January 2026

Powerlink 2027-32 Revenue Proposal

Project Pack

CP.02860 Ingham South Substation Reinvestment

Project Status: Stage 1 Approved

Network Requirement

The Ingham South Substation was commissioned in 2005 and is a critical node in Powerlink Queensland's 132kV transmission network, supplying the Ergon 66kV Ingham Substation and the broader Ingham load centre. The substation includes two 132/66kV transformers, three 132kV PASS M0 hybrid modules (now obsolete), and secondary systems installed between 2005 and 2008.

The primary switchgear and secondary systems at Ingham South Substation have been identified as being in poor condition or at the end of their technical service lives, with identified obsolescence issues. The condition of the substation's primary switchgear has significantly deteriorated, with a high number of associated defects and obsolescence issues, increasing the risk to supply in the Ingham area. The site utilises gas insulated hybrid modules for all switching bays and manufacturer support has ceased for these units and there are now limited spares available. This poses a significant risk to Powerlink's ability to undertake emergency replacement works as there is no direct like for like replacement option.

The secondary systems at Ingham South Substation are also nearing the end of their technical service lives and have become or are becoming obsolete, where they are no longer supported by the manufacturer and have only limited, or no, spares available.

Powerlink must therefore take action to avoid the increasing likelihood of unserved energy arising from failure of the aging equipment at the substation and to ensure customers are provided with a reliable and safe supply of electricity.

Planning studies have confirmed that in order to continue to meet the reliability standard in Powerlink's Transmission Authority, the services currently provided by Ingham South Substation are required into the foreseeable future to meet ongoing customer requirements. [1]

Recommended Option

The project need and options are currently being assessed via a public Regulatory Investment Test for Transmission (RIT-T) consultation process. The following credible options are being considered in the RIT-T process:

Option 1: Replace hybrid switchgear modules in-situ with air insulated switchgear. Replace secondary systems in a new control building on existing substation platform by 2028.

Option 2: Extend substation platform and replace hybrid switchgear modules with air insulated switchgear using adjacent spare bay locations. Replace secondary systems in a new control building by 2028.

Cost and Timing

The estimated cost of option 1 is $25.6 million ($2025/26). The expected commissioning date for the project is February 2028. [2]

Documents in CP.02860 Project Pack

Public Documents

1. Maintaining Reliability of Supply and Addressing Condition Risks at Ingham South – Project Specification Consultation Report
2. CP.02860 Ingham South Substation Reinvestment – Project Management Plan

10 JUNE 2025

Maintaining Reliability of Supply and Addressing Condition Risks at Ingham South

Project Specification Consultation Report

Preface

Powerlink Queensland is a Transmission Network Service Provider (TNSP) that owns, develops, operates and maintains Queensland's high-voltage electricity transmission network. The network transfers bulk power from Queensland generators to electricity distributors Energex and Ergon Energy (part of the Energy Queensland Group), and to a range of large industrial customers.

This Project Specification Consultation Report has been prepared in accordance with version 230 of the National Electricity Rules (NER), and the Regulatory Investment Test for Transmission (RIT-T) Instrument (November 2024) and RIT-T Application Guidelines (November 2024). The RIT-T Instrument and Application Guidelines are made and administered by the Australian Energy Regulator.

The NER requires Powerlink to carry out forward planning to identify future reliability of supply requirements, which may include replacement of network assets or augmentations of the transmission network. Powerlink must then identify, evaluate and compare network and non-network options (including, but not limited to, generation and demand side management) to identify the preferred option which can address future network requirements at the lowest net cost to electricity customers.

Powerlink also has obligations under the NER to address power system security requirements identified by the Australian Energy Market Operator in its annual System Security Reports.

The main purpose of this document is to provide details of the identified need, credible options, technical characteristics of non-network options, and categories of market benefits likely to impact selection of the preferred option. In particular, it encourages submissions from potential proponents of feasible non-network options to address the identified need.

This document also provides customers, stakeholders and communities with information on the potential investment/s (network and non-network) that are required in the near-term to meet an identified need, and offers the opportunity to provide input into the future development of the transmission network in Queensland.

More information on the RIT-T process and how Powerlink applies it to ensure that safe, reliable and cost-effective solutions are implemented to deliver better outcomes to customers is available on Powerlink's website.

A copy of this report will be made available to any person within three business days of a request being made. Requests should be directed to the Manager Network and Alternate Assessments, by phone ((07) 3860 2111) or email (networkassessments@powerlink.com.au).

Powerlink acknowledges the Traditional Owners and their custodianship of the lands and waters of Queensland and in particular, the lands on which we operate. We pay our respect to their Ancestors, Elders and knowledge holders and recognise their deep history and ongoing connection to Country.

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Executive Summary

Ageing and obsolete secondary systems and primary plant at Ingham South Substation require Powerlink to take action

Ingham South Substation was established in 2005 to replace the original Ingham substation equipment and provide an injection point into the Ergon Energy (part of the Energy Queensland Group) distribution network. Planning studies have confirmed there is an enduring need for Ingham South Substation to maintain the supply of electricity to the Ingham area and meet legislative requirements.

The primary switchgear and secondary systems at Ingham South Substation have been identified as being in poor condition or at the end of their technical service lives, with identified obsolescence issues. The condition of the substation's primary switchgear – the equipment through which the electrical power passes – has significantly deteriorated, with a high number of associated defects and obsolescence issues, increasing the risk to supply in the Ingham area. The site utilises gas insulated hybrid modules for all switching bays and manufacturer support has ceased for these units and there are now limited spares available. This poses a significant risk to Powerlink's ability to undertake emergency replacement works as there is no direct like for like replacement option.

Secondary systems are the control, protection and communications equipment that are necessary to operate the transmission network and prevent damage to primary systems when adverse events occur. Many of the secondary systems at Ingham South Substation are nearing the end of their technical service lives and have become or are becoming obsolete, where they are no longer supported by the manufacturer and have only limited, or no, spares available. Under the National Electricity Rules (NER), Powerlink is required to provide sufficient secondary systems, including redundancies, to ensure the transmission system is adequately protected.

Powerlink must therefore take action to avoid the increasing likelihood of unserved energy arising from failure of the aging equipment at Ingham South substation and to ensure customers are provided with a reliable and safe supply of electricity.

Powerlink is required to apply the Regulatory Investment Test for Transmission

The estimated capital cost of the most expensive credible option to address secondary system and primary plant risks at Ingham South Substation meets the minimum threshold (currently $8 million) to apply the Regulatory Investment Test for Transmission (RIT-T). As the identified need for the proposed investment is to meet reliability and service standards specified within Powerlink's Transmission Authority, guidelines and standards published by AEMO, and Powerlink's ongoing compliance with Schedule 5.1 of the NER, it is classified as a reliability corrective action under the NER. The identified need is not discussed in AEMO's most recent Integrated System Plan (ISP) and is therefore subject to the application and consultation process for RIT-T projects that are not actionable ISP projects. As the identified need is a reliability corrective action, the preferred option may have a net economic cost.

Powerlink will adopt the expedited process for non-ISP projects for this RIT-T, as the estimated capital cost of the preferred option is below $54 million and is unlikely to result in any material market benefits, other than those arising from a reduction in involuntary load shedding. The reduction in involuntary load shedding under the credible network options is included in the risk cost modelling and consequentially represented in the economic analysis of the options.

