Regulatory Investment Test for Distribution (RIT-D)

Reliability Corrective Action
The Pimpama-Coomera Network Area

Draft Project Assessment Report

29 May 2026

energex
Part of Energy Queensland

INTRODUCTION

Purpose

The National Electricity Rules (NER) require that, subject to certain exclusions, distribution network service providers who are looking to address an identified need, by investing in the network, must apply the regulatory investment test for distribution (RIT-D). This Draft Project Assessment Report (DPAR) has been prepared by Energex Limited (Energex) in accordance with the requirements of clause 5.17.4(j) of the NER and is published in accordance with 5.17.4(i) of the NER.

In preparing this DPAR, Energex is required to consider reasonable future scenarios. With respect to major customer loads and generation, Energex has 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.

About Energex

Energex Limited (Energex) is a subsidiary of Energy Queensland Limited and manages the electricity distribution network in the growing region of South-East Queensland which includes the major urban areas of Brisbane, Gold Coast, Sunshine Coast, Logan, Ipswich, Redlands and Moreton Bay. Our electricity distribution area runs from the NSW border north to Gympie and west to the base of the Great Dividing Range.

Our electricity network consists of approximately 57,000 kilometres of powerlines and 450,000 power poles, along with associated infrastructure such as major substations and power transformers.

Today, we provide distribution services to more than 1.5 million domestic and business connections, delivering electricity to a population base of around 4 million people.

CONTENTS

1 ASSUMPTIONS AND TECHNICAL CHARACTERISTICS OF THE IDENTIFIED NEED

1.1 Existing supply arrangement

1.1.1 Geographic Region

Coomera zone substation (SSCMA) and Pimpama East zone substation (SSPPE) are located in the northern side of the Gold Coast City Council area, approximately 18km north-west from Southport.

Coomera and Pimpama have been designated as a high to medium density residential zone in the Gold Coast City Plan. Growth data from the 2021 census shows that, from 2011 to 2021, the number of private dwellings in Pimpama grew from 3,957 to 8,499. The area continues to see strong population growth and economic development as there are still pockets of undeveloped land within the area. This is reflected in the significant increase in the load forecast, causing network limitations in the area.

The geographical location of Energex's sub-transmission network and substations in the area is shown in Figure 1.

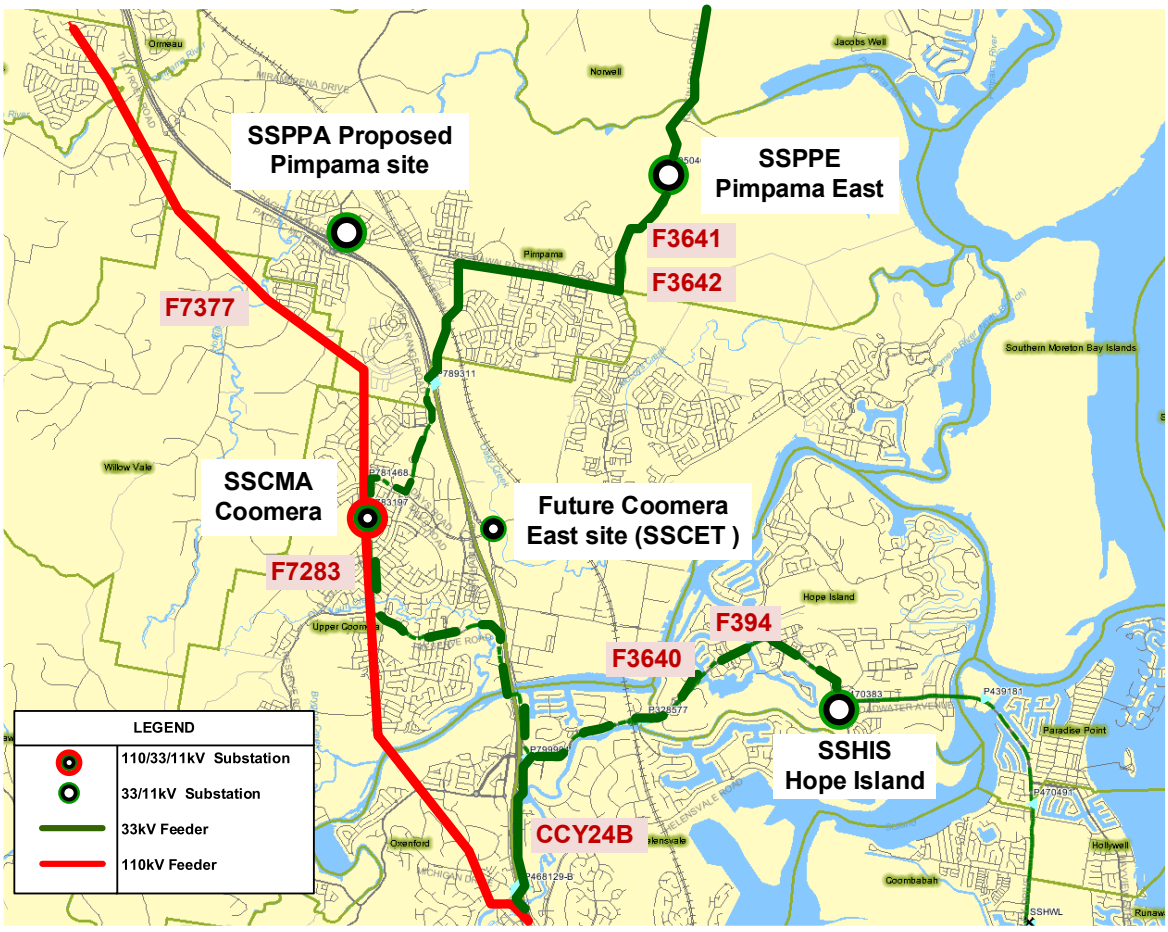


Figure 1: Existing network arrangement (geographic view)

1.1.2 Overview of Existing System

SSCMA is a 110/33/11kV bulk supply and zone substation with 2 x 80MVA, 110/33kV and 2 x 25MVA, 33/11kV transformers. The SSCMA 11kV supply area provides electricity supply to approximately 11,990 predominantly residential customers in the Upper Coomera, Coomera, Pimpama, and Willow Vale areas.

SSPPE is a 33/11kV substation with 2 x 25MVA transformers supplied from SSCMA BS via 33kV feeders F3641 and F3642. SSPPE provides electricity supply to approximately 14,017 predominantly residential customers in the Pimpama, Coomera, Jacobs Well and Steiglitz areas.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2.

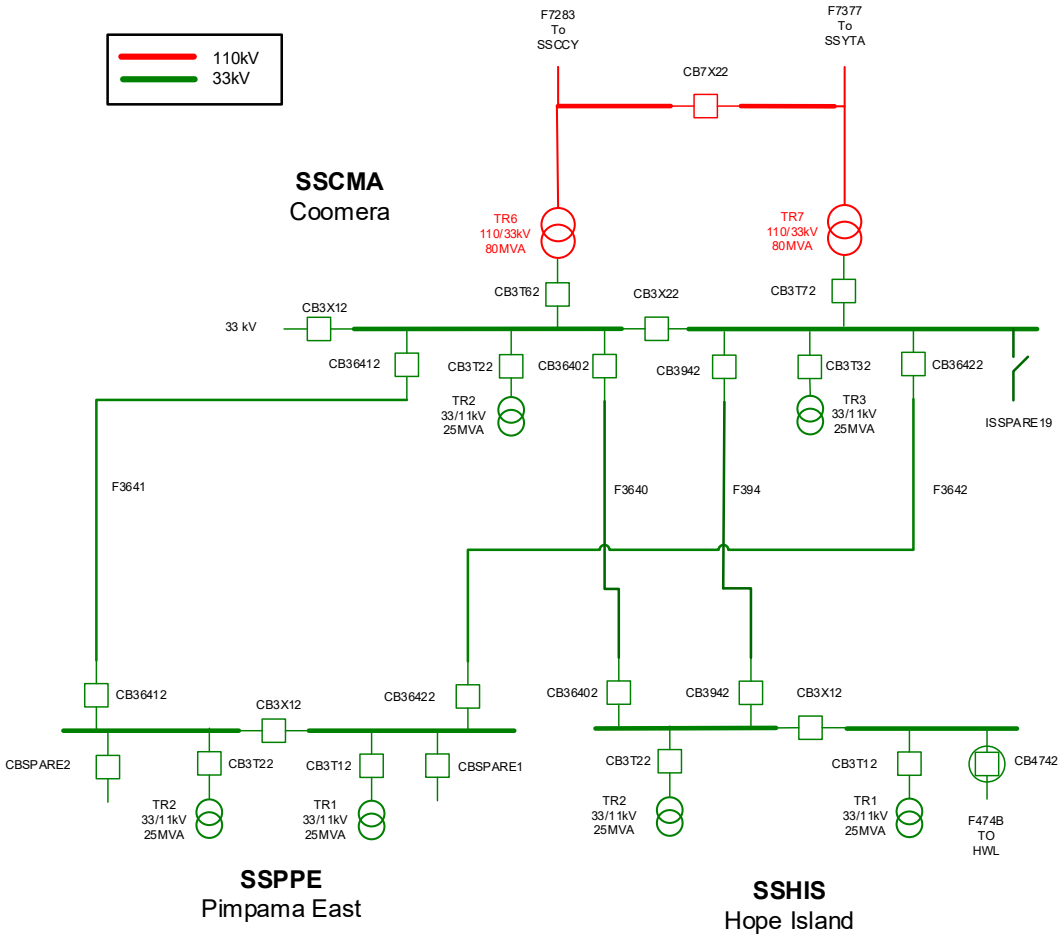


Figure 2: Existing sub-transmission network arrangement (schematic)

1.2 Size of load reduction or additional supply

To meet Energex's ongoing operational needs, any alternate solution must provide capacity or demand reduction to the distribution network as measured at the 11kV bus at SSPPE and SSCMA are shown on Table 1 and Table 2, respectively. This support must be available at short notice when called upon. The periods where this support may be required is from October to April of the following year.

