Non-Network Options Report

9 November 2020

Version 1.0

Caloundra Network Limitation

Consultation Period Starts: 16/11/2020

Consultation Period Closes: 15/02/2021

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

Caloundra 132/11kV zone substation (SSCLD) is in Caloundra, in the Sunshine Coast area of South East Queensland. SSCLD provides electricity supply to approximately 22,000 predominantly domestic customers in the Aroona, Caloundra, Currimundi, Meridan Plains, Pelican Waters and Shelly Beach areas.

There is a significant master-planned community (Aura) to the south-west of SSCLD that when completed is forecast to add at least 47MVA load to the network. Further, an additional 15MVA of load to be added to the network from the Sunshine Coast Industrial Park, located to the west of SSCLD.

The identified need for this Non-Network Options Report is that Energex will experience two upcoming network limitations:

- Forecast exceedance of the Target Maximum Utilisation on 11kV feeder CLD11 in 2021 and on feeders CLD1A, CLD18A and CLD29A from 2023 onwards.
- Forecast breach of its Safety Net obligation as outlined in its Distribution Authority at SSCLD in the period between 2027 and 2030.

The requirements of a non-network option to solve the identified need are summarised in Table 1.

Year	CLD1A Load (MVA)	CLD11 Load (MVA)	CLD18A Load (MVA)	CLD29A Load (MVA)
2020	0.00	0.00	0.00	0.00
2021	0.00	0.26	0.00	0.00
2022	0.00	0.85	0.00	0.00
2023	0.00	1.15	0.00	0.41
2024	0.00	1.31	0.00	1.31
2025	0.00	1.57	0.00	3.31
2026	0.03	1.82	0.00	5.41
2027	0.21	2.07	0.50	7.51
2028	0.38	2.32	1.45	9.81
2029	0.56	2.57	2.40	12.01
2030	0.74	2.82	3.36	14.51

Table 1: Forecast Load at Risk

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 network investment is essential in this case for it to continue to provide electricity to the consumers in the Caloundra area in a reliable, safe and cost-effective manner and meet its obligations under its Distribution Authority. Accordingly, this investment is subject to a RIT-D. This non-network options report has been prepared by Energex in accordance with the requirements of clause 5.17.4(e) of the NER and seeks information from interested parties about possible alternate solutions to address the need for investment.

Submissions in writing (electronic preferably) are due by 15 February 2021 by 4:00 PM. For further information on this or to enquiry further, please refer to section 1.2 Contact Details.

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1. Introduction

This document is a Non-Network Options Report (NNOR) requesting stakeholders' submissions for credible options to address the identified need in the network. This report is the first stage of the consultation process in the application of the Regulatory Investment Test for Distribution (RIT-D) on credible options to address the identified need for this study area.

The report includes background information about the limitations in this area, highlights the identified need, outlines credible network options, provides the requirements that a non-network proponent would need to meet and specifies the process for interested stakeholder submissions.

1.1. General Terms and Conditions

1. By issuing this NNOR, 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 NNOR 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 15 February 2021.

Ergon Energy Corporation Limited ABN 50 087 646 062
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2. Background

2.1. Existing Network

Caloundra Zone Substation (SSCLD) provides electricity supply to approximately 22,000 predominantly residential customers in the Aroona, Caloundra, Currimundi, Meridan Plains, Pelican Waters and Shelly Beach areas. SSCLD is supplied from the Powerlink Palmwoods injection point via a 132kV ring network, which also supplies Mooloolaba zone substation (SSMLB), Currimundi zone substation (SSCMD), Birtinya zone substation (SSBTY), Kawana zone substation (SSKWA), Alexandra Headlands zone substation (SSAHD) and West Maroochydore zone substation (SSWMD). There is also a 33kV network that is supplied by Beerwah bulk supply substation (SSBWH) that provides supply to Woodford zone substation (SSWFD) and Landsborough zone substation (SSLBH).

Geographic and schematic views of the network area under study are provided in Figure 1 to Figure 4.

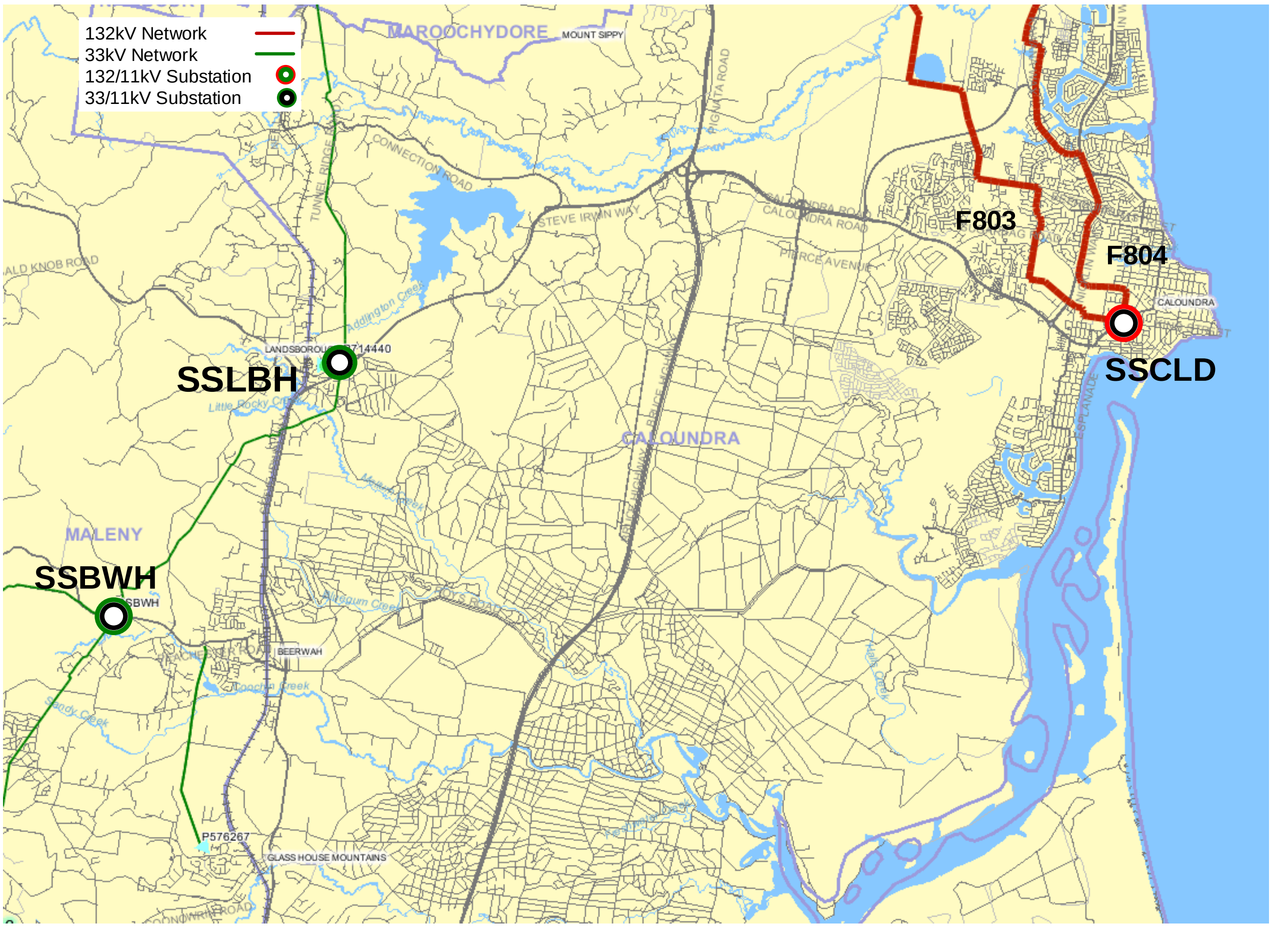

Figure 1: Existing Subtransmission Network Arrangement (geographic view)

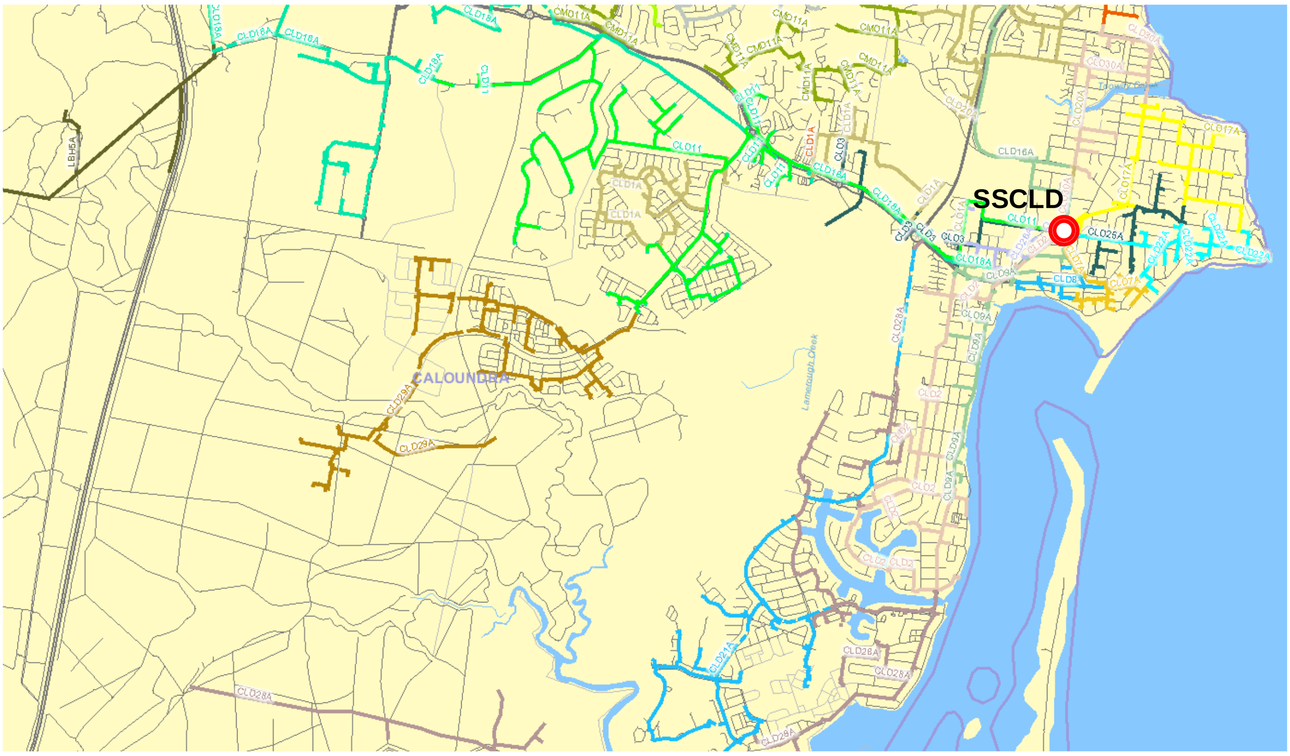

Figure 2: Existing 11kV Network Arrangement (geographic view)

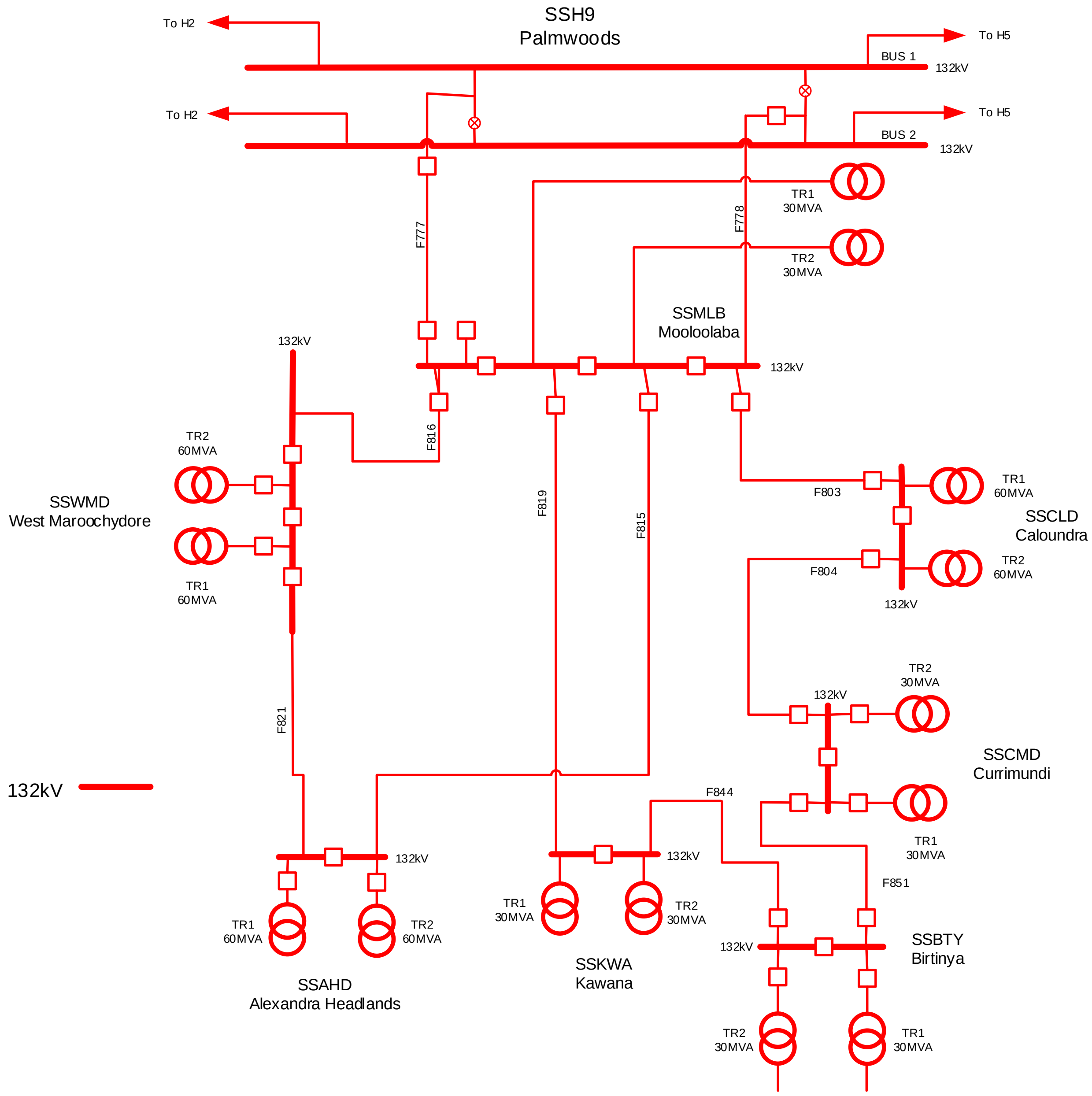

Figure 3: Existing network arrangement (schematic view)