Powerlink has developed a non-credible base case against which to compare credible options

Powerlink has modelled a non-credible option where the asset condition issues are managed via operational maintenance or operational measures only. This would result in an increase in overall risk levels due to continuing deterioration of asset condition and increasing failure rectification timeframes due to obsolescence issues. These increasing risk levels are assigned a monetary value and added to the ongoing maintenance costs to form the base case.

Powerlink has developed two credible network options to address the identified need

The table below details the credible network options and shows that both options have a negative Net Present Value (NPV) relative to the base case, as allowed for under the NER for reliability corrective actions. Of the credible network options, Option 1 has the highest NPV relative to the base case.

Summary of Credible Options

Option	Description	Total Costs ($m, 2025)	NPV relative to base case ($m)	Ranking
1	Replace hybrid switchgear modules in-situ with air insulated switchgear. Replace secondary systems in a new control building on existing substation platform by 2028.	25.60	-17.58	1
2	Extend substation platform and replace hybrid switchgear modules with air insulated switchgear using adjacent spare bay locations. Replace secondary systems in a new control building by 2028.	31.62	-22.10	2

Note: Total costs exclude risk and contingency.

Powerlink welcomes the potential for non-network options to form part or all of the solution

To enhance engagement outcomes, Powerlink proactively applies an engagement strategy to each RIT-T consultation. The scope of engagement activities undertaken is dependent upon various considerations, such as the characteristics and complexity of the identified need and potential credible options outlined in the RIT-T stakeholder engagement matrix. A non-network option that avoids the proposed replacement of the ageing assets would need to provide supply to the 66kV network of up to a peak of 22 megawatts, and up to a peak of 370 megawatt hours per day on a continuous basis. Powerlink welcomes submissions from proponents who consider they could offer a potential non-network option that is both economically and technically feasible, on an ongoing basis.

Lodging a submission with Powerlink

Powerlink seeks written submissions on this Project Specification Consultation Report (PSCR), on or before **Friday, 5 September 2025**, particularly on the credible options presented in this PSCR. Submissions should be addressed to:

Monan Higgs
Manager Network and Alternate Solutions
Powerlink Queensland
PO Box 1193
VIRGINIA QLD 4014
Telephone: (07) 3860 2111; Email: networkassessments@powerlink.com.au

1. Introduction

1.1. Powerlink asset management and obligations

Powerlink is committed to sustainable asset management practices. To ensure a consistent approach that delivers cost-effective and efficient services, Powerlink's Asset Management System is adapted from the Institute of Asset Management and aligns with ISO55000 Asset Management Standards.[1] Powerlink's approach to asset management delivers value to customers and stakeholders by optimising whole of life cycle costs, benefits and risks, while ensuring compliance with relevant legislation, regulations and standards. This is underpinned by Powerlink's corporate risk management framework and international risk assessment guidelines and methodologies.

1.2. Overview of the Regulatory Investment Test for Transmission

The purpose of a Regulatory Investment Test for Transmission (RIT-T) is to identify the preferred investment option that meets the identified network need. The preferred option maximises the present value of economic benefits, taking into account changes to Australia's greenhouse gas emissions where relevant. If the identified need is for a reliability corrective action, the preferred option may have a net economic cost.[2]

Powerlink applies the RIT-T to potential prescribed (regulated) investments in the transmission network where the estimated capital cost of the most expensive option exceeds $8 million.[3] The identified need referred to in this RIT-T – to maintain reliability of supply and address condition risks at Ingham South – is not included in AEMO's most recent Integrated System Plan (ISP), published in June 2024. As such, this RIT-T is subject to the application and consultation process for RIT-T projects that are not actionable ISP projects.[4] This Project Specification Consultation Report (PSCR) is the first step in the RIT-T process.[5] More information on the RIT-T process is provided in Appendix 1.

2. Consumer and Non-network Engagement

More than five million Queenslanders and 241,000 Queensland businesses depend on Powerlink's performance. Powerlink recognises the importance of engaging with a diverse range of customers and stakeholders who have the potential to affect, or be affected by, Powerlink activities and/or investments.

Together with our industry counterparts from across the electricity and gas supply chain, Powerlink has committed to the Energy Charter. The charter is a national CEO-led collaboration that supports the energy sector towards a customer-centric future. Powerlink joins other signatories in committing to progress the culture and solutions needed to deliver more affordable, reliable and sustainable energy systems. Powerlink's Energy Charter Disclosure Statement for 2023/24 shows Powerlink's achievements against the principles of the Energy Charter.

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[1] Refer to AS *ISO55000:2014 Asset Management – Overview, principles and terminology*.

[2] National Electricity Rules, clause 5.15A.1(c) and chapter 10, glossary ('net economic benefit').

[3] National Electricity Rules, clauses 5.15.3(a) and (b)(2) set the threshold at $5 million. The Australian Energy Regulator's (AER) latest cost threshold review increased the value to $8 million for three years from 1 January 2025.

[4] National Electricity Rules, rule 5.16.

[5] This RIT-T consultation process has been prepared in accordance with clauses 5.16.4(b) to (g) of the National Electricity Rules and AER, *Regulatory Investment Test for Transmission Application Guidelines*, November 2024.

2.1. Powerlink takes a proactive approach to engagement

Powerlink regularly hosts a range of activities to provide timely and transparent information to customers and stakeholders within the broader community.

Powerlink's annual Transmission Network Forum (TNF) is a primary vehicle used to engage with the community, understand broader customer and industry views and obtain feedback on key topics. It also provides Powerlink with an opportunity to further inform its business network and non-network planning objectives. TNF participants include customers, landholders, environmental groups, Traditional Owners, government agencies, and industry bodies.

Engagement activities such as the TNF help inform the future development of the transmission network and assist Powerlink in providing services that align with the long-term interests of customers. Powerlink also incorporates feedback from these activities into a number of publicly available reports.

2.2. Working collaboratively with Powerlink's Customer Panel

Powerlink's Customer Panel provides a face-to-face opportunity for customers and consumer representatives to give their input and feedback about Powerlink's decision-making, processes and methodologies. The panel also provides Powerlink with a valuable avenue to keep customers and stakeholders better informed, and to receive feedback about topics of relevance, including RIT-Ts.

The Customer Panel is regularly advised on the publication of Powerlink's RIT-T documents, and is briefed quarterly on the status of current RIT-T consultations as well as upcoming RIT-Ts. This provides an ongoing opportunity for the Customer Panel to ask questions and provide feedback to further inform RIT-Ts, and for Powerlink to better understand the views of customers when undertaking the RIT-T consultation process.

Powerlink will continue to provide updates to and request input from the Customer Panel throughout the RIT-T consultation process.

2.3. Transparency on future network requirements

Powerlink's annual planning review findings are published in the Transmission Annual Planning Report (TAPR) and TAPR templates (available via the TAPR portal). It provides early information and technical data to customers and stakeholders on potential transmission network needs over a 10-year outlook period. The TAPR plays an important part in planning Queensland's transmission network and helping to ensure it continues to meet the needs of Queensland electricity consumers and participants in the National Electricity Market (NEM).