Year	Max Demand Reduction (MVA)	Yearly (estimate)		Peak Day (estimate)	
		Energy Reduction (MWh)	Number of hours	Energy Reduction (MWh)	Number of hours
2027/28	6.2	27.5	8	16	4
2028/29	7.0	34	8.5	19.3	4
2029/30	7.8	40.8	9.5	22.4	4
2030/31	8.7	49.3	10.5	25.8	4
2031/32	9.7	58.5	11	29.4	4
2032/33	10.4	66.6	12	32.4	4
2033/24	11.2	74.9	13.5	35.2	4.5
2034/35	11.8	83.4	15	38.1	4.5

Table 1: Forecast size of load reduction or additional supply required at SSPPE

Year	Max Demand Reduction (MVA)	Yearly (estimate)		Peak Day (estimate)	
		Energy Reduction (MWh)	Number of hours	Energy Reduction (MWh)	Number of hours
2027/28	3.4	33.4	6	12.8	1
2028/29	8.0	110.4	30.5	32	1.5
2029/30	8.0	112.8	31.5	32	1.5
2030/31	8.0	126	36.5	32.7	1.5
2031/32	8.0	143.5	41.5	33.5	2
2032/33	8.0	160.6	48	34.4	2
2033/24	8.0	180.3	54.5	35.3	2
2034/35	8.0	201.5	59	36	2

Table 2: Forecast size of load reduction or additional supply required at SSCMA

1.3 Location

Whilst the locations where network support and load restoration capability will be measured / referenced is on the 11kV buses at SSPPE Pimpama East and SSCMA Coomera substations, alternative options may be located downstream of the reference buses.

1.4 Contribution to power system security or reliability

The solution must enable Energex to maintain a level of security that complies with the service safety net targets required under its Distribution Authority, which has specific outage restoration timeframe targets that Energex is required to achieve. Both SSPPE and SSCMA zone substations are classified as “Urban” for the purposes of the safety net. Details of the safety net targets are shown in Appendix A.

1.5 Contribution to power system fault levels

The solution must consider the fault level contribution to the network and include any mitigation works that are required due to a change in fault level. The maximum fault level on 33kV and 11kV network should not exceed 25kA and 13.1kA, respectively.

1.6 Operating profile

Full Annual Load Profile

The full annual load profiles for SSPPE and SSCMA over 2025 are shown in Figure 3. It can be noted that the peak load occurs during summer.

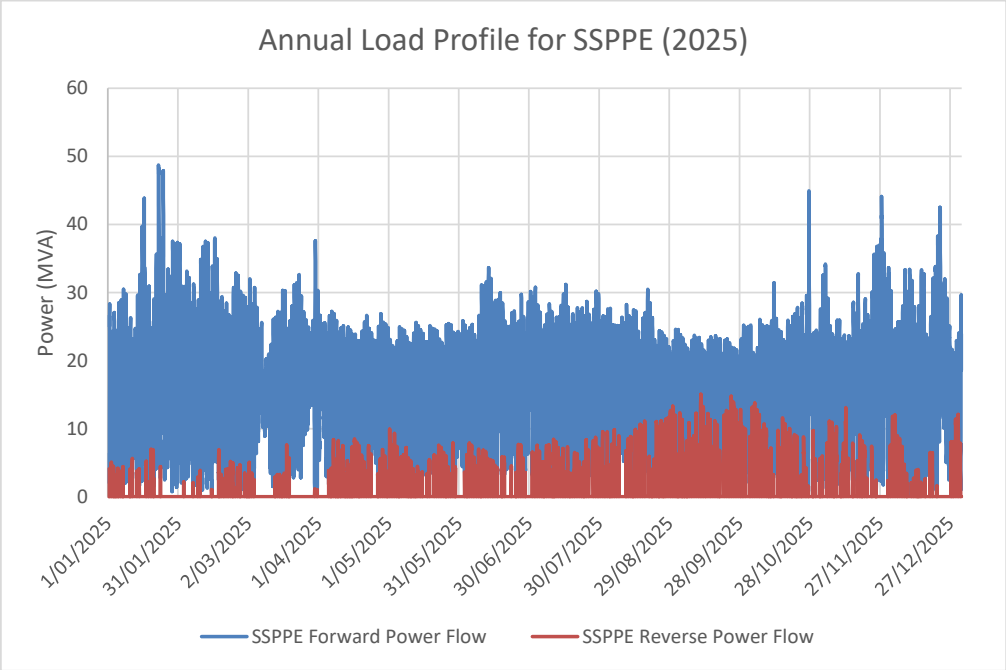


Figure 3: SSPPE Substation actual annual load profile

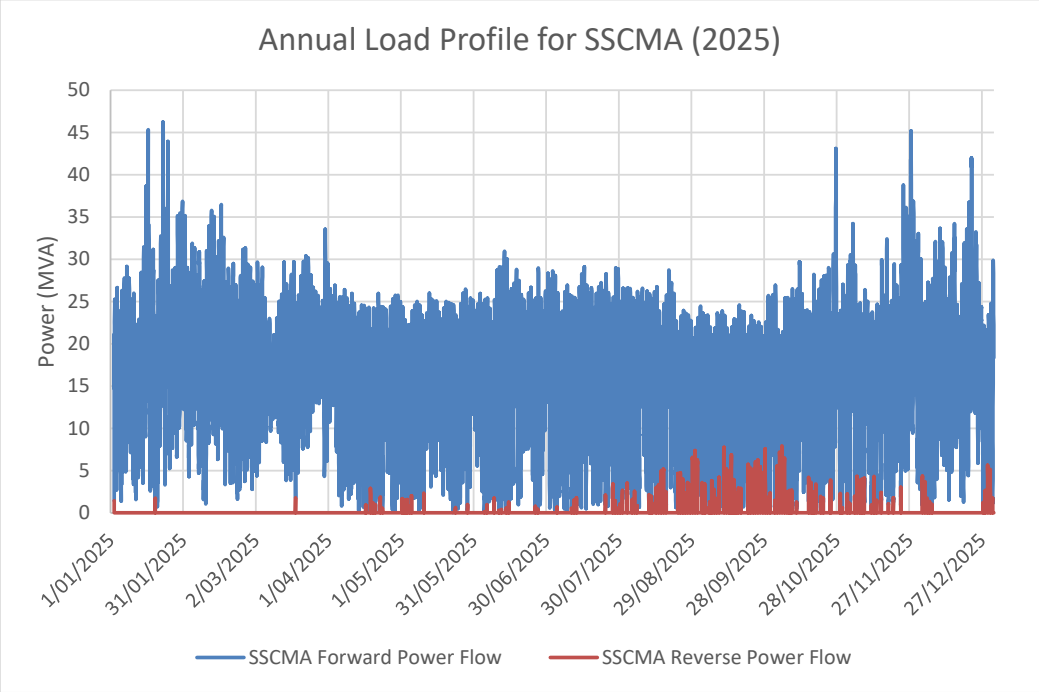


Figure 4: SSCMA Substation actual annual load profile

Load Duration Curve

The load duration curve for SSPPE in 2025 is shown in Figure 5.

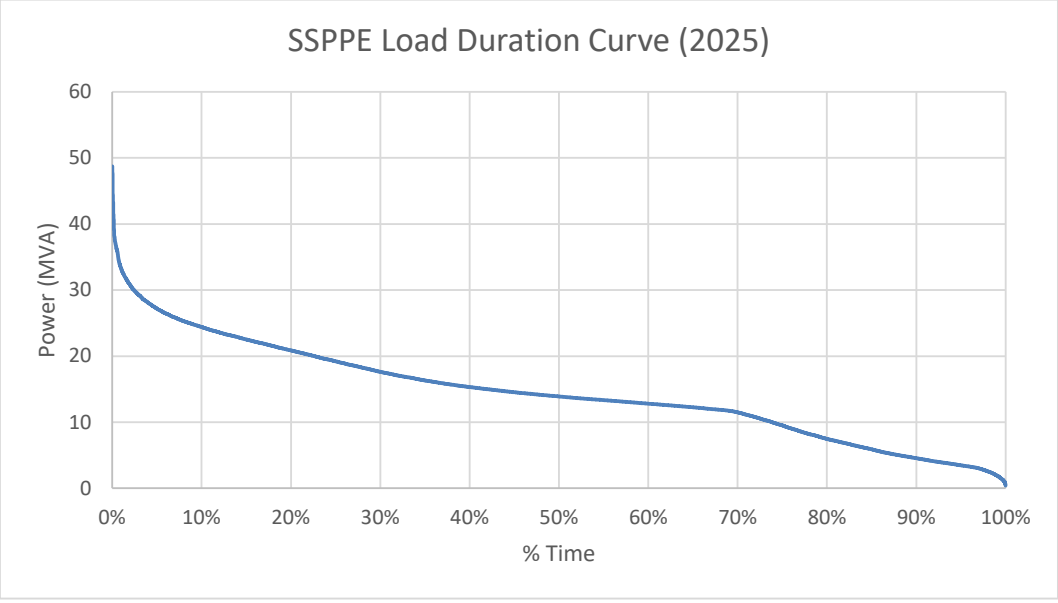


Figure 5: SSPPE Substation load duration curve

The load duration curve for SSCMA in 2025 is shown in Figure 6.