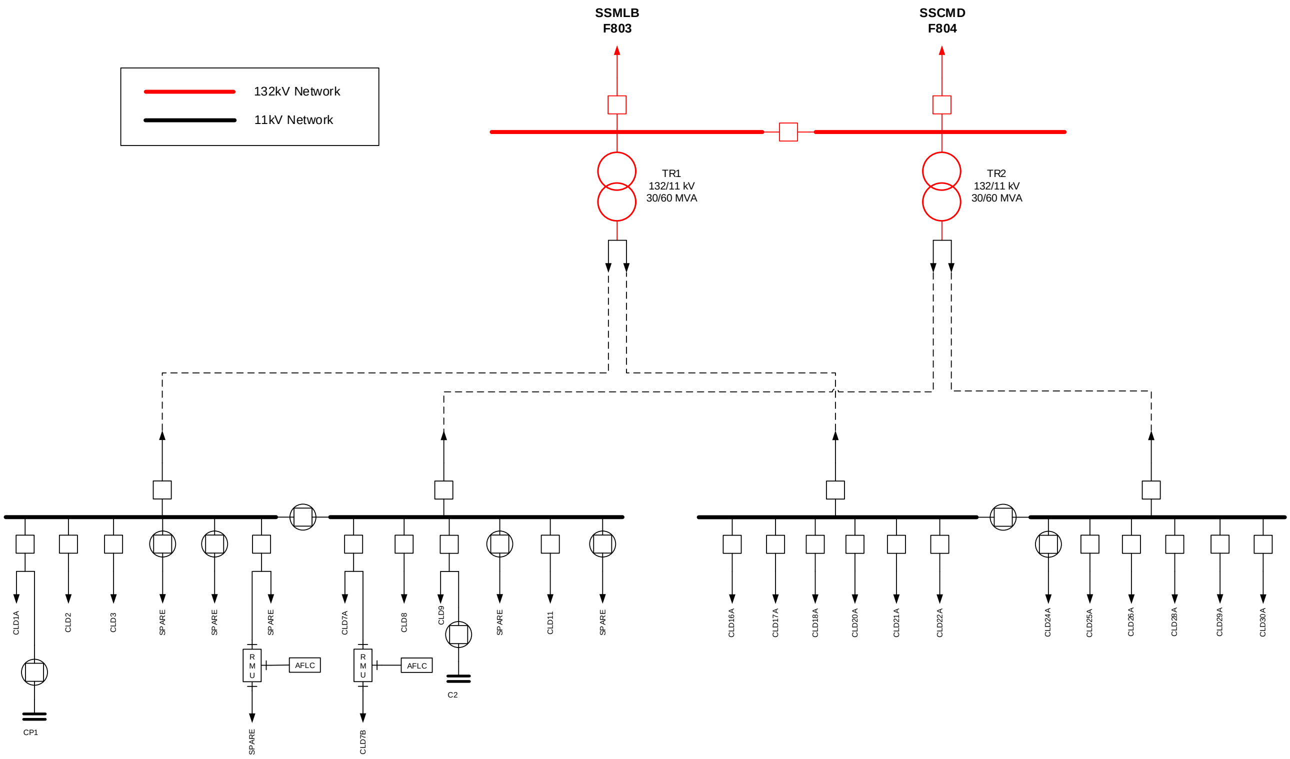

Figure 4: Existing network arrangement (schematic view)

2.2. Development Overview and Demand Forecast

The Aura development (previously known as Caloundra South) is south-west of SSCLD and is a master-planned community that will have over 20,000 new homes in a 24km^2 site within the next 30 years. The development also contains a significant commercial and light industrial area, forecast to be roughly half the load of the development. Further to this, there is an existing Sunshine Coast Industrial Park directly west of SSCLD which is currently planned for a large expansion.

When fully developed, this industrial park will represent a load of around 15MVA to 20MVA. Figure 5 below shows the development area, with Table **2** showing the ultimate load of the area. As can be seen from Table **2**, even under a low load scenario, the ultimate load in the Aura development alone totals at least 47MVA. When this is combined with the projected low load scenario of the Sunshine Coast Industrial Park directly north of Aura the total load in the area is forecast to be at least 62MVA.

For the Energex network, a typical 132/11kV zone substation has a capacity of between 40-70MVA, with the capacity of a two transformer 33/11kV zone substation around 30-40MVA. There are 4 feeders surrounding the Aura development – CLD1A, CLD11, CLD18A and CLD29A (see Figure 2) however, CLD29A is the only dedicated feeder feeding the Aura development. CLD1A and CLD11 both predominately feed the established Bellavista development adjacent to Aura while CLD18A will be the main feeder supplying the future Sunshine Coast Industrial Park.

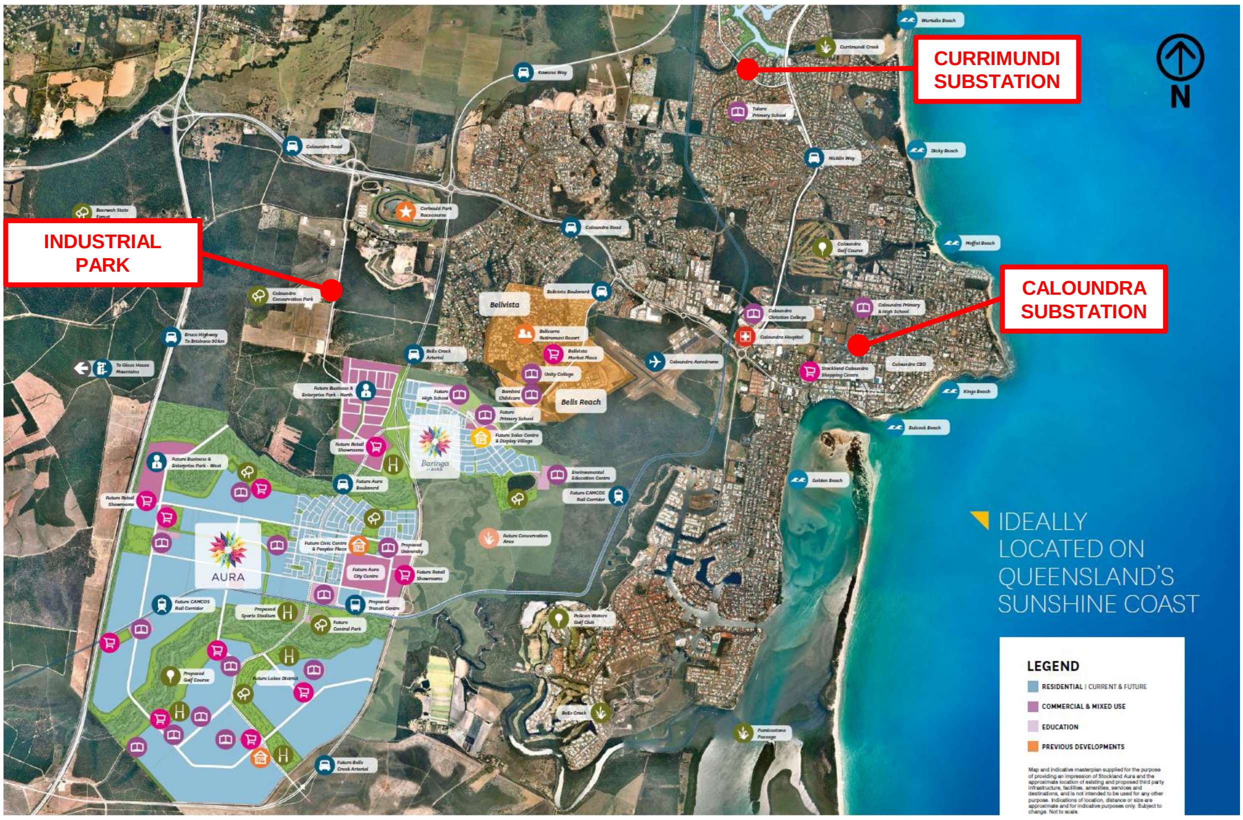

Figure 5: Proposed Aura development area

Load Type	Low Load Scenario (MVA)	Medium Load Scenario (MVA)
Commercial	14.90	18.60
Industrial Light	8.50	10.60
Residential High	0.50	0.60
Residential High B5	1.80	2.40
Residential Medium	6.00	8.00
Residential Undeveloped	15.30	20.40
Total for Aura Development	**47.00**	**60.40**
Sunshine Coast Industrial Park	15.00	20.00
Area Total – South Caloundra	**62.00**	**80.40**

Table 2: Ultimate Load for the Development

2.3. Load Profiles

The load duration curve for feeders CLD1A, CLD11, CLD18A and CLD29A are shown in Figure 6 to Figure 9 below. It should be noted CLD29A is a new feeder established in September 2020 and approximately 2MVA of load was transferred from CLD18A. Due to the new feeder not having historic data, the load duration curve for CLD29A was developed from CLD18A data and utilising the new CLD29A load forecast.