Powerlink's 2023 and 2024 TAPRs identified a need to address emerging obsolescence and compliance risks on 132kV primary plant and secondary systems at the Ingham South Substation. The 2024 TAPR indicated the full replacement of primary plant and secondary systems, for an estimated cost of $27 million by December 2027, as the proposed network solution.[6]

Powerlink has not received any submissions from prospective non-network solution providers proposing credible, genuine non-network options in the normal course of business, in response to the publication of TAPRs, or as a result of stakeholder engagement activities.

[6] Powerlink, *2024 Transmission Annual Planning Report*, October 2024, page 112. Powerlink's 2021 and 2022 TAPRs also discussed the need to address secondary system condition risks at Ingham South Substation.

2.4. Powerlink applies a considered approach to RIT-T engagement

Powerlink undertakes a considered and consistent approach to ensure an appropriate level of stakeholder engagement is undertaken for each individual RIT-T consultation. The scope of engagement activities is dependent upon various considerations, such as the characteristics and complexity of the identified need and potential credible options.

For all RIT-Ts, members of Powerlink's Non-network Engagement Stakeholder Register receive email notifications of publication of RIT-T reports. For projects where Powerlink identifies material or significant market benefits, additional activities such as webinars or dedicated engagement forums may be appropriate. For more information, see Powerlink's RIT-T stakeholder engagement matrix.

2.5. Community engagement

Powerlink recognises the importance of engaging with stakeholders who may reasonably be expected to be affected by the works required to meet the identified need described in this PSCR.

The engagement frameworks and strategies that underpin Powerlink's engagement approach include:

- The International Association for Public Participation (IAP2) spectrum[7], noting each stakeholder group has unique needs and requires an individual assessment on the spectrum;
- Powerlink's Stakeholder Engagement Framework, Community Engagement Strategy and Reflect Reconciliation Action Plan; and
- the Energy Charter Landholder and Community Better Practice Engagement Guide; and Better Practice Social Licence Guideline.

2.5.1. Powerlink assesses the requirement for community engagement based on the identified need

Powerlink undertakes an assessment of the potential for social and environmental impacts of anticipated replacement or augmentation projects well in advance of the identified need timing. Understanding if and when community engagement may be required, as well as the appropriate engagement approach, is an integral component of the early planning analysis needed to inform option identification, consideration of statutory processes (e.g. Ministerial Infrastructure Designation if required) and subsequent project development strategy and engagement plans.

Powerlink's engagement approach is tailored to maximise the accessibility of the proposed project's information to the stakeholder groups and/or communities affected by the project once the need to undertake community engagement is identified. Key stakeholders may include, but are not limited to, directly impacted and adjacent landholders, Traditional Owner groups, local residents, businesses and other organisations such as schools, community organisations and environmental groups as well as local government authorities and elected representatives within local and state governments.

2.5.2 Assessment and basis of assessment on the need for community engagement

Powerlink has assessed that minimal community engagement is required given the scope of works under consideration for any proposed network options to meet the identified need. This is due to all network options

[7] Refer to IAP2's website.

including replacement of equipment within the existing Ingham South substation. Powerlink will provide notifications to nearby residents to ensure all affected parties are appropriately informed of project activities.

3. Identified Need

In a RIT-T, the identified need is the objective the RIT-T proponent seeks to achieve by investing in the network.[8] The identified need should be framed in terms of why an investment is required, rather than as a description of a particular solution to a network need. The Australian Energy Regulator's (AER) RIT-T Application Guidelines note that network and non-network options can address an identified need.[9]

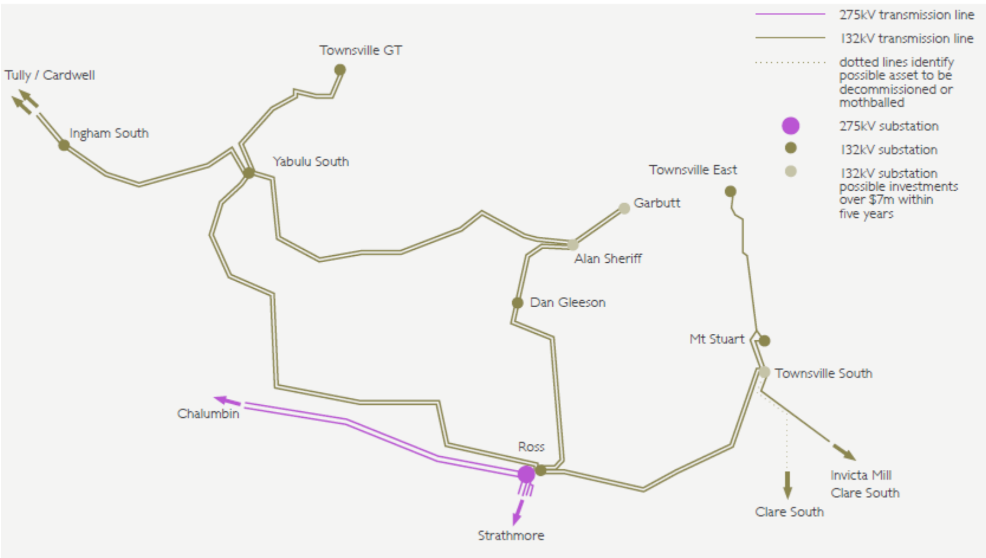
The primary driver for reinvestment at Ingham South Substation is plant reliability leading to loss of load to the Ingham load centre, as a result of the condition of secondary and primary plant assets. Ingham South Substation also forms part of the coastal 132kV network to Far North Queensland.

3.1. Geographical and network need

Ingham South Substation is approximately 110 kilometres (km) north of Townsville, and 1.6km south of Ingham city centre. The substation was established in 2005 to replace the original Ingham substation equipment and provide an injection point into the Ergon Energy (part of the Energy Queensland Group) distribution network. Planning studies have confirmed there is an enduring need for Ingham South substation to maintain the supply of electricity to the Ingham area.

As shown below, Ingham South Substation is located in the Ross zone of Powerlink's Northern Queensland region.

Figure 3.1: Northern Ross Zone Transmission Network



[8] National Electricity Rules, chapter 10 (definition of 'identified need').
[9] AER, *Application Guidelines, Regulatory Investment Test for Transmission*, November 2024, page 13.