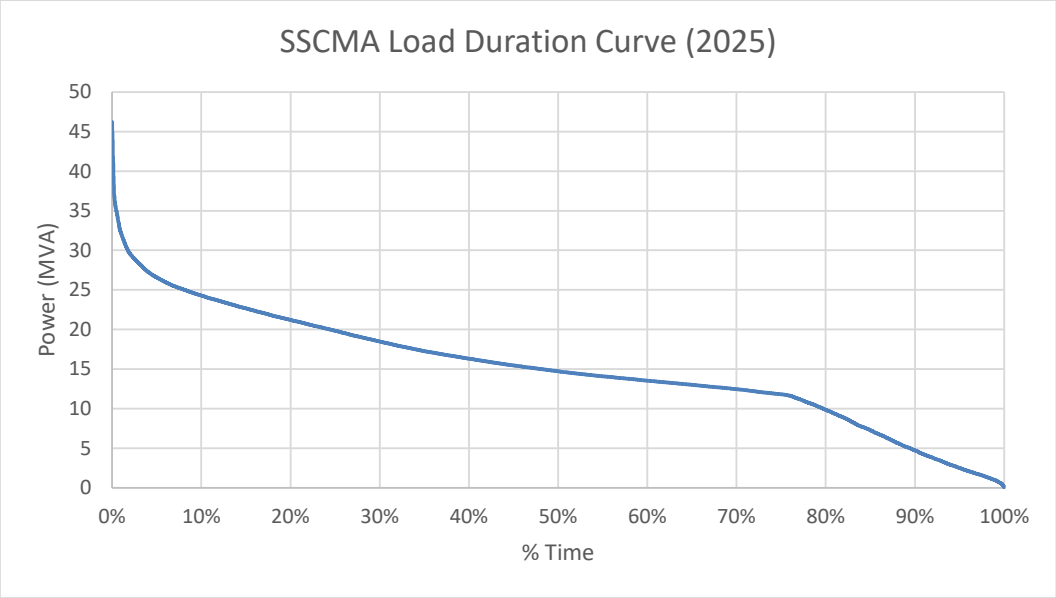


Figure 6: SSCMA Substation load duration curve

Average Peak Weekday Load Profile (Summer)

The daily load profiles for SSPPE and SSCMA on an average peak weekday during summer are illustrated below in Figure 7 and Figure 8. It can be noted that the summer peak loads at SSPPE and SSCMA are historically experienced from late afternoon to evening.

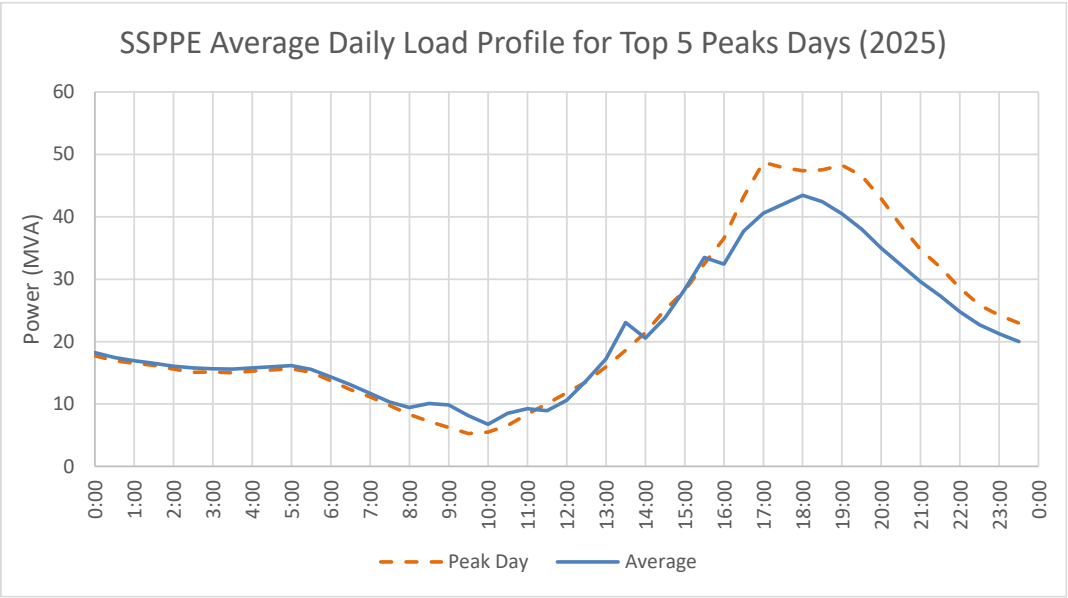


Figure 7: SSPPE Substation average peak weekday load profile (summer)

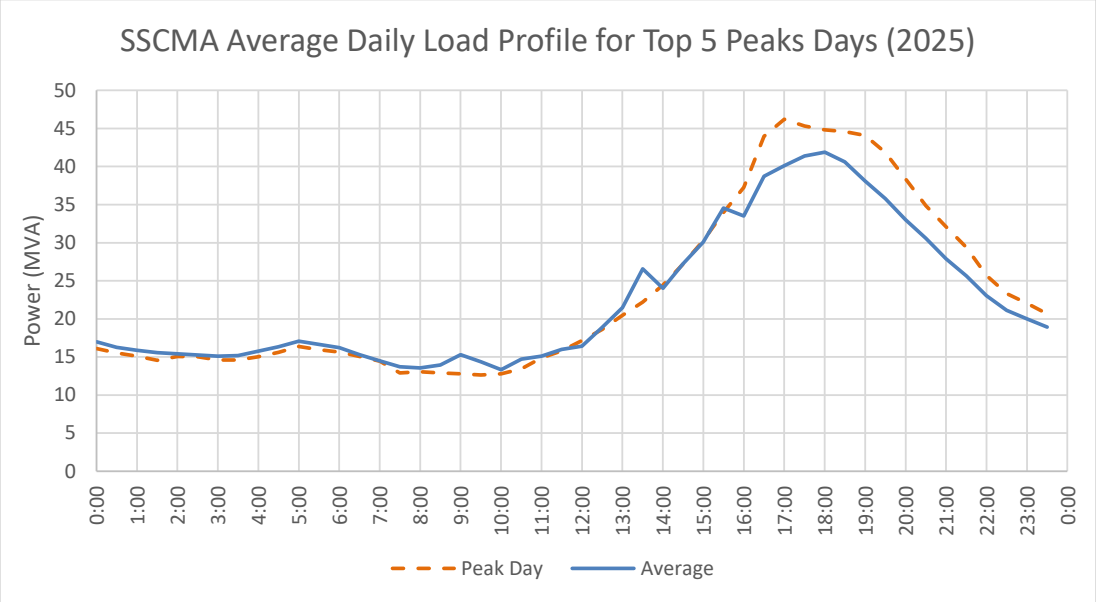


Figure 8: SSCMA Substation average peak weekday load profile (summer)

1.7 Forecast

The 10% PoE and 50 PoE% load forecasts for the base case load growth scenario for SSPPE is illustrated in Figure 9. The historical peak load for the past six years has also been included in the graph.