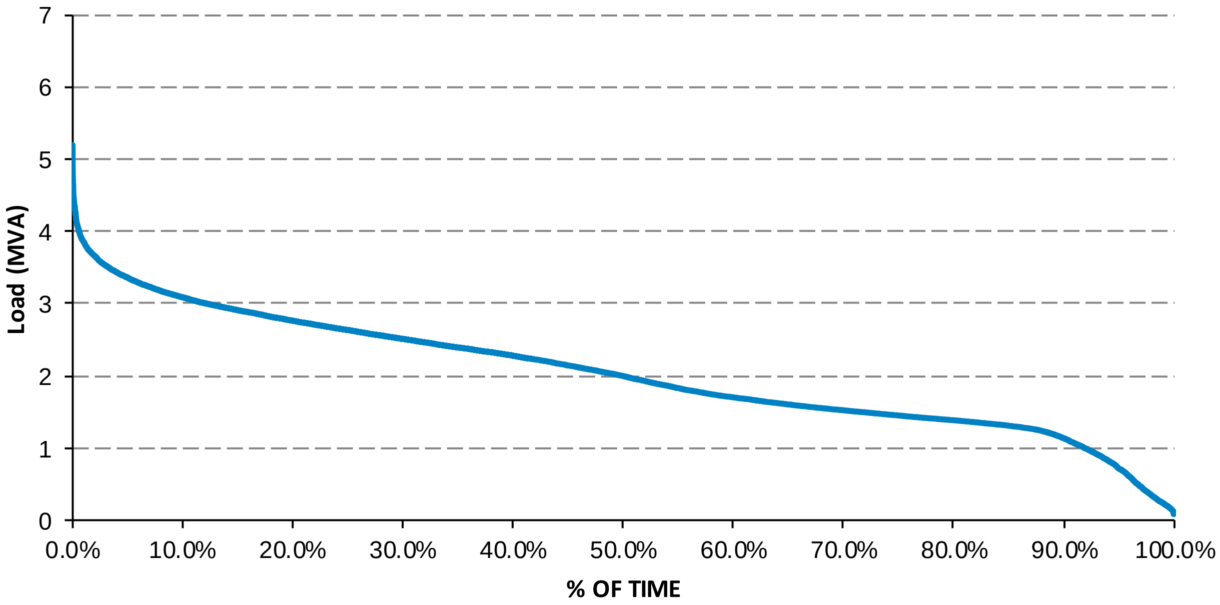

Figure 6: Load duration curve for CLD1A

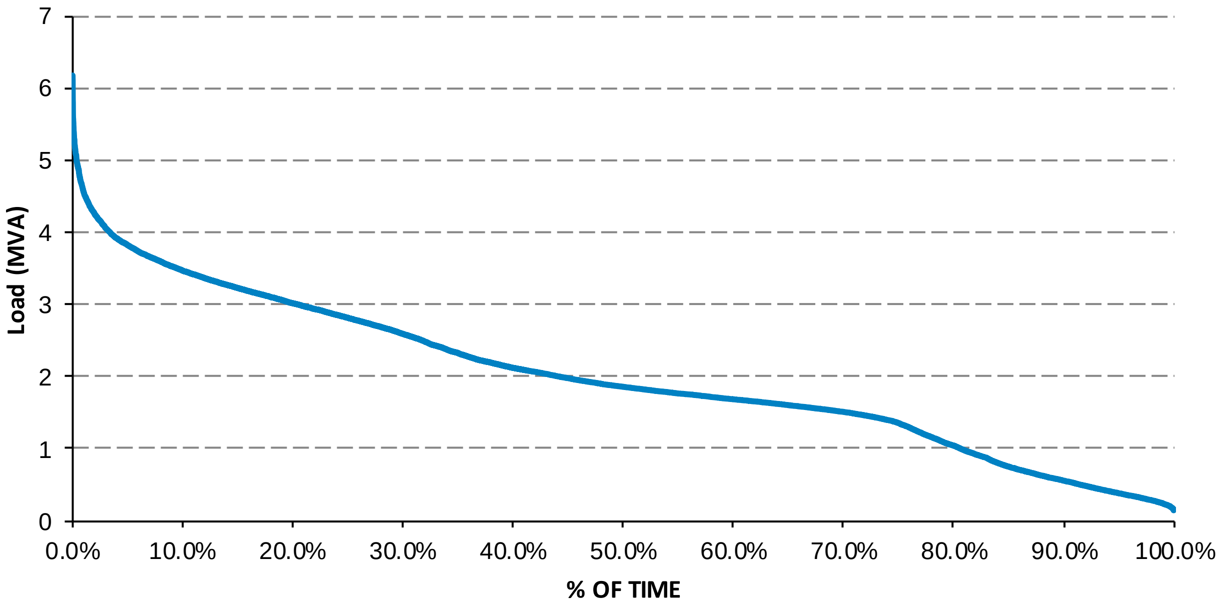

Figure 7: Load duration curve for CLD11

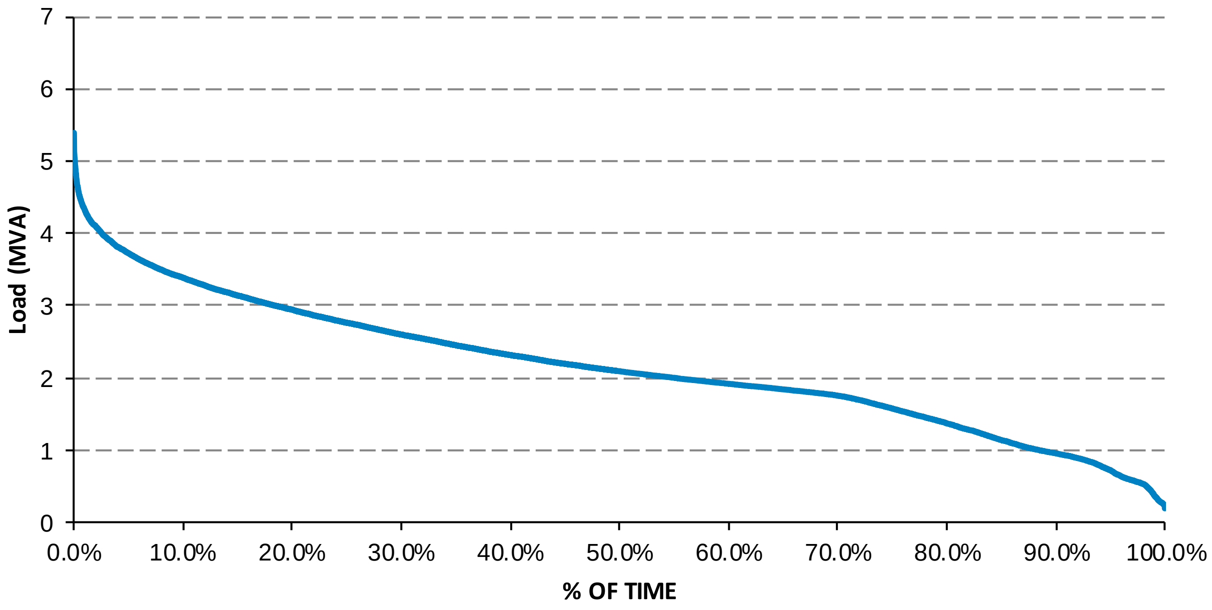

Figure 8: Load duration curve for CLD18A

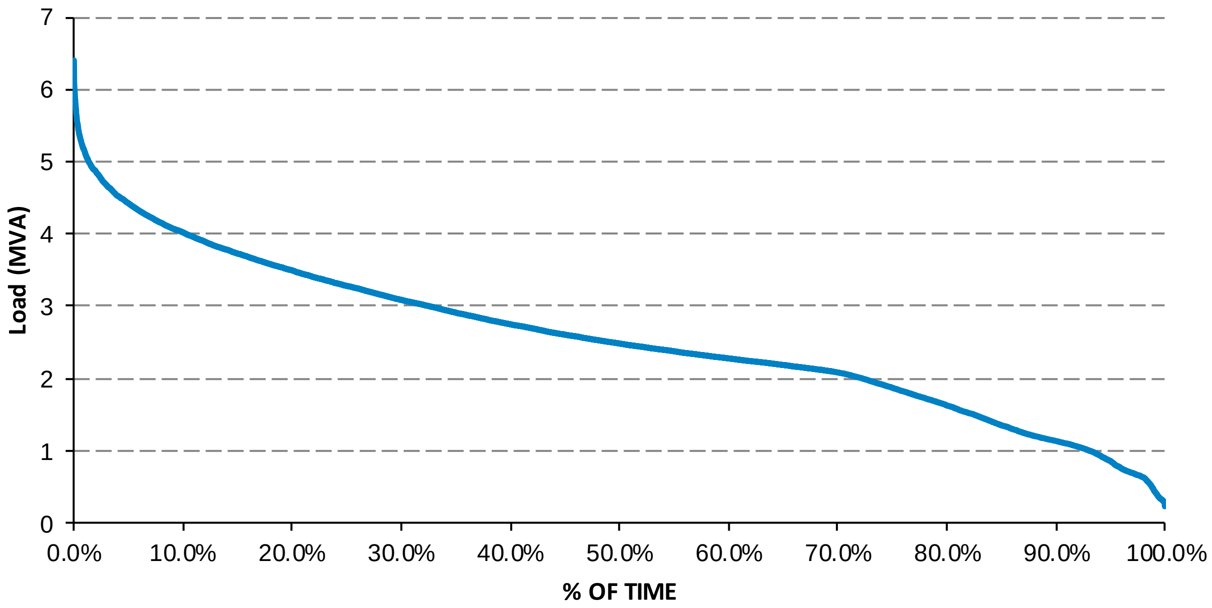

Figure 9: Load duration curve for CLD29A

3. Identified Need

3.1. Applied Service Standard

Distribution Network

Energex plans its 11kV distribution network for a Target Maximum Utilisation (TMU) of 80% at 50PoE load. This ensures the feeder is not overloaded whist having sufficient transfer capacity for contingencies on the 11kV network. This level of utilisation also allows transfer capacity to ensure that Energex meets is Safety Net obligations under the Distribution Authority.

Sub-transmission Network

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

SSCLD is classified as an Urban substation, 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

There are two major identified needs in this NNOR:

- 11kV Feeder limitations – there are currently only 4x11kV feeders in the study area. Without augmentation, these feeders will not be able to provide enough capacity to continue to supply new customers, nor meet Energex's TMU of 80%.
- Safety Net Limitation at SSCLD - where load continues to be added to SSCLD, the redundancy requirement specified in Energex's Distribution Authority will not be achieved.

These limitations are discussed in more detail below.

3.3. Quantification of the Identified Need

3.3.1. 11kV Feeder Limitations

Energex has applied the following assumptions in developing it forecast load for the 11kV feeders in the area:

- In the Aura development, there will be an increase of around 500 customers/year between 2020 and 2025. After 2025, this will be around 1,000 customers/year.
- A demand increase is expected of between 1.3kVA/dwelling to 1.6kVA/dwelling which is consistent with the existing demand/customer of the 2,418 customers already connected in the development.
- After 2025, the Sunshine Coast Industrial Park is forecast to increase by around 1MVA /year.

As seen below in Table 4, CLD11 is forecast to exceed its TMU in 2021, with CLD29A, CLD1A and CLD29A all forecast to exceed their TMU in the next ten years. Red cells indicate TMU exceedance.

Year	CLD1A Load (MVA)	CLD11 Load (MVA)	CLD18A Load (MVA)	CLD29A Load (MVA)
80% (TMU)	5.17	5.91	4.89	5.99
2020	4.19	5.64	2.48	4.57
2021	4.25	6.17	2.55	5.01
2022	4.29	6.76	2.65	5.69
2023	4.38	7.07	2.76	6.38
2024	4.53	7.22	2.88	7.30
2025	5.02	7.49	3.87	9.29
2026	5.20	7.73	4.63	11.38
2027	5.38	7.98	5.39	13.48
2028	5.55	8.23	6.34	15.76
2029	5.73	8.48	7.30	18.05
2030	5.90	8.73	8.25	20.53

Table 4: Maximum 11kV Feeder Load

Figure 10 to Figure 13 show the proportion of the load duration curve for the 50% POE forecast for each feeder that is above the TMU. Table 5 to Table 8 show the load at risk and the duration of the feeder is above the Target Maximum Utilisation limits.

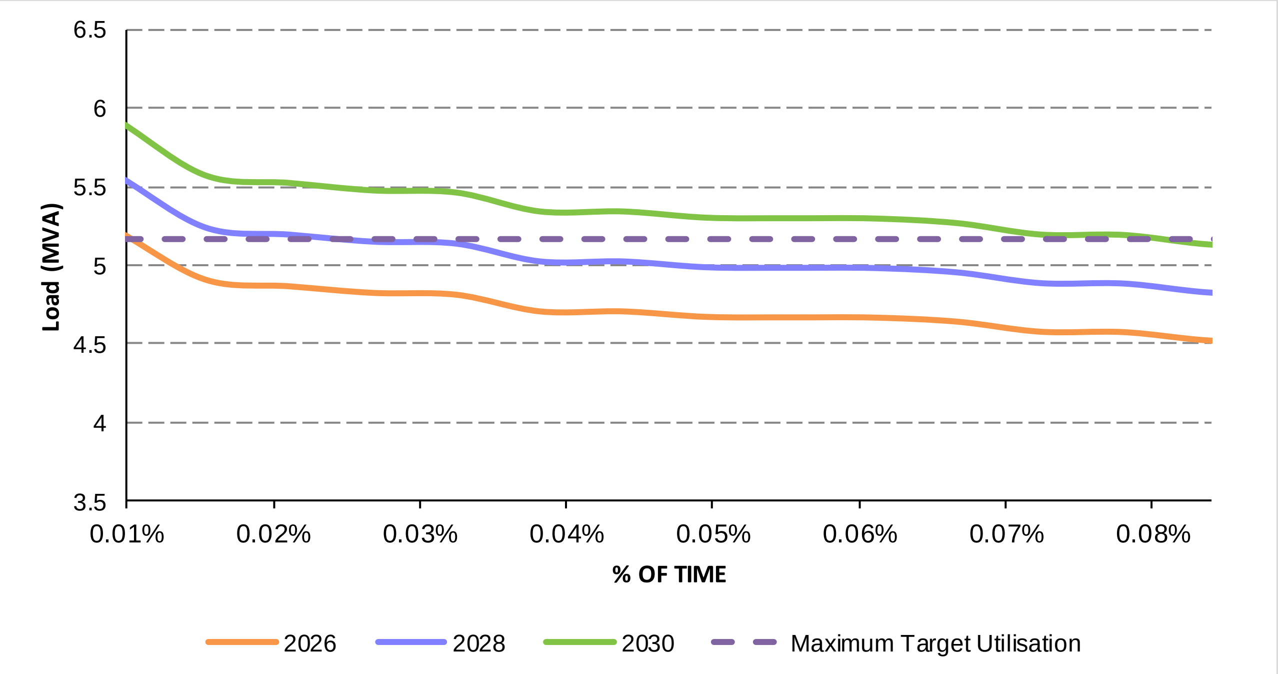

Figure 10: CLD1A Target Maximum Utilisation Limit Exceedance Forecast

Target Maximum Utilisation Limit (MVA)	Year	Forecast 50 PoE Load (MVA)	Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
-	2020	4.19	0.00	-	-	-
-	2021	4.25	0.00	-	-	-
-	2022	4.29	0.00	-	-	-
-	2023	4.38	0.00	-	-	-
-	2024	4.53	0.00	-	-	-
-	2025	5.02	0.00	-	-	-
5.2	2026	5.20	0.03	1	0.01%	0.5
5.2	2027	5.38	0.21	1	0.01%	0.5
5.2	2028	5.55	0.38	1	0.02%	1.5
5.2	2029	5.73	0.56	4	0.04%	3.5
5.2	2030	5.90	0.74	5	0.07%	6.5