3.2. Description of identified need

Powerlink's Transmission Authority requires it to plan and develop the transmission 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. It allows load to be interrupted during a critical single network contingency, provided the maximum load and energy will not exceed 50 megawatts (MW) at any one time, or will not be more than 600 megawatt hours (MWh) in aggregate.[10] The Transmission Authority is also subject to a broader obligation under the *Electricity Act 1994* (Qld) (the Electricity Act) that Powerlink operate, maintain (including repair and replace if necessary) and protect its transmission grid to ensure the adequate, economic, reliable and safe transmission of electricity.[11]

Secondary systems are used to control, monitor, protect and secure communication to facilitate safe and reliable network operation.[12] Schedule 5.1 of the NER sets minimum standards for network service providers on the availability and operation of protection systems. Schedule 5.1.9(c) specifically requires Powerlink provide sufficient primary and back-up protection systems (including breaker fail protection systems) to ensure that a fault anywhere on the transmission system is automatically disconnected.[13]

Protection systems are also important for maintaining power transfer following a credible contingency event, such as the disconnection of a generating unit or transmission line. Powerlink is required to ensure that all protection systems for lines at voltages above 66kV, including associated inter-tripping, are well maintained so as to be available at all times other than for periods not greater than eight hours while maintenance of a protection system is being carried out.[14]

AEMO's Power System Security Guidelines clarify the Registered Participant response to unplanned outages of the protection systems. In the event of an unplanned outage of a secondary system, the guidelines require that the primary network assets be taken out of service if the fault cannot be rectified within 24 hours, obligating Powerlink to take action to ensure the restoration period of unplanned outages of secondary systems does not exceed 24 hours.[15]

Similar to protection requirements, AEMO's Power System Data Communication Standard specifies that the total period of critical outages over a 12-month period must not exceed 24 hours for remote control and monitoring functions.[16] This relates to both the reliability of the equipment (i.e. how often the device fails) and the repair time. It follows that the repair time for any single fault on this equipment must not exceed 24 hours if there are no other faults during the 12-month period. Powerlink must therefore plan (have systems and processes in place) to safely resolve all protection, remote control and monitoring system problems and defects within 24 hours.

[10] Transmission Authority No. T01/98, section 6.2(c).
[11] *Electricity Act 1994* (Qld), section 34(1)(a).
[12] National Electricity Rules, Schedule 5.1.
[13] National Electricity Rules, Schedule 5.1.9(c).
[14] National Electricity Rules, Schedule 5.1.2.1(d).
[15] AEMO, *Power System Operating Procedure SO_OP_3715*, Power System Security Guidelines, Version 105, June 2024, section 13.3 (Unplanned Outage of One Protection of a Duplicated Scheme). AEMO develops and publishes the Power System Operating Procedures pursuant to clause 4.10.1(b) of the NER, which Powerlink must comply with as per clause 4.10.2(b).
[16] AEMO, *Power System Data Communication Standard*, Version 3.0, April 2023, section 3 (Reliability) and section 6 (Maintenance, planning and testing). AEMO makes the standard under clause 4.11.2(c) of the NER and incorporates the standards and protocols referred to in clauses 4.11.1 and 4.11.2.

The primary switchgear and secondary systems at Ingham South Substation have been identified as being in poor condition or at the end of their technical service lives, with identified obsolescence issues. The condition of the substation's primary switchgear – the equipment through which the electrical power passes – has significantly deteriorated, with a high number of associated defects and obsolescence issues, increasing the risk to supply in the Ingham area. The site utilises gas insulated hybrid modules for all switching bays and manufacturer support has ceased for these units and there are now limited spares available. This poses a significant risk to Powerlink's ability to undertake emergency replacement works as there is no direct like for like replacement option.

The secondary systems at Ingham South Substation are also nearing the end of their technical service lives and have become or are becoming obsolete, where they are no longer supported by the manufacturer and have only limited, or no, spares available.

Powerlink must therefore take action to avoid the increasing likelihood of unserved energy arising from failure of the aging equipment at the substation and to ensure customers are provided with a reliable and safe supply of electricity.

As the proposed investment is for meeting reliability and service standards arising from Powerlink's Transmission Authority and to ensure Powerlink's ongoing compliance with Schedule 5.1 of the NER, it is a reliability corrective action under the NER.[17] A reliability corrective action differs from that of an increase in producer and consumer surplus (market benefit) driven need in that the preferred option may have a negative net economic outcome because it is required to meet an externally imposed obligation on the network business.[18]

3.3. Assumptions and requirements underpinning the identified need

Planning studies have confirmed that in order to continue to meet the reliability standard in Powerlink's Transmission Authority, the services currently provided by Ingham South Substation are required into the foreseeable future to meet ongoing customer requirements.

Powerlink's condition assessment of the hybrid switchgear modules has highlighted that they are operating in a deteriorated condition. The consequence of these at-risk modules remaining in service beyond 2028, without corrective action, would result in Powerlink being exposed to potential risk of failure. This could lead to a breach of Powerlink's obligations under the *Electrical Safety Act 2002* (Qld) and Regulations, *Work Health and Safety Act 2011* (Qld), and *Environmental Protection Act 1994* (Qld), as well as service standards under the Electricity Act and Regulations, and Powerlink's Transmission Authority. The failure of the hybrid modules to operate or clear faults in sufficient time to avoid damage to the power system may leave Powerlink unable to meet its public safety and supply obligations to its customers.

Removing the deteriorated assets from service will in many cases eliminate the risk of breaching these safety obligations. However, removing the assets from the Powerlink network without a suitable network or non-network alternative would result in Powerlink not complying with the NER or its Transmission Authority. This would result in the need for load shedding to ensure that the system is able to be operated without breaching the satisfactory operating state provisions in clause 4.2.2(d) of the NER.

The load shedding requirement under an intact system, as well as for a credible contingency, would result in breaches of Powerlink's Transmission Authority.

[17] National Electricity Rules, clause 5.10.2 (definition of 'reliability corrective action').
[18] National Electricity Rules, clause 5.15A.1(c).

Powerlink analysis, based on historical equipment performance, has shown that operating a secondary system beyond 20 years of effective age significantly impacts its ability to perform within acceptable limits.[19] Delaying replacement of secondary system assets beyond this optimal 20-year timeframe places the network at risk due to the limited supply of suitable spares, which prolongs the duration of any emergency corrective maintenance associated with replacing failed obsolete components beyond the 24-hour limit. In the case of protection systems, extended outages beyond 24 hours will result in the need to switch out network assets, placing the supply of electricity to customers at risk.[20]

With an increasing likelihood of faults and longer rectification periods arising from the ageing secondary systems and primary plant remaining in service at Ingham South Substation, Powerlink must undertake reliability corrective action if it is to continue to meet its jurisdictional obligations and the standards for reliability of supply set out by AEMO and in the NER.

3.4. Description of asset condition and risks

Primary Plant

The hybrid switchgear modules were installed at Ingham South in 2005 and enclose all functions of a complete switchgear bay in a single gas insulated module. Each three phase module includes the circuit breaker, disconnector and earthing switches, voltage transformers and current transformers.

The condition of the hybrid switchgear modules has significantly deteriorated, resulting in numerous defects, some of which have caused maloperations. Despite increased maintenance activities and refurbishment projects to address these issues, the number of ongoing defects has not been reduced. A recent condition assessment indicates that condition driven risks associated with the existing hybrid switchgear modules should be addressed by 2028 in order to maintain the current network reliability and availability.

Powerlink has undertaken a comprehensive condition assessment of the hybrid switchgear modules at Ingham South Substation using an asset health index modelled from zero (0) to ten (10), where zero represents new assets and ten indicates that the asset requires urgent action to address the increasing risk of unavailability and unreliable operation. This has identified that these modules will reach the end of their technical service lives by 2028. The condition of the at-risk primary plant at Ingham South Substation is summarised in the table below.

[19] CIGRE (International Council on Large Electric Systems), Study Committee B3, Paper B3_205_2018, 'Modelling Substation Control and Protection Asset Condition for Optimal Reinvestment Decision Based on Risk, Cost and Performance' by T. Vu, M. Pelevin, D. Gibbs, J. Horan, C. Zhang (Powerlink Queensland).
[20] AEMO, *Power System Operating Procedure SO_OP_3715*, Power System Security Guidelines, Version 104, June 2024.