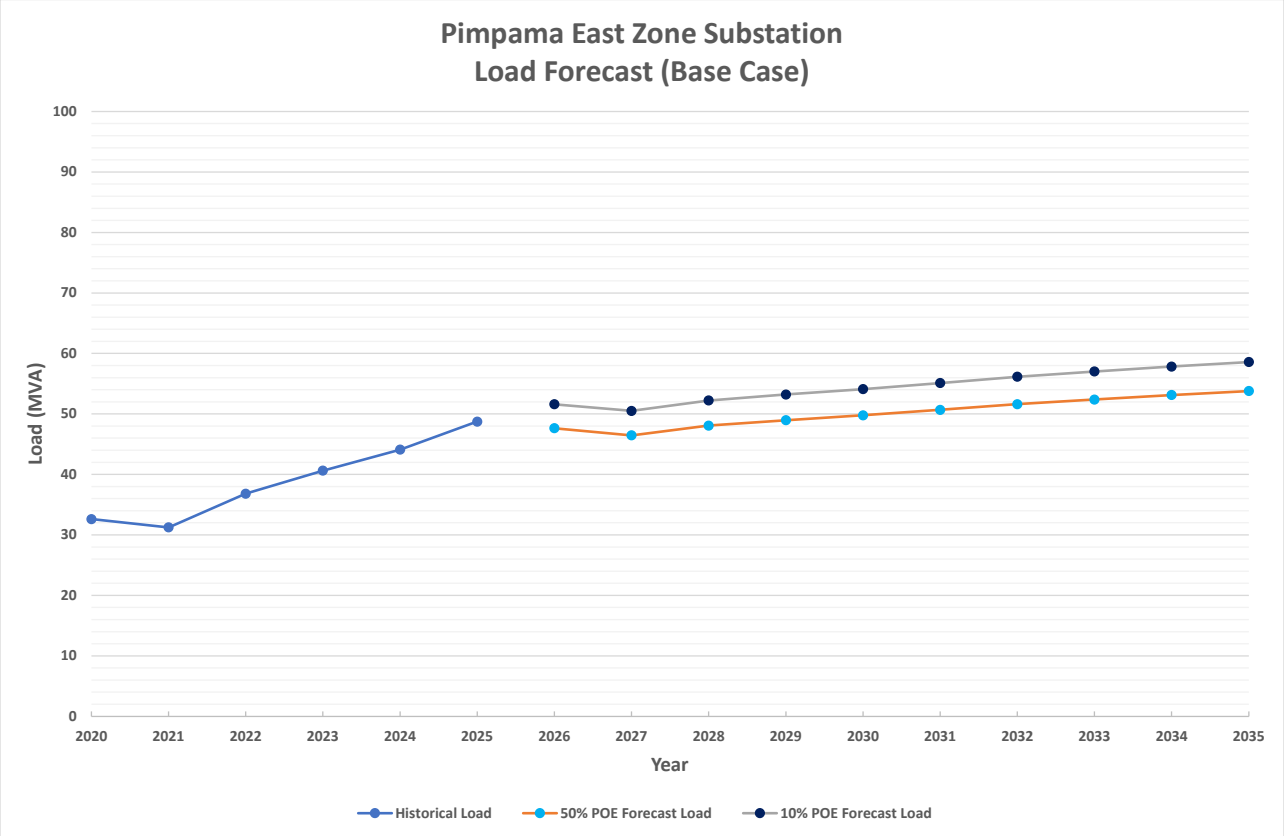


Figure 9: SSPPE Substation base case load forecast

The 10% PoE and 50 PoE% load forecasts for the base case load growth scenario for SSCMA is illustrated in Figure 10. The historical peak load for the past six years has also been included in the graph.

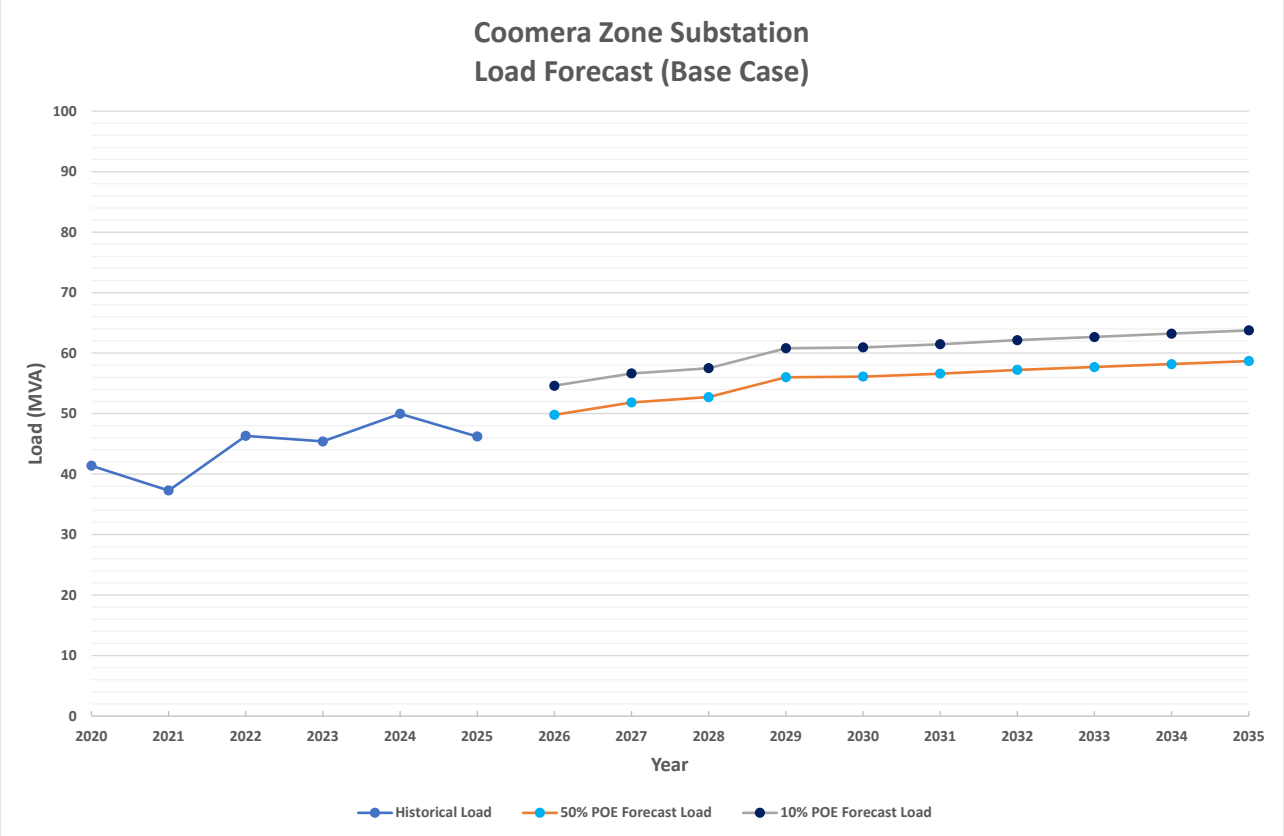


Figure 10: SSCMA Substation base case load forecast

2 IDENTIFIED NEED

The identified need is for reliability corrective action to ensure that reliability of supply and service obligations are maintained to customers in the Pimpama-Coomera network area. This is due to significant increase in load in this area, such that reasonable supply to customers cannot be maintained.

Under applicable regulatory instruments, Energex is required to connect new customers and maintain the reliability of supply to these customers (see below). To ensure that Energex can continue to meet these requirements, reliability corrective action is required.

Energex seeks to address the identified need by 2027/28 which is estimated to be the earliest date that the network option could be implemented. Energex estimates that reliability corrective action is required by 2027/28, otherwise it may breach its regulatory obligations, including:

- *National Energy Retail Law (Queensland)* – Under Part 3, Division 2, Energex has an obligation to provide a connection service for the premises of a customer who requests those services to be connected to the distribution system.
- Energex's Distribution Authority issued under the *Electricity Act 1994 (Qld)* – Under Clause 10, Energex is required to design, plan and operate its network to meet the service safety net, which aims to mitigate the risk of low probability-high consequence network outages to avoid unexpected customer hardship and/or significant community or economic disruption. The safety net has specific outage restoration timeframe targets that Energex is required to achieve. Details of the safety net targets are shown in Appendix A.

If Energex did not invest to address this identified need, it may result in a breach of these regulatory obligations, due to:

- Insufficient capacity from 2028 onwards at SSCMA limits Energex's ability to connect new customers to the distribution system. This would likely place Energex in breach of the *National Energy Retail Law (Queensland)* Part 3, Division 2.
- The failure of a transformer at SSPPE or SSCMA could result in 2,000-3,000 customers without power for a prolonged period. Electricity supply to these customers would likely not be able to be restored within the timeframes stipulated under Energex's safety net targets in its Distribution Authority.

Therefore, Energex considers that reliability corrective action in the Pimpama-Coomera area is necessary.

2.1 Associated Relevant Annual Deferred Augmentation Charge

A present value analysis of the costs associated with the preferred option show that there is a saving of approximately $0.916 million for each year the proposed augmentation cost is deferred.

3 SUBMISSIONS ON THE OPTIONS SCREENING REPORT

Consultation on the Options Screening Report closed on 4 April 2026. However, it is noted that that although no formal submissions were received, Energex is aware of some interest from the market for a non-network option. Engagement with Energex is ongoing, and any potential proponent is encouraged to enquire further and submit a proposal.

4 POTENTIAL CREDIBLE OPTIONS

4.1 Credible Options Identified

Energex has considered all options that could reasonably be classified as a credible option without bias to energy source, technology, ownership and whether it is a network option, a non-network option or a SAPS option.

As there were no formal submissions received in response to the Options screening Report, Energex is proceeding on the basis that there is no non-network option or a SAPS option that is a credible option or that forms a significant part of a credible option. However, as noted above, potential proponents are encouraged to enquire further and submit a proposal.

Energex has identified the below 3 potential credible options that are commercially and technically feasible and can be implemented in an appropriate timeframe to address the identified need.

4.1.1 Option A: Establish new 1 x 25MVA 33/11kV Pimpama Zone Substation (SSPPA)

This option would involve:

Establish a new 1 x 25MVA 33/11kV zone substation consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11kV protection panels, and associate plant, 1 x 25MVA 33/11kV transformer, cut in and out of existing 33kV feeder F3642 with a mix of 1.9kms of UG and 1.6kms of OH, establish new 4 x 11kV feeders from the new substation and reconfigure existing 11kV feeders at SSPPE and SSCMA by 2027.

Future Stage:

- Establishing 2nd 25MVA 33/11kV transformer, connected to the existing 11kV bus at SSPPA by 2032.
- Establishing a 2nd module and associated switchgear at SSPPA, consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11 kV protection panels, and associated plant, establish new 33kV & 11kV tie feeders between both modules and reconfigure existing 11kV feeders at SSPPA by 2037.

Figure 11 and Figure 12 provide geographic and schematic diagrams for Option A.

