Draft Project Assessment Report

30 April 2021

Version 1.0

Coomera-Pimpama Network Limitation

Consultation Period Starts: 04/05/2021

Consultation Period Closes: 15/06/2021

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

Coomera zone substation (SSCMA) and Pimpama East Zone Substation (SSPPE) are both supplied from Coomera bulk supply substation (SSCMA BSP). SSCMA and SSPPE provide electricity supply to approximately 21,400 predominately domestic customers in the areas of Coomera, Jacobs Well, Norwell, Ormeau, Pimpama, Steiglitz, Upper Coomera, Willow Vale, and Woongoolba. With new developments in the Coomera and Pimpama areas, loads are forecast to increase significantly causing network limitations in the area.

The identified need for this Non-Network Options Report is that Energex will not meet its Safety Net obligation as outlined in its Distribution Authority at SSCMA in the summer of 2020/21 and SSPPE in the summer of 2022/23 due to load growth in the area. The requirements of a non-network option to solve the identified need are summarised in Table 1 and Table 2 below.

Substation	Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
SSCMA (Coomera Zone Substation)	2020/21	45.3	1.5	1	0.03%	2.5
	2021/22	46.0	2.2	1	0.05%	4
	2022/23	46.8	3.0	2	0.06%	5.5
	2023/24	47.2	3.4	2	0.07%	6.5
	2024/25	47.8	4.0	3	0.09%	8
	2025/26	48.4	4.6	3	0.11%	9.5
	2026/27	49.0	5.2	5	0.15%	13.5
	2027/28	50.2	6.4	7	0.21%	18.5
	2028/29	51.2	7.4	9	0.31%	27
	2029/30	52.5	8.7	9	0.41%	35.5

Table 1: Non-network Option Requirements for SSCMA

Substation	Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
SSPPE (Pimpama East zone substation)	2020/21	32.0	0.0	-	-	-
	2021/22	33.2	0.0	-	-	-
	2022/23	34.6	0.8	1	0.02%	1.5
	2023/24	35.8	2.0	2	0.05%	4
	2024/25	36.9	3.1	4	0.09%	7.5
	2025/26	38.1	4.3	4	0.13%	11.5
	2026/27	39.4	5.6	6	0.21%	18
	2027/28	41.0	7.2	9	0.33%	28.5
	2028/29	42.5	8.7	12	0.45%	39.5
	2029/30	44.2	10.4	17	0.65%	57

Table 2: Non-network Option Requirements for SSPPE

As part of its operational strategy following a contingency, Energex will deploy 4MVA of generation using its fleet of mobile generators. In addition to the requirements above, Energex would be interested in any network support solutions that provide a cost-effective alternative to this requirement. Submissions to this Draft Project Assessment Report (DPAR) should clearly separate their proposal for this extra support opportunity from their proposed solution to the identified need.

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.

In order to eliminate the load at risk and satisfy the Safety Net obligations, Energex has identified several network options to address the limitations identified, as below:

- Option 1: Establish new 25MVA 33/11kV Pimpama zone substation
- Option 2: Establish new 25MVA 33/11kV Coomera East zone substation
- Option 3: Upgrade Coomera zone substation by installing a 3rd 25MVA 33/11kV transformer and associated switchgear

Ergon Energy Corporation Limited ABN 50 087 646 062
Energy Queensland Limited ABN 96 612 535 583
Energex Limited ABN 40 078 849 055

Following the release of the Non-Network Options Report (NNOR), three submissions were received by the closing date of 21 December 2020. These submissions identified two feasible options:

- Option 4: Establish multiple Battery Energy Storage Systems on multiple 11kV feeders across SSCMA and SSPPE
- Option 5: Establish a single Battery Energy Storage System connected to SSCMA

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 Systems on multiple 11kV feeders across SSCMA and SSPPE. 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 **15 June 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 will include a summary of all submissions. Energex view the information provided as part of submissions to the DPAR as Commercial-in-Confidence and as such will not publish the capital and operating costs associated with a proponents proposal.

1.2. Contact Details

Submissions in writing in response to this report may be submitted to demandmanagement@energex.com.au and are due by 15 June 2021.

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2. Background

2.1. Existing Network

Coomera zone substation (SSCMA) and Pimpama East zone substation (SSPPE) provide electricity supply to approximately 11,600 and 9,800 predominately domestic customers in the areas of Coomera, Jacobs Well, Norwell, Ormeau, Pimpama, Steiglitz, Upper Coomera, Willow Vale, and Woongoolba area.

SSCMA and SSPPE are both supplied from Coomera bulk supply substation (SSCMA BSP). There are two 33kV feeders, F3641 and F3642, connecting SSPPE to SSCMA BSP, and with the current loads, each feeder can supply the SSPPE substation load for an outage of the other. Geographic and schematic views of the network area under study are provided in Figure 1, Figure 2, and Figure 3.

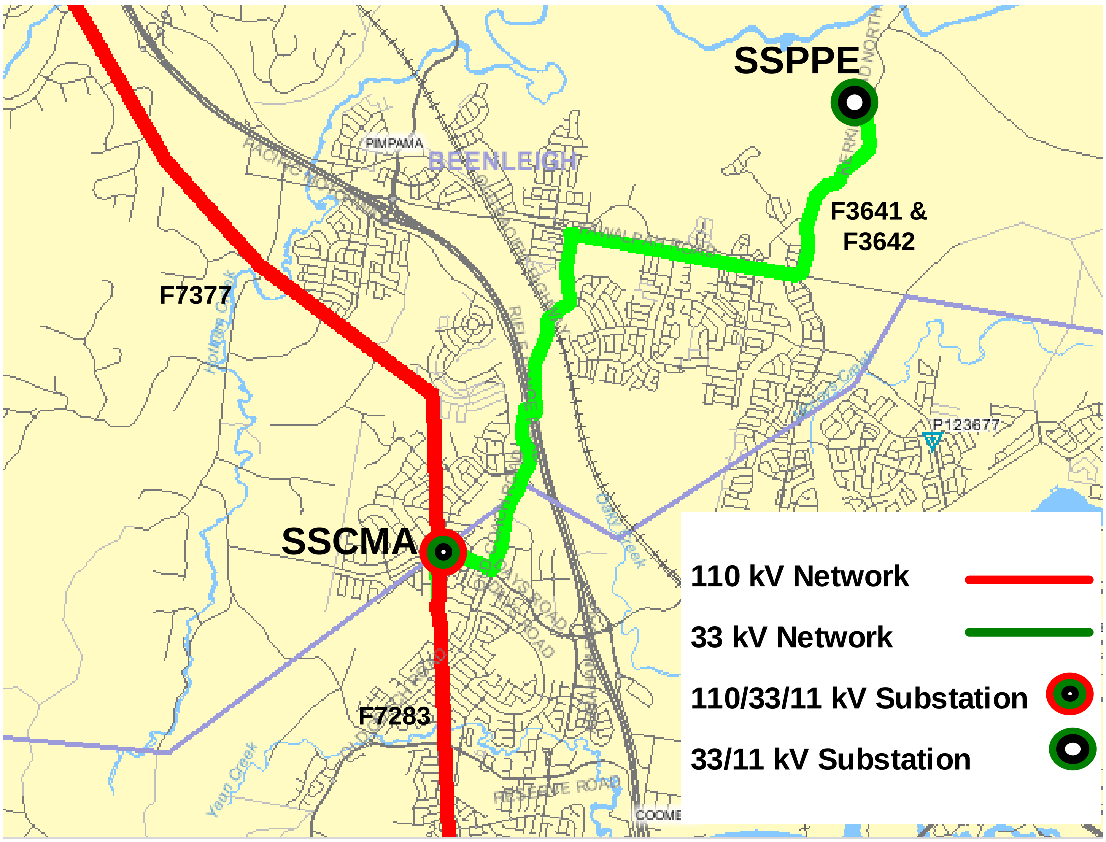


Figure 1: Existing sub-transmission network arrangement (Geographic view)

