km)	2039			2039
Establish new 33kV feeder from Jimboomba zone subtation, energise at 11kV (approx. 10km)	2045			2045
Establish new zone substation at Yarabilba Central	2050		2050	2050
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)		2027		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)		2033		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)		2039		
Establish new 11kV Feeder from Yarabilba North zone substation (approx. 500m)		2045		
Establish 2nd 25MVA 33/11kV Transformer and associated modular switchgear at Yarabilba North Substation		2050		
Establish new 33kV feeder from Jimboomba zone substation to Yarabilba Central		2060		
Establish new 11kV Feeder from Jimboomba zone substation (approx. 8km)			2027	
Establish new 11kV Feeder from Jimboomba zone substation (approx. 8km)			2033	
Establish new 33kV feeder from Yarabilba zone substation, energised at 11kV (approx. 8km)			2039	
Establish new 33kV feeder from Jimboomba zone subtation, energise at 11kV (approx. 10km)			2045	
Establish 2nd 25MVA 33/11kV Transformer and associated modular switchgear at Yarabilba Central Substation	2060		2060	2060
Establish battery solution				2023
Establish battery solution				2033
Incremental maintenance cost associated with single transformer site				2023
Incremental maintenance cost associated with single transformer site				2033

Table 9 – Project Staging for the Low Demand Scenario

Option Number	Option Name	Rank	Net Economic Benefit ($M)	PV of CAPEX ($M)	PV of OPEX (SM)
1	2nd Transformer at SSLGV	2	-24,031	-22,768	-1,263
2	New Substation at Yarrabilba North	4	-26,965	-25,420	-1,545
3	Upgrade SSJBB	3	-24,536	-23,053	-1,483
4	5MW Battery followed by Yarrabilba Central	1	Withheld	Withheld	Withheld

Table 10 – NPV Results for Low Demand Scenario