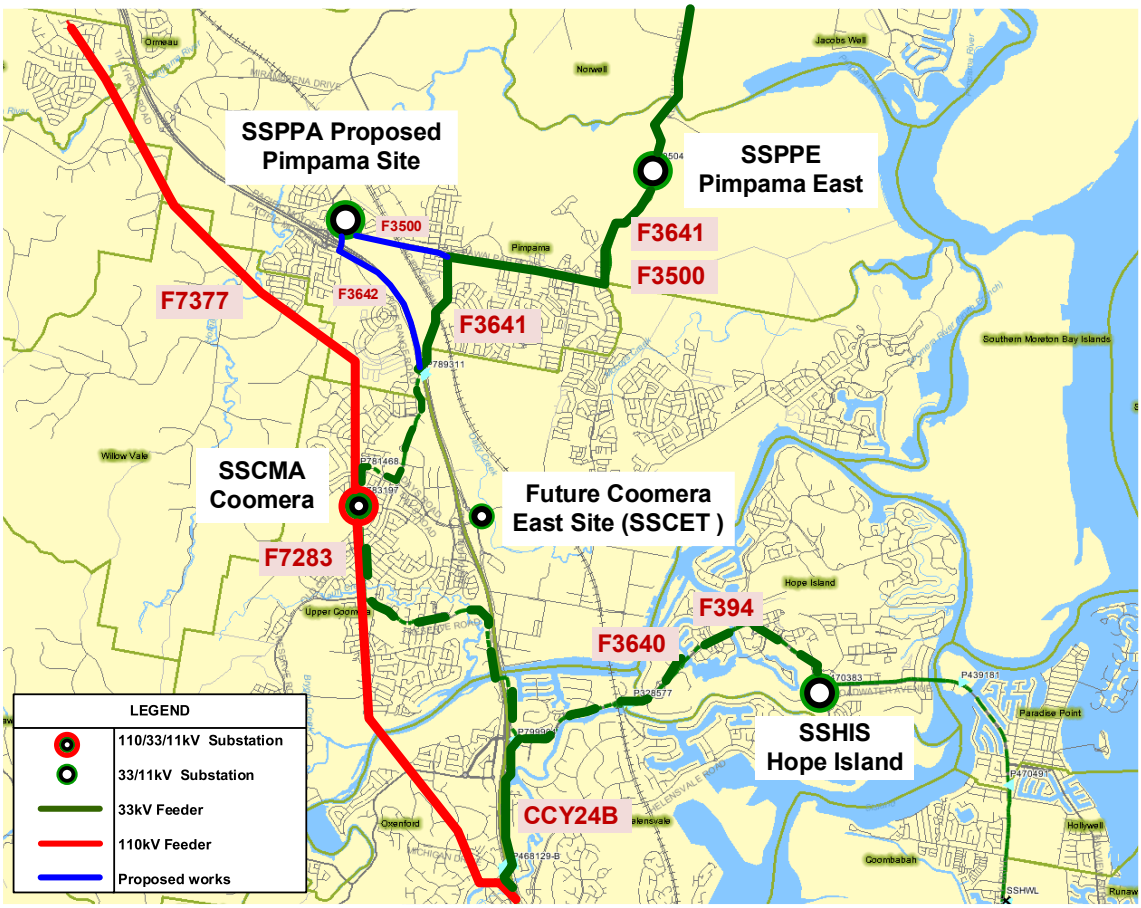


Figure 11: Proposed network arrangement - option A (geographic view)

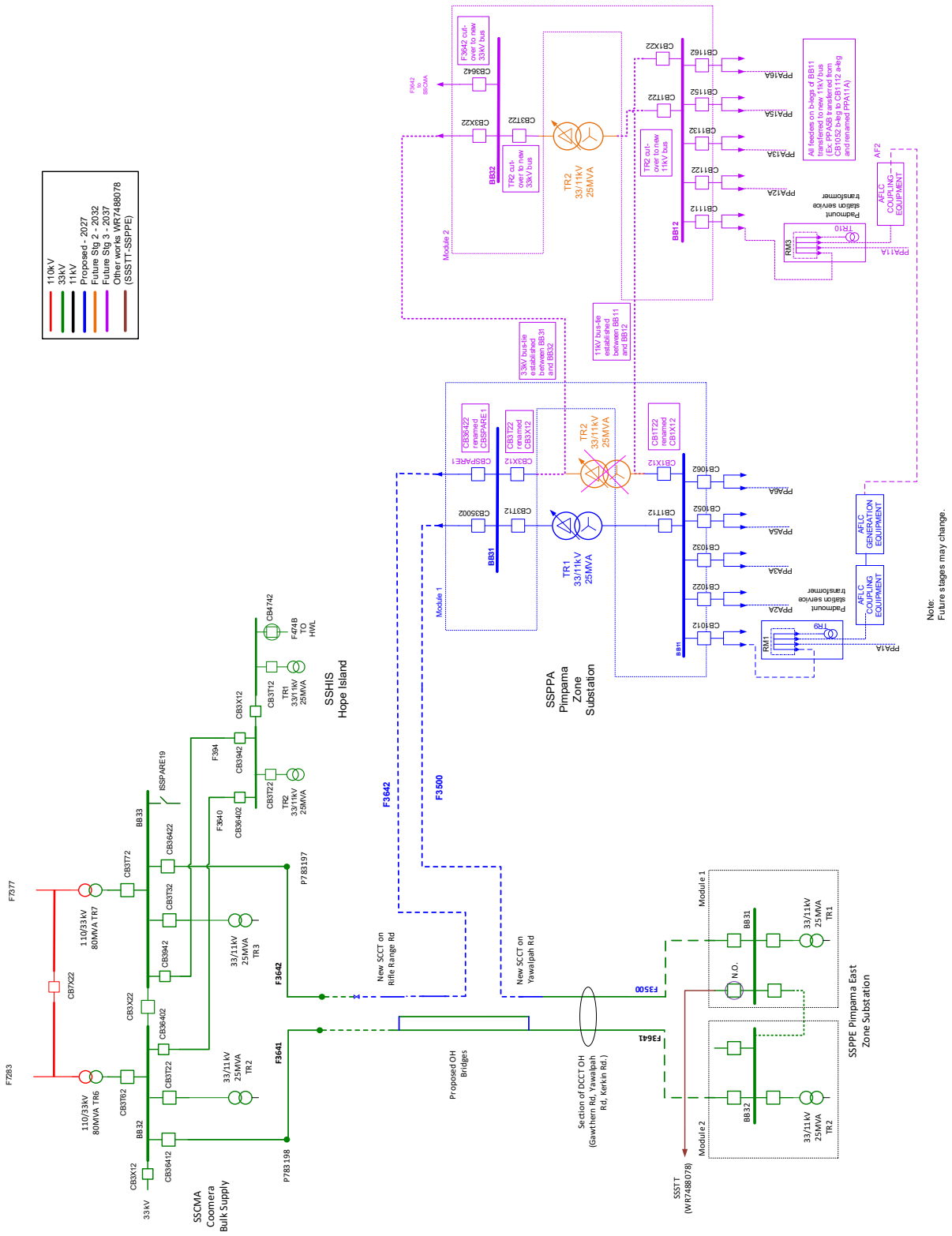


Figure 12: Proposed network arrangement - option A (schematic view)

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by providing reliable supply and additional capacity to the Pimpama-Coomera area, which enables Energex to connect new customers to the distribution network and contribute to the reliability requirements stipulated in Energex's Distribution Authority.

The estimated initial capital cost of this option would be $25,285,000. The estimated initial operating costs of this option would be $33,000 per annum. The estimated commissioning date of this option would be 2027.

The estimated construction timetable[1] is:

- Construction start: 2026
- Commissioning: 2027

The estimated costs comprise the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option) - estimated at $25,285,000 per annum.
- operating and maintenance costs - estimated at $33,000 per annum.
- costs of complying with relevant laws, regulations and administrative requirements – included in the above ; and
- costs unique to asset replacement projects or programs – N/A.

There are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline of this option. This is described further in section 8.

4.1.2 Option B: Establish new 1 x 25MVA 33/11kV Coomera East Zone Substation (SSCET)

This option would involve:

Establish a new 1 x 25MVA 33/11kV zone substation at Coomera East (SSCET), consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11kV protection panels, and associated plant, tee-off existing 33kV feeders F3642 & F394 with a mix of UG and OH, establish new 4 x 11kV feeders from the new substation and reconfigure existing 11kV feeders at SSPPE and SSCMA by 2027.

Future Stage:

- Establish 2nd 25MVA 33/11kV transformer, connected to existing 11kV bus at SSCET by 2032.
- Establishing a 2nd module and associated switchgear at SSCET, consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11 kV protection panels, and

[1] Timings shown in this report are indicative and depend on the completion of the RIT-D process.

associated plant, establish new 33kV & 11kV tie feeders between both modules and reconfigure existing 11kV feeders at SSCET by 2037.

Figure 13 and Figure 14 provide geographic and schematic diagrams for Option B.