Table 3.1: At-risk 132kV primary plant

Bay	Construction Year	Average Health Index
Feeder Bay D06 Hybrid Module	2005	8
Feeder Bay D03 Hybrid Module	2005	9
Coupler Bay D05 Hybrid Module	2005	7

Secondary Systems

The secondary system was installed around 2005, with some equipment added between 2005 and 2013. A recent condition assessment indicates that condition driven risks associated with existing secondary systems equipment should be addressed by 2028 in order to maintain the current network reliability and availability.

Powerlink has undertaken a comprehensive condition assessment of the secondary systems at Ingham South Substation using the same asset health index approach used to assess the primary plant. This has identified that a significant amount of the 132kV secondary system equipment at Ingham South will reach the end of their technical service lives by 2028. The condition of the at-risk secondary systems at Ingham South Substation is summarised in the table below.

Table 3.2: At-risk 132kV secondary systems

Panel	Construction Year	Average Health Index
Metering	2005	9.8
2x Feeder Bays Protection and Control	2005, 2013	9.8
1x Coupler Bay Protection and Control	2005	9.8
Non-bay Secondary Systems (includes OpsWAN, SCADA, RTUs)	2005	9.7
2x Transformer Bays Protection and Control	2005	9.8

Notwithstanding the assessed condition of the asset, Powerlink's ongoing operational maintenance practices are designed to monitor equipment condition and ensure any emerging risks are proactively managed.

3.5. Consequences of failure of primary plant

Poor asset condition increases the risk and frequency of faults, while obsolescence increases the time needed for Powerlink to undertake any necessary repairs, prolonging the return to service time. Due to the substation's configuration, utilising the same breakers for feeder and transformer protection, failure of a breaker to operate to clear a fault, could result in loss of supply to Ingham substation and the vicinity. The potential in-service failure of ageing primary plant at Ingham South presents Powerlink with a range of unacceptable safety, network and financial risks, and the inability to meet legislative obligations and customer service standards. The condition and consequences of failure of the main at-risk items of equipment is summarised in the table below.

Table 3.3: Summary of primary plant condition issues and potential consequences of failure

Equipment	Condition / Issue	Potential Consequences of Failure
Hybrid Switchgear Modules	• Obsolescence and limited availability of spares; no longer supported by the manufacturer. • No direct like for like replacement option • Increasing failure rates of circuit breakers, current transformers and disconnectors/earth switches due to deteriorated components. • SF6 leaks, corrosion and moisture ingress issues	• Failure to operate to clear a fault, resulting in slower clearance times and additional plant being taken out of service to clear the fault, increasing supply risk. • Extended time to restore supply to customers due to a limited availability of spares • Environmental impacts from SF6 gas release • Increased maintenance resulting in less reliable and more costly supply to customers

3.6. Consequences of failure in an obsolete secondary system

The duration of a fault is not only dependent on the nature and location of the fault, but also on the availability of a like-for-like replacement of the failed component. If a like-for-like replacement is available (i.e. same hardware and firmware as the failed device), then the replacement is often not complex and can generally be rectified within the timeframes specified by AEMO. If a like-for-like replacement is not available, then replacement is operationally and technically more complex due to:

- physical differences with the mounting and installation;
- development and testing of new configurations and settings;
- cabling, connectivity and protocol differences;
- interoperability between other devices on site, and with remote ends (if applicable);
- non-standard settings / configuration requirements; and
- legislative requirements for professional engineering certification.

All of the above complexities add time to fault resolution, typically resulting in a fault duration well in excess of 24 hours.

Given the specific nature of the NER obligations and the AEMO requirements relating to protection, control and monitoring systems, accepted good industry practice is often to replace the ageing and obsolete secondary systems when they reach the end of their technical service lives, rather than letting them run to failure. Due to the condition and obsolescence issues with the secondary systems at Ingham South Substation, there is a significant risk of breaching the mandated obligations and requirements if the secondary systems are left to operate beyond February 2028. A summary of the equipment condition issues and associated potential consequences of failure of the equipment is shown in the table below.

Table 3.4: Summary of secondary systems equipment condition issues and potential consequences of failure

Equipment	Condition / Issue	Potential Consequences of Failure
Protection and Control for High Voltage Bay	• Obsolescence and limited availability of spares; no longer supported by the manufacturer. • Increasing failure rates due to ageing electronic components.	• Failure to operate to clear a fault, resulting in slower clearance times and additional plant being taken out of service to clear the fault, increasing supply risk. • Prolonged outages of equipment placing load at risk and resulting in less reliable supply to customers. • Unable to comply with Power System Data Communication Standard. • Unable to comply with the Power System Security Guidelines. • Increased failures resulting in less reliable supply to customers.
SCADA System	• Obsolescence and limited availability of spares; no longer supported by the manufacturer. • Increasing failure rates due to ageing electronic components.	• Unable to comply with the Power System Security Guidelines. • Increased failures resulting in less reliable supply to customers.
Metering	• Obsolescence and limited availability of spares; no longer supported by the manufacturer. • Increasing failure rates due to ageing electronic components.	• Unable to restore metering installation upon malfunction within the two business days – requirement of the NER.[21]

In addition to the site-specific impacts of obsolescence at Ingham South Substation, it is also important to note the compounding impact of equipment obsolescence occurring across the fleet of secondary systems assets installed in the Powerlink network. When a particular equipment type or model is no longer supported by the manufacturer, and limited spares are available to service the fleet of assets, running multiple secondary systems to failure across the network increases the likelihood of concurrent systemic faults that would overwhelm Powerlink's capacity to undertake corrective maintenance or replacement projects. This would leave Powerlink in breach of the NER, the AEMO standards and jurisdictional obligations.

4. Required Technical Characteristics for Non-network Options

The information provided in this section is intended to enable interested parties to formulate and propose genuine and practicable non-network solutions such as, but not limited to, local generation and demand side management initiatives.

[21] National Electricity Rules, clause 7.8.10.

Powerlink welcomes submissions from proponents who consider that they could offer a non-network solution in full or in part by 2028 on an ongoing basis, and will investigate the feasibility of any potential non-network option proposed or otherwise identified.

4.1. Criteria for proposed network support services

Non-network solutions would need to replicate, in part or full, the support that Ingham South Substation delivers to customers in the area on a cost-effective basis. That is, a non-network solution would need to provide supply to the 66kV network of up to a peak of 22MW, and up to a peak of 370MWh per day on a continuous basis.

Powerlink is not aware of any Demand Side Management (DSM) in the Ingham Load centre. However, Powerlink will consider any proposed solution that can contribute significantly to the requirements of ensuring that Powerlink continues to meet its required reliability of supply obligations as part of the formal RIT-T consultation process.

Powerlink has identified the following common criteria that must be satisfied if proposed network support services are to meet supply requirements.[22]

Size and location

- Proposed solutions must be large enough, individually or collectively, to provide the size of injection or demand response set out above. However, the level of support is dependent on the location, type of network support and load forecasts.
- Due to the bulk nature of the transmission network, aggregation of sub 10MW non-network solutions will be the sole responsibility of the non-network provider.
- Notwithstanding the location of any solution, each proposal would require assessment in relation to technical constraints pertinent to the network connection, such as impacts on intra-regional transfer limits, fault level, system strength, maintaining network operability and quality of supply.

