Regulatory Investment Test for Distribution (RIT-D)

Reliability Corrective Action
The Southwest QLD Network Area

Final Project Assessment Report

12/06/2026

NETWORK

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 Final Project Assessment Report (FPAR) has been prepared by Ergon Energy Corporation Limited (Ergon Energy) in accordance with the requirements of clause 5.17.4(r) of the NER and is published in accordance with 5.17.4(o) of the NER.

In preparing this FPAR, Ergon Energy is required to consider reasonable future scenarios. With respect to major customer loads and generation, Ergon Energy has included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Ergon Energy 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 Ergon Energy

Ergon Energy is part of Energy Queensland and manages an electricity distribution network which supplies electricity to more than 765,000 customers. Our vast operating area covers over one million square kilometres (around 97% of the state of Queensland) from the expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Our electricity network consists of approximately 160,000 kilometres of powerlines and one million power poles, along with associated infrastructure such as major substations and power transformers.

We also own and operate 33 stand-alone power stations that provide supply to isolated communities across Queensland which are not connected to the main electricity grid.

CONTENTS

1. BACKGROUND AND TECHNICAL CHARACTERISTICS OF THE IDENTIFIED NEED

1.1. Location

Charleville is located in the Maranoa area of the Southwest Region of Ergon Energy's Network. The Charleville area is supplied via a single 272km 66kV sub-transmission feeder from T83 Roma 132/66/33kV bulk supply point (ROMA) and customers in Quilpie and Cunnamulla are supplied via separate 200km long 66kV feeders from Charleville. Distribution supply from Charleville 66/22/11kV zone substation (CHAR) and Cunnamulla 66/22/11kV zone substation (CUNN) is at 11kV for urban, and 22kV and 19.1kV single wire earth return (SWER) for more rural customers. Supply from Quilpie 66/11kV zone substation (QUIL) is predominantly 11kV, but also consists of extensive 19.1kV SWER networks. The distribution network supplied from these three zone substations supplies 5,379 customers and encompasses more than 10% of the total geographic area of Queensland.

Figure 1 provides an overview of the sub-transmission network in the region and the location of the zone substations supplied from ROMA. Figure 2 shows the site layout of CHAR.

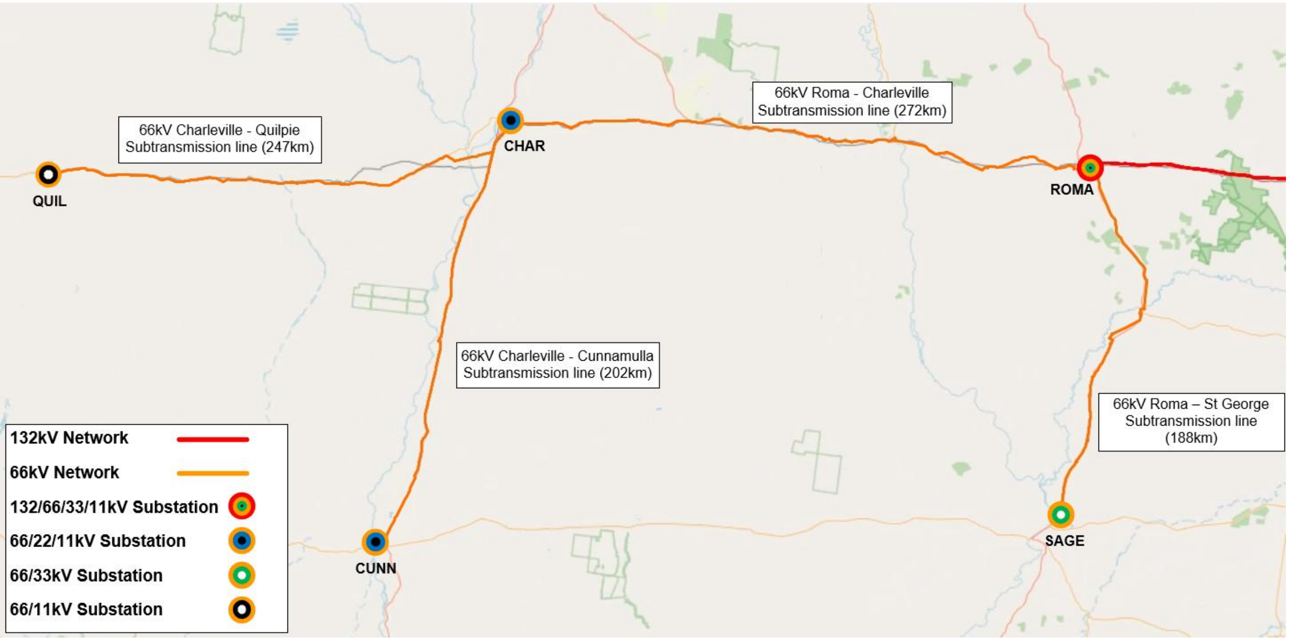

Figure 1 - Southwest 66kV sub-transmission network.

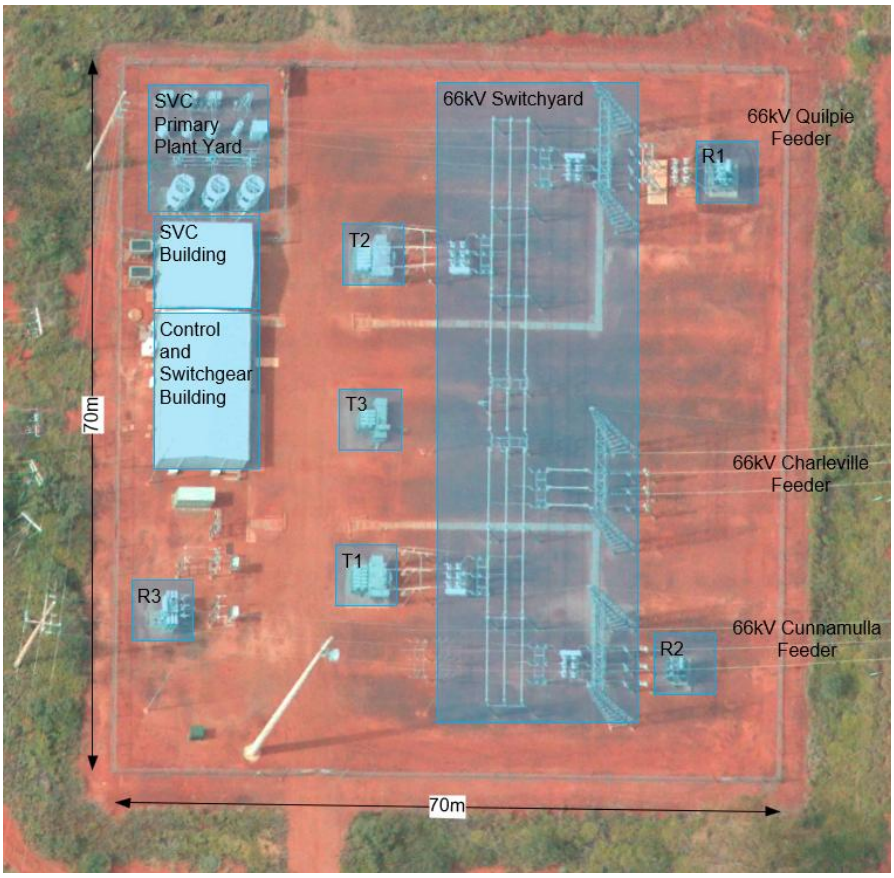

Figure 2 – CHAR site layout.