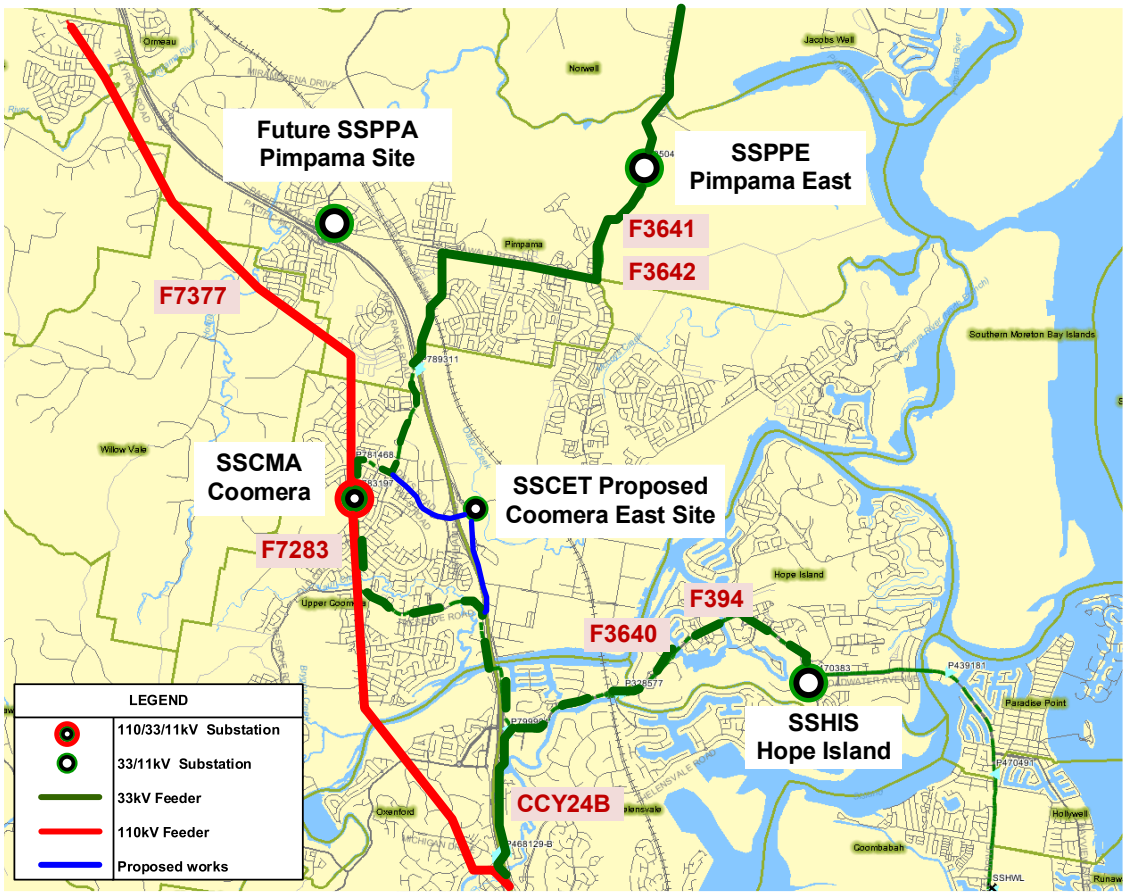


Figure 13: Proposed network arrangement - option B (geographic view)

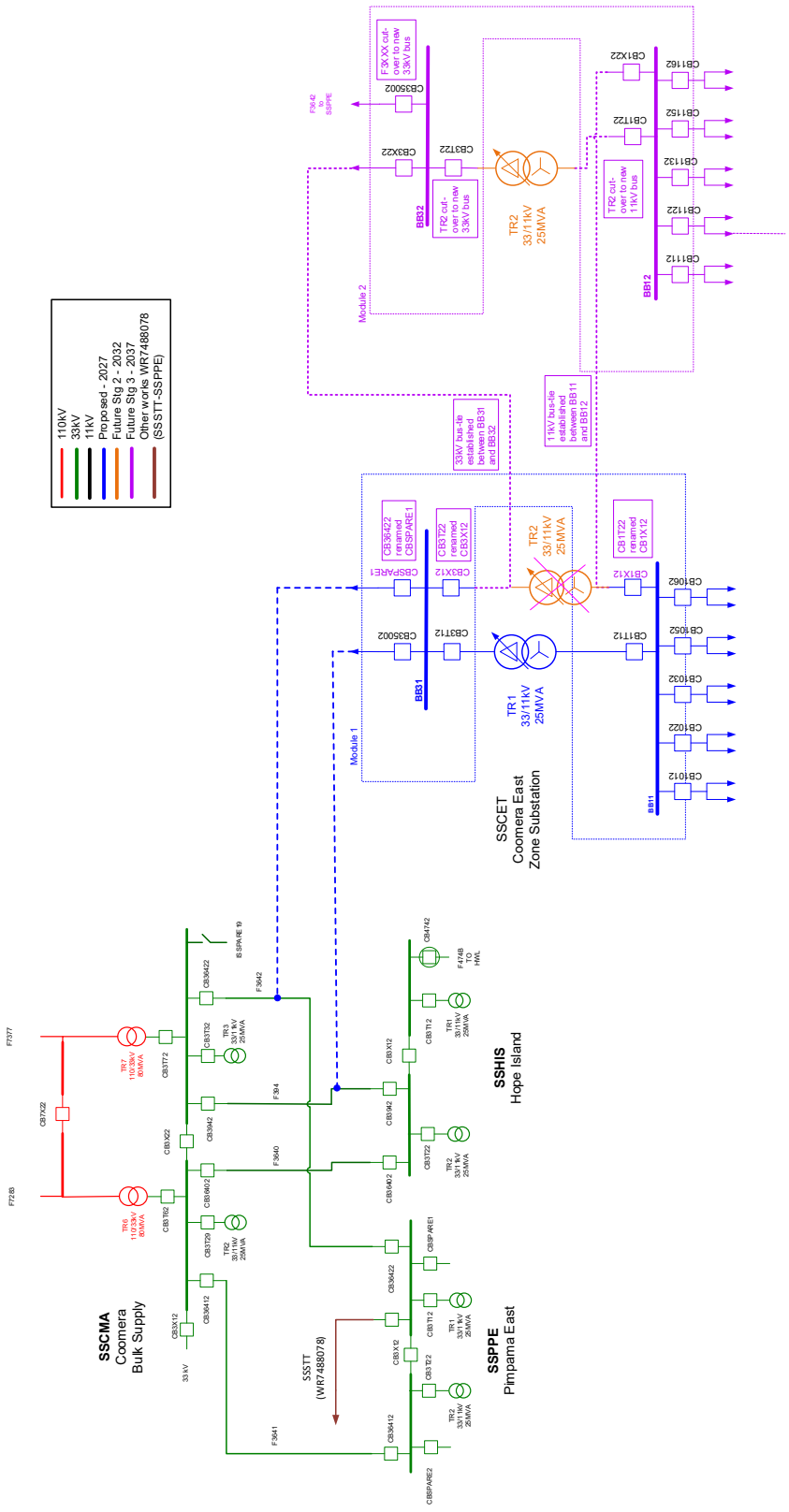


Figure 14: Proposed network arrangement - option B (schematic view)

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by providing reliable supply and additional capacity to the Pimpama-Coomera area, which enables Energex to connect new customers to the distribution network and contribute to the reliability requirements stipulated in Energex's Distribution Authority.

The estimated initial capital cost of this option would be $25,915,000. The estimated initial operating costs of this option would be $33,000 per annum. The estimated commissioning date of this option would be 2027.

The estimated construction timetable[2] would be:

- Construction start: 2026
- Commissioning: 2027

The estimated costs comprise the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option) - estimated at $25,915,000 per annum.
- operating and maintenance costs - estimated at $33,000 per annum.
- costs of complying with relevant laws, regulations and administrative requirements – included in the above; and
- costs unique to asset replacement projects or programs – N/A.

There are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline of this option. This is described further in section 8.

4.1.3 Option C: Install a 3rd module at Coomera Zone Substation (3rd module at SSPPE for future stage).

This option would involve:

Establishing a 3rd module and associated switchgear at SSCMA, consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11 kV protection panels, and associated plant, new 1 x 25MVA 33/11kV transformer, establish new 33kV & 11kV tie feeders between both substations and reconfigure existing 11kV feeders at SSPPE and SSCMA to address existing TMU (Target Maximum Utilisation) limitations by 2027.

Future Stage:

- Establishing a 3rd module and associated switchgear at SSPPE, consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11 kV protection panels, and associated plant, new 1 x 25MVA 33/11kV transformer, establish new 33kV & 11kV tie

[2] Timings shown in this report are indicative and depend on the completion of the RIT-D process.

feeders between both modules and reconfigure existing 11kV feeders at SSPPE and SSCMA by 2034.

Figure 15 provide schematic diagram for Option C.