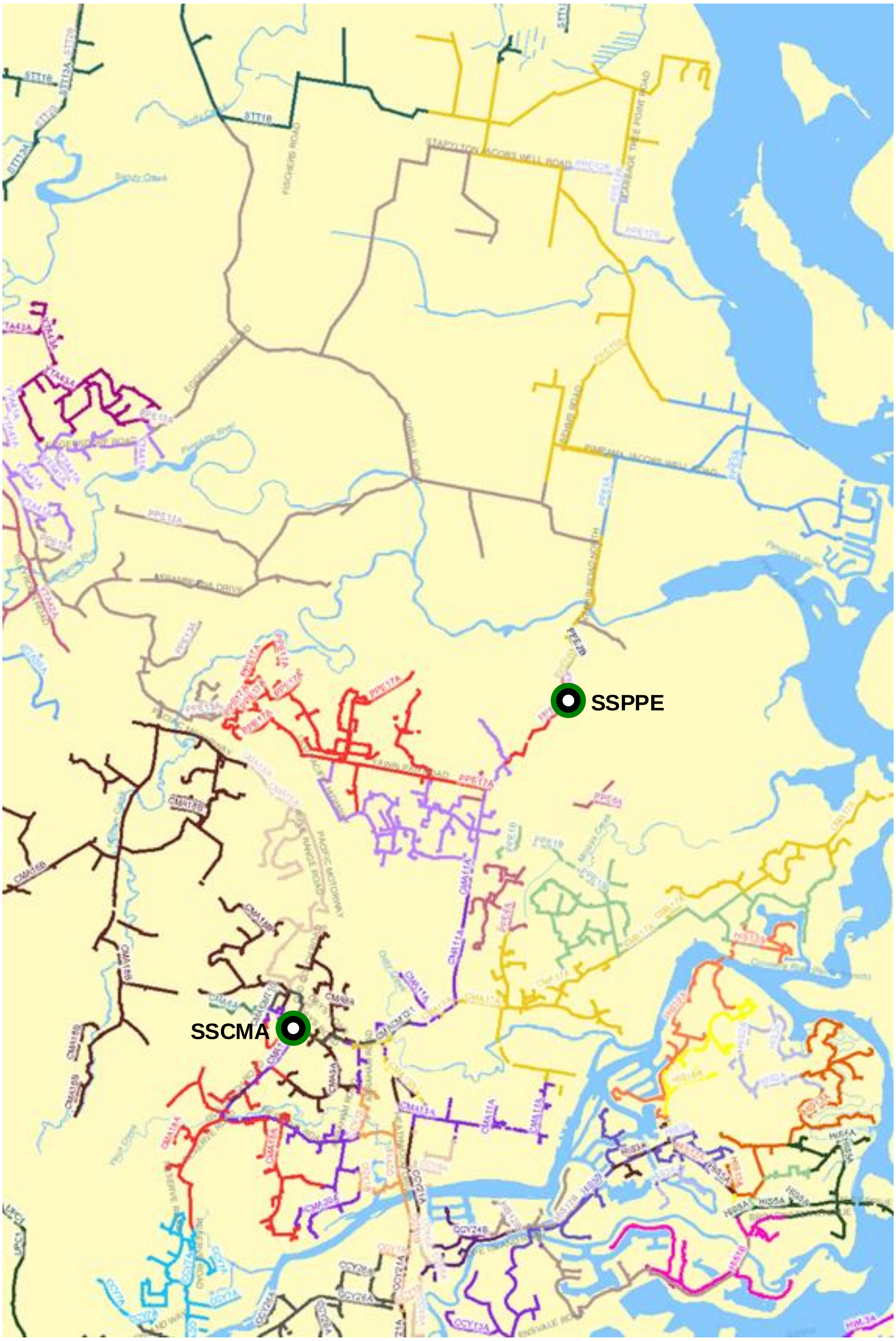


Figure 2: Existing 11kV network arrangement (Geographic view)

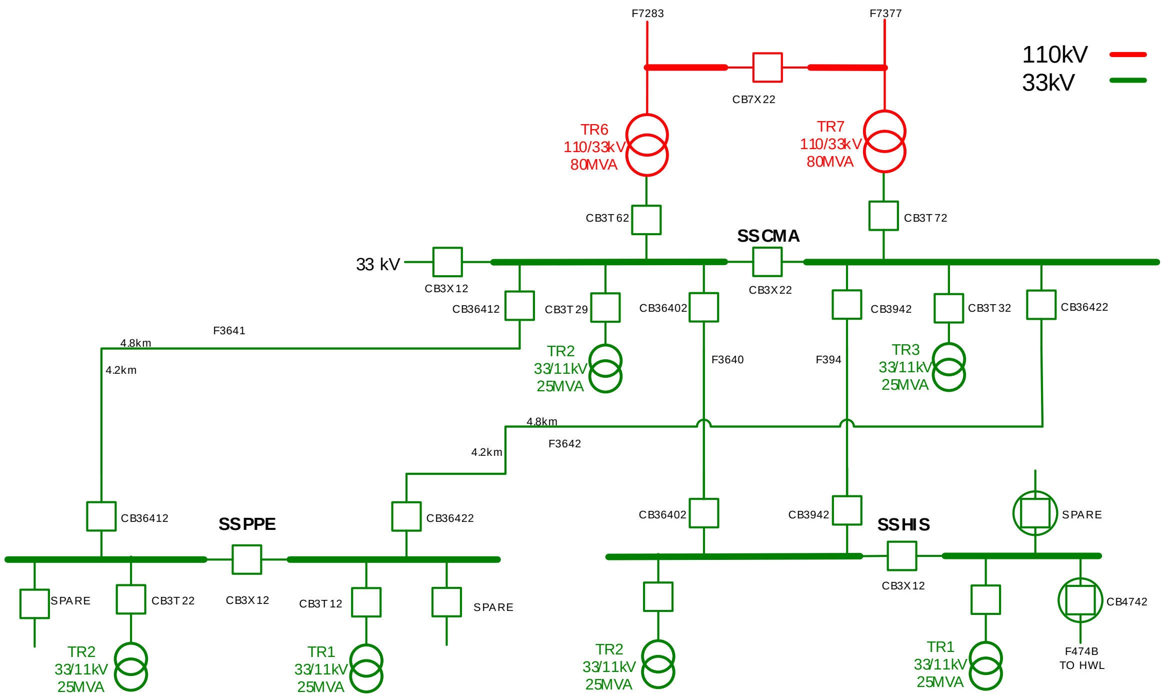


Figure 3: Existing network arrangement (schematic view)

2.1. Load Profiles

The annual load profiles for SSCMA & SSPPE are shown in Figure 4 & Figure 5 below.

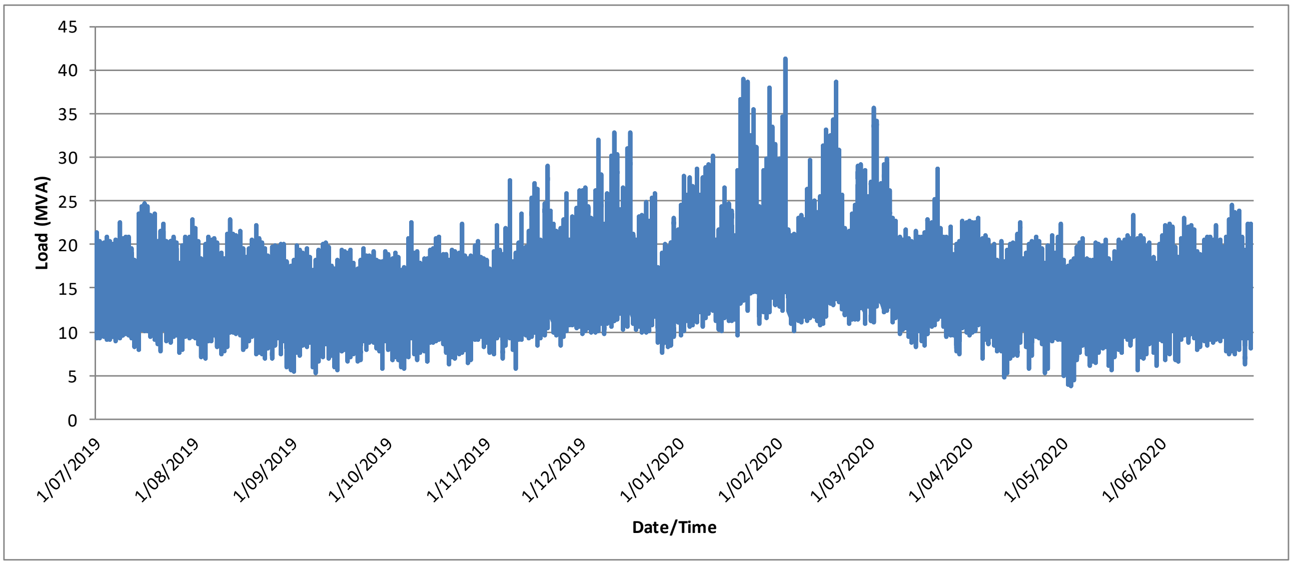


Figure 4: Annual load profile (MVA) for SSCMA in 2018/19

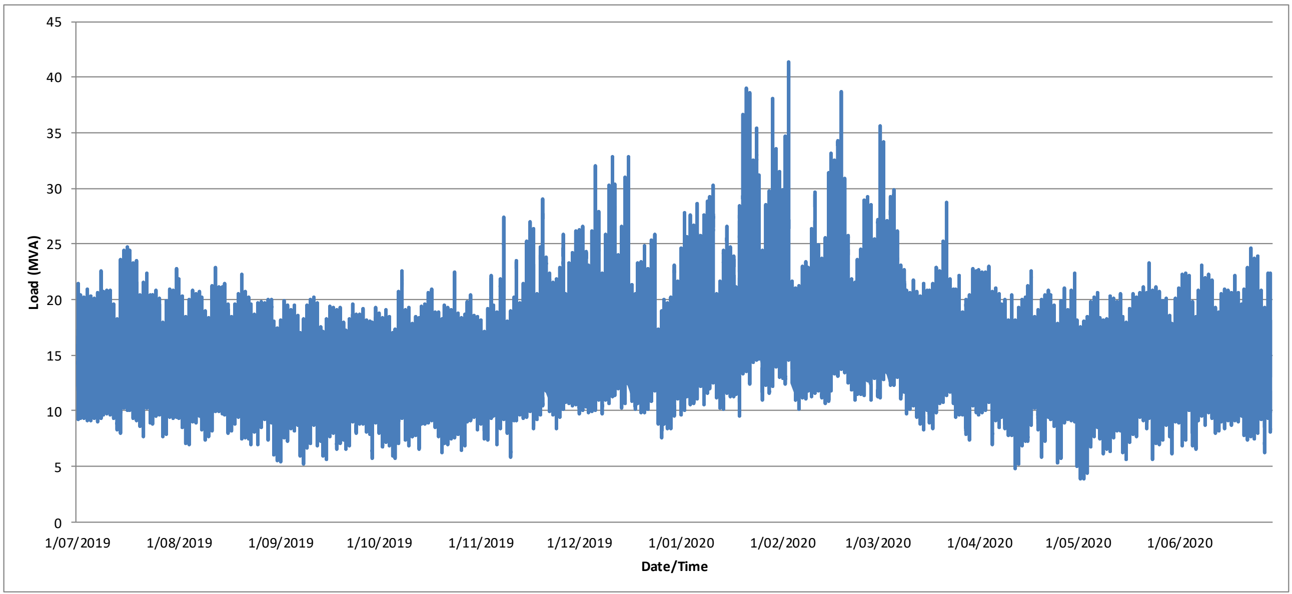
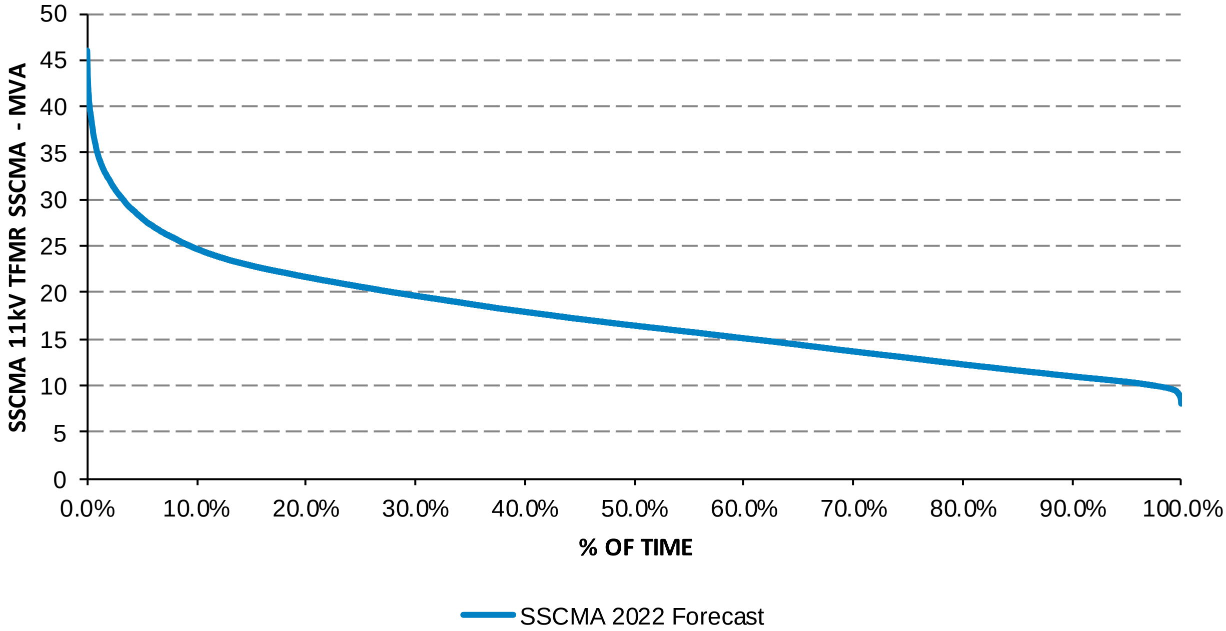