1.2. Existing supply arrangement

Figure 3 provides a single line diagram showing the 66kV network supplying CHAR, CUNN and QUIL from ROMA bulk supply point. During normal operation, the 66kV network voltages are regulated by the ROMA T1 on load tap changer (OLTC) in combination with a variety of reactive plant installed at the downstream zone substations buses.

CHAR contains a 66/11kV transformer, a 66/22kV transformer, and a 22/11kV transformer linking the 22kV and 11kV busbars, providing backup for each of the 66kV transformers (as shown in Figure 3 below). CHAR contains a Static Var Compensator (SVC) connected to the 11kV bus. The SVC controls the 66kV bus voltage and has a range of 7MVAr inductive to 10MVAr capacitive.

The CHAR SVC is the only dynamic reactive plant in this part of the network and provides continuously variable reactive power compensation, set to control the CHAR 66kV bus voltage. The other reactive plant consist of fixed capacitor banks and reactors installed at CHAR and CUNN as shown in Figure 3. These fixed devices are manually controlled and can be remotely switched via their respective circuit breakers (CBs) (apart from CHAR 66kV R2 which lacks a CB) by system operators in order to manage reactive power flows within the system.

During times when the CHAR SVC is out of service, the fixed reactors and capacitor banks at CHAR and CUNN are manually switched to manage reactive power flows and bus voltages depending on network loading. However, this switching creates transients on the network, is difficult to manage, and relies on some plant which is also approaching end of life. There is also insufficient reactive power capability to maintain voltages at all times and customer load shedding would be required during high load periods (estimated to be 24% of the time).

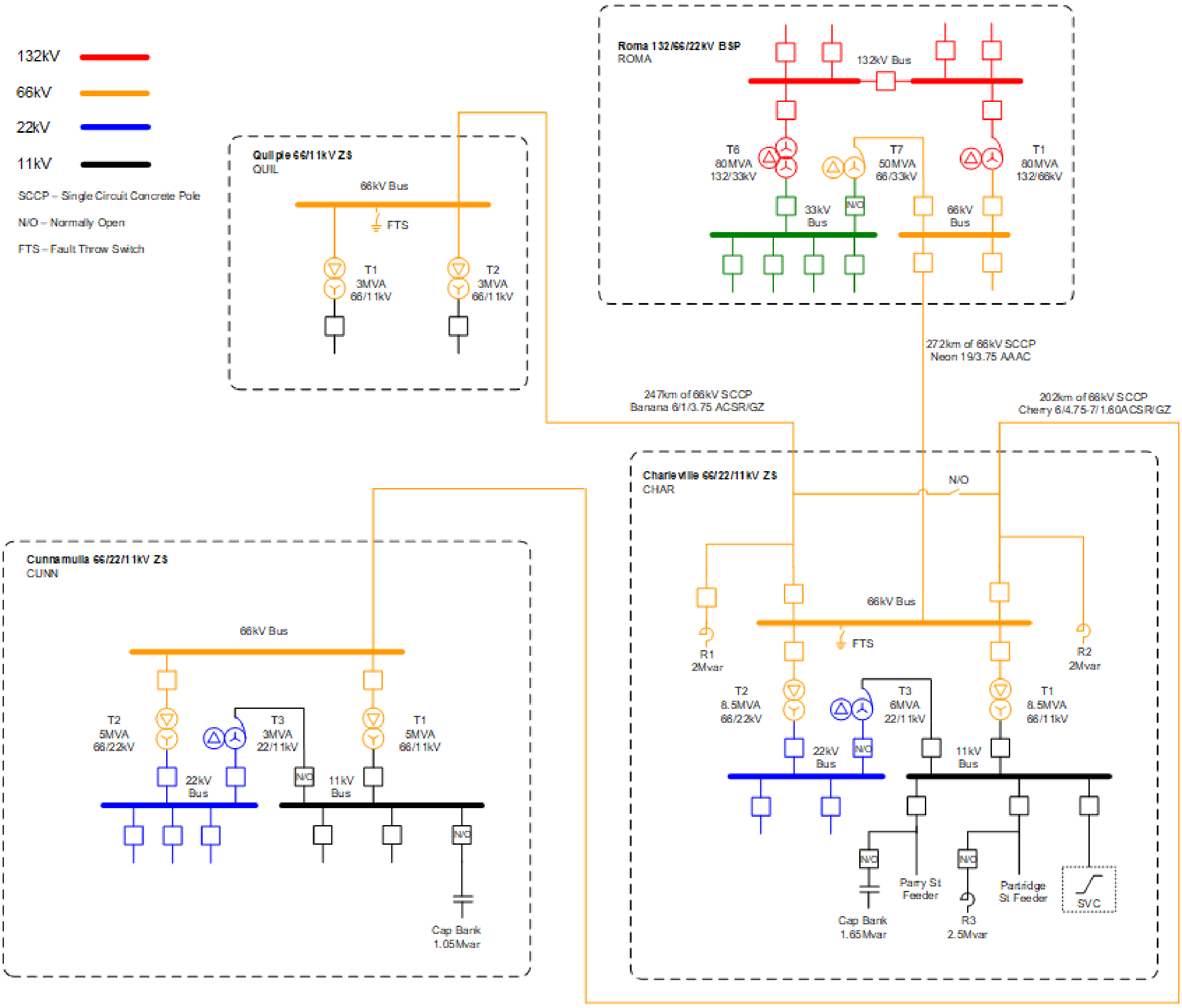

Figure 3 – Network single line diagram.