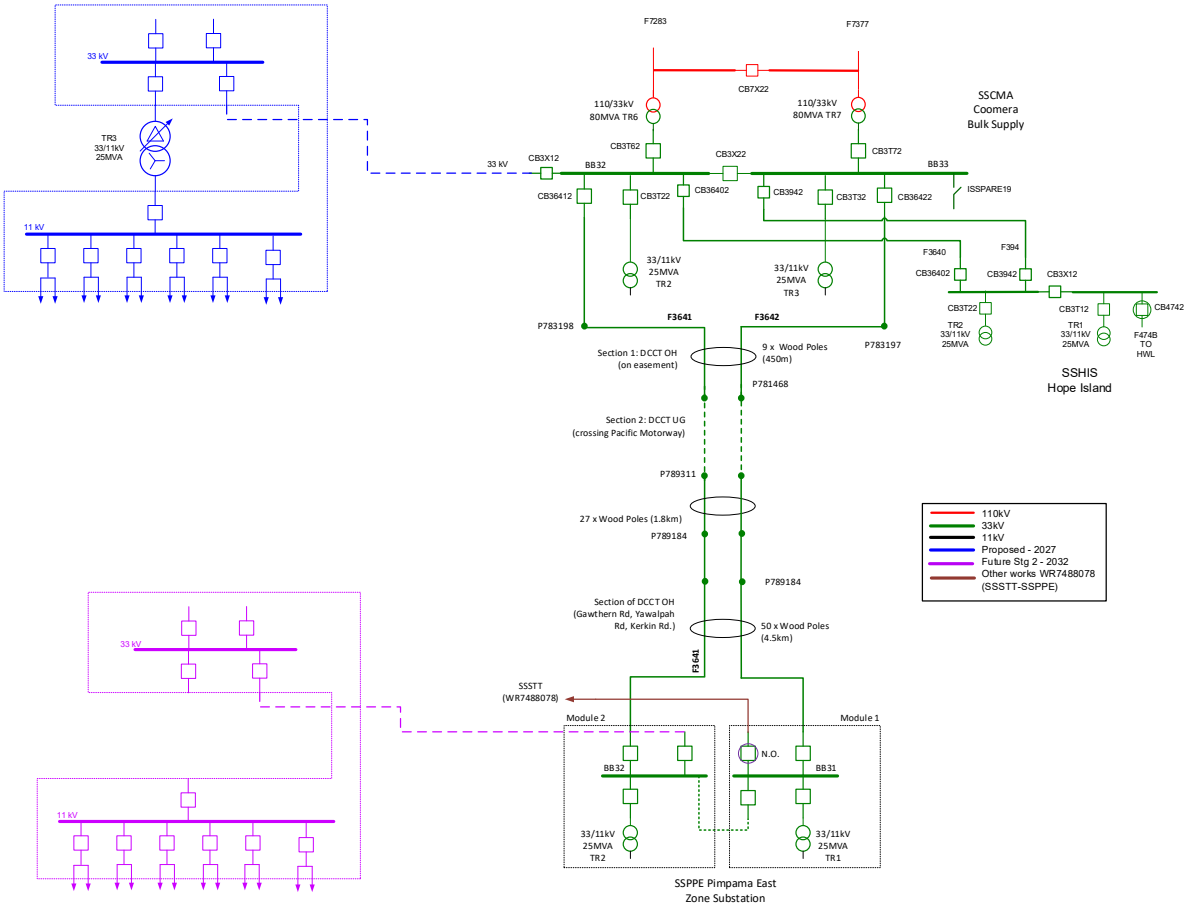


Figure 15: Proposed network arrangement - option C (schematic view)

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by providing reliable supply and additional capacity to the Pimpama-Coomera area, which enables Energex to connect new customers to the distribution network and contribute to the reliability requirements stipulated in Energex's Distribution Authority.

The estimated initial capital cost of this option would be $23,112,000. The estimated initial operating costs of this option would be $70,000 per annum. The estimated commissioning date of this option would be 2027.

The estimated construction timetable[3] would be:

[3] Timings shown in this report are indicative and depend on the completion of the RIT-D process.

- Construction start: 2026
- Commissioning: 2027

The estimated costs comprise the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option) - estimated at $23,112,000 per annum.
- operating and maintenance costs - estimated at $70,000 per annum.
- costs of complying with relevant laws, regulations and administrative requirements – included in the above; and
- costs unique to asset replacement projects or programs – N/A.

There are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline of this option. This is described further in section 8.

5 QUANTIFICATION OF MARKET BENEFITS FOR EACH CREDIBLE OPTION

Energex has analysed the following classes of market benefits.

5.1 Changes in Voluntary Load Curtailment

There are no customers on voluntary load curtailment agreements in the study area, therefore, Energex has determined that there will be no material change in this class of market benefit for any of the potential credible options.

5.2 Changes in Involuntary Load Shedding and Customer Interruptions

Involuntary load shedding is where electricity supply for a customer's load is interrupted from the network without their agreement or warning. Energex has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed.

Involuntary load shedding of a credible option is derived by the quantity in kWh of involuntary load shedding under the credible option multiplied by the Value of Customer Reliability (VCR). The VCR is measured in dollars per kWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

The customer export curtailment value (CECV) represents the detriment to customers and the National Electricity Market (NEM) from the curtailment of distributed energy resource (DER) exports (e.g. rooftop solar PV systems). A reduction in curtailment due to the implementation of a credible option results in a positive contribution to the market benefits of that option. These benefits have been calculated according to the Australian Energy Regulator's (AER) CECV methodology based on the capacity of DER currently installed and forecast to be installed within the study area.

5.3 Changes in Costs for Other Parties

Energex has determined that there will be no material change in costs incurred by other parties due to any of the potential credible options.

5.4 Differences in the Timing of Expenditure

The potential credible options included in this RIT-D assessment are not expected to affect the timing of other distribution investments for unrelated identified needs. Energex has determined that there will be no material change in this class of market benefit for any of the potential credible options.

5.5 Changes in Load Transfer Capacity and the Capacity of Distribution Connected Units to Take Up Load

The potential credible options included in this RIT-D assessment will increase the load transfer capacity in the Pimpama East and Coomera distribution network as well as increasing the hosting capacity for distribution connected embedded generators. The market benefits gained from increased load transfer capability and/or the ability of embedded generators to take up load is treated in the same way as changes in involuntary load shedding and customer interruptions.

5.6 Additional Option Value

Energex has not identified any additional option value that would result in a material change in market benefit.

5.7 Changes in Electrical Energy Losses

Energex anticipates that the credible options included in the RIT-D assessment will reduce electrical energy losses, however, the reduction is not significant enough to result in a material change in market benefit.

5.8 Changes in Australia's Greenhouse Gas Emissions

Energex has determined that the change in Australia's greenhouse gas emissions for any of the potential credible options do not result in a material change in market benefit.

6 NPV ANALYSIS OF EACH CREDIBLE OPTION

This section outlines the methodology applied in assessing the market benefits and costs associated with each potential credible option.

The RIT-D requires Energex to identify the credible option that maximises the present value of net economic benefit to all who produce, consume and transport electricity in the National Electricity Market. Accordingly, a base case Net Present Value (NPV) comparison of the potential credible options has been undertaken. A sensitivity analysis was then conducted to establish the option that remained the lowest cost option in the scenarios considered.

6.1 Overview of Analysis Framework

All costs and benefits for each credible option have been measured against a 'business as usual' base case. Under this base case, Energex would not be compliant with its requirements under applicable regulatory instruments. The base case is therefore not a realistic state of the world.

The RIT-D analysis has been undertaken over a 20-year period, from 2027 to 2047. Energex considers this period is appropriate for this analysis as it takes into account the size, complexity and forecast growth of the area to provide a reasonable indication of the market benefits and costs of the options.

Where the capital components of the credible options have asset lives greater than 20 years, Energex has taken a terminal value approach to incorporate capital costs in the assessment, which ensures that the capital cost of long-lived options is appropriately captured in the 20 year assessment period. The terminal value has been calculated as the undepreciated value of capital costs at the end of the analysis period.

Energex has adopted a real, pre-tax discount rate of 3.69% as the central assumption for the NPV analysis, this aligns with the latest AER Final Decision for a Distribution Network Service Provider's (DNSP's) regulated weighted average cost of capital (WACC) at the time of preparing this DPAR. To test the results against variations in the discount rate, an upper value sensitivity of 4.69% and a lower value sensitivity of 2.69% have been adopted for this RIT-D.

6.2 Estimating the Costs of each Potential Credible Option

Energex uses a combination of comparative and standard cost estimating methodologies, underpinned by a bottom-up approach as the basis for the estimation process of individual projects, which provides the platform for the development of forecast capital and operating expenditure.

Standard cost estimation forms the basis of typical larger, lower volume high complexity type network projects. With this approach, the most common network configurations associated with transmission, sub-transmission and distribution project types or components are catered for, incorporating the experience and knowledge of agreed engineered standard ways of construction of network components. These cover a wide range of activities and are adjusted on application to cater for site specific identified requirements through a bottom-up quantification of project scope and application.

Comparative costing is used where a statistically significant historical sample size exists, whereby actual project or program costs are reconciled and assessed. This approached is used in determining the operating costs.

Energex has estimated the capital and operating costs of each potential credible option which is inclusive of the following components:

- All material costs, including land.
- All labour costs incurred in delivery of the project (e.g. planning, design, construction, commissioning, network operations, and project management).
- All contractor costs incurred.
- Ancillary cost such as location allowances, environmental offsets.

6.3 Sensitivity Analysis

A sensitivity analysis was conducted to establish the option that remained the lowest cost option in the scenarios considered.

Table 3 outlines the major sensitivities analysed within the Monte-Carlo analysis which was undertaken to assess the sensitivity to a change in parameters of the NPV model.

Parameter	Mode Value	Lower Bound	Upper Bound
Discount Rate	3.69%	2.69%	4.69%
Project Costs	Standard estimates	-50%	+50%
Opex Costs	Comparative estimates	-10%	+10%

Table 3: Economic parameters and sensitivity analysis factors

6.4 Considered Scenarios

The only scenario that has been considered is the base case load forecast. The low or high growth scenarios have not been considered due to the actual load has already exceeded the firm capacity of SSPPE and SSCMA, hence, alternative scenarios have no impacts to the timing of the reliability corrective action.