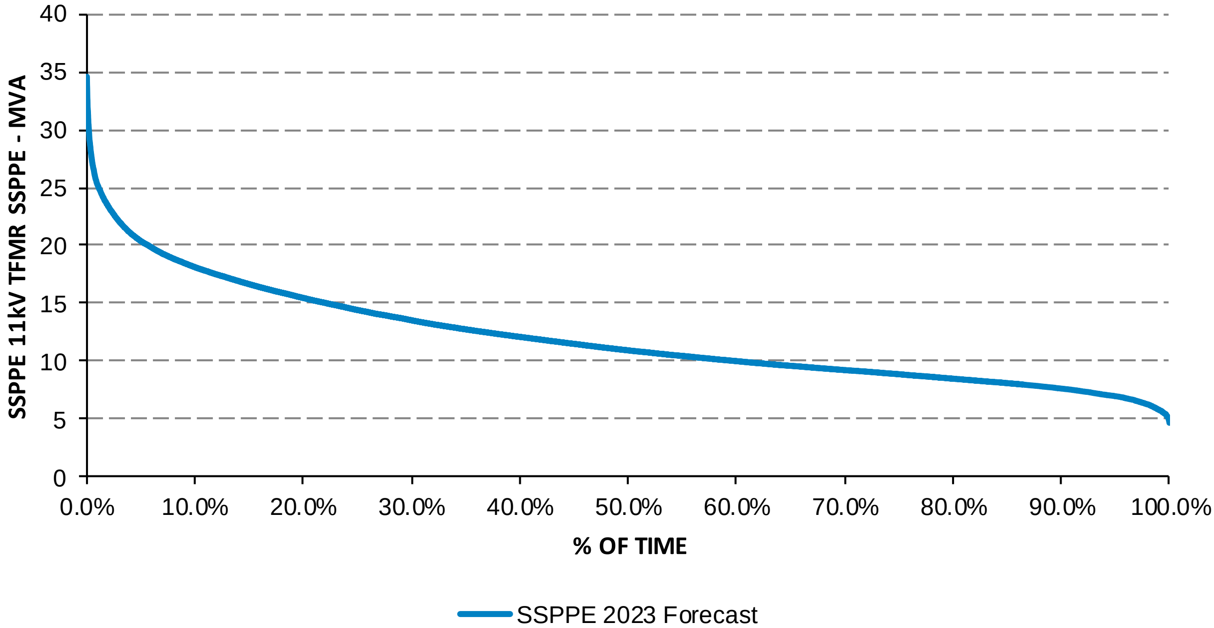
Figure 5: Annual load profile (MVA) for SSPPE in 2018/19

Figure 6 & Figure 7 show the load duration curves for SSCMA and SSPPE respectively. These are based on the previous 3 years of data and are scaled to their respective maximum 50% Probability of Exceedance (50PoE) forecasts.



*The values for SSCMA have been scaled to the 2022 peak forecast load of 46.0MVA. 2022 is the year the identified need first appears at SSCMA.

Figure 6: Load duration curve for SSCMA



*The values for SSPPE have been scaled to the 2023 peak forecast load of 34.6MVA. 2023 is the year the identified need first appears at SSPPE.

Figure 7: Load duration curve for SSPPE

3. Identified Need

3.1. Applied Service Standard

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 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

SSCMA and SSPPE are classified as Urban substations, and as such, the following Safety Net criteria apply:

- For an urban 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 12MVA, provided that all load except for up to 4MVA can be restored within 3 hours, and the remaining 4MVA is fully restored within 8 hours.

Table 3 below outlines the Safety Net criteria.

Category	Demand Range	Allowed Outage to be OK
Urban	> 40MVA	No outage OK
	12-40MVA	30 minutes OK
	4-12MVA	3 hours OK
	<4MVA	8 hours OK

Table 3: 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 Coomera area does not meet the Safety Net for an unplanned outage of a transformer at SSCMA. The following section outlines the substation limitations of the existing network. The system normal condition is assessed against the 10% PoE load forecast for SSCMA BSP and SSCMA and SSPPE. The 50% PoE load forecast is used for N-1 contingency analysis.

3.3. Quantification of the Identified Need

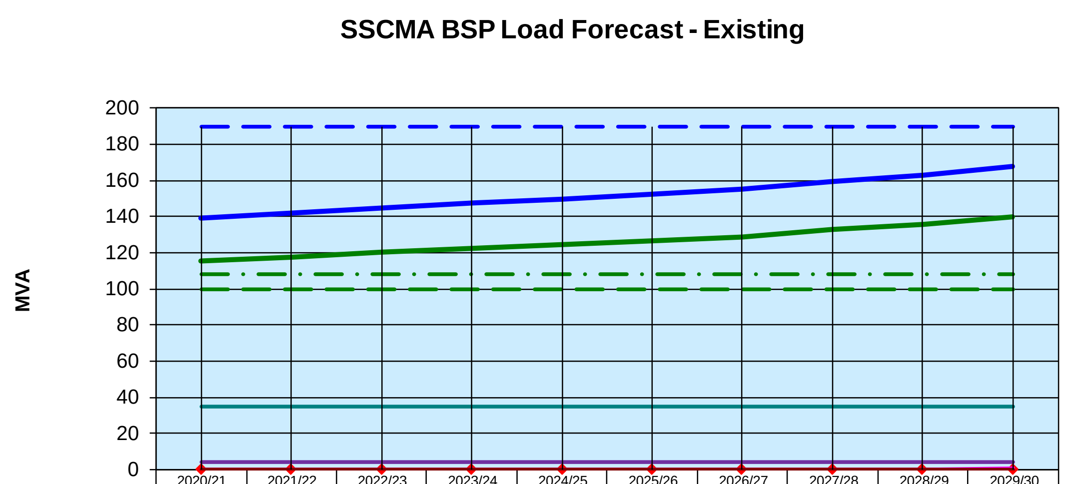
3.3.1. Safety Net Non-Compliance

SSCMA BSP Limitations

SSCMA BSP is equipped with 2 x 80MVA 110/33kV transformers. The substation capacity is limited by the transformer ratings and has a Normal Cyclic Capacity (NCC), Emergency Cyclic Capacity (ECC) and 2 Hour Emergency Capacity (2HEC) as below:

- NCC – 189.6MVA
- ECC – 100.0MVA
- 2HEC – 108.0MVA

Figure 8 shows the limitations at SSCMA BSP.