1.3. Contribution to power system security or reliability

The SVC plays a critical role in maintaining voltage stability and reliability of customer supply across Ergon Energy's Southwest network which includes Charleville, Quilpie, and Cunnamulla. This network is characterised by low fault levels making it susceptible to large voltage disturbances during switching of reactive plant and during load rejection events. By dynamically injecting or absorbing reactive power in response to system conditions, the SVC helps stabilise voltage fluctuations caused by load changes, faults, or switching operations. This improves the system's ability to withstand disturbances and prevents voltage collapse, which is critical for maintaining continuous and reliable power supply.

The SVC also operates to balance the three-phase system via Negative Phase Sequence (NPS) correction, improving voltage balance and power quality for rural customers. This capability is required to correct the significant phase unbalance caused by the extensive SWER networks in the region.

1.4. Contribution to power system fault levels

Like other SVCs in general, the Charleville SVC is a shunt-connected device that provides reactive power support without contributing real power, therefore its direct contribution to fault current is minimal. However, by improving voltage stability and supporting system voltage during disturbances, the SVC can help maintain the operational integrity of nearby generators and sub-transmission lines, indirectly affecting fault levels.

1.5. Operating profile

The CHAR SVC is capable to operate with a nominal swing range of 7Mvar inductive to 10Mvar capacitive however during normal operation, ±2.4Mvar is reserved for dynamic/transient response resulting in a reduced range available for steady state voltage control (4.6Mvar inductive to 7.6Mvar capacitive). As can be seen in Figure 4 during high load events the SVC provides capacitance, while Figure 5 shows that during low load events the SVC provides inductance to help manage voltage stability.

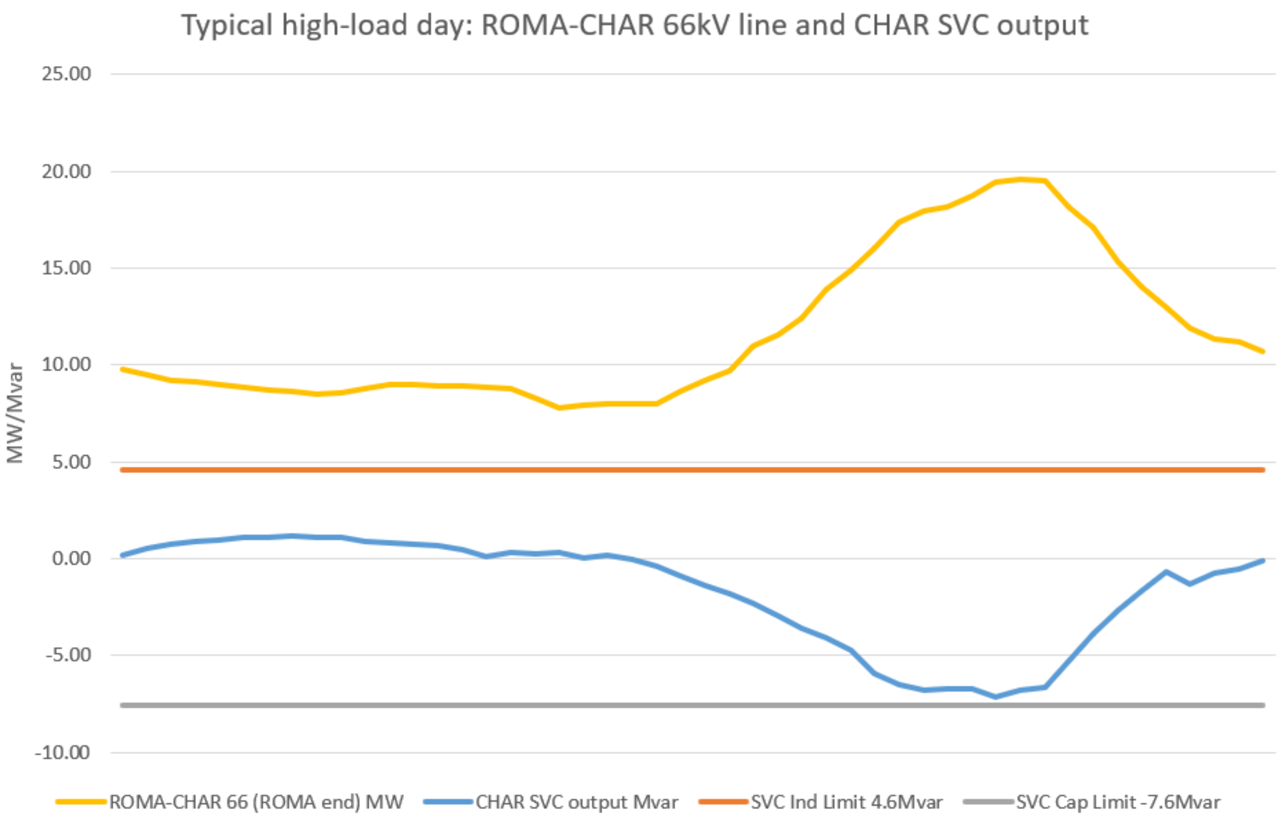

Figure 4 – CHAR SVC and ROMA-CHAR 66kV line loading – Typical high-load day profile (+ve is absorbing reactive power)