Table 5: CLD1A Target Maximum Utilisation Limit

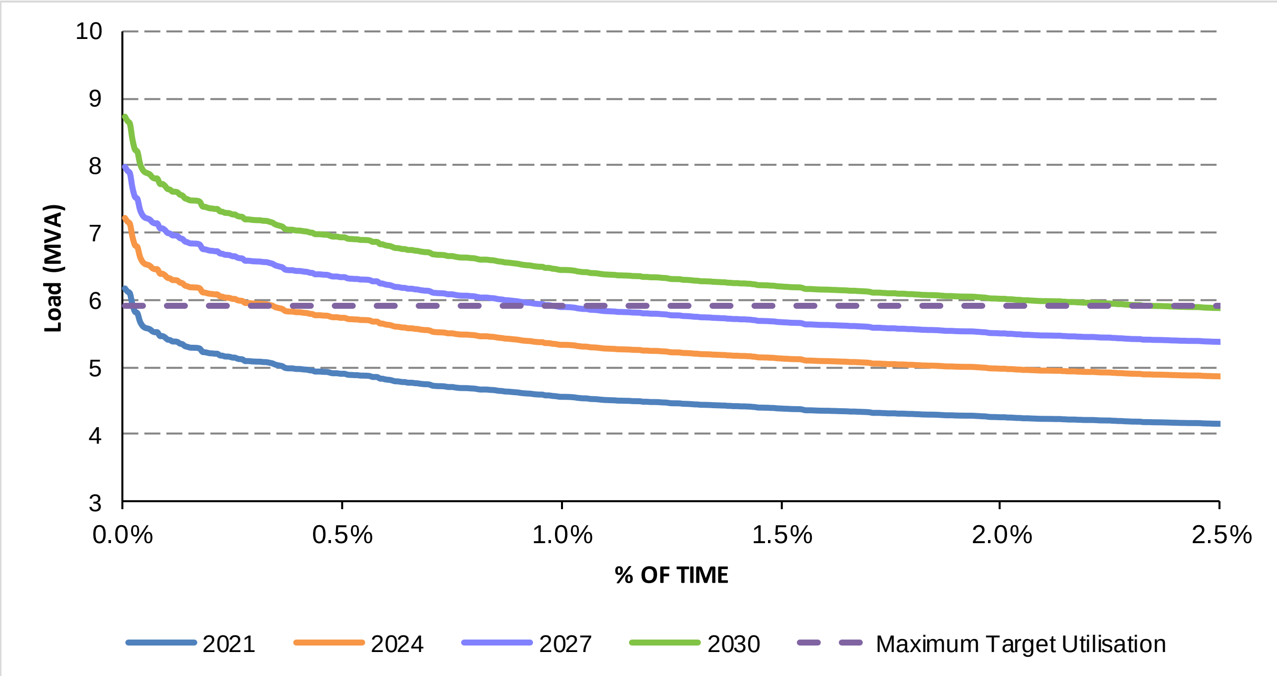

Figure 11: CLD11 Target Maximum Utilisation Limit Exceedance Forecast

Target Maximum Utilisation Limit (MVA)	Year	Forecast 50 PoE Load (MVA)	Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
-	2020	5.64	0.00	-	-	-
5.9	2021	6.17	0.26	1	0.02%	2.0
5.9	2022	6.76	0.85	6	0.11%	9.5
5.9	2023	7.07	1.15	11	0.23%	20.0
5.9	2024	7.22	1.31	17	0.34%	29.9
5.9	2025	7.49	1.57	25	0.54%	46.9
5.9	2026	7.73	1.82	28	0.71%	62.4
5.9	2027	7.98	2.07	39	0.97%	85.3
5.9	2028	8.23	2.32	52	1.34%	117.8
5.9	2029	8.48	2.57	67	1.79%	157.2
5.9	2030	8.73	2.82	88	2.34%	205.1

Table 6: CLD11 Target Maximum Utilisation Limit

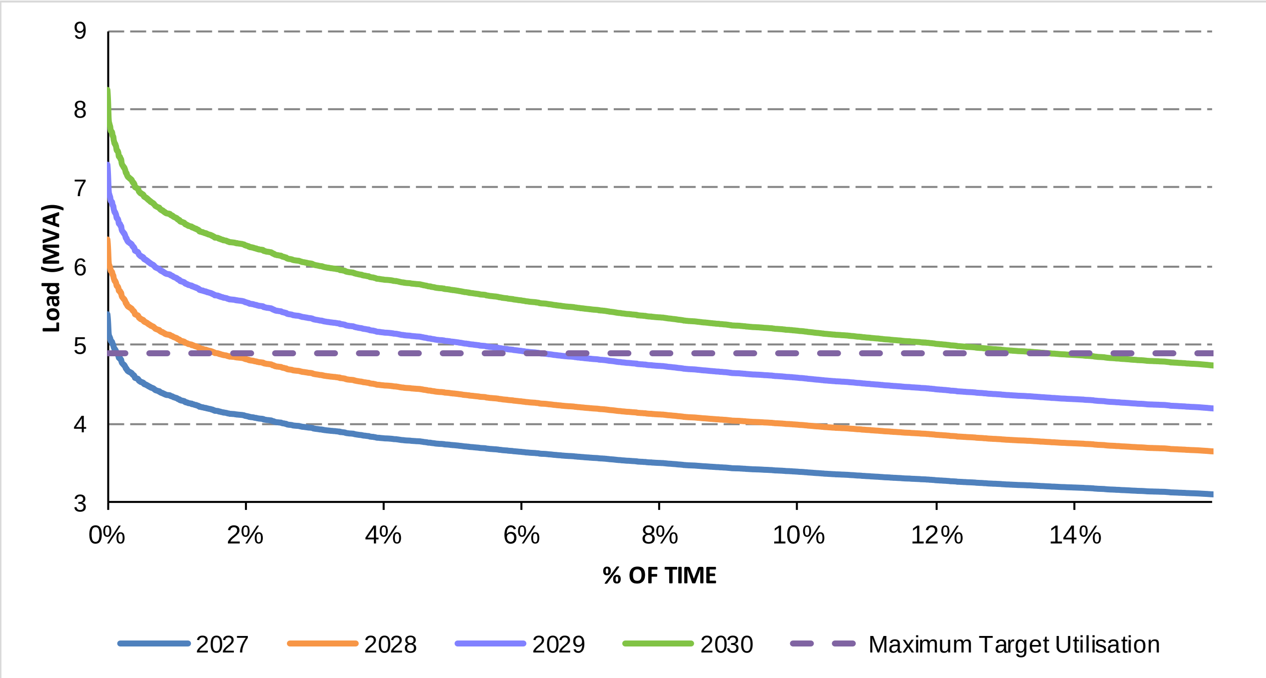

Figure 12: CLD18A Target Maximum Utilisation Limit Exceedance Forecast

Target Maximum Utilisation Limit (MVA)	Year	Forecast 50 PoE Load (MVA)	Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
-	2020	2.48	0.00	-	-	-
-	2021	2.55	0.00	-	-	-
-	2022	2.65	0.00	-	-	-
-	2023	2.76	0.00	-	-	-
-	2024	2.88	0.00	-	-	-
-	2025	3.87	0.00	-	-	-
-	2026	4.63	0.00	-	-	-
4.9	2027	5.39	0.50	9	0.14%	12.0
4.9	2028	6.34	1.45	73	1.60%	140.2
4.9	2029	7.30	2.40	165	6.27%	549.0
4.9	2030	8.25	3.36	252	13.65%	1195.8

Table 7: CLD18A Target Maximum Utilisation Limit

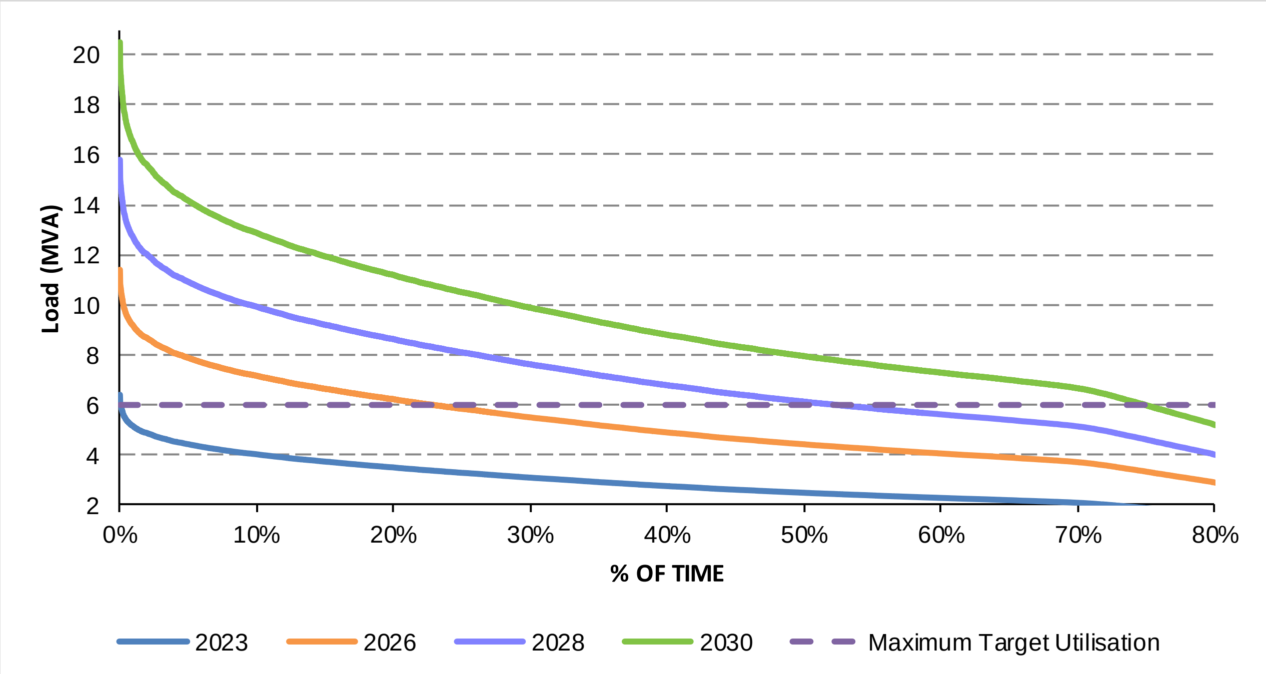

Figure 13: CLD29A Target Maximum Utilisation Limit Exceedance Forecast

Target Maximum Utilisation Limit (MVA)	Year	Forecast 50 PoE Load (MVA)	Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
-	2020	4.6	0.00	-	-	-
-	2021	5.0	0.00	-	-	-
-	2022	5.7	0.00	-	-	-
6.0	2023	6.4	0.41	5	0.05%	4.5
6.0	2024	7.3	1.31	40	0.70%	60.9
6.0	2025	9.3	3.31	204	8.34%	730.2
6.0	2026	11.4	5.41	294	22.93%	2008.3
6.0	2027	13.5	7.51	312	37.07%	3247.1
6.0	2028	15.8	9.81	316	52.46%	4595.6
6.0	2029	18.0	12.01	323	67.78%	5937.7
6.0	2030	20.5	14.51	340	74.97%	6567.0

Table 8: CLD29A Target Maximum Utilisation Limit

It should be noted that although there is technically an exceedance of the TMU for CLD11 in 2021, this is an extremely small load at risk of 0.26MVA. As such, Energex are not proposing to provide a solution, either network or non-network, to this limitation until 2022.

3.3.2. Future Limitation

SSCLD is equipped with 2 x 60MVA 132/11kV transformers. The substation capacity is limited by the cables from the transformer to the 11kV bus bars and has a Normal Cyclic Capacity (NCC), Emergency Cyclic Capacity (ECC) and 2 Hour Emergency Capacity (2HEC) as below:

- NCC – 115.10MVA
- ECC – 64.50MVA
- 2HEC – 81.00MVA

The substation currently has the capacity to supply all forecast loads and meet the Safety Net criteria until 2025. As load in the Aura and surrounding developments continues to grow, Energex forecasts that the Safety Net criteria may not be met somewhere between 2027 and 2030.

4. Assessment Methodology & Assumptions

4.1. Demand Forecasts

Please refer to Section 5 (Network Forecasting) of the latest Energex DAPR publication for in-depth details regarding the methods and assumptions behind Energex's demand forecasts.