	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	138.93	141.73	144.84	147.47	149.79	152.51	155.08	159.44	163.27	167.72
Summer NCC	189.60	189.60	189.60	189.60	189.60	189.60	189.60	189.60	189.60	189.60
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	115.40	117.76	120.37	122.59	124.54	126.84	129.00	132.66	135.87	139.61
Summer ECC	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Summer 2HEC	108.00	108.00	108.00	108.00	108.00	108.00	108.00	108.00	108.00	108.00
LAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.61
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
Avail Mobile Eqpt	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Figure 8: SSCMA BSP Load at Risk

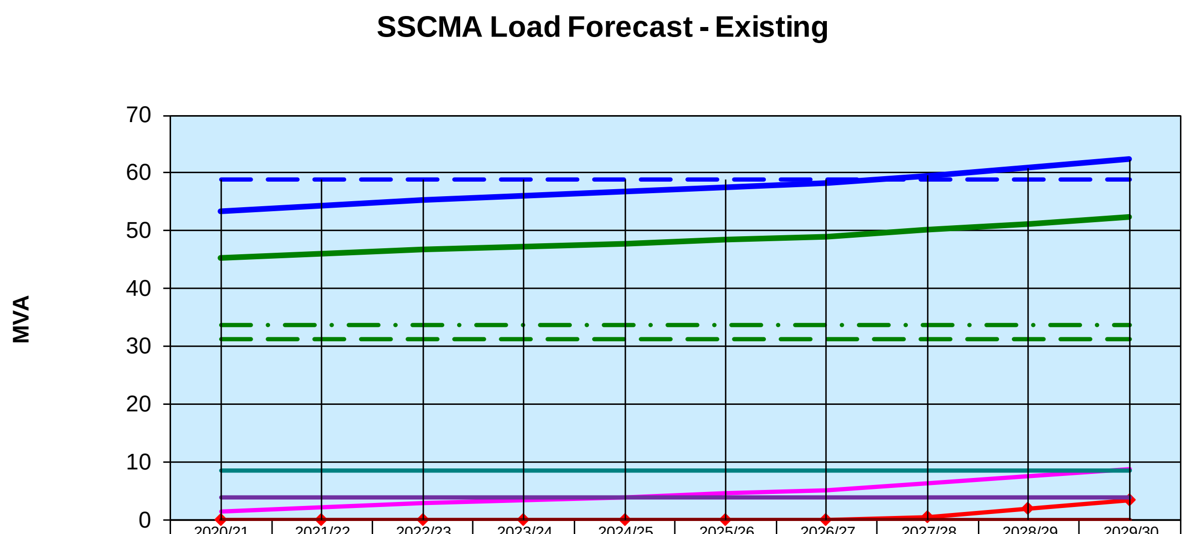
Figure 8 indicates that there is a load at risk under contingency for an outage of a 110/33kV transformer at SSCMA BSP from 2029/30. Whilst this limitation is not the immediate focus of this non-network options report, it is possible that a non-network solution that resolves or defers the limitations at either SSCMA and SSPPE may also resolve or defer the future limitation at SSCMA BSP.

It should also be noted that there is an already approve project to establish a Plant Overload Protection Scheme to reduce load below the 2HEC rating of the transformer following an outage of a transformer. The effect of this scheme has been considered in identifying the limitations for the network area.

SSCMA Limitations

SSCMA is equipped with 2 x 25MVA 33/11kV transformers. The substation capacity is limited by the transformer ratings as below:

- NCC – 59.0MVA
- ECC – 31.3MVA
- 2HEC – 33.8MVA



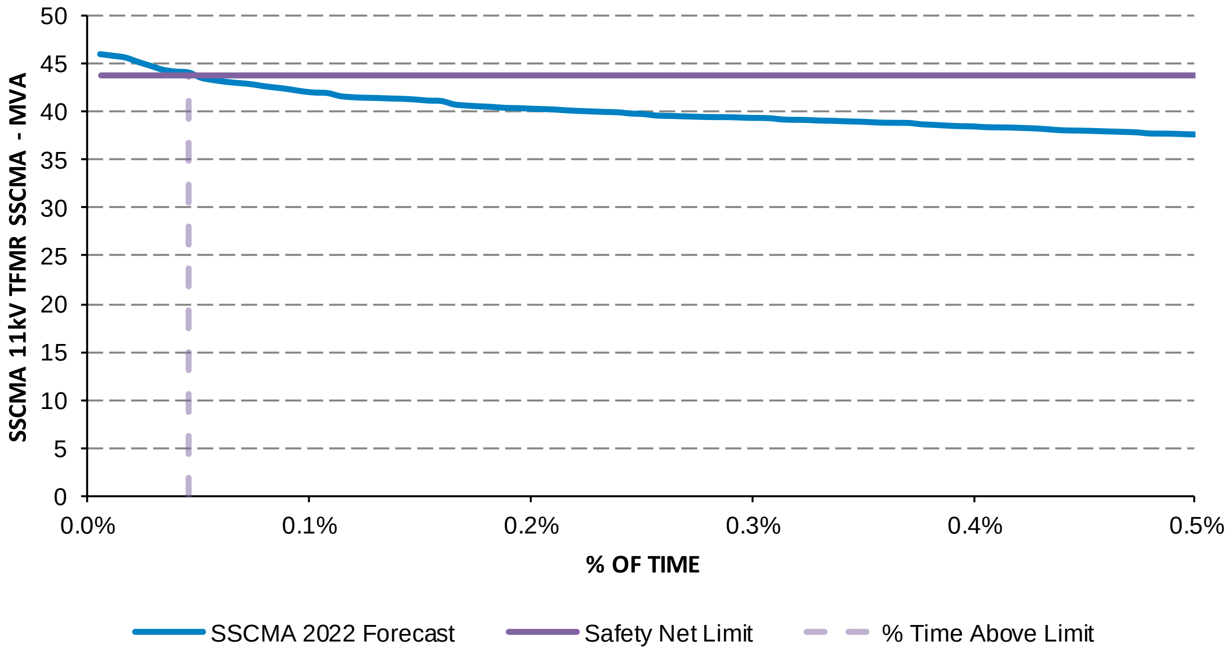
	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	53.46	54.29	55.24	56.08	56.73	57.47	58.15	59.56	60.86	62.35
Summer NCC	59.00	59.00	59.00	59.00	59.00	59.00	59.00	59.00	59.00	59.00
Load > NCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56	1.86	3.35
50 PoE Load	45.32	46.02	46.83	47.23	47.77	48.40	48.97	50.16	51.25	52.50
Summer ECC	31.30	31.30	31.30	31.30	31.30	31.30	31.30	31.30	31.30	31.30
Summer 2HEC	33.80	33.80	33.80	33.80	33.80	33.80	33.80	33.80	33.80	33.80
LAR	1.52	2.22	3.03	3.43	3.97	4.60	5.17	6.36	7.45	8.70
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
Avail Mobile Eqpt	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Figure 9: SSCMA Load at Risk

Figure 9 illustrates that there is an NCC load at risk (LAR) limitation with the existing equipment at SSCMA from 2027/28. There is also Safety Net limitation for an outage of a transformer at SSCMA from 2021/22.

It should also be noted that there is an already approve project to establish a Plant Overload Protection Scheme to reduce load below the 2HEC rating of the transformer following an outage of a transformer. The effect of this scheme has been considered in identifying the network limitations in the area.

To meet Energex's Safety Net obligations, SSCMA can supply up to 43.8MVA. This incorporates 31.3MVA of ECC transformer capacity, 8.5MVA of available load transfers and 4MVA of mobile generation support. Figure 10 shows the portion of the load duration curve for the forecast 11kV load of SSCMA and the available capacity at SSCMA.



*The values for SSCMA have been scaled to the 2022 peak forecast load of 46.0MVA

Figure 10: Load Duration Curve SSCMA in 2022 with Safety Net Limit

Figure 10 shows that approximately 0.05% of the time in 2021/22 the load is above the 43.8MVA limit.

As seen by the substation limitations, the load on SSCMA is forecast to increase. In order to determine how the increasing load will impact the substation, the historical load duration curve data has been scaled up to the forecast 50% PoE peak loads for future years. Figure 11 illustrates that as the load increases; the limit is surpassed for a longer duration per year. For readability, only every second year is shown.

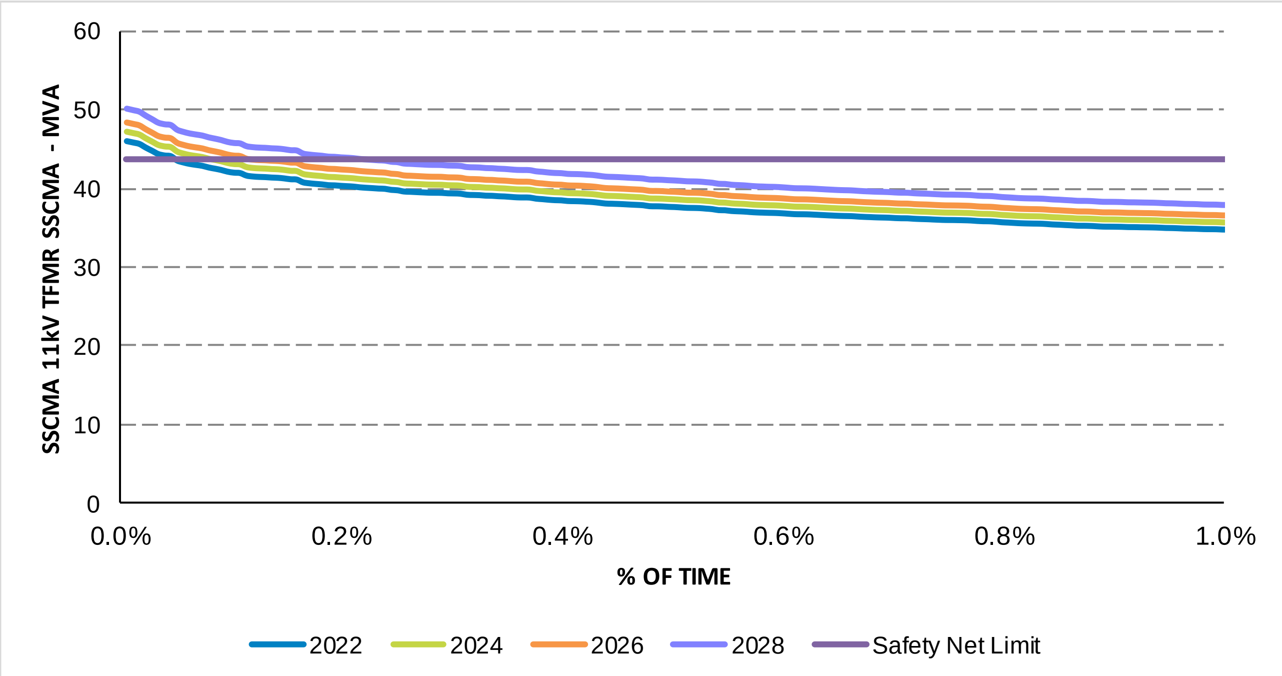


Figure 11: Load duration curves for SSCMA for future years after limitation

Table 4 below describes the amount of time that the safety net limit is forecast to be exceeded each year, as well as the number of days per year.