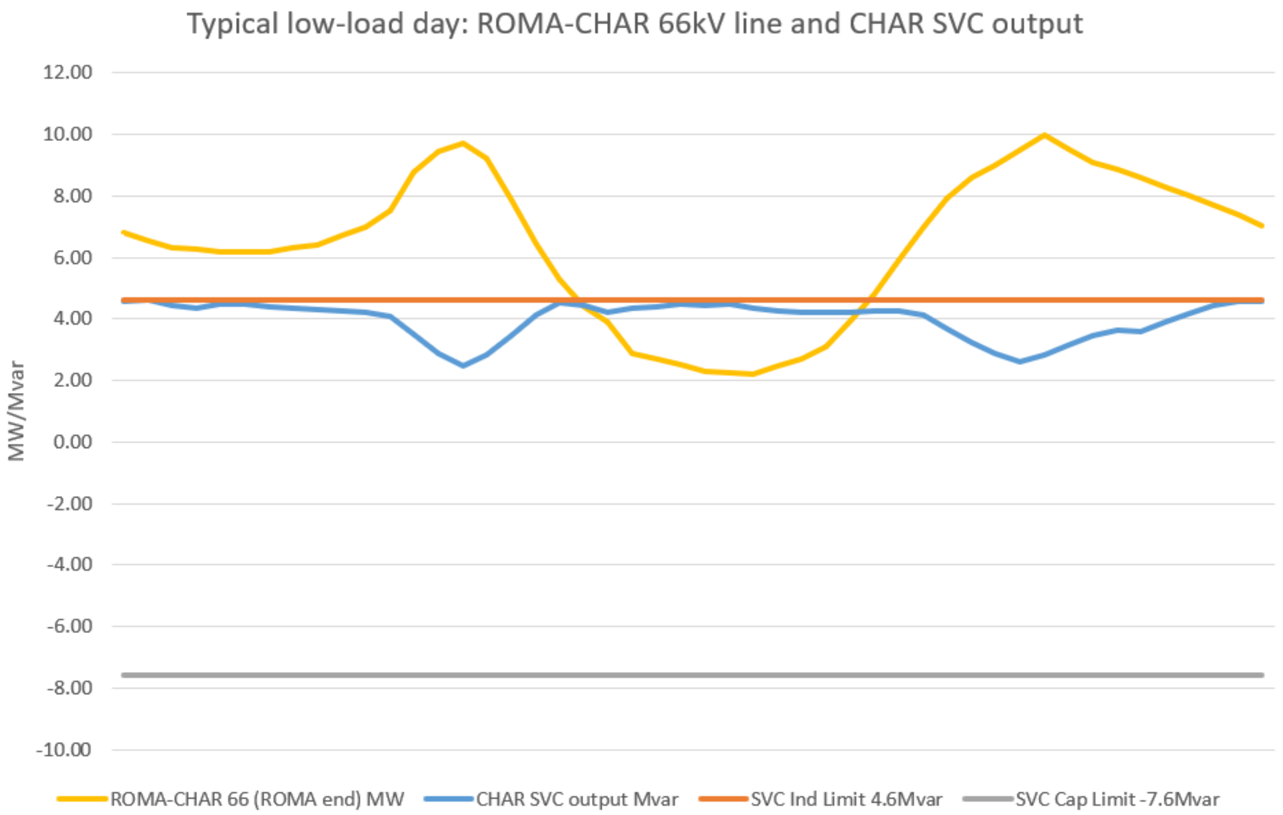

Figure 5 - CHAR SVC and ROMA-CHAR 66kV line loading – Typical low-load day profile (+ve is absorbing reactive power)

1.6. Forecast

The SVC was commissioned in 1991, and this operating range was designed to cater for the existing and forecast demand at the time. Over the life of the SVC, system demand has increased considerably e.g. in 1991 the maximum demand seen by the ROMA-CHAR 66kV line was approximately 12.2MW (as measured from the ROMA end) compared to the peak of 25.7MW recorded in January 2025. At the same time, growth of customer energy resources (CERs) (e.g. rooftop solar PV) has resulted in a decrease in minimum demand. This changing demand profile has increased the reactive power requirements during high and low load times to the extent that the SVC frequently reaches both the capacitive and inductive limits (see Figure 4 and Figure 5).

The network maximum demand forecast is relatively flat, however there is significant CER growth expected within the Charleville, Cunnamulla and Quilpie distribution networks. Large customers in the area are also exploring opportunities to reduce their load with onsite generation. The lowest loads are now seen during the middle of the day, during months with more mild weather conditions (see Figure 6-8 below). In short, it is expected that low-load periods will continue to decline, increasing inductive compensation requirements within the network.

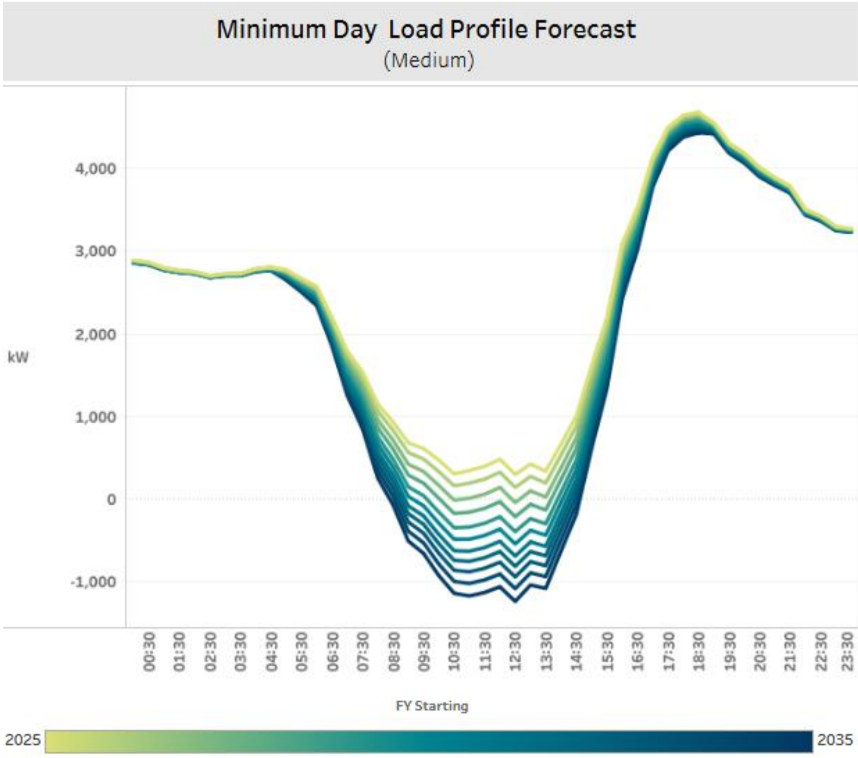

Figure 6 - CHAR minimum day load profile forecast.

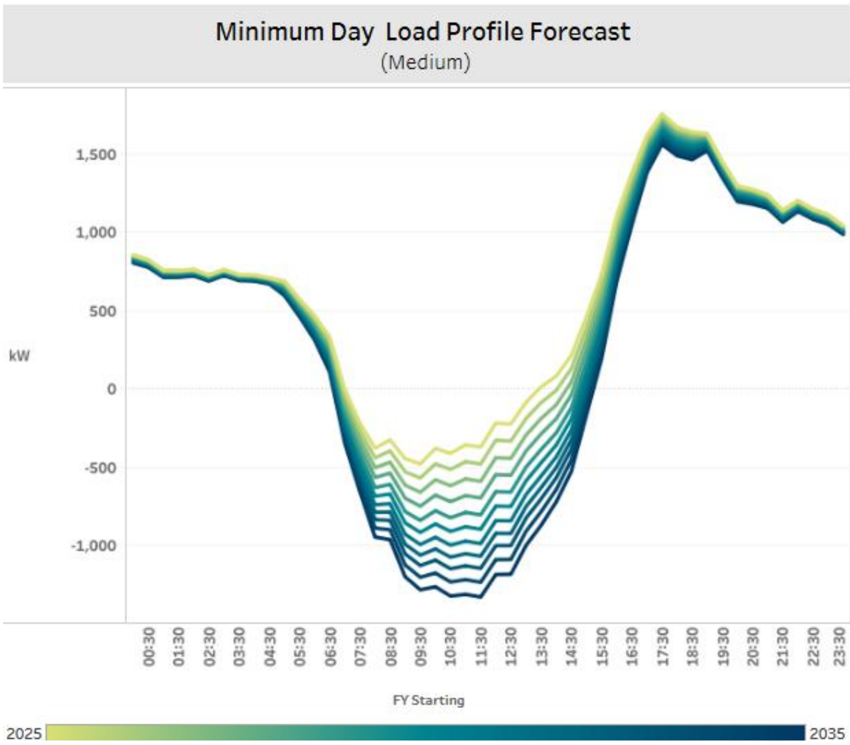

Figure 7 - CUNN minimum day load profile forecast.