4.2. 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 period. The identified need described in this Non-Network Options Report occurs in the 2020-2025 AER period, where the WACC is 2.62%. (Note that this is lower than the WACC in the previous regulatory period.)

4.3. Cost Estimates

Project costs are calculated using standard estimate components which are developed & evaluated by estimation teams in Energex. The costs are split into 2 components: direct cost, which is the costs which are directly applied 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.

4.4. Evaluation Test Period

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

5. Internal Options Considered

5.1. Non-Network Options Identified

No internal non-network options have been identified at this stage.

5.2. Do Nothing (Base Case)

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

5.3. Initial Limitation Network Option Identified

The option considered to resolve CLD11 exceeding Target Maximum Utilisation is to establish a new feeder from SSCLD to Aura. The cost of establishing this new feeder is approximately $3 million, with an operating cost of around $7,000/year. Energex are currently proposing to establish this feeder in October 2022. The works involved to implement this option are:

- Establish 8km 11kV feeder in both new and existing conduits
- Install 800m conduit

5.4. Future Limitation Network Options Identified

A total of 9 network options were identified to resolve the identified limitations. Table 9 gives a summary, the initial capital costs and forecast yearly operating costs. Further details of each option can be found in Appendix C.

Option	Option Name	Initial Capital Cost	Operating Cost/Year
1	11kV Feeders from SSCLD, 132kV Feeders, 132/11kV Bells Creek Central Substation	$4,257,500	$28,580
2	132kV Feeders from F803 & 132/11kV Bells Creek Central Substation	$60,878,334	$301,171
3	11kV Feeder from SSCLD & 132kV Feeders (Disconnected), 132/11kV Bells Creek Central Substation	$41,278,348	$179,132
4	132kV Feeders & 132/11kV Bells Creek North Substation	$57,420,017	$324,213
5	132/33kV Meridan Plains Substation, 33kV Feeders & 33/11kV Bells Creek Central Substation	$53,844,406	$350,494
6	132/33/11kV Meridan Plains Substation & 33kV Feeders @11kV, 33/11kV Bells Creek Central Substation	$44,096,500	$243,858
7	132/33kV & 33/11kV Meridan Plains Substation & 33kV Feeders @11kV, 33/11kV Bells Creek Central Substation	$44,528,189	$243,858
8	132kV Feeders from Mark Rd East (83%UG 17%OH) & 132/11kV Bells Creek Central Substation	$63,167,951	$301,171
9	132kV Feeders from SSCLD (88%UG 12%OH) & 132/11kV Bells Creek Central Substation	$51,532,504	$150,552

Table 9: Future Limiation Network Options

5.5. Preferred Network Option

In order to resolve the initial limitation for CLD11 exceeding the Target Maximum Utilisation, the identified network option is to establish a new 11kV feeder to de-load CLD11. This option is estimated approximately $3 million and the works involved to implement this option are:

- Establish 8km 11kV feeder
- Install 800m conduit

Option 2 is currently the preferred network option to resolve Energex's future 11kV feeder limitations and emerging Safety Net limitation at SSCLD. This provides the most economically efficient network option, with the lowest NPV cost to address the network limitations. It is proposed to establish Bell's Creek Central substation in October 2025. Works include:

- Installation of 2 x 13km of 132kV overhead feeders;
- installation of 132kV CBs:
  - 2 x bus sections with 1 x bus section CB
  - 1 x transformer CB
  - 2 x feeder CBs;
- installation of 132kV control room;
- installation of 1 x 60MVA 132/11kV transformers;
- installation of an 11kV indoor switchroom including 1 x bus section with 1 x bus section CB, 1 x transformer CB, 5 x feeder CBs;
- installation of 1 x AFLC;

The preferred network option has an estimated initial capital project cost of $60.7M, and an annual operating cost of approximately $301,171. It should be noted that although this option has a higher initial capital cost than Option 1, the future stages associated with Option 1, which is essentially to establish a new 11kV feeder every two years, is not the most economically efficient solution in NPV terms.

5.6. 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 following represents the following savings per annum:

- Initial Limitation: $85,901
- Future Limitation: $1,884,008

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. Depending on the proposal, Energex may be required to establish some network to facilitate the solution, and where this is the case the deferral amount would be calculated on the quantum of capital and operating expense that is avoided.

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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6. Non-Network Options

6.1. Assessment of Non-Network Solutions

To reduce, defer or avoid network expenditure, a non-network proponent would need to provide a non-network option that would eliminate the initial limitation of the 11kV feeder CLD11 exceeding the TMU and the establishment of a new substation at Bells Creek Central.

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 the 11kV feeder exceeding the Target Maximum Utilisation. As such, solutions that prudently and efficiently address these constraints will be considered.

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

Although the TMU and emerging 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 from 2022 onwards. Energex will be seeking responses from interested parties who are able to provide network support to reduce or eliminate this limitation starting from 2022 in a cost-effective manner. Any proposed solution must at least be available by October 2022, when the initial network solution is currently forecast to be able to be delivered. Solutions to future limitations on the 11kV feeders and at SSCLD will need to be progressively available from 2025 and beyond.

7. Submission and Next Steps

7.1. Submission from Solution Providers

Energex invites written submissions to address the identified need in this report from registered participants and interested parties. With reference to Section 5, all submissions should include sufficient technical and financial information to enable Energex to undertake comparative analysis of the proposed solutions against alternative options. The proposals should include, but are not limited to, the following:

- Full costs of completed works including delivery and installation where applicable.
- Whole of life costs include operational costs.
- Project execution strategy including design, testing and commissioning plans.
- Engineering network system studies and study reports.

Energex will not be legally bound 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 in accordance with Energex's standards for procurement.

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

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7.2. Next Steps

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

Step 1	Publish Non-Network Options Report (this report) inviting non-network options from interested participants	Date Released: **16 November 2020**
Step 2	Submissions in response to the Non-Network Options Report	Due Date: **15 February 2021**
Step 3	Review and analysis of proposals by Energex This is likely to involve further consultation with proponents and additional data may be requested.	Anticipated to be completed by: **19 April 2021**
Step 4	Release of Draft Project Assessment Report (DPAR)	Anticipated to be released by: **17 May 2021**
Step 5	Submissions in response to the Draft Project Assessment Report.	Due Date: **9 August 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: **13 September 2021**
Step 7	Release of Final Project Assessment Report (FPAR) including summary of submissions received	Anticipated to be released by: **21 September 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

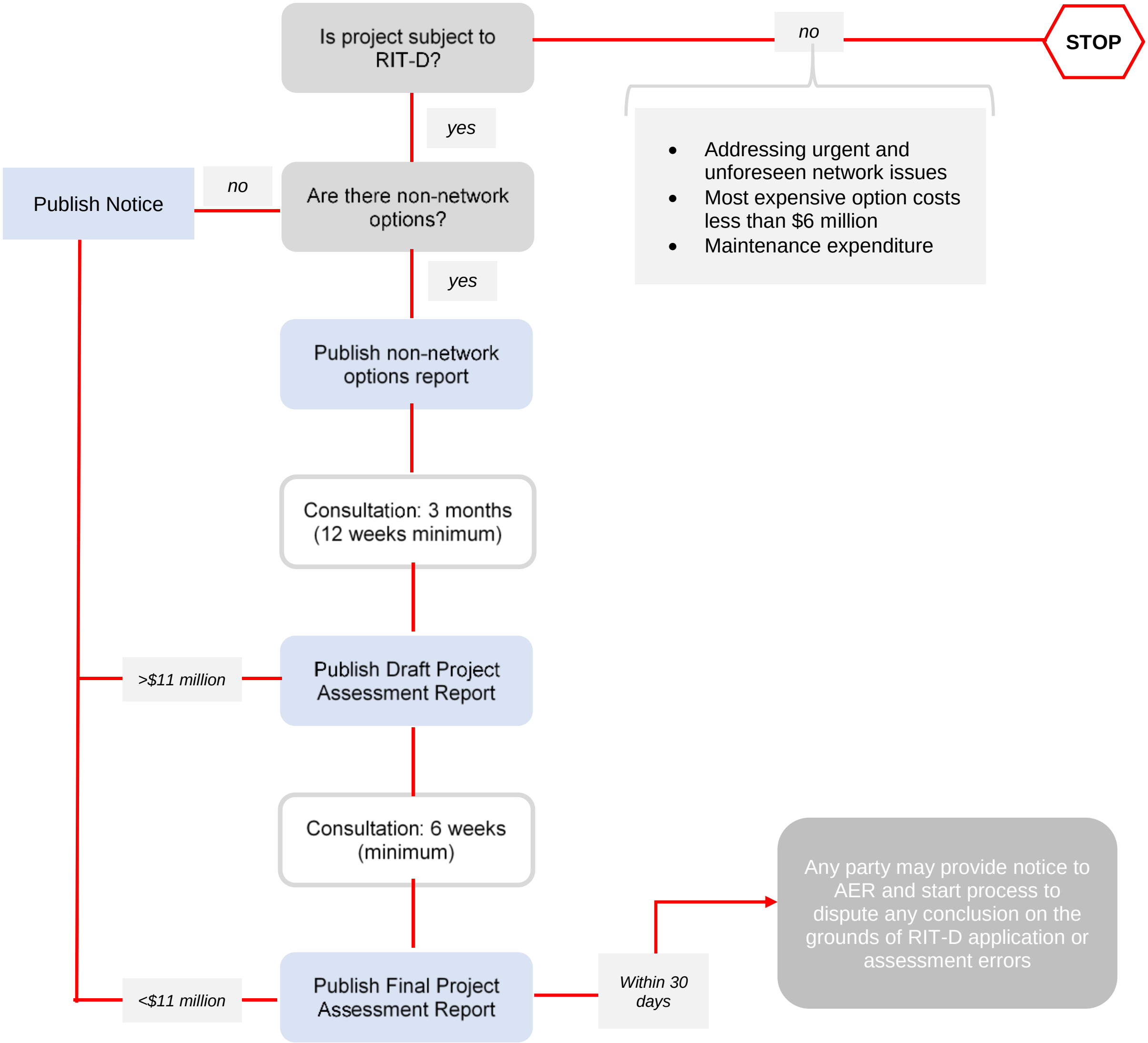
During the consultation period, Energex will review, compare and analyse all internal and external solutions. At the conclusion of the consultation process, Energex will publish a final report which will detail the most feasible option. Energex will then proceed to take steps to progress the recommended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

8. 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
(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;	5.6
(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;	2, 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;	5 & 6.2
(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	5, Appendix C
(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.	6 & 7.1

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 – Future Limitation Network Options

The following sections outline the identified Network Options in more detail.

Option 1: Supply New Demand with 11kV Feeders from SSCLD, then Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment

This option involves continuing to supply the Aura subdivision and surrounding area with 11kV feeders from SSCLD until an additional 132/11kV substation is triggered by the Safety Net limitation at SSCLD. The costs for 11kV feeders have been determined individually considering conduit requirements, civil and other works in each case. Standard costs include $1300/m for conduit installation (6 conduits), plus $250/m for cable installation.

The works required to implement this option are:

- Establish 11kV feeders from SSCLD to supply Aura up to 2029
- Establish 2 x 132kV feeders to Bell's Creek Central, establish Bell's Creek Central 132/11kV zone substation in 2029 to supply the continued load growth in the area and address the safety net limitation at Caloundra. In this case it is assumed the 132kV feeders are constructed overhead for the first 9km and underground for the remaining 4km based on the timing of the works;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2031 at Bell's Creek Central;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $4.2 million ± 40% (2026)
- Estimated initial operating cost per annum: $28,580 (2026)

A schematic diagram of the proposed solution is shown in Figure 14 below.