Operation

- A non-network option would need to be capable of operating continuously 24 hours per day over a period of years.
- If a generation service is proposed (either standalone or in conjunction with other services), such operation will be required regardless of the market price.[23]
- Proponents of generation services are advised that network support payments are intended for output that can be demonstrated to be additional to the plant's normal operation in the NEM.
- Where there are network costs associated with a proposed non-network option, including asset decommissioning, these costs form part of the scope of a non-network option and will be included in the overall cost of a non-network option as part of the RIT-T cost-benefit analysis.

[22] Powerlink's Network Support Contracting Framework provides a general guide to assist potential non-network solution providers. This framework outlines the key contracting principles that are likely to appear in any network support agreement.
[23] National Electricity Rules, clause 3.9.7 prevents a generator that is providing network support from setting the market price.

Reliability

- Proposed services must be capable of reliably meeting electricity demand under a range of conditions and, if a generator must meet all relevant NER requirements related to grid connection.
- Powerlink has obligations under the NER, its Transmission Authority and connection agreements to ensure supply reliability is maintained to its customers. Failure to meet these obligations may give rise to liability. Proponents of non-network options must also be willing to accept any liability that may arise from its contribution to a reliability of supply failure.

Timeframe and certainty

- Proposed services must be able to be implemented in sufficient time to meet the identified need, using proven technology and, where not already in operation, provision of information in relation to development status such as financial funding and development timeline to support delivery within the required timeframe must be provided.

Duration

- The agreement duration for any proposed service will provide sufficient flexibility to ensure that Powerlink is pursuing the most economic long run investment to address the condition risks arising from the ageing secondary systems and primary plants at Ingham South Substation.

Powerlink welcomes submissions from potential proponents who consider that they could offer a credible non-network option that is both economically and technically feasible.

5. Potential Credible Network Options to Address the Identified Need

Powerlink has developed two credible network options to maintain reliability of supply and to address condition risks at Ingham South Substation:

- Option 1 – replace hybrid switchgear modules in-situ with air-insulated switchgear and replace secondary systems equipment within a new control building installed on the existing Ingham South Substation platform by 2028; and
- Option 2 – extend substation platform and replace hybrid switchgear modules with air-insulated switchgear utilising adjacent spare bay locations where possible (designed to minimise outage durations), and replace secondary systems equipment within a new control building by 2028.

Option 1 seeks to minimise civil works and environmental impacts by installing new equipment in-situ to avoid having to extend the substation platform. Under Option 1, design will commence in 2025, construction works will commence in 2026 and commissioning will be completed by February 2028.

Option 2 seeks to minimise return to service times and outage requirements for civil construction works. Under Option 2, design will commence in 2025, construction works will commence in 2026 and commissioning will be completed by February 2028.

A summary of these options is shown in the table below.

Table 5.1: Summary of credible options

Option	Description	Total costs ($m, 2025)	Indicative annual O&M costs ($m, 2025)
1	Replace hybrid switchgear modules in-situ with air insulated switchgear. Replace secondary systems in a new control building on existing substation platform by 2028.	25.60	0.03
2	Extend substation platform and replace hybrid switchgear modules with air insulated switchgear using adjacent spare bay locations. Replace secondary systems in a new control building by 2028.	31.62	0.03

Note: O&M denotes operations and maintenance.

Each credible option addresses the risks resulting from the of ageing primary plant and secondary systems at Ingham South Substation to allow Powerlink to meet its reliability of supply and safety obligations under its Transmission Authority, the Electricity Act and Schedule 5.1 of the NER, by the replacement of the deteriorated equipment.

Powerlink does not consider that any of the credible options being considered will have a material inter-network impact, based on AEMO's screening criteria.[24]

6. Materiality of Market Benefits

The NER requires RIT-T proponents to quantify a number of classes of market benefits for each credible option, unless the proponent can demonstrate that a specific category(ies) is/are unlikely to materially affect the outcome of the assessment of credible options.[25]

6.1. Market benefits that are material for this RIT-T assessment

Powerlink considers that changes in involuntary load shedding – that is, the reduction in expected unserved energy (USE) – between options, set out in this PSCR, may impact the ranking of the credible options under consideration and that this class of market benefit could be material. Powerlink has quantified and included these benefits in the cost-benefit and risk cost analysis as network risk.

6.2. Market benefits that are not material for this RIT-T assessment

A discussion of each market benefit under the RIT-T that Powerlink considers not to be material is presented below.

[24] National Electricity Rules, clause 5.16.4(b)(6)(ii). AEMO has published guidelines for assessing whether a credible option is expected to have a material inter-network impact.
[25] National Electricity Rules, clauses 5.15A.2(b)(4), (5) and (6). See also AER, *Regulatory Investment Test for Transmission*, November 2024, paragraphs 10 to 13.

- **Changes in patterns of generation dispatch**: replacement of ageing assets under the credible options by itself does not affect transmission network constraints or affect transmission flows that would change patterns of generation dispatch. It follows that changes through different patterns of generation dispatch are not material to the outcome of the RIT-T assessment.
- **Changes in voluntary load curtailment**: replacement of ageing assets under the credible options by itself does not affect prices in the wholesale electricity market. It follows that changes in voluntary load curtailment will not be material for the purposes of this RIT-T.
- **Changes in costs for other parties**: the effect of replacement of ageing assets under the credible options considered are localised to the substation they are located at and do not affect the capacity of transmission network assets and therefore are unlikely to change generation investment patterns (which are captured under the RIT-T category of 'costs for other parties')
- **Differences in the timing of expenditure**: credible options for asset replacement do not affect the capacity of transmission network assets, the way they operate, or transmission flows. Accordingly, differences in the timing of expenditure of unrelated transmission investments are unlikely to be affected.
- **Changes in network losses**: credible options are not expected to provide any changes in network losses as replacing secondary systems does not affect the characteristics of primary transmission assets.
- **Changes in ancillary services cost**: there is no expected change to the costs of Frequency Control Ancillary Services (FCAS), Network Control Ancillary Services (NCAS), or System Restart Ancillary Services (SRAS) due to credible options under consideration. These costs are therefore not material to the outcome of the RIT-T assessment.
- **Changes in Australia's greenhouse gas emissions**: Powerlink does not consider that any of the credible options will materially affect Australia's greenhouse gas emissions, and the cost of quantifying any greenhouse gas emission benefits would involve a disproportionate level of effort compared to the additional insight it would provide.
- **Competition benefits:** Powerlink does not consider that any of the credible options will materially affect competition between generators, and generators' bidding behaviour and, consequently, considers that the techniques required to capture any changes in such behaviour would involve a disproportionate level of effort compared to the additional insight it would provide.
- **Option value**: Powerlink does not consider that the identified need for the options considered in this RIT-T is affected by uncertain factors about which there may be more clarity in future. As a consequence, option value is not a relevant consideration for this RIT-T.
- **Costs associated with social licence activities:** Powerlink does not consider that the cost of social licence activities is materially different between the credible options under consideration in this RIT-T. These costs are therefore not material to the outcome of the RIT-T assessment.