Substation	Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
SSCMA (Coomera Zone Substation)	2020/21	45.3	1.5	1	0.03%	2.5
	2021/22	46.0	2.2	1	0.05%	4
	2022/23	46.8	3.0	2	0.06%	5.5
	2023/24	47.2	3.4	2	0.07%	6.5
	2024/25	47.8	4.0	3	0.09%	8
	2025/26	48.4	4.6	3	0.11%	9.5
	2026/27	49.0	5.2	5	0.15%	13.5
	2027/28	50.2	6.4	7	0.21%	18.5
	2028/29	51.2	7.4	9	0.31%	27
	2029/30	52.5	8.7	9	0.41%	35.5

Table 4: Forecast duration load will be at risk at SSCMA

Table 4 shows that to solve the identified need at Coomera zone substation, the non-network solution would need to provide 2.2MVA of network support, with a likely requirement for approximately 0.05% (4 hours) of the year in 2022. This will increase to 8.7MVA of network support for a likely requirement for 0.41% (35.5 hours) of the year in 2029/30.

As part of its operational strategy following a contingency, Energex will deploy 4MVA of generation using its fleet of mobile generators. In addition to the requirements above, Energex would be interested in any network support solutions that provide a cost-effective alternative to this requirement. Submissions to this DPAR should clearly separate their proposal for this extra support opportunity from their proposed solution to the identified need.

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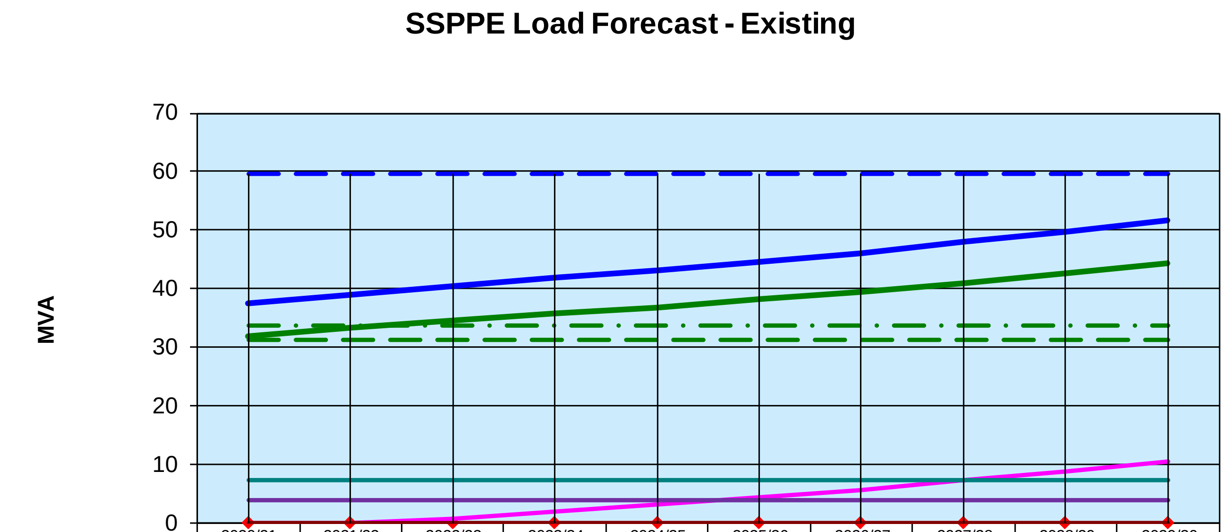
SSPPE Limitations

SSPPE is equipped with 2 x 25MVA 33/11kV transformers. The substation capacity is limited by the transformer ratings as below:

- NCC – 59.5MVA
- ECC – 31.3MVA
- 2HEC – 33.8MVA

Figure 12 shows the limitations at SSPPE.

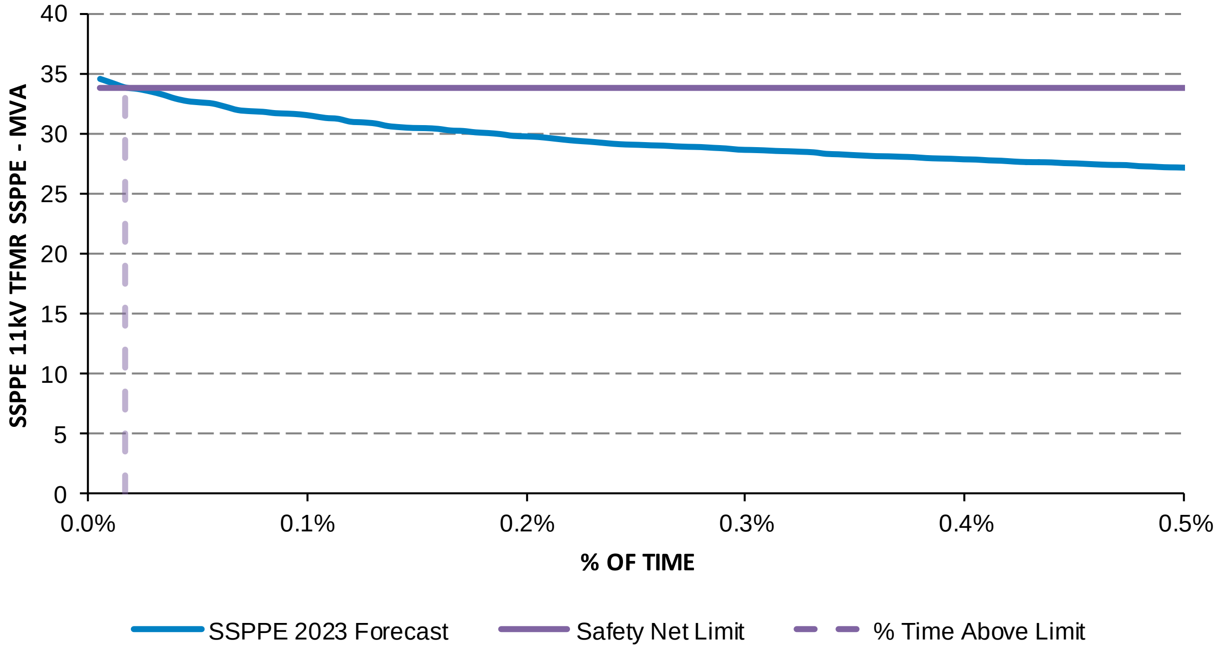


	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	37.41	38.88	40.42	41.79	43.10	44.60	46.02	47.97	49.73	51.72
Summer NCC	59.50	59.50	59.50	59.50	59.50	59.50	59.50	59.50	59.50	59.50
Load > NCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50 PoE Load	31.99	33.25	34.57	35.76	36.86	38.13	39.35	41.01	42.52	44.22
Summer ECC	31.30	31.30	31.30	31.30	31.30	31.30	31.30	31.30	31.30	31.30
Summer 2HEC	33.80	33.80	33.80	33.80	33.80	33.80	33.80	33.80	33.80	33.80
LAR	0.00	0.00	0.77	1.96	3.06	4.33	5.55	7.21	8.72	10.42
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	7.40	7.40	7.40	7.40	7.40	7.40	7.40	7.40	7.40	7.40
Avail Mobile Eqpt	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Figure 12: SSPPE Load at Risk

There is no NCC load at risk (LAR) limitations with the existing equipment at SSPPE. Figure 12 shows that the 50% PoE load at SSPPE zone substation exceeds the 2-hour rating from Summer 2022/23. This type of limitation is commonly addressed by implementing a Plant Overload Protection Scheme (POPS) project at the substation, which is a relatively inexpensive solution. If this limitation is resolved, the next limitation at the substation will be from 2029/30.

Figure 13 shows the portion of the load duration curve for the forecast load of SSPPE with a safety net limit of 33.8MVA illustrated, which is the 2-hour rating of each transformer. It is evident that approximately 0.03% of the time in that year, the load is above the 33.8MVA limit.



*The values for SSPPE have been scaled to the 2023 peak forecast load of 35.2MVA

Figure 13: Load Duration Curve SSPPE in 2023 with Safety Net Limit

To show the increase in load over time, the historical load duration curve data was scaled up to the forecast 50% PoE peak loads for future years. Figure 14 illustrates that as the load increases; the limit is surpassed for a longer duration per year.

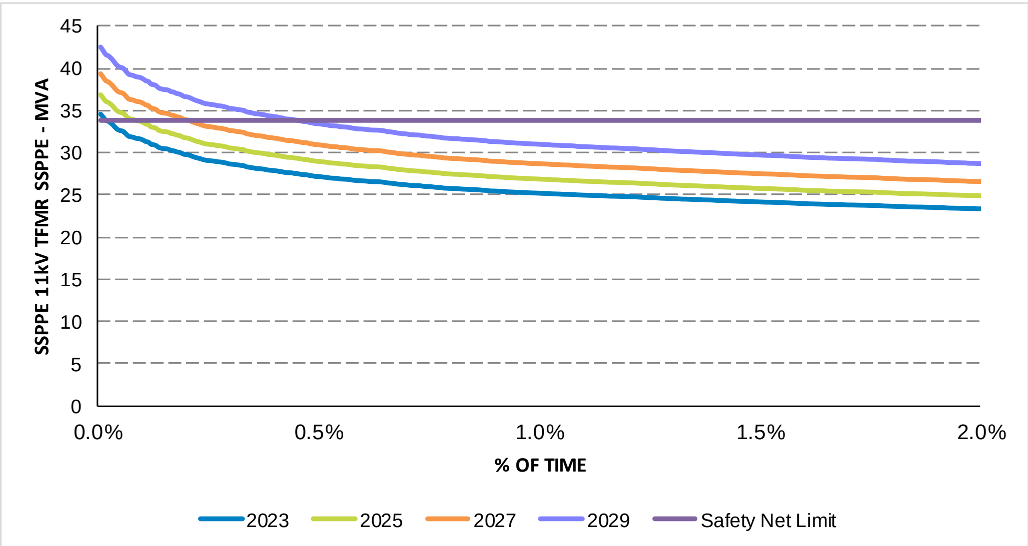


Figure 14: Load duration curves for SSPPE for future years after limitation

Table 5 below outlines the amount of time that the Safety Net limit is forecast to be exceeded each year, as well as the number of days per year.