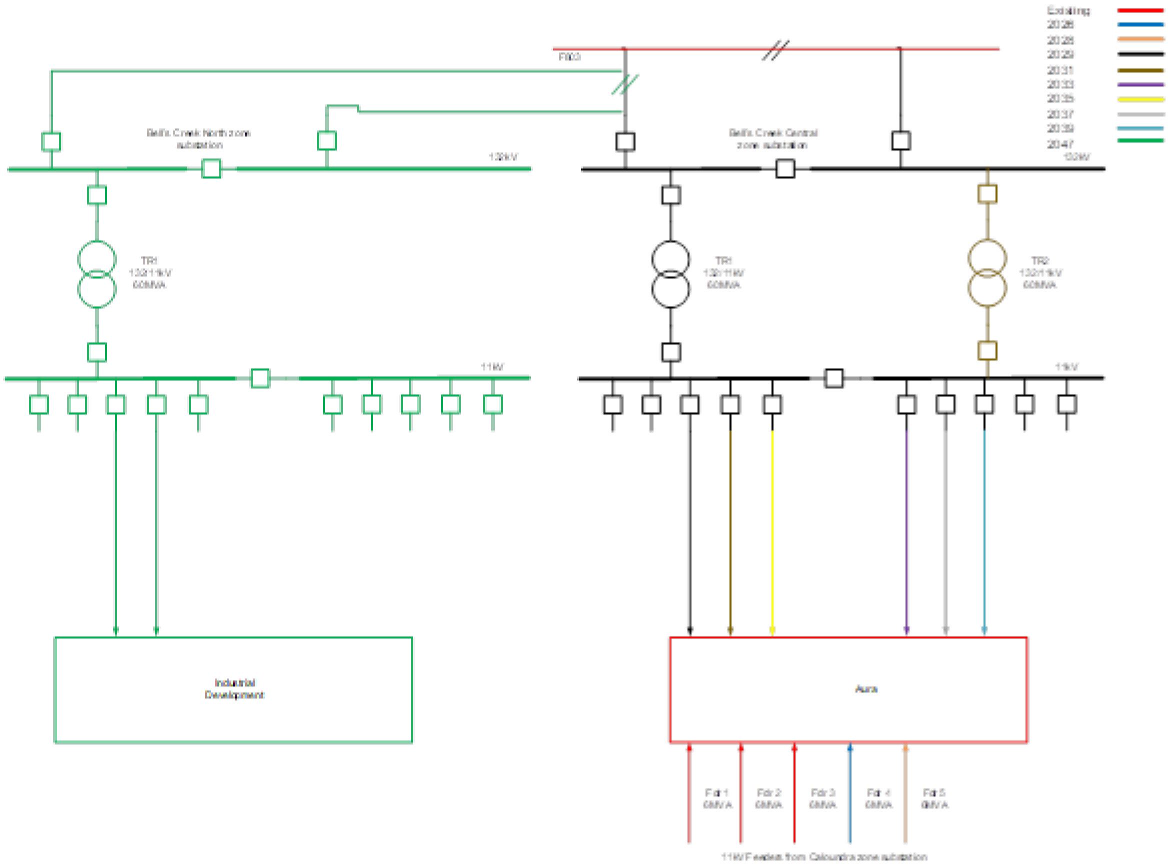

Figure 14: Proposed network arrangement under option 1

Option 2: Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment

This option involves supplying the Aura subdivision and surrounding area with 11kV feeders from a new substation at Bell's Creek central.

The works required to implement this option are:

- Establish Bell's Creek Central 132/11kV zone substation in 2026 with the following:
  - single 132/11kV transformer,
  - associated switchgear,
  - 13km of 132kV overhead double circuit line;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2029 at Bell's Creek Central;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $60.8 million ± 40% (2026)
- Estimated initial operating cost per annum: $301,171 (2026)

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

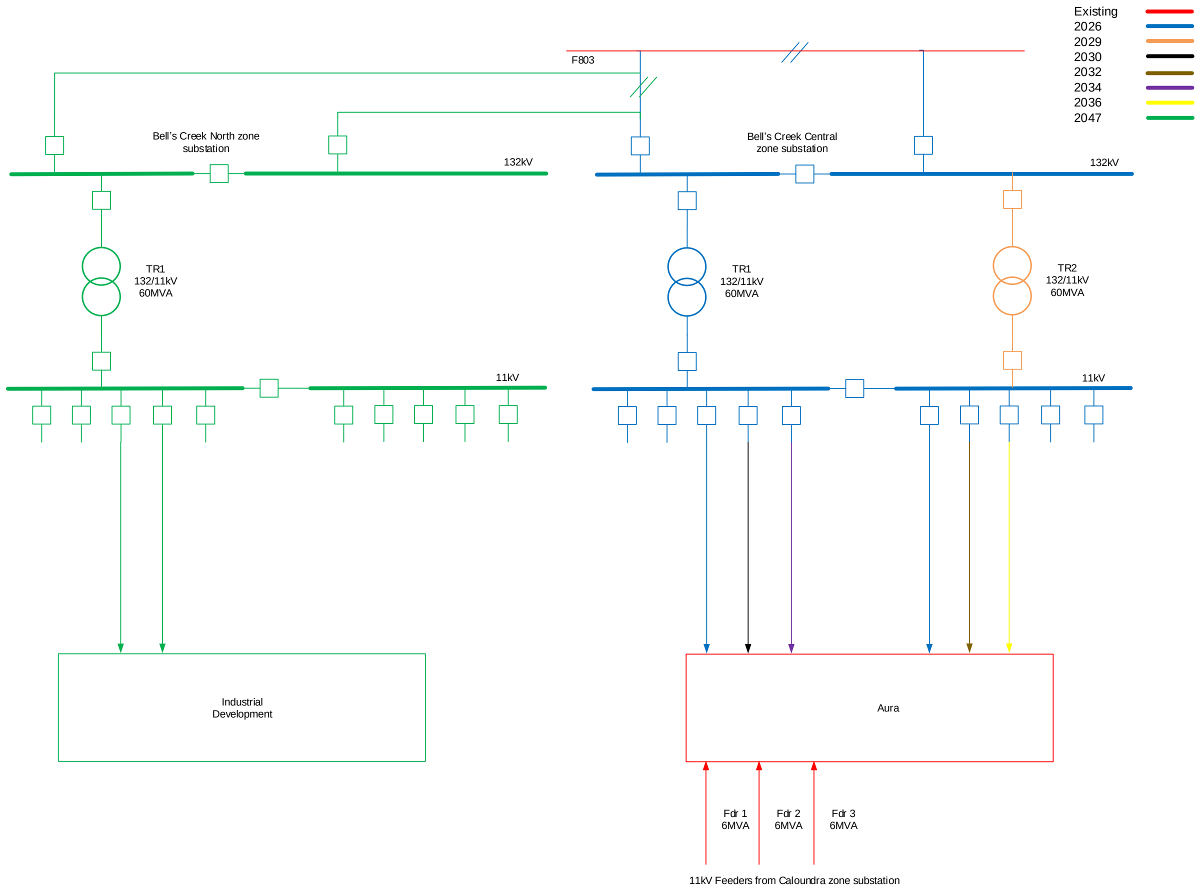

Figure 15: Proposed network arrangement under option 2

Option 3: Supply New Demand with 11kV Feeders from SSCLD and Establish 132kV Feeders, then Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment

This option involves establishing the 132kV double circuit line to Bell's Creek central and utilising it only when required at 132kV. This option de-risks the later construction of underground 132kV. An 11kV feeder from Caloundra will be established to supply the Aura subdivision and surrounding area to delay the establishment of the Bell's Creek Central substation.

The works required to implement this option are:

- Establish 13km of 132kV overhead double circuit line and one 11kV feeder to from Caloundra 11kV in 2026;
- Establish Bell's Creek Central 132/11kV zone substation in 2028 with the following:
    - single 132/11kV transformer,
    - associated switchgear,
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2030 at Bell's Creek Central;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth
- Estimated initial capital cost: $41 million ± 40% (2026)
- Estimated initial operating cost per annum: $179,132 (2026)

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

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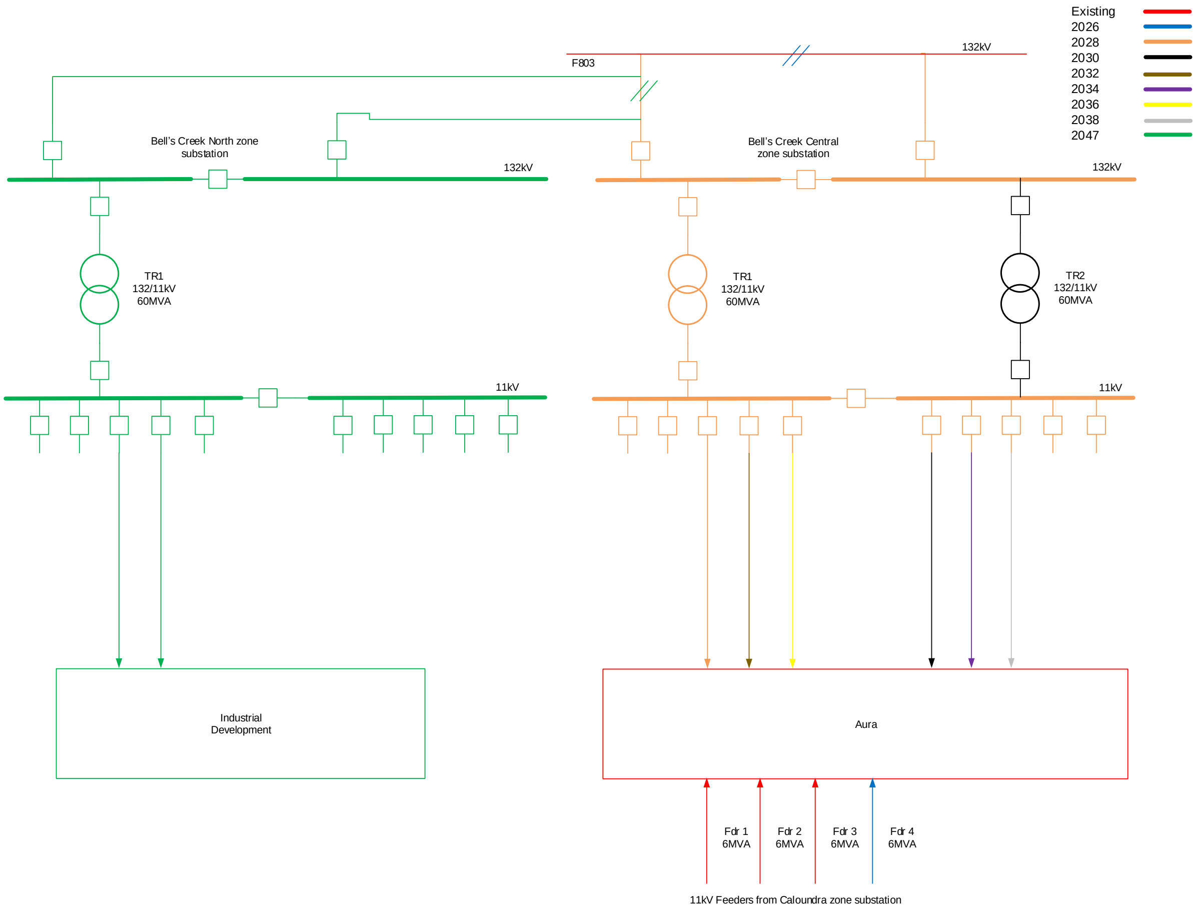

Figure 16: Proposed network arrangement under option 3

Option 4: Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek North Establishment

This option involves establishing a new substation at Bell's Creek North to supply the Aura subdivision and surrounding area.

The works required to implement this option are:

- Establish Bell's Creek North 132/11kV zone substation in 2026 with the following:
    - single 132/11kV transformer,
    - associated switchgear,
    - 8km of 132kV overhead double circuit line;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2029 at Bell's Creek North;
- Establish Bell's Creek Central 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $57.1 million ± 40% (2026)
- Estimated initial operating cost per annum: $324,213 (2026)

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

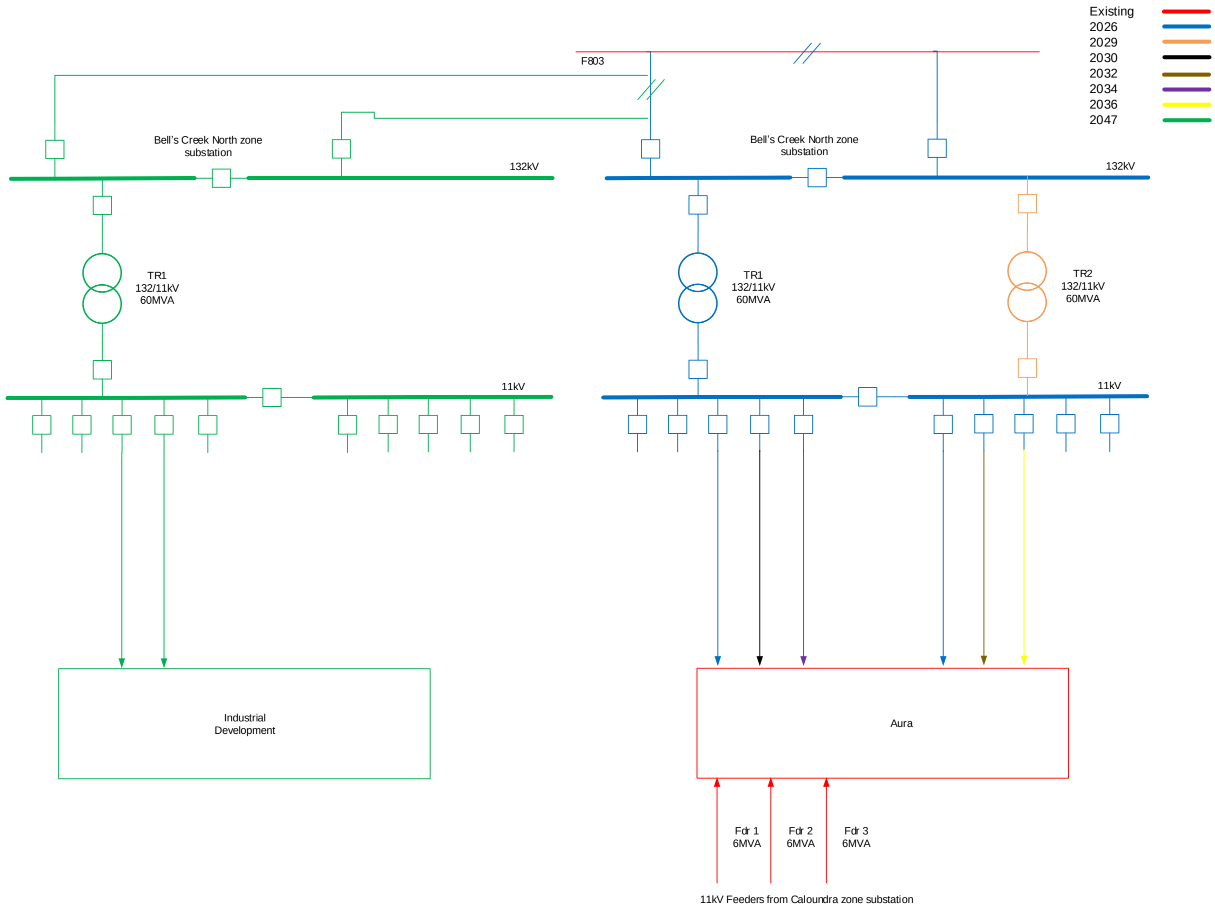

Figure 17: Proposed network arrangement under option 4

Option 5: Supply New Demand with 33kV Feeders from Meridan Plains Establishment to Bell's Creek Central Establishment

This option involves establishing a new 132/33kV substation at Meridan Plains and a new 33/11kV substation at Bell's Creek central.