6.3. Consideration of market benefits for non-network options

Powerlink notes that non-network options may impact the wholesale electricity market (for example by displacing generation output). Accordingly, it is possible that several of the above classes of market benefits will be material where there are credible non-network options, depending on the specific form of the option.

Where credible non-network options are identified as part of the consultation process on this PSCR, Powerlink will assess the materiality of market benefits associated with these options. Where the market benefits are considered material, these will be quantified as part of the cost-benefit analysis.

7. Base Case

7.1. Modelling a base case under the RIT-T

In a RIT-T that is not an actionable ISP project, the base case is the situation in which the RIT-T proponent does not implement a credible option to meet the identified need, and continues with business-as-usual (BAU) activities.[26]

The assessment undertaken in this PSCR compares the costs and benefits of credible options to address the risks arising from an identified need with a base case. As characterised in the RIT-T Application Guidelines, the base case reflects a state of the world in which the condition and obsolescence issues arising from the ageing assets are only addressed through standard operational activities, with escalating safety, financial, environmental and network risks.[27]

To develop the base case, the existing condition and obsolescence issues are managed by undertaking operational maintenance or operational measures only. This results in an increase in overall risk levels as the condition and availability of the asset deteriorates over time. These increasing risk levels are assigned a monetary value that is used to evaluate the credible options designed to offset or mitigate these risk costs.

The base case therefore includes the costs of work associated with operational maintenance and the risk costs associated with the failure of the assets. The costs associated with equipment failures are modelled in the risk cost analysis and are not included in the operational maintenance costs.

The base case acts as a benchmark and provides a clear reference point in the cost-benefit analysis to compare and rank the credible options against each other over the same timeframe.

7.2. Ingham South base case risk costs

Powerlink has developed a risk modelling framework consistent with the RIT-T Application Guidelines. An overview of the framework is available on Powerlink's website and the principles of the framework have been used to calculate the risk costs of the Ingham South base case. The framework includes the modelling methodology and general assumptions underpinning the analysis.

7.3. Base case assumptions

To calculate the potential USE arising from a failure of the ageing and obsolete secondary systems and primary plant at the Ingham South Substation, Powerlink has made the following modelling assumptions:

- Spares for secondary system equipment items are assumed available prior to the point of expected spares depletion, as after this point the cost and time to return the secondary system back to service increases significantly;
- Historical load profiles have been used when assessing the likelihood of unserved energy under concurrent failure events;
- Unserved energy generally accrues under concurrent failure events, and consideration has been given to potential feeder trip events within the wider area;

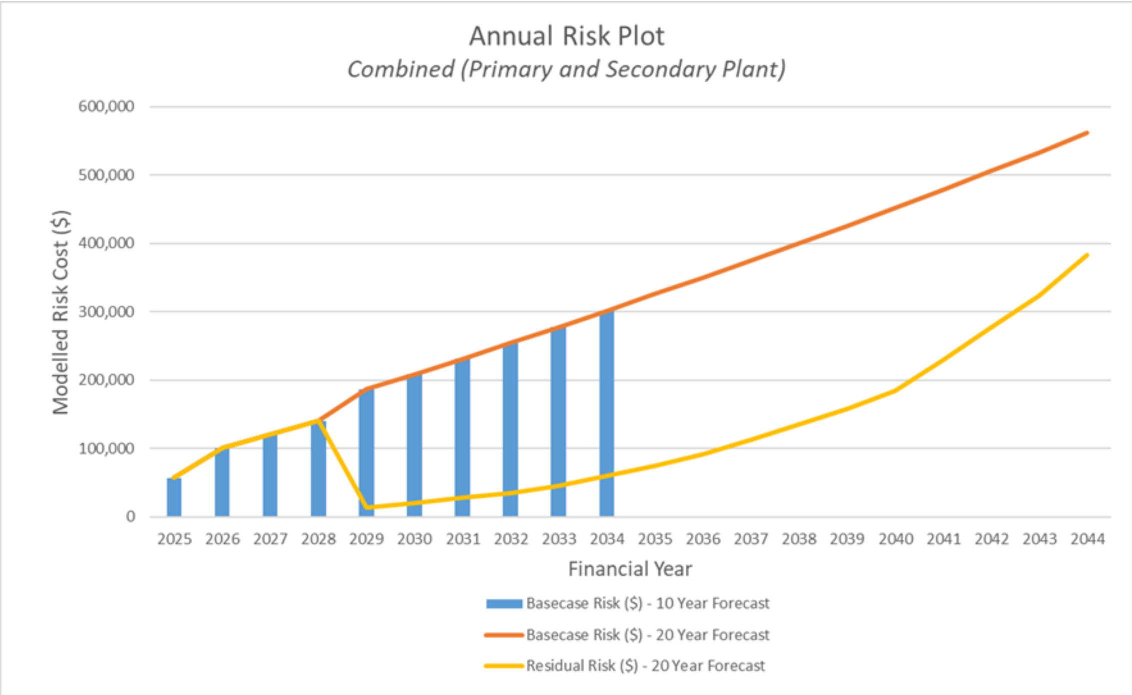
[26] AER, *Regulatory Investment Test for Transmission*, November 2024, glossary ('base case').

[27] AER, *Application Guidelines, Regulatory Investment Test for Transmission*, November 2024, page 21.

- Ingham South Substation supplies a mixture of residential, industrial and agricultural load types. Historical load data has been analysed to approximate the ratio of the load types, resulting in a Value of Customer Reliability (VCR) of $36,598/MWh; and
- The most relevant residential, industrial and agricultural VCR values published within the 'Value of customer reliability – Final report on VCR values' by the AER (updated in December 2024) have been used to determine this VCR.

The 15-year forecast of risk costs for the base case is shown in Figure 7.1.

Figure 7.1: Modelled base case and option residual risk costs



Based upon the assessed condition of the ageing secondary systems and primary plants at Ingham South, the total risk costs are projected to increase from around $57,000 in 2025 to $560,000 in 2044.

The main areas of risk costs for both the primary plant and secondary systems are network risks that involve reliability of supply through the failure of deteriorated equipment modelled as probability weighted USE[28] and financial risk costs associated with the replacement of failed assets in an emergency.

These risks increase over time as the condition of equipment further deteriorates, more equipment becomes obsolete and the likelihood of failure rises.

7.4. Modelling of risk in options

Each option is scoped to manage the major risks arising in the base case and to maintain compliance with all statutory requirements, the NER and AEMO standards. The residual risk is calculated for each option based upon

[28] USE is modelled using a VCR consistent with that published by the AER in its *Values of Customer Reliability, Final Report and Appendices A-D*, 2024.

the individual implementation strategy of the option. This is included with the capital and operational maintenance cost of each option to develop the Net Present Value (NPV) inputs.

8. General Modelling Approach for Net Benefit Analysis

8.1. Analysis period

Powerlink has undertaken the RIT-T analysis over a 20-year period, from 2025 to 2044. A 20-year period takes into account the size and complexity of the secondary system and primary plant replacement options. There will be remaining asset life by 2044, at which point a terminal value is calculated to account for capital costs under each credible option.