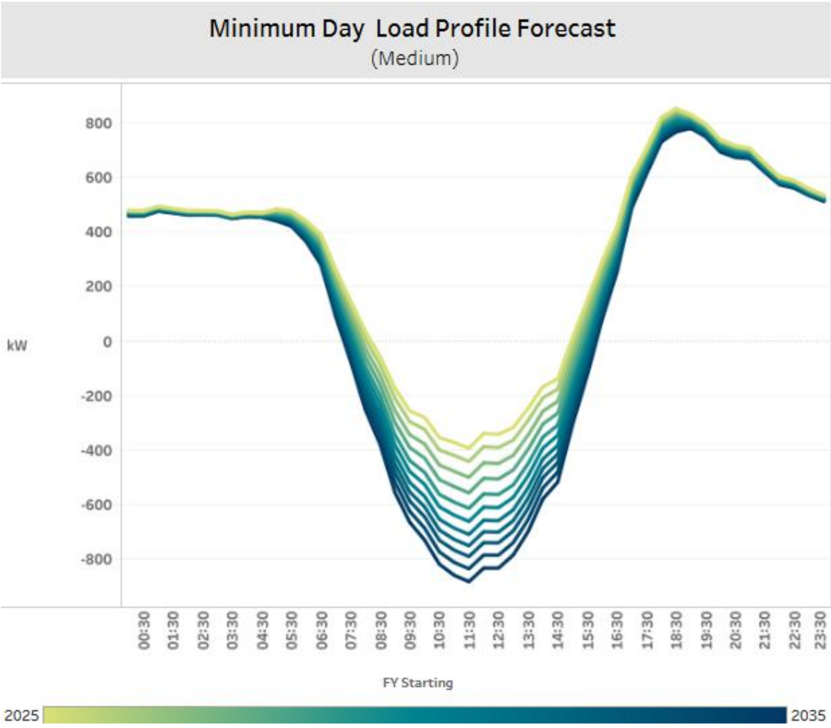

Figure 8 - QUIL minimum day load profile forecast.

1.7. Design Parameters and Specified Performance Levels for Reactive Power Compensation at Charleville

To ensure that a non-network solution meets the NER technical requirements, it must comply with the design parameters and specified performance levels attached in **Appendix A**.

1.8. Size of load reduction or additional supply

Reducing the peak demand of the network would lead to a reduction in the capacitive range of reactive power compensation required. Similarly, inductive compensation requirements might be reduced by adding load to increase the minimum demand profile. However, due to the specific network characteristics (see section 1.3), it is anticipated that there would always be a need for some form of dynamically controlled, reactive power compensation capability within the 66kV network supplying CHAR, CUNN and QUIL.

2. IDENTIFIED NEED

The increasing probability of failure of the SVC is deemed to have reached unacceptably high levels and the assets are in need of replacement. A long-term outage to the SVC would cause a breach of Ergon Energy's regulatory obligations, reliability performance standards and technical requirements (as listed below). As such, Ergon Energy is seeking to undertake reliability corrective action by immediately replacing the SVC in order to ensure continued adherence to these requirements under applicable regulatory instruments.

The SVC is operating well beyond its design life and is experiencing an increasing failure rate of its aged components. Due to a lack of inbuilt redundancy within the SVC, the failure of a single component could cause a loss of the full functionality of the SVC. Spare parts are no longer able to be sourced for some of the SVC components, such as the PCB inner loop control cards, and there is a distinct possibility that if a failed card cannot be repaired then the entire SVC would be rendered inoperable and would need to be replaced. In this scenario there would be a long-term outage to the SVC while it is being replaced. As described in section 1.2, there are customer reliability impacts during a long term outage to the SVC and it is estimated that, depending on the time of the year, up to 10MW of customer load shedding would be required in order to maintain network voltages.

As well as customer reliability impacts, SVC failure would lead to voltage compliance issues on the network. Sub-transmission and distribution voltage levels would not be controlled within statutory planning limits, increasing the risk of network over-voltages, under-voltages and voltage unbalance potentially leading to premature failure of customers' appliances and equipment.

Ergon Energy has obligations to comply with the reliability performance standards specified in its Distribution Authority (DA), issued under the *Electricity Act 1994* (Qld) (the Act). If network investment did not occur, this would likely result in breaches of reliability performance obligations under Ergon Energy's DA, namely:

- Clause 7 - Guaranteed Service Levels (reliability of supply)
  - During a long-term, unplanned outage of the SVC, customer load shedding would be required at times in order to maintain voltage stability of the network. The duration of customer supply interruption is likely to exceed the performance levels stipulated within the guaranteed service level regime.
- Clause 8 - Distribution Network Planning
  - This clause states that the distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services. The SVC performs a critical role in maintaining voltages and power transfer capability in the network. Failing to maintain a reliable and secure reactive power capability within the network may be seen as a breach of this clause.
- Clause 9 - Minimum Service Standards
  - During a long-term, unplanned outage of the SVC, rolling customer load shedding would be required at times in order to maintain voltage stability of the network. This would have a large, negative impact on system-wide SAIDI and SAIFI limits stipulated within the Minimum Service Standards.
- Clause 10 - Safety Net
  - A failure of the SVC is deemed to be a credible N-1 contingency in terms of Safety Net planning requirements. A long-term outage to the SVC would result in some customers being unsupplied beyond the 48-hour, full restoration target stipulated within the Schedule 4 Service Safety Net Targets. Additionally, on failure of the SVC rolling load shedding of up to 10MVA would be required (24% of the time) until the plant could be being replaced.