The works required to implement this option are:

- Establish Meridan Plains 132/33 kV zone substation in 2026 with the following:
  - single 132/33kV transformer,
  - associated switchgear,
  - 13km of 33kV overhead double circuit line to Bell's Creek Central;
- Establish Bell's Creek central 33/11kV zone substation in 2026 with the following:
  - single 33/11kV transformer,
  - associated switchgear;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/33kV and 33/11kV transformer in 2029 at Meridan Plains and Bell's Creek Central respectively;
- Establish Bell's Creek North 33/11kV zone substation with a single 33/11kV transformer in 2040 and a second 33/11kV transformer in 2044 based on continued demand growth.
- Estimated initial capital cost: $53.6 million ± 40% (2026)
- Estimated initial operating cost per annum: $350,494 (2026)

A schematic diagram of the proposed solution is shown in Figure 18 below.

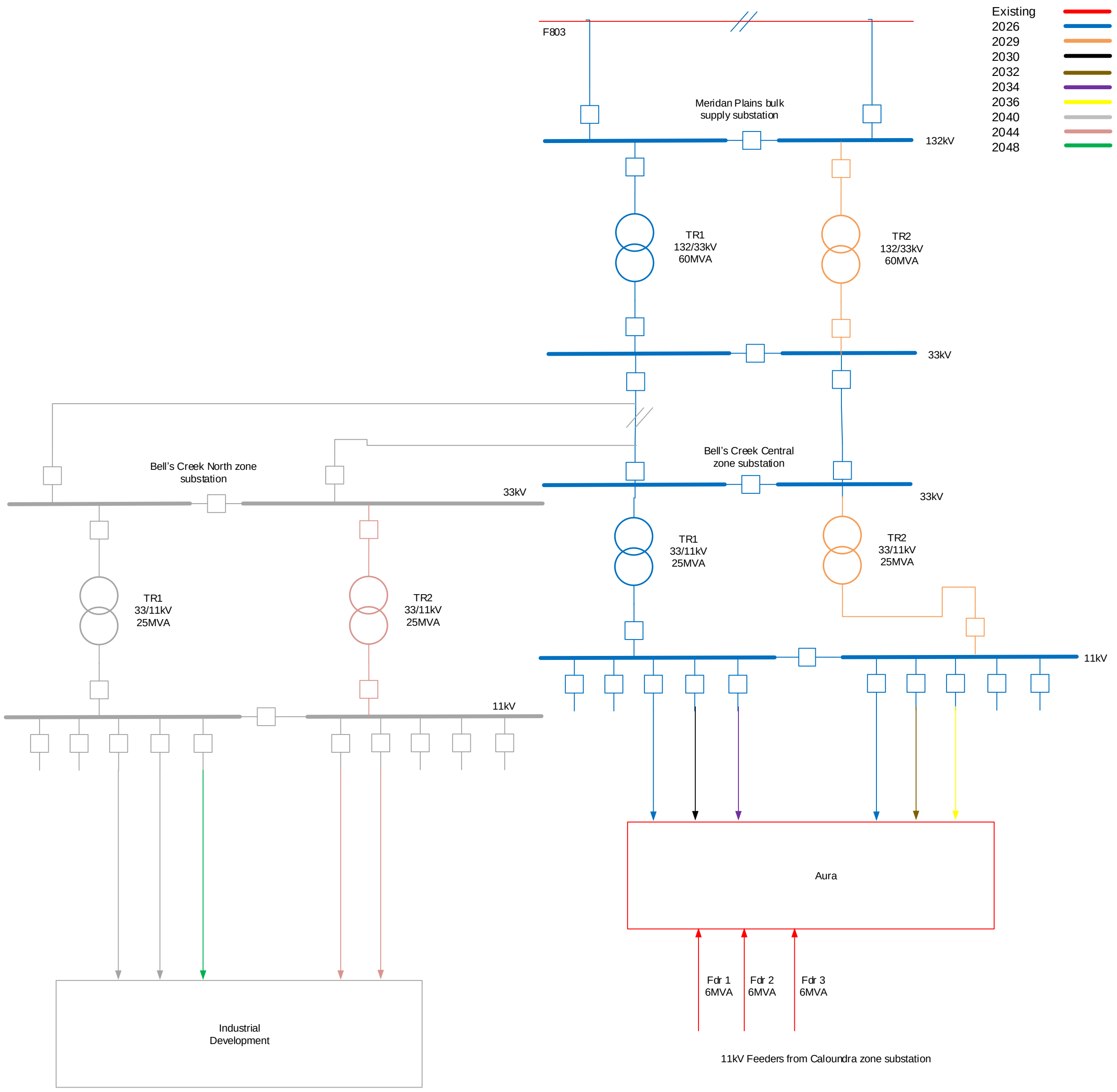

Figure 18: Proposed network arrangement under option 5

Option 6: Supply New Demand with 33kV Feeders from Meridan Plains (132/33/11kV) Establishment to Bell's Creek Central Establishment

This option involves establishing the 132kV double circuit line to Bell's Creek central and utilising it only when required at 132kV. This option de-risks the later construction of underground 132kV. An 11kV feeder from Caloundra will be established to supply the Aura subdivision and surrounding area to delay the establishment of the Bell's Creek Central substation.

The works required to implement this option are:

- Establish Meridan Plains Bulk supply substation in 2026 with the following:
    - single multivoltage 132/33/11kV transformer (Big Bertha),
    - associated switchgear,
    - 4 voltage regulators at Aura,
- 13km of 33kV overhead double circuit line to Aura (utlizied at 11kV);
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/33/11kV Big Bertha transformer at Meridan Plains in 2028;
- Establish Bell's Creek Central 33/11kV zone substation in 2031 with the following:
    - two 33/11kV transformers,
    - associated switchgear;
- Establish Bell's Creek North 33/11kV zone substation with a single 33/11kV transformer in 2040 and a second 33/11kV transformer in 2044 based on continued demand growth.
- Estimated initial capital cost: $43.9 million ± 40% (2026)
- Estimated initial operating cost per annum: $243,858 (2026)

A schematic diagram of the proposed solution is shown in Figure 19 below.

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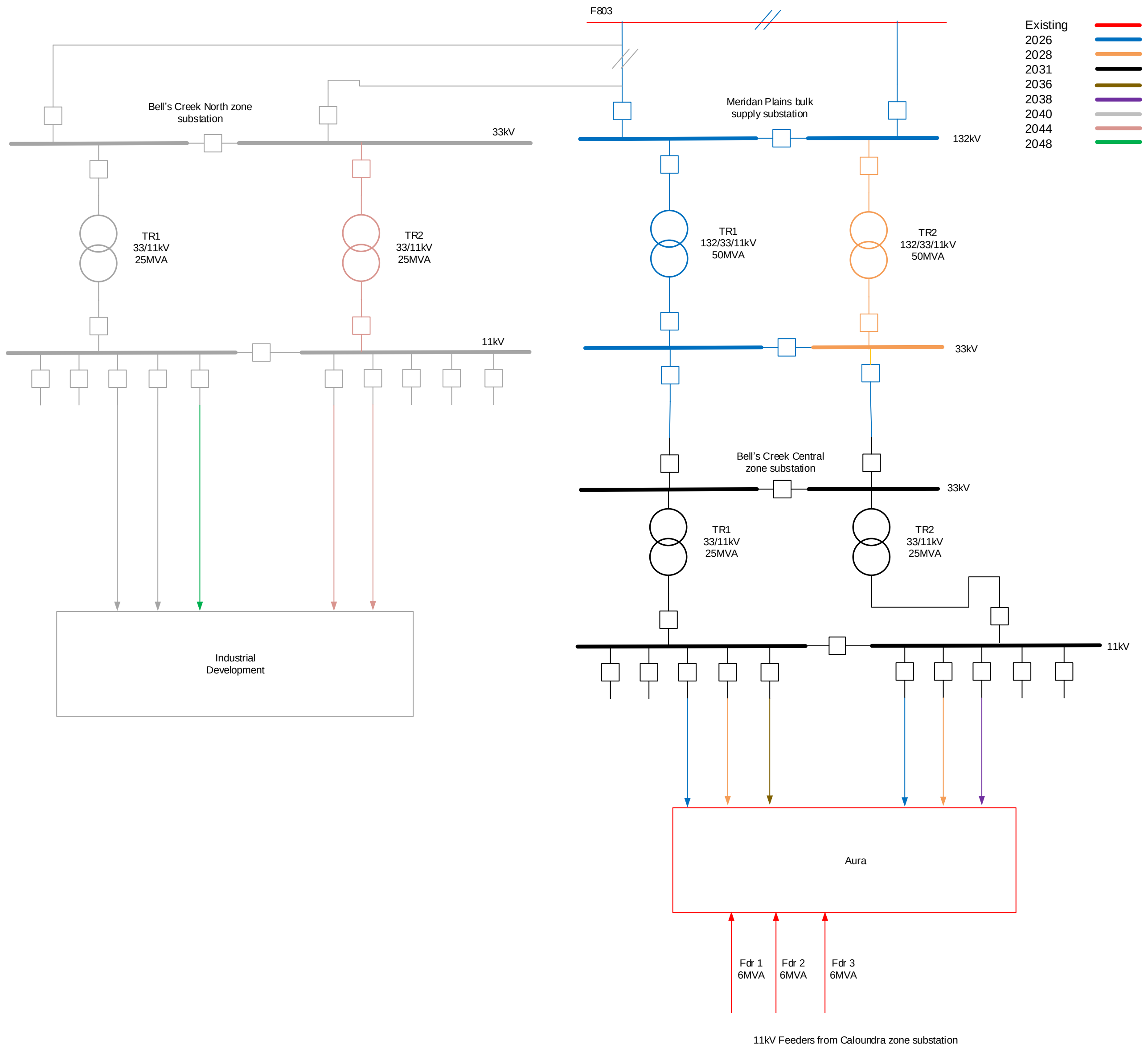

Figure 19: Proposed network arrangement under option 6

Option 7: Supply New Demand with 33kV Feeders from Meridan Plains (132/33kV, 33/11kV) Establishment to Bell's Creek Central Establishment

This option involves establishing a new 132/11kV and 33/11kV substation at Meridan Plains and establishing the 33kV double circuit line to Bells Creek central and utilising it initially at 11kV to supply the Aura subdivision and surrounding area. This option de-risks the later construction of underground 33kV by constructing it in 2026 and utilising it at 33kV only when required in 2031.

The works required to implement this option are:

- Establish Meridan Plains bulk supply substation in 2026 with the following:
  - single 132/33kV transformer,
  - single 33/11kV transformer,
  - 4 voltage regulators at Aura,
- 13km of 33kV overhead double circuit line to Aura (utlizied at 11kV);
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/33kV transformer at Meridan Plains in 2028;
- Establish the 2nd 33/11kV transformer at Bell's Creek Central in 2028;
- Establish Bell's Creek Central 33/11kV zone substation in 2031 with the following:
  - reuse the two 33/11kV transformers from Meridan Plains
  - associated switchgear;
- Establish Bell's Creek North 33/11kV zone substation with a single 33/11kV transformer in 2040 and a second 33/11kV transformer in 2044 based on continued demand growth.
- Estimated initial capital cost: $44.2 million ± 40% (2026)
- Estimated initial operating cost per annum: $243,858 (2026)

A schematic diagram of the proposed solution is shown in Figure 20 below.