Substation	Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
SSPPE	2020/21	32.0	0.0	-	-	-
	2021/22	33.2	0.0	-	-	-
	2022/23	34.6	0.8	1	0.02%	1.5
	2023/24	35.8	2.0	2	0.05%	4
	2024/25	36.9	3.1	4	0.09%	7.5
	2025/26	38.1	4.3	4	0.13%	11.5
	2026/27	39.4	5.6	6	0.21%	18
	2027/28	41.0	7.2	9	0.33%	28.5
	2028/29	42.5	8.7	12	0.45%	39.5
	2029/30	44.2	10.4	17	0.65%	57

Table 5: Forecast duration load will be at risk at SSPPE

Table 5 shows that to solve the identified need at SSPPE, the non-network solution(s) will be required to provide 0.8MVA of network support, with a likely requirement for approximately 0.02% (1.5 hours) of the year in 2022/23. This will increase to 10.4MVA of network support for a likely requirement for 0.65% (57 hours) of the year in 2029/30.

As part of its operational strategy following a contingency, Energex will deploy 4MVA of generation using its fleet of mobile generators. In addition to the requirements above, Energex would be interested in any network support solutions that provide a cost-effective alternative to this requirement. Submissions to this DPAR should clearly separate their proposal for this extra support opportunity from their proposed solution to the identified need.

4. Network Options Identified

4.1. Do Nothing (Base Case)

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

4.1.1. Option 1: Establish new 25MVA 33/11kV Pimpama zone substation (SSPPA)

This option involves establishing SSPPA as 1 x 25MVA zone substation with 33kV double circuit by double tee-off from 33kV feeders F3641 and F3642 between SSCMA bulk supply and SSPPE zone substation by October 2023.

The works required to implement this option are:

- Establish a single modular or equivalent masonry building substation with a 33/11kV 25MVA transformer at SSPPA.
- Construct 1.6 km of 33kV DCCT into SSPPA with double tee-off from existing 33kV DCCT feeders, F3641 and F3642. Following detailed design, this option may become a loop-in, loop-out arrangement from one of these 33kV feeders, however this will not materially change the cost or network arrangement of this option.
- Cut over into existing 11kV feeders and establish new 11kV feeders as needed
- Establish a Plant Overload Protection Scheme at SSPPE
- Estimated capital cost: $12.93 million ± 40%
- Estimated operating cost per annum: $50,250

A schematic diagram of the proposed solution is shown in
Figure **15** below.

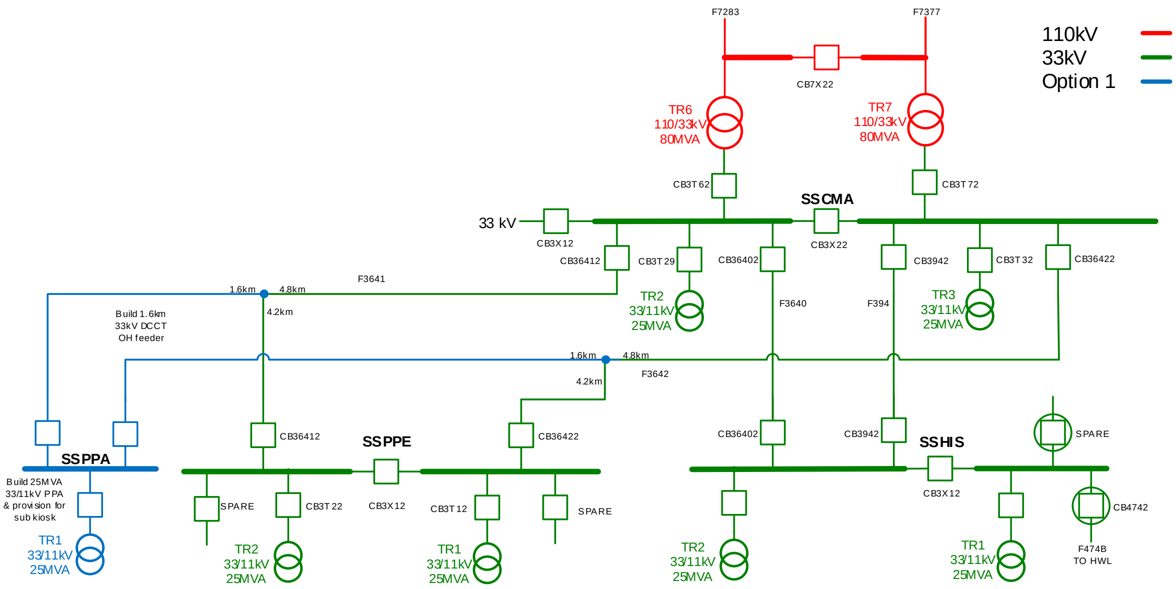


Figure 15: Proposed network arrangement under option 1

It should be noted that the option to construct a single 33kV feeder to SSPPA was considered, however due to the future requirements of a second circuit and the constraints in obtaining duplicate 33kV routes, the most economical solution is to establish these feeders as a double circuit in the first instance.

4.1.2. Option 2: Establish new 25MVA 33/11kV Coomera East zone substation (SSCET)

This option involves establishing SSCET as a 1 x 25MVA zone substation by October 2023. To reduce feeder costs, the CCY21A 11kV feeder which is constructed at 33kV can be energised at 33kV and cut-in-and-out of F3640 to supply SSCET from SSCMA bulk supply, in combination with 0.4km of 33kV SCCT OH as well as 2km of 11kV OH to replace the second 11kV supply to Dreamworld.

The works required to implement this option are:

- Establish 1 x 25MVA 33/11kV single modular or equivalent masonry building substation at SSCET.
- Construct 400m of 33kV SSCT OH from SSCET to end of CCY21A.
- Build 2km of 11kV OH from end of CCY21A to CET and connect to replace Dreamworld second 11kV supply.
- Cut into F3640 and joint in P129550.
- Energise CCY21A to SSCET at 33kV.
- Reconductor, uprate and reconfigure existing 11kV network to provide optimum 11kV supply capacity to Pimpama area and provide relief to existing 11kV feeders and adjacent zone substations (SSCMA and SSPPE).
- Establish a Plant Overload Protection Scheme at SSPPE
- Estimated cost: $13.5 million ± 40%
- Estimated operating cost per annum: $62,600

A schematic diagram of the proposed solution is shown in Figure 16 below.

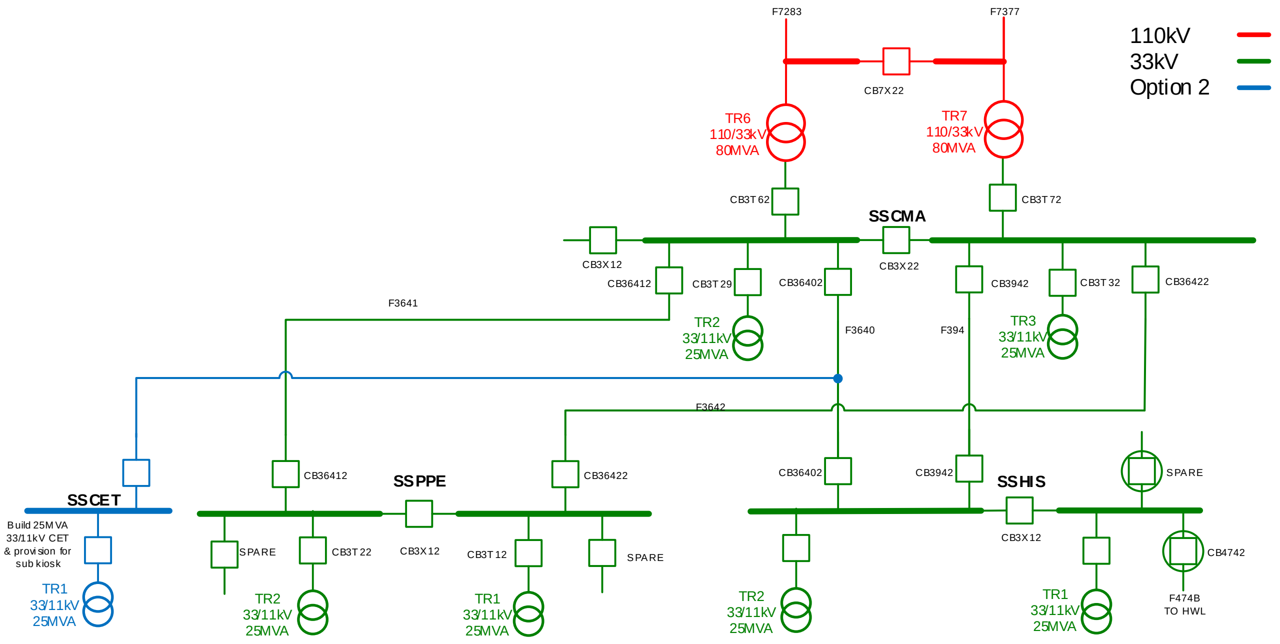


Figure 16: Proposed network arrangement under option 2

It should be noted that this option is dependent on an existing 33kV feeder, energised at 11kV. Therefore a 2nd 33kV feeder is not included in this option.