8.2. Discount rate

Under the RIT-T Instrument:

- RIT-T proponents must adopt the discount rate from AEMO's most recent Inputs, Assumptions and Scenarios Report unless the proponent can demonstrate why variation is necessary; and
- the present value calculations of the costs and benefits of credible options must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.[29]

In this RIT-T Powerlink has adopted a real, pre-tax commercial discount rate of 7.0% as the central assumption for the NPV analysis.[30]

Powerlink has tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 3.63% and an upper bound discount rate of 10.37% (i.e. a symmetrical upwards adjustment).[31]

8.3. Description of reasonable scenarios

The RIT-T analysis is required to incorporate a number of different reasonable scenarios, which are used to estimate market benefits and rank options.[32] The number and choice of reasonable scenarios must be appropriate to the credible options under consideration and reflect any variables or parameters that are likely to affect the ranking of the credible options, where the identified need is reliability corrective action.[33]

Based on the minor differences between the options in terms of operational outcomes, Powerlink has chosen to present a single reasonable scenario for comparison purposes. The detailed market modelling of future generation and consumption patterns required to assess alternative scenarios relating to connection of renewable generation represents a disproportionate cost in relation to the scale of the proposed network investment.

[29] AER, *Regulatory Investment Test for Transmission*, November 2024, paragraphs 18 and 19.
[30] This indicative commercial discount rate of 7.0% is based on AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, page 123.
[31] A discount rate of 3.63% real pre-tax Weighted Average Cost of Capital is based on *TasNetworks 2024–29* Final Determination, April 2024.
[32] AER, *Regulatory Investment Test for Transmission*, November 2024, paragraph 22.
[33] AER, *Regulatory Investment Test for Transmission*, November 2024, paragraph 23.

Notwithstanding this, we have considered capital cost, discount rate and risk cost sensitivities individually and in combination and found that none of the parameters has an impact on ranking of results. Hence, Powerlink has chosen to present a 'central scenario' illustrated in Table 8.1.

Table 8.1: Reasonable scenario parameters

Key parameter	Central Scenario
Capital cost	100% of base capital cost estimate
Maintenance cost	100% of base maintenance cost estimate
Discount rate	7.0%
Risk cost	100% of base risk cost forecast

8.4. Cost estimation

Regulatory requirements

Where the estimated capital cost of the preferred option exceeds $100 million, a RIT-T proponent must:

- outline the process undertaken to ensure cost estimates are accurate to the extent practicable having regard to the purpose of the relevant stage of the RIT-T;
- for all credible options, including the preferred option, apply the Association for the Advancement of Cost Engineering (AACE) cost estimation classification system, or identify an alternative system/arrangements and explain why the alternative is more appropriate/suitable than the AACE system.[34]

Further, for each credible option a RIT-T proponent must specify to the extent practicable and in a manner that is fit-for-purpose for the stage of the RIT-T:

- key inputs and assumptions adopted in deriving the cost estimate;
- main components of the cost estimate;
- methodologies and processes applied to derive the cost estimate;
- reasons in support of key inputs and assumptions adopted and methodologies and processes applied; and
- the level of, and basis for, any contingency allowance that has been included in the cost estimate.[35]

The RIT-T Application Guidelines also encourage RIT-T proponents, where the estimated capital cost of the preferred option is less than $100 million, to outline the process undertaken to ensure cost estimates are as accurate as possible.

At the Project Assessment Draft Report (PADR) and PACR stages of a RIT-T, RIT-T proponents must include a quantification of costs, including a breakdown of operating and capital expenditure for each credible option.[36] At

[34] AER, *Application Guidelines, Regulatory Investment Test for Transmission*, November 2024, pages 28-29.
[35] AER, *Application Guidelines, Regulatory Investment Test for Transmission*, November 2024, page 29.
[36] National Electricity Rules, clauses 5.16.4(k)(3) and (v)(1).

the PSCR stage however, information for each credible option is only required on total indicative capital and operating and maintenance costs, to the extent practicable.[37]

Basis of Estimation

The basis for the estimation for the credible options presented in this PSCR is outlined in the methodologies and processes used to derive cost estimates as described in Powerlink's Cost Estimation Methodology. The estimates are informed by the level of specific project information available at the time of PSCR preparation. Powerlink's Cost Estimation Methodology also provides context to the classes of estimate discussed in this section.[38]

Key inputs and assumptions

Option 1: Replace hybrid switchgear modules in-situ with air insulated switchgear. Replace secondary systems in a new control building on existing substation platform by 2028.

A Class 3 Project Proposal Estimate has been produced for Option 1 with an accuracy range of -20% to +30%. Powerlink has made the following scope assumptions in producing this estimate:

- Powerlink can continue to utilise the existing Energy Queensland owned building for telecommunications equipment and amenities;
- All existing equipment in good condition and working order, the site is accessible and there are no restricted access zones (RAZ);
- All resources will be available including necessary resources to complete design, construction, testing and commissioning activities;
- Availability of site access for works as required;
- Existing ground conditions are suitable for the construction of standard foundations;
- Laydown area is located within the substation yard;
- Outages will be available, based on appropriate contingency arrangements being put in place to ensure Return to Service requirements are met. Primary and secondary system equipment is available within current agreed lead times; and
- Primary and secondary system equipment is available within current agreed lead times.

Option 2: Extend substation platform and replace hybrid switchgear modules with air insulated switchgear using adjacent spare bay locations. Replace secondary systems in a new control building by 2028.

A Class 5 Concept Estimate has been produced for Option 2 with an accuracy range of -50% to +100%. Powerlink has made the following assumptions in producing this estimate:

- Powerlink can continue to utilise the existing Energy Queensland owned building for telecommunications equipment and amenities;
- All existing equipment in good condition and working order, the site is accessible and there are no RAZs;
- All resources will be available including necessary resources to complete design, construction, testing and commissioning activities;
- Availability of site access for works as required;
- Existing ground conditions are suitable for the construction of standard foundations;
- Laydown area is located within the substation yard;

[37] National Electricity Rules, clause 5.16.4(b)(6)(v).
[38] The methodology is available on the RIT-T Consultations page of Powerlink's website.

- Outages will be available;
- Local material is available for fill / platform extension;
- Environmental approvals are granted for platform extension; and
- Primary and secondary system equipment is available within current agreed lead times.

9. Cost-benefit Analysis and Identification of Preferred Option

9.1. NPV analysis

Table 9.1 outlines the NPV and the corresponding ranking of each credible option relative to the base case.

Table 9.1: NPV of credible options relative to the base case

Option	Description	NPV relative to base case ($m)	Ranking
1	Replace hybrid switchgear modules in-situ with air insulated switchgear. Replace secondary systems in a new control building on existing substation platform by 2028.	-17.58	1
2	Extend substation platform and replace hybrid switchgear modules with air insulated switchgear using adjacent spare bay locations. Replace secondary systems in a new control building by 2028.	-22.10	2

Both credible options will address the identified need on an enduring basis. Option 1 is ranked first, with Option 2 being $4.5 million more expensive compared to Option 1 in NPV terms.

Figure 9.1 sets out the breakdown of capital cost, operational maintenance cost and risk cost for each option in NPV terms under the central scenario. Note that the non-credible base case consists of operational maintenance and total risk costs and does not include any capital expenditure.

Figure 9.1: NPV of the base case and each credible option (NPV $m)