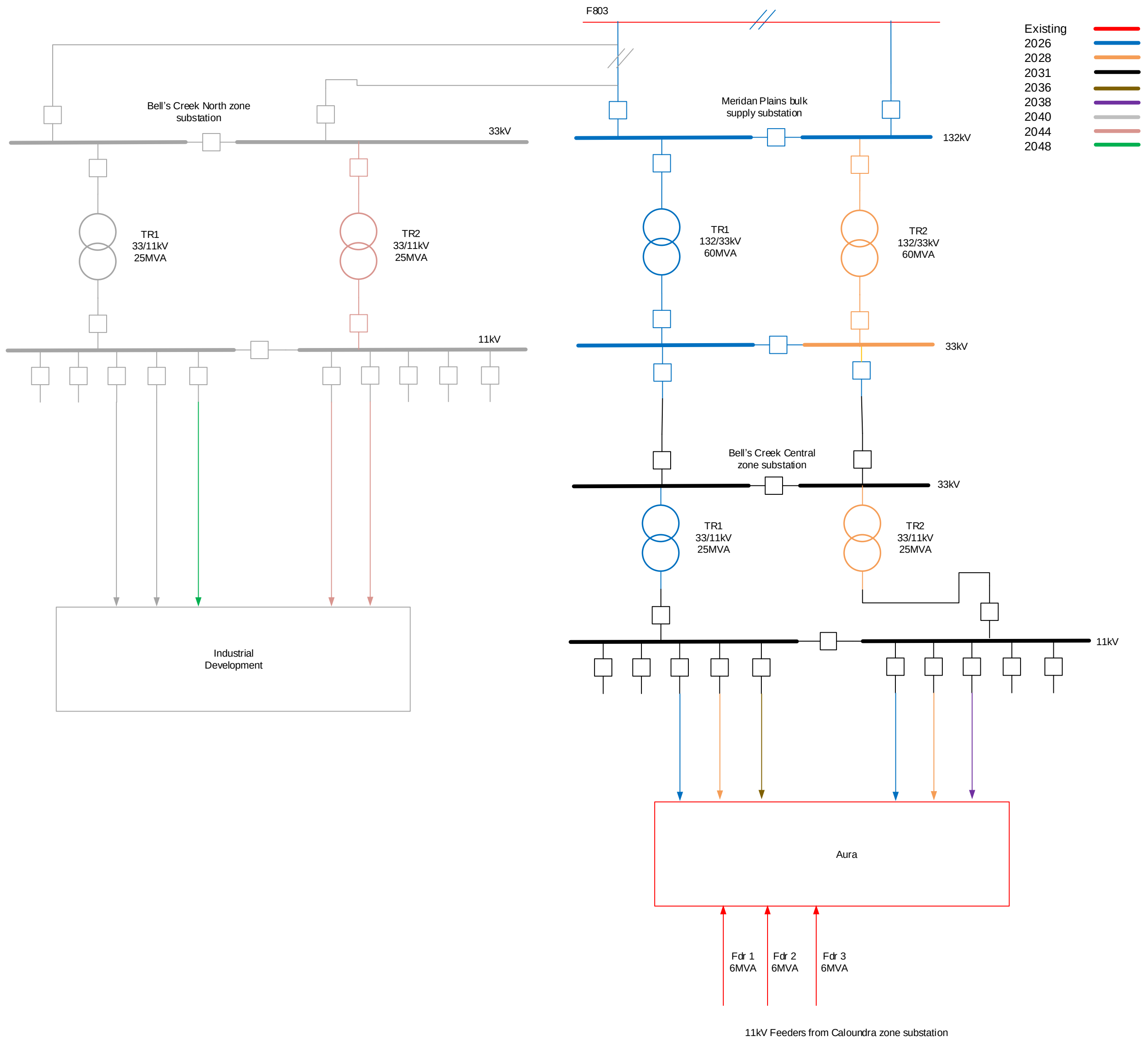

Figure 20: Proposed network arrangement under option 7

Option 8: Supply New Demand with 132kV Feeders (Tee off at Mark Rd East) to Bell's Creek Central Establishment

This option involves establishing a new substation at Bell's Creek Central to supply the Aura subdivision and surrounding area. This option is similar to Option 2.

The works required to implement this option are:

- Establish Bell's Creek Central 132/11kV zone substation in 2026 with the following:
  - single 132/11kV transformer,
  - associated switchgear,
  - 7km of 132kV double circuit line (1km OH, 6km UG) from Mark Rd East;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2029 at Bell's Creek North;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: \$62.7 million ± 40% (2026)
- Estimated initial operating cost per annum: \$301,171 (2026)

A schematic diagram of the proposed solution is shown in Figure 21 below.

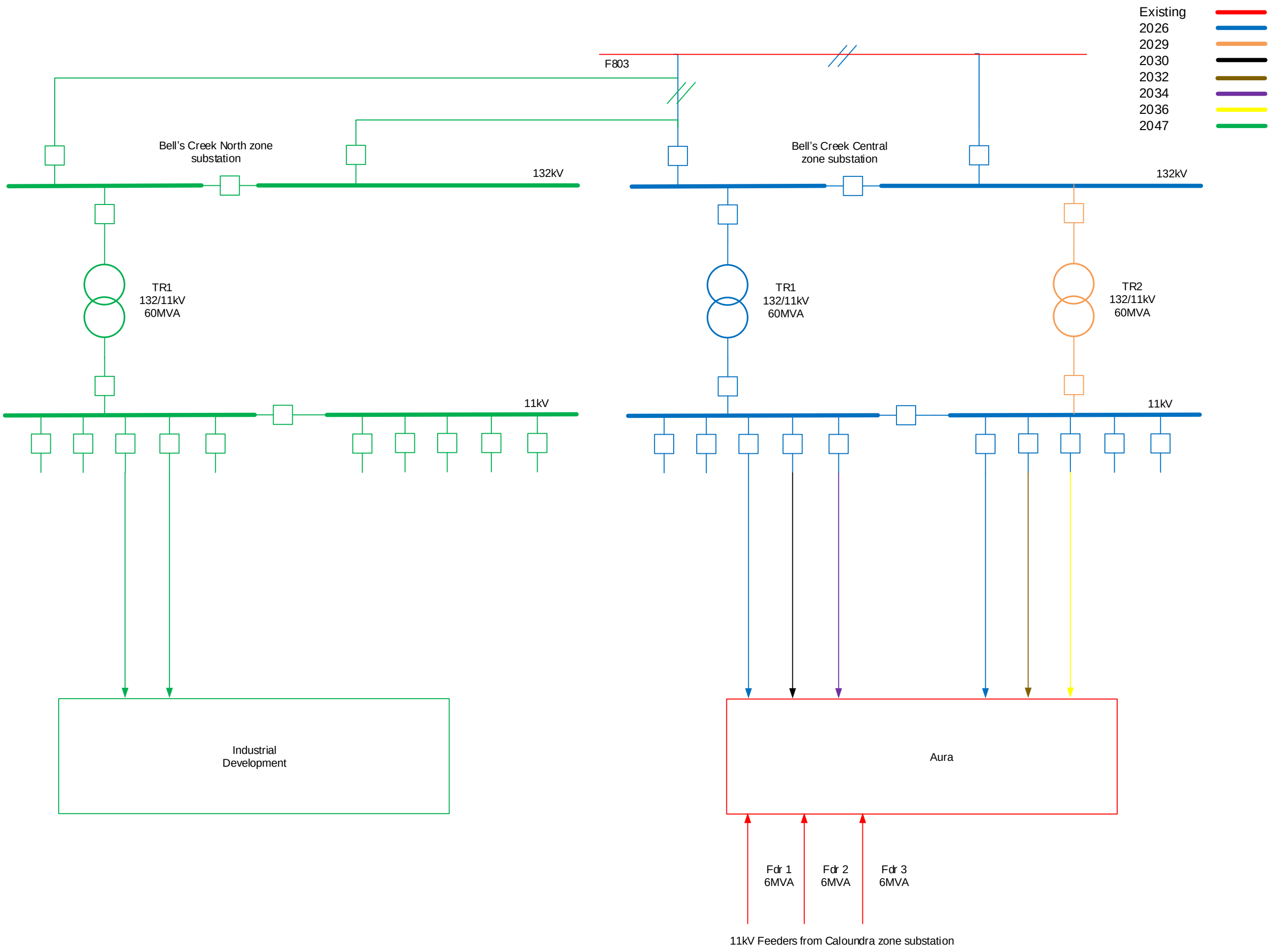

Figure 21: Proposed network arrangement under option 8

Option 9: Supply New Demand with 132kV Feeders from Caloundra Substation to Bell's Creek Central Establishment

This option involves establishing a new 132kV double circuit line from Caloundra Substation and utilising it initially at 11kV to supply the Aura subdivision and surrounding area. This option is similar to Option 1 where the construction of Bell's Creek Central establishment is deferred and constructed when required in 2029.

The works required to implement this option are:

- Establish 9km of 132kV double circuit line (1km OH, 8km UG) from SSCLD in 2026;
- Establish Bell's Creek Central 132/11kV zone substation in 2029 with the following:
    - two 132/11kV transformers,
    - associated switchgear;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $50.9 million ± 40% (2026)
- Estimated initial operating cost per annum: $150,552 (2026)

A schematic diagram of the proposed solution is shown in Figure 22 below.

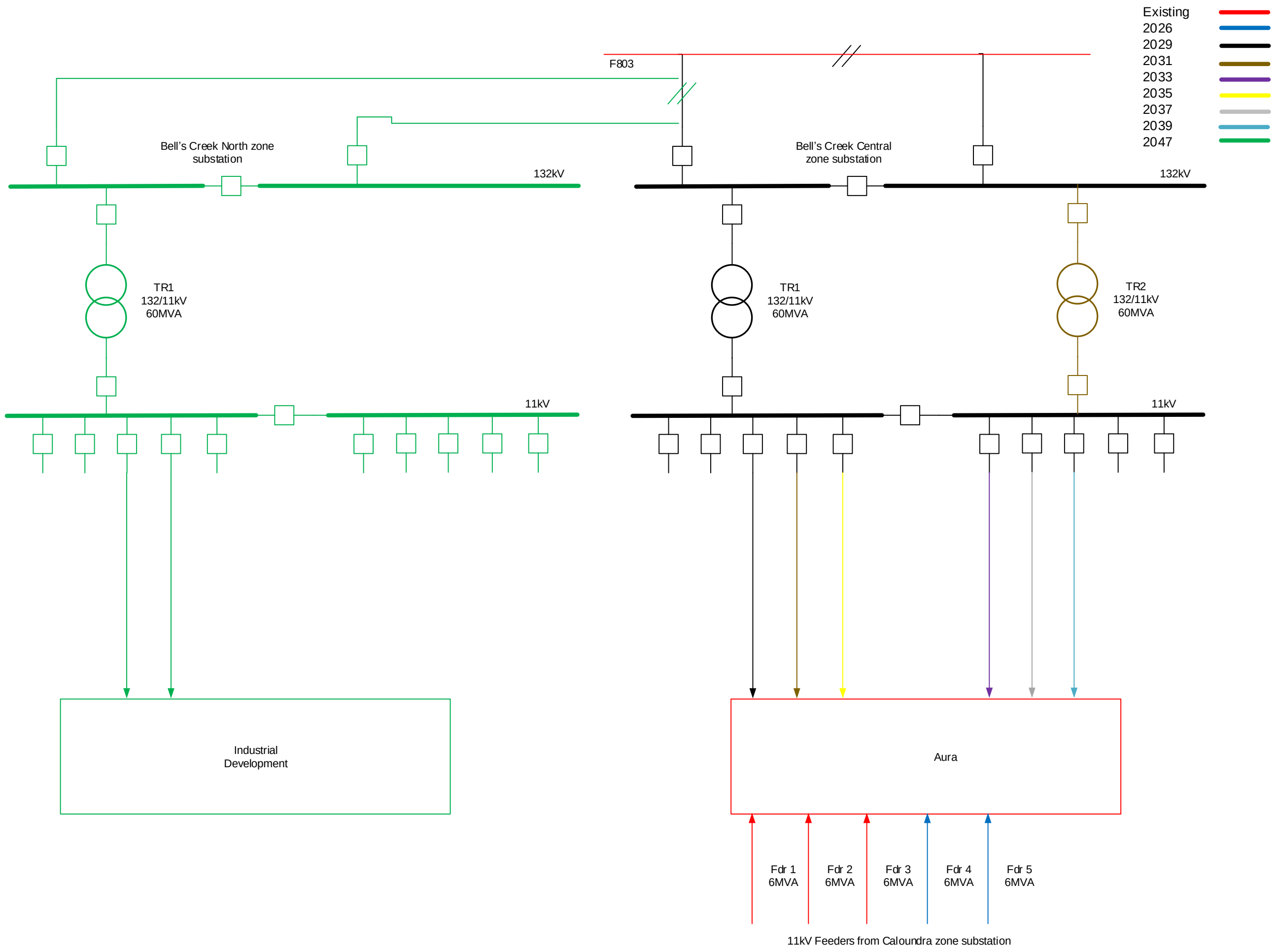

Figure 22: Proposed network arrangement under option 9