4.1.3. Option 3: Upgrade SSCMA by installing a 3rd 25MVA 33/11kV transformer and associated switchgear

This option involves installing a third 25MVA 33/11kV transformer an associated switchgear at Coomera zone substation by October 2023. This option relies on building greater 11kV network capacity in the future in order to help manage the load increases in the Pimpama area.

The works required to implement this option are:

- Install 3rd 25MVA 33/11kV transformer at SSCMA.
- Install 33kV and 11kV switchgear
- Cut over 3 x 11kV feeders to the new 11kV switchgear.
- Split 11kV bus by opening section breaker (CB1X22) and implement ACO scheme for loss of TR2.
- Establish a Plant Overload Protection Scheme at SSPPE
- Estimated capital cost: $11.96 million ± 40%
- Estimated operating cost per annum: $2,680 (there is only a small marginal increase in operating expenditure due to the substation already being established)

A schematic diagram of the proposed solution is shown in Figure 17 below.

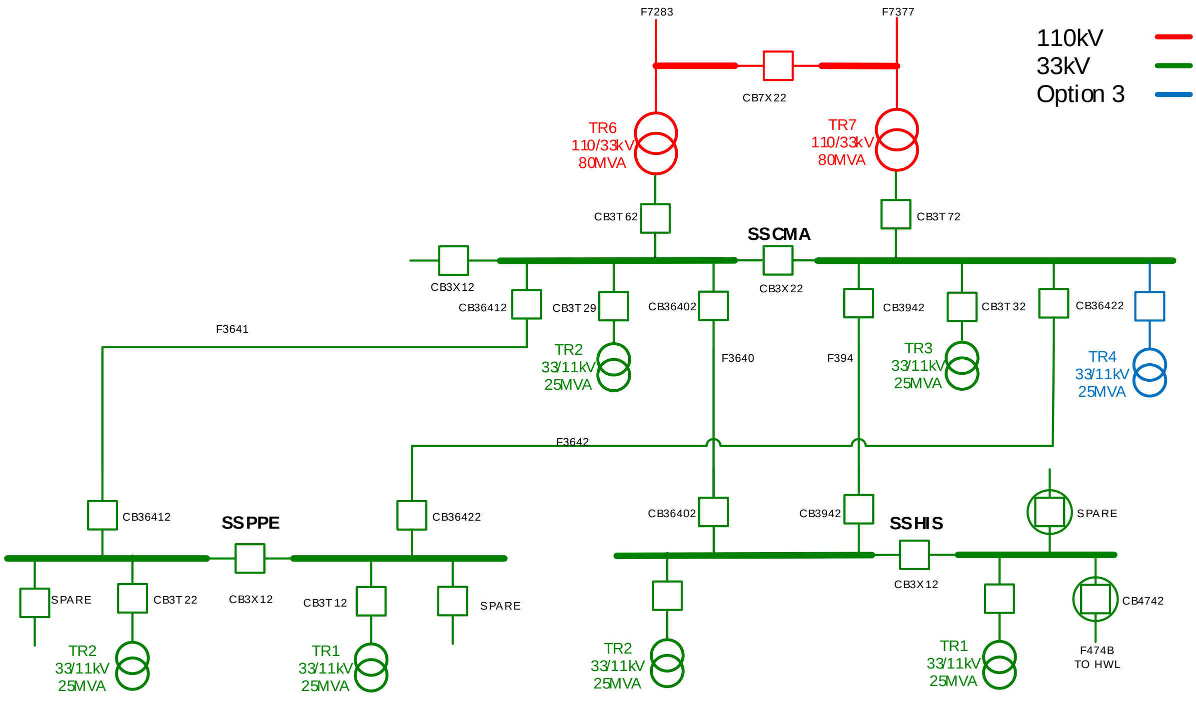


Figure 17: Proposed network arrangement under option 3

4.2. Preferred Network Option

Option 1 is currently the preferred network option. SSPPA is closer to most of the new developments meaning there are less costs to construct 11kV feeders to supply the new forecast loads. The scope of the preferred network option includes:

- Establish new single transformer 33/11kV modular substation or equivalent masonry building.
- Establish 2 x 33kV feeders to supply the new substation.
- Establishing a Plant Overload Protection Scheme at SSPPE.

The preferred network option has an estimated capital project cost of $12.93M, and an annual operating cost of approximately $50,250.

4.3. 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 $388,200 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.

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Energy Queensland Limited ABN 96 612 535 583
Energex Limited ABN 40 078 849 055

5. Summary of Submissions Received

On 21 September 2020 Energex published the NNOR providing details on the identified need at SSCMA and SSPPE. This report sought information from Registered Participants, AEMO and Interested Parties regarding alternative potential credible options or variants to the potential credible options presented by Energex.

In response to the NNOR, Energex received three submissions by 21 December 2020. These responses identified two credible options:

- Establish several battery systems and/or load curtailment of customer load on various 11kV feeders.
- Establish a single battery system to allow for restoration of supply following a contingency.

As two of the submissions Energex received were effectively the same, they have been referred to together as Option 4 below.

5.1. Option 4: Contract multiple Battery Energy Storage Systems

This option involves contracting a proponent to establish battery systems on multiple 11kV feeders, up to a value of 10MVA / 16MWh progressively delivered over the period between 2023/24 to 2027/28. A further 6MVA / 14MWh will be delivered in the period 2028/29 to 2029/30. This solution provides network support to resolve the identified limitation at SSCMA, SSPPE and potential future 11kV feeder limitations due to the connection across the network.

This option will allow for a contingency response for a transformer outage at SSCMA or SSPPE, decrease load on the 11kV feeders, thereby deferring expenditure on the 11kV network and increasing transfer capacity between SSCMA and SSPPE.

5.2. Option 5: Contract a single Battery Energy Storage System connected to SSCMA

This option involves contracting a proponent to establish a single battery system connected to SSCMA, installing a battery of 5MW/15MWh in 2022, and a further 4MW/12MWh in 2028. This solution will provide network support to SSCMA to resolve the identified Safety Net limitation and will require Energex to establish a Plant Overload Protection System at SSPPE to manage the potential small overload at SSPPE.

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6. Non-Network Options

6.1. Assessment of Non-Network Solutions

To reduce, defer or avoid network expenditure as part of the identified Non-Network Options, a proponent would need to provide a series of batteries or other energy system up to a value of 10MVA/16MWh over the period between 2023/24 to 2027/28. A further 6MVA / 14MWh will be required in the period 2028/29 to 2029/30 to eliminate the Load at Risk outlined in Table 4 and Table 5.

6.2. Feasible vs Non-Feasible Options

6.2.1. Potentially Feasible Options

The identified need presented in this Non-Network Options Report is driven by Energex not meeting its Safety Net obligations. Specifically, an outage of an existing transformer at SSCMA zone substation leads to a Safety Net load at risk of 1.5MVA in 2020/21 which increases in future years, and an outage of a transformer at SSPPE results in 0.8MVA Safety Net load at risk in 2022/23 which also increases significantly. As such, solutions that prudently and efficiently address these constraints will be considered.

In addition, there is a forecast N-1 limitation at Coomera bulk supply from 2029 onwards which is not the focus of this DPAR and therefore not a requirement that the non-network solution/s would need to address. However, it is mentioned in this report as this security standard load at risk may be reduced or even resolved as a result of any feasible solution/s to the identified need in this report.

In respect of the requirements under 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.

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 multiple substations in the network. For example, embedded solutions or load curtailment options could be implemented in the supply areas of SSPPE and SSCMA to provide the required network support.

Although the Safety Net constraints must be addressed, these are minimum requirements and solutions that can provide greater capacity to the network and improved reliability and security of supply may be considered. Furthermore, if a proponent is unable to support the total load required, Energex still encourages the submission of any solutions to reduce the constraints as it may be possible to aggregate multiple proposals to address the limitation or to have a hybrid solution with a potential network solution.

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.

6.2.3. Timing of Feasible Options

The limitations presented in this report are for the summer period of 2021/22. Until its most recent forecast, Energex was not forecasting any limitations on the Coomera and Pimpama network. Because of this, the preferred network option will not be completed by the time of the Safety Net limitation. Irrespective, the Safety Net non-compliance will still exist and as such Energex will still be seeking responses from interested parties who are able to provide network support to reduce or eliminate this limitation starting from 2021/22 in a cost-effective manner. Any proposed solution must at least be available by October 2023, when the network solution is currently forecast to be able to be delivered.

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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 two submissions 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 DPAR.

Proponents are still encouraged to put forward submissions in response to this DPAR and feasible options will be evaluated against selection criteria.

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 are the costs 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 **Error! Reference source not found.** 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 around the Pimpama and Coomera areas every 3 years, whether this is from SSPPE, SSCMA or a new Pimpama zone substation. For Option 4, this means that the initial battery solution will be able to support the load for 10 years and would be able to extend the time required between establishing new 11kV feeders. For Option 5, the battery system only defers the need for the new substation. This scenario has been assigned a likelihood of 70% in the weighted average NPV.
- **Low demand** – under this scenario the assumption is that new 11kV feeders are required around every four years and any subsequent stages for each option shifted out accordingly. For Option 4, this means that the initial battery solution would defer the establishment of these feeders, however Energex have still assumed that the new substation is required at the end of the proposed contract period. For Option 5, the battery system only defers the need for the new substation. This scenario has been assigned a likelihood of 30% in the weighted average NPV.

8.4. NPV Results

Table 6 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	Establish new Pimpama zone substation	3	-21,468	-19,392	-2,076
2	Establish new Coomera East zone substation	5	-27,995	-24,042	-3,953
3	Upgrade Coomera zone substation	4	-22,719	-20,439	-2,280
4	Contract multiple Battery Energy Storage Systems	1	Withheld	Withheld	Withheld
5	Contract a single Battery Energy Storage System connected to SSCMA	2	Withheld	Withheld	Withheld

Table 6: 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 series of battery systems for 16MVA overall defers the investment in a new zone substation at Coomera and enables Energex to monitor load growth in the area. The scope of the preferred non-network option includes:

- Contract 10MW/16MWh battery systems to allow for generation support under a contingency at SSCMA in the period from 2023/24 to 2027/28
- Contract a further 6MVA/14MWh battery systems as load grows in the area in the period from 2028/29 to 2029/30

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 4.3.