6.5 Ranking of Credible Options

The table below summarises the costs and benefits relative to the counterfactual, of the potential credible options in present value terms. The counterfactual is the continual operation of the existing network without augmentation and assuming load growth is lower than the forecast.

Option	Option Name	Rank	Initial Capital Cost ($ million)	Net Economic Benefit ($ million)	PV of Capex ($ million)	PV of Opex ($ million)	PV of Benefits ($ million)
A	Establish new 1 x 25MVA 33/11kV Pimpama Zone Substation	1	25.285	-23.109	-22.566	-0.605	0.062
B	Establish new 1 x 25MVA 33/11kV Coomera East Zone Substation	2	25.915	-23.536	-22.993	-0.605	0.062
C	Install a 3rd module at Coomera Zone Substation	3	23.112	-28.933	-27.562	-1.393	0.022

Table 4: Present value analysis and ranking of credible options

The table below summarises the results of the sensitivity analysis.

Option	Option Name	Average NPV ($ million)	Maximum NPV ($ million)	Minimum NPV ($ million)
A	Establish new 1 x 25MVA 33/11kV Pimpama Zone Substation	-23.062	-15,897	-31,438
B	Establish new 1 x 25MVA 33/11kV Coomera East Zone Substation	-23.495	-16,216	-33,145
C	Install a 3rd module at Coomera Zone Substation	-28.874	-19,345	-40,634

Table 5: Summary of sensitivity analysis results

7 PREFERRED OPTION

Option A has been identified as the preferred option, and it satisfies the regulatory investment test for distribution. This option maximises the present value of the net economic benefit.

This statement is made on the basis of the detailed analysis set out in this DPAR. The preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenario.

8 SOCIAL LICENCE AND COMMUNITY ENGAGEMENT

8.1 Social Licence

Energex has not identified any social licence considerations that have affected the identification and selection of credible options to address the identified need.

This is due to proposed network options being located on Energex owned and managed sites. The new SSPPA or SSCET substation sites have been acquired over a decade ago prior to the development of neighbouring properties, and developers have been made aware of Energex's intention of building a substation. Furthermore, the sites are located in commercial/industrial areas (e.g. SSPPA site is next to an on-ramp to the Pacific Motorway on the southern and western boundary and on a major road on the northern boundary). Any new feeders proposed are along road reserve and are expected to be mostly underground construction. In addition, there are also reliability and economic benefits of these options to the local community.

8.2 Community Engagement

As described above, given the options do not involve impact beyond sites already owned by Energex and planned for future substation use prior to development of neighbouring properties, it is not expected to cause any disruption to the community at large. Community consultations will be held at the early stage of implementation. As a result, we have not identified any community stakeholders who might reasonably be expected to be affected by the development of this project.

While Energex does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Energex Community Engagement Framework which is integrated into the project workflow.

9 REQUEST FOR SUBMISSIONS

Energex engages with customers and demand management providers to develop and implement demand side, non-network and SAPS solutions in accordance with our Industry Engagement Document.[4]

Energex invites written submissions on the matters set out in this DPAR, including the proposed preferred option, from registered participants, AEMO, interested parties, non-network providers and persons registered on Energex's industry engagement register.

Energex will not be legally bound in any way or otherwise obligated to any person who may receive this DPAR or to any person who may provide a submission. At no time will Energex be liable for any costs incurred by a proponent in the assessment of this DPAR, 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 DPAR.

For any queries in relation to this DPAR, please contact:

E: demandmanagement@energex.com.au
P: 13 12 53

Submissions in writing are due by 4pm on the 7th August 2026 and should be lodged to demandmanagement@energex.com.au

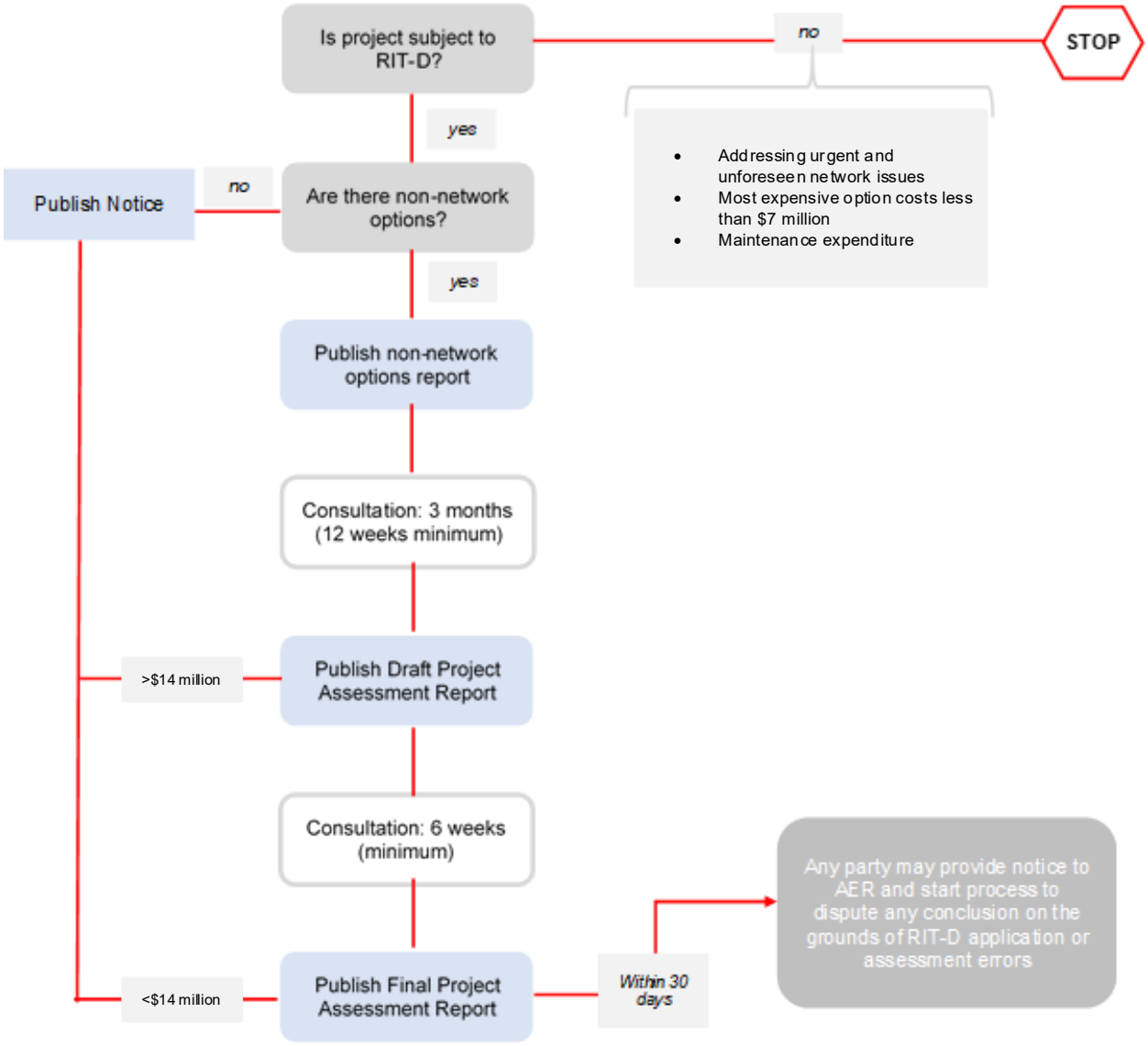
[4] Available at: https://www.energex.com.au/__data/assets/pdf_file/0020/1005725/Industry-Engagement-Document.pdf

10 COMPLIANCE STATEMENT

This DPAR complies with the requirements of clause 5.17.4(j) of the NER as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	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;	1 and 2
(3) if applicable, a summary of, and commentary on, the submissions received on the Options Screening Report;	N/A
(4) a description of each credible option assessed	4
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	5 and 6
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	5
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	5
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	6
(10) the identification of the proposed preferred option	6 and 7
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (iii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	 1 4 4 7 N/A
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	9
5.17.4(k) request for submissions on the matters set out in DPAR	9

11 APPENDIX A – THE RIT-D PROCESS



12 APPENDIX B – SAFETY NET TARGETS

Energex has an obligation to meet the Safety Net Targets under its Distribution Authority. The Safety Net targets are defined by the load impacted and the duration of this impact. The table below shows the specific requirements that Energex needs to achieve.

17
Distribution Authority - No. D07/98
ENERGEX Limited

SCHEDULE 3

Service Safety Net Targets

Feeder Type	Targets
CBD	• Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute
Urban	Following an N-1 event, load not supplied must be: • Less than or equal to 40MVA (16,000 customers) for no more than 30 minutes; • Less than or equal to 12MVA (5,000 customers) for no more than 3 hours; • Less than or equal to 4MVA (1,600 customers) for no more than 8 hours; • Fully Restored after 8 hours
Short Rural	Following an N-1 event, load not supplied must be: • Less than or equal to 40MVA (16,000 customers) for no more than 30 minutes; • Less than or equal to15MVA (6,000 customers) for no more than 4 hours; • Less than or equal to 10MVA (4,000 customers) for no more than 12 hours; • Fully Restored after 12 hours

Notes:
- All modelling and analysis will be benchmarked against 50 POE Loads and based on credible contingencies.
- Outages ≤ 3 minutes in duration excluded from Safety Net Targets.

[as inserted on 05 December 2025]