Further to the above obligations, section 42(a)(i) of the Act states that distribution entities must comply with the reliability requirements, system standards and performance requirements specified within the National Electricity Rules (NER). Without investing in the network, the following system standards would likely be breached:

- Schedule 5.1a System Standards
    - S5.1a.3 System stability
    - S5.1a.4 Power frequency voltage
    - S5.1a.5 Voltage fluctuations
    - S5.1a.6 Voltage waveform distortion
    - S5.1a.7 Voltage unbalance
- Schedule 5.1 Network Performance Requirements
    - S5.1.2 Network reliability
    - S5.1.2.1 Credible contingency events
    - S5.1.4 Magnitude of power frequency voltage
    - S5.1.5 Voltage fluctuations
    - S5.1.6 Voltage harmonic or voltage notching distortion
    - S5.1.7 Voltage unbalance
    - S5.1.8 Stability

The network and regulatory requirement risks described above are based upon the present load profile of the Charleville 66kV network and the current condition of the SVC. As described in section 1.6, the SVC frequently reaches it's steady-state capacitive and inductive limits and it is expected that network reactive compensation requirements will increase into the future (particularly in the inductive range). This leads to increasing load at risk and an increasing likelihood of Ergon Energy breaching its regulatory obligations, reliability performance standards and technical requirements. A failure to promptly complete a project to address the SVC asset condition risk is likely to materially affect the reliability and secure operating state of a significant part of the network. Based on this, Ergon Energy seeks to address the identified need by June 2029 which is estimated to be the earliest date that the network option could be implemented (see section).

As described above, there is underlying customer load at risk that would remain until the identified need is resolved by a credible option. Options that could be implemented promptly would have increased customer reliability benefits (compared to options that took longer to implement) which is taken into account during the cost-benefit analysis of credible options.

3. SUBMISSIONS ON THE DRAFT PROJECT ASSESSMENT REPORT

The Draft Project Assessment Report was published on 01/04/2026 and the consultation period concluded on 27/05/2026. No submissions were received.

4. CREDIBLE OPTIONS

4.1. Credible Options Identified

Ergon Energy 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.

The Options Screening Report was published on 31/10/2025 seeking information from all interested parties, as listed in clause 5.17.4(a) of the NER, about alternative potential credible options to address the identified need. Subsequently, the Draft Project Assessment Report was published on 01/04/2026 and the consultation period concluded on 27/05/2026. No submissions were received for either the Options Screening Report or the Draft Project Assessment Report. Based on this, Ergon Energy has determined 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.

Ergon Energy has identified one credible option that would address the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need (Option A: 10Mvar FACTS[1], as described below).

4.1.1. Option A: 10Mvar FACTS

This option replaces the CHAR SVC with two separate 5Mvar Flexible AC Transmission Systems (FACTS) connected to the 11kV and 22kV buses respectively, and with the capability to be easily expanded up to 7.5Mvar units in the future. The FACTS is designed to have N-1 redundancy so that it retains at least 50% of its rated capacity in the event of a failure of any single element.

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by:

- Providing sufficient inductive and capacitive reactive power capability to manage network voltages at Charleville, Quilpie and Cunnamulla zone substations and surrounding distribution areas.
- Being able to be easily expanded to cater for future load growth and load degradation.
- Providing NPS correction to address voltage balance issues associated with SWER networks.
- Reducing voltage transients caused by inductor or capacitor switching and flicker caused by motor starting currents.
- Meeting Ergon Energy's reliability performance standards as specified in its DA (as described in section 2). This is achieved by providing redundancy to maintain adequate reactive power capability to avoid the need for customer load shedding during any credible contingency to the FACTS.
- Meeting Ergon Energy's reliability, system standards and performance requirements specified in the NER (as described in section 2).

The estimated capital cost of this option is $8,455,000 and the estimated operating costs of this option is $70,000 per annum. The estimated commissioning date of this option is 01/06/2029.

[1] Note that the Option A description within the Options Screening Report referred to the term STATCOM which has been replaced by the more general term FACTS (Flexible AC Transmission Systems) in this DPAR. This change was made to encapsulate the full range of technologies that might be suitable for this application, rather than limiting it to a STATCOM solution only (which is one particular type of FACTS).

The estimated project schedule is:

Activity	Duration (months)	Planned completion date
RIT-D	9	1/08/2026
Project approval	12	1/08/2027
Detailed design	12	1/08/2028
Construction	12	1/08/2029
Commissioning	1	1/09/2029

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 $8,455,000.
- operating and maintenance costs - estimated at $70,000 per annum.
- costs of complying with relevant laws, regulations and administrative requirements – included in overheads allocated to the project and incorporated within the above CAPEX and OPEX costs; and
- costs unique to asset replacement projects or programs - nil.

Due to Option A's scope of works being entirely contained within the existing CHAR site, as well as the expected reliability and safety benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs or lead to an increase in the delivery timeline of this option.

5. QUANTIFICATION OF MARKET BENEFITS FOR EACH CREDIBLE OPTION

5.1. Changes in Voluntary Load Curtailment

There are no customers on voluntary load curtailment agreements in the study area and therefore Ergon Energy has determined that there will be no material change in this class of market benefits for the credible option.

5.2. Changes in Involuntary load shedding and Customer Interruptions

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Ergon Energy 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 MWh of involuntary load shedding required, assuming the credible option is completed, multiplied by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D. Customer export Curtailment value (CECV) represents the detriment to all customers from the curtailment of DER export (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.

As described in section 1.2, in the existing system, without the SVC in service, there is insufficient reactive power capability to maintain voltages at all times and customer load shedding would be required during high load periods (calculated to be approximately 24% of the year).

Ergon Energy has applied a VCR estimate of $30.00/kWh for the CHAR load, which has been derived from the AER 2025 VCR values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

The parameters and assumptions used in calculating involuntary load shedding market benefits are:

- SVC forced outage rate is predicted using a Weibull distribution with a Shape Parameter (β) of 4 and a Characteristic Life (η) of 25.
- Average time to repair failed plant = 1 weeks.
- VCR = $30.00 per kWh.

Note: A failure of the SVC is likely to extend beyond a week, however for the purpose of VCR quantification the outage has been limited to 7 days.

5.3. Changes in Costs for Other Parties

Ergon Energy has determined that there will be no material change in costs incurred by other parties due to the credible option.

5.4. Differences in the Timing of Expenditure

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

5.5. Changes in Load Transfer Capacity and the capacity of Distribution Connected Units to take up load

By improving voltage stability limits, particularly on the 66kV network, the credible option is expected to improve the load transfer capacity and the capacity of embedded generators to take up load between the zone substations in the network area. However, this benefit is expected to be significantly less than other classes of market benefits being quantified and is therefore deemed to be immaterial.

5.6. Additional Optional Value

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change[2].

Ergon Energy does not consider that the identified need for the option included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

5.7. Changes in Electrical Energy Losses

Ergon Energy 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

Ergon Energy does not anticipate that the credible option included in the RIT-D assessment will lead to any material change in greenhouse gas emissions.