9. Submission and Next Steps

9.1. Submission 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 this report may be submitted to demandmanagement@energex.com.au and are due by **15 June 2021.**

9.1. 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 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 30 July 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 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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9.2. Next Steps

Energex intends to carry out the following process to assess what action should be taken to address the identified need in the Coomera-Pimpama supply area:

Step 1	Publish Non Network Options Report (this report) inviting non-network options from interested participants	Date Released: **21 September 2020**
Step 2	Submissions in response to the Non-Network Options Report	Due Date: **21 December 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.	Completed By: **24 March 2021**
Step 4	Release of Draft Project Assessment Report (DPAR)	Date Released: **4 May 2021**
Step 5	Submissions in response to the Draft Project Assessment Report.	Due Date: **15 June 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: **30 July 2021**
Step 7	Release of Final Project Assessment Report (FPAR) including summary of submissions received	Anticipated to be released by: **17 August 2021**
Energex reserves the right to revise this timetable at any time. The revised timetable will be made available on the Energex website.		

Energex will use its reasonable endeavours to maintain the consultation program listed above. However, due to changing power system conditions or other circumstances beyond the control of Energex, this consultation schedule may change. Up-to-date information will be available on the Current Consultations webpage which can be accessed by the following link:

https://www.energex.com.au/home/our-services/projects-And-maintenance/current-consultations

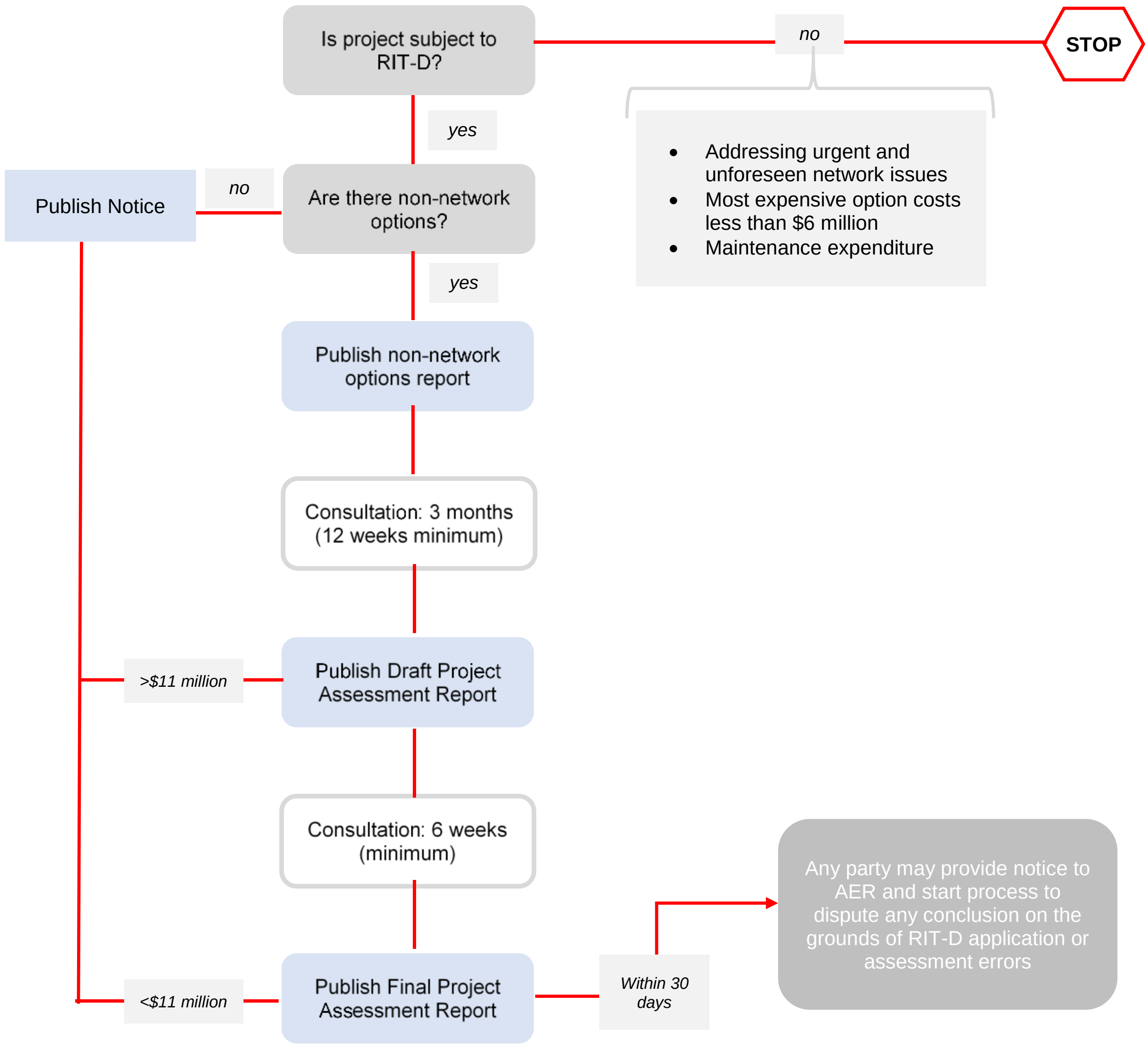
During the consultation period, Energex will review, compare and analyse all internal and external solutions. At the conclusion of the consultation process, Energex will publish a final report which will detail the most feasible option. Energex will then proceed to take steps to progress the recommended solution to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvement, as necessary.

10. Compliance Statement

This Non-Network Options Report 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;	4.3
(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;	6
(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 & 5
(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); and	4 & 5
(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.	5 & 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.

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

Network Limitation	Component Title Selection	Stage Timing Option 1	Stage Timing Option 2	Stage Timing Option 3	Stage Timing Option 4	Stage Timing Option 5
Safety Net Limitation at SSCMA	Establish new 25MVA 33/11kV Pimpama zone substation	2023		2040	2028	2028
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPA to supply new load	2025				
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPA to supply new load	2028				
Safety Net Limitation at SSCMA	Establish 2nd Module at SSPPA	2030			2030	2030
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPE	2033				
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPE	2036				
Safety Net Limitation at SSCMA	Establish new 25MVA 33/11kV Coomera East zone substation		2023			
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from Coomera East zone substation		2025			
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from Coomera East zone substation		2028			
Safety Net Limitation at SSCMA	Establish 2nd Module at SSPPA		2030			
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from Coomera East zone substation		2033			
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from Coomera East zone substation		2036			
Safety Net Limitation at SSCMA	Upgrade SSCMA by installing a 3rd 25MVA transformer and associated switchgear			2023		
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPE to supply new load			2025		
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSCMA, including 11kV underbore.			2028		
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSCMA, utilising existing conduit and underbore			2033		
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSCMA, utilising existing conduit and underbore			2036		
Safety Net Limitation at SSCMA	10MW Battery connected across 4 sites (7 years)				2023	
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPE				2026	
Safety Net Limitation at SSCMA	5MW Battery connected at SSCMA (7 years)					2023
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPE					2025

Figure 18 – 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	Establish new Pimpama zone substation	2	-22,202	-20,015	-2,188
2	Establish new Coomera East zone substation	4	-28,683	-24,630	-4,053
3	Upgrade Coomera zone substation	3	-25,210	-22,628	-2,582
4	Establish multiple Battery Energy Storage Systems	1	Withheld	Withheld	Withheld
5	Establish a single Battery Energy Storage System connected to SSCMA	2	Withheld	Withheld	Withheld

Table 7 – NPV Results for Medium Demand Scenario

Network Limitation	Component Title Selection	Stage Timing Option 1	Stage Timing Option 2	Stage Timing Option 3	Stage Timing Option 4	Stage Timing Option 5
Safety Net Limitation at SSCMA	Establish new 25MVA 33/11kV Pimpama zone substation	2023			2033	2032
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPA to supply new load	2028			2033	
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPA to supply new load	2032			2033	2032
Safety Net Limitation at SSCMA	Establish 2nd Module at SSPPA	2036			2036	2036
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPA to supply new load	2037			2037	2037
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPA to supply new load	2042			2042	2042
Safety Net Limitation at SSCMA	Establish new 25MVA 33/11kV Coomera East zone substation		2023			
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from Coomera East zone substation		2028			
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from Coomera East zone substation		2032			
Safety Net Limitation at SSCMA	Establish 2nd Module at SSPPA		2036			
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from Coomera East zone substation		2037			
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from Coomera East zone substation		2042			
Safety Net Limitation at SSCMA	Upgrade SSCMA by installing a 3rd 25MVA transformer and associated switchgear			2023		
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPE to supply new load			2028		
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSCMA, including 11kV underbore.			2032		
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSCMA, utilising existing conduit and underbore			2037		
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSCMA, utilising existing conduit and underbore			2042		
Safety Net Limitation at SSCMA	10MW Battery connected across 4 sites (10 years)				2023	
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPE				2030	
Safety Net Limitation at SSCMA	5MW Battery connected at SSCMA (10 years)					2023
80% TMU limitation at 11kV Feeders at SSPPE	11kV Feeder from SSPPE					2028

Table 8 – 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	Establish new Pimpama zone substation	2	-19,754	-17,937	-1,817
2	Establish new Coomera East zone substation	5	-26,389	-22,669	-3,720
3	Upgrade Coomera zone substation	1	-16,907	-15,331	-1,576
4	Establish multiple Battery Energy Storage Systems	4	Withheld	Withheld	Withheld
5	Establish a single Battery Energy Storage System connected to SSCMA	3	Withheld	Withheld	Withheld

Table 9 – NPV Results for Low Demand Scenario