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 Ergon Energy 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, known as the counter factual. In the counter factual, the aged SVC is not replaced and experiences escalating rates of failure as its condition degrades. The base case is not a realistic state of the world, because Ergon Energy would be in breach of its regulatory obligations, reliability performance standards and technical requirements (see section 2).

[2] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A.8. Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/regulatory-investment-test-distribution-application-guidelines

The RIT-D analysis has been undertaken over a 40-year period, from 2029 to 2069. Ergon Energy considers this period is appropriate as it takes into account the size, complexity and expected life of the credible option to provide a reasonable indication of the market benefits and costs of the option.

Ergon Energy has adopted a real, pre-tax discount rate of 3.69% as the central assumption for the NPV analysis which 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 the Credible Option

Ergon Energy 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 approach is used in determining the operating costs.

Ergon Energy has estimated the capital and operating costs of the credible option which is inclusive of the following components:

- All material costs.
- 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 1 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.

Table 1: Economic Parameters and Sensitivity Analysis Factors

Parameter	Mode Value	Lower Bound	Upper Bound
Discount Rate	3.69%	2.69%	4.69%

Project Costs	Standard Estimate	-40%	+40%
Opex Costs	Comparative Estimate	-10%	+10%

6.4. Considered Scenarios

Only the base case load forecast scenario has been considered. The variation between the low and high forecast did not have a material impact on the timing or credible options for addressing the identified need.

6.5. Net Present Value (NPV) Results

An overview of the NPV results is provided in Table 2. The only credible option assessed, Option A, shows a positive net NPV of $19,907,000. The large positive benefits NPV figure is due to the reduction in involuntary load shedding expected from Option A by replacing the aged SVC with a more reliable FACTS.

Table 2: NPV Results

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	10Mvar FACTS	1	$19,907,000	-$12,551,000	$731,000	$31,727,000

Further to the base NPV analysis, a Monte-Carlo analysis simulation was undertaken to assess the sensitivity to a change in the parameters of the NPV model. The Monte-Carlo analysis undertook 1000 simulations across the range of variables specified in Table 1. Table 3 summarises the results and shows that Option A has a large, positive NPV across the entire range of simulated variables.

Table 3: NPV Sensitivity Analysis Results

WACC	Option	Option Name	Rank	Average NPV	Maximum NPV	Minimum NPV
2.69%	A	10Mvar FACTS	1	$28,103,000	$33,065,000	$23,189,000
3.69%	A	10Mvar FACTS	1	$20,778,000	$25,412,000	$16,017,000
4.69%	A	10Mvar FACTS	1	$15,466,000	$20,055,000	$10,821,000

7. PREFERRED OPTION

Option A: 10Mvar FACTS 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

Ergon Energy has not identified any social licence considerations that have affected the identification and selection of credible options to address the identified need. The scope of works of the preferred option is contained within the existing site. Given the reliability benefits to the local community, there are not expected to be any social licence issues.

8.2. Community Engagement

As the scope of works for this project will not extend into new areas of the community and will be entirely contained within the existing site owned by Ergon Energy, it is not expected to cause any disruption to the community at large. 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 Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

9. QUERIES IN RELATION TO THIS REPORT

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

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P: 13 74 66

10. COMPLIANCE STATEMENT

This FPAR complies with the requirements of clause 5.17.4(r) of the NER as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	1 and 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 Draft Project Assessment Report;	3
(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
(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 and 6
(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	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	4 and 7
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the FPAR may be directed.	9

11. APPENDIX A – DESIGN PARAMETERS AND SPECIFIED PERFORMANCE LEVELS FOR REACTIVE POWER COMPENSATION AT CHARLEVILLE

All plant and systems supplied under this proposal are required to be designed with respects to the following parameters:

Table 4: Charleville 66/22/11kV Substation Environmental Conditions

Item	Particular	Details
1.1	Altitude	1000 metres above sea level
1.2	Ambient temperature	50°C summer daytime (maximum) -5°C winter night-time (minimum) AS 2067 2.4.3.4 “very hot climates”
1.3	Humidity	100% (maximum) 25% (minimum)
1.4	Isokeraunic level	Ergon Energy standards and AS1768 must be applied for lightning protection design.
1.5	Pollution	Site pollution severity class d (Heavy) in accordance with SA TS60815.1
1.6	Rainfall intensity	Five-minute duration 350 mm/h
1.7	Solar radiation (maximum)	1100 W/m2 AS 2067 normal
1.8	Wind velocity	Wind load in accordance with (AS/NZS 1170.2, 2021) as follows: • Annual probability 1:2000 • Terrain Category 2 • Shielding Multiplier 1.0 • Topographical Multiplier to suit site • Region C with V2000 Wind gust speed 260 km/h (72 m/s)

Table 5: Charleville 66/22/11kV Substation System Conditions

Item	Description	Rating
2.1	Highest voltage, under normal system conditions, for equipment with nominal voltage from 1kV up to 35kV	Per Table 3 of AS 60038-2022
2.2	Highest voltage, under normal system conditions, for equipment with nominal voltage above 35kV and not exceeding 230kV	Per Table 4 of AS 60038-2022

Table 6: Charleville 66/22/11kV Substation Fault Levels

System Configuration	Fault Location	Fault Type	Network Fault Current Contribution at Fault Location (kA)
Existing *distribution system* – system normal	CHAR 11kV Bus	3ϕ - Maximum	1.50
		1ϕ-g - Maximum	2.12
		3ϕ - Minimum	1.26
		1ϕ-g - Minimum	1.79
Existing *distribution system* – N-1 condition (CHAR T1 Out of Service)	CHAR 11kV Bus	3ϕ - Minimum	1.06
		1ϕ-g - Minimum	1.51
Existing *distribution system* – system normal	CHAR 22kV Bus	3ϕ - Maximum	0.75
		1ϕ-g - Maximum	1.00
		3ϕ - Minimum	0.63
		1ϕ-g - Minimum	0.85
Existing *distribution system* – N-1 condition (CHAR T2 Out of Service)	CHAR 22kV Bus	3ϕ - Minimum	0.53
		1ϕ-g - Minimum	0.73
Existing *distribution system* – system normal	CHAR 66kV Bus	3ϕ - Maximum	0.32
		1ϕ-g - Maximum	0.14
		3ϕ - Minimum	0.26
		1ϕ-g - Minimum	0.12
Existing *distribution system* – N-1 condition (ROMA T1 Out of Service)	CHAR 66kV Bus	3ϕ - Minimum	0.24
		1ϕ-g - Minimum	0.12

- Maximum and minimum fault levels are sourced from the published 2025 Ergon Energy Fault Level Summary Report. The information obtained from the report is intended as general in nature, may be based on assumptions that change with time and may not necessarily be complete. Information contained in, or obtained from, the report should not be relied upon, and use of the information contained in the report is at your own risk.
- Fault summaries were performed in Powerfactory with fault level calculation method IEC 60909.
- For minimum faults:
    - The network model used included the full PSSE snapshot (minimum fault level case uses a minimum dispatch scenario with all asynchronous generation offline as provided by Powerlink Queensland) of the NEM, with the addition of all of the relevant Ergon Energy network.
- For maximum faults:
    - Maximum fault levels are produced based on all network elements being 'intact'; where normally open switches, circuit breakers, and isolators are closed within the boundary of a substation to produce the maximum fault levels results for that substation, except where indicated in the report. This assumption can result in short circuit current appearing to be higher at some locations compared to its system normal fault level configuration.

Table 7 lists the Specific Performance Levels required for the proposed solution. Note that additional performance levels and technical requirements might also apply, depending on the type/size of plant used in the solution and the specific connection arrangement. E.g. a HV connected renewable generation solution would be expected to meet Ergon Energy Standard STNW1175 (Standard for High Voltage EG Connections) as well as these Specific Performance Levels.

Table 7: Specific Performance Levels for Reactive Power Compensation at Charleville

Item	Description	Rating
4.1	Likely frequency for which the reactive power support is expected to be dispatched	Continuously 24 h x 365 days / year
4.2	Maximum time taken to become fully available to provide the service following a 66kV circuit breaker reclose event at Roma	0 s (must remain operational following a reclose event and ride through other dips or transients)
4.3	Minimum continuous reactive power capability range at connection point: 0.9 - 1.1 pu voltage, frequency 49.75 to 50.25 Hz at Charleville substation	±10 Mvar (10 Mvar Inductive to 10 Mvar Capacitive)
4.4	Capability for system to be easily expanded in the future if required	Expandable to ± 15 Mvar
4.5	Redundancy of system design	System must retain 50% of reactive power capacity in the event of a single failure of any system element (N – 1)
4.6	Be capable, on receipt of appropriate input signals, of changing its output from fully inductive to fully capacitive	≤ 40 ms
4.7	Capability of continuous uninterrupted operation during and following a system voltage disturbance e.g. a load reduction event	Capable of continuous operation for voltage changes of up to 30% from its pre-disturbance level
4.8	Black-start capability	System must be able to provide reactive power support during re-energisation of the 66kV line from Roma
4.9	Average Annual Availability (*)	99.81% (8743 h / yr)

	% Availability $= \frac{\text{Total Time VCNSS is able to Perform Specific Performance Levels}}{\text{Total Time Period}}$	
4.10	Maximum percentage Downtime (**) $\%\,\text{Downtime} = \frac{\text{Total Downtime}}{\text{Total Time Period}} \times 100$ also, $\%\,\text{Downtime} = 100 - \%\,\text{Availability}$	0.19% (17 h / yr)
4.11	Maximum number of downtime events	1 / yr
4.12	System voltage at point of connection	
	a. Nominal system voltage	66kV / 22kV / 11kV
	b. Voltage range for continuous operation	0.9 to 1.1 pu of nominal
4.13	Measurement accuracy for voltage transformers	Class 0.5M
4.14	Allowable Droop Settings	
	a. Boost	0% to 10%, 0.1% increment
	b. Buck	0% to 10% 0.1 % increment
	c. Voltage Dead band	0 to ±0.1 pu 0.001 pu increment
4.15	Required to ride through and operate to the expected performance levels during and following power system voltage, frequency and voltage/current waveform disturbances some of which may occur simultaneously as follows:	
	a. Maximum temporary voltage (30 sec)	1.30 pu V
	b. Minimum temporary voltage (30 sec)	0.70 pu V
	c. Long term over-voltage (1800s)	1.15 pu V

	d. Short term over-voltage (0.2s)	1.50 pu V
	e. A drop in one or more phases of the voltage at the point of connection	0.5 pu V for 0.6 sec
	f. Voltage oscillating (at a frequency of ± 0.25 to ± 2.5Hz)	0.7 to 1.3 pu V
	g. Worst asymmetrical faults to be expected at 66 kV bus	0.25 pu V
	h. Worst asymmetrical faults to be expected at 22 kV bus	0.33 pu V
	i. Worst asymmetrical faults to be expected at 11 kV bus	0.33 pu V
	j. A switching surge of 2.2 pu at the connection point	Up to 20 msec
	k. A fall in system frequency to 46.5 Hz, with recovery to 46.5 – 52.5 Hz	Within 4 minutes
	l. High speed autoreclose	
	i. Dead time	5 – 15 s
	ii. Reclaim time	20 s
4.16	Maximum allowable reactive power step	0.03 pu
4.17	System frequency at point of connection	
	a. Nominal frequency	50 Hz
	b. Normal control range	49.75 - 50.25 Hz
	c. Transient excursions (less than 10 minutes)	49.0 - 51.0 Hz
	d. Transient excursions (less than 2 minutes)	46.5 - 52.5 Hz
4.18	Maximum equipment design fault currents	
	a. 66kV	25kA rms for 3 s
	b. 22kV	25kA rms for 3 s
	c. 11kV	25kA rms for 3 s
4.19	Negative Phase Sequence Control	
	a. Minimum reactive power required, per phase, for individual phase control.	1/3 of ± 10 Mvars
	b. Typical dead band setting	0 - 10%
	c. Deadband setting range	4%
4.20	Power System Monitoring	
	a. Power Quality Measurement System	Relevant IEC Standards Up to 100th Harmonics
	b. High Speed Fault Recorder System (multi-channels)	Up to 24kHz per channel
	c. Synchrophasor Measurement Units (PMU)	Per Standard IEC / IEEE 60255-118-1:2018
4.21	Maximum allowable sound pressure levels at one metre outside VCNSS perimeter fence	55 dBA

4.22	Maximum Radio Interference Voltage outside of the VCNSS perimeter fence.	500 µV
4.23	Maximum Allowable Electric Field	
	a. Occupational for the whole working day	10 kV/m
4.24	Maximum Allowable Magnetic Field	
	a. Occupational for the whole working day	10,000 mG

(*) The system is considered to be available for service only if it is able to perform the whole of the specified duty. Operation with limited control functions or within a limited range of outputs not meeting the specified levels due to a component, software or subsystem failure is to be treated as unscheduled servicing downtime.

(**) Total Downtime within a Total Time Period is defined as the sum of the scheduled service downtime and unscheduled service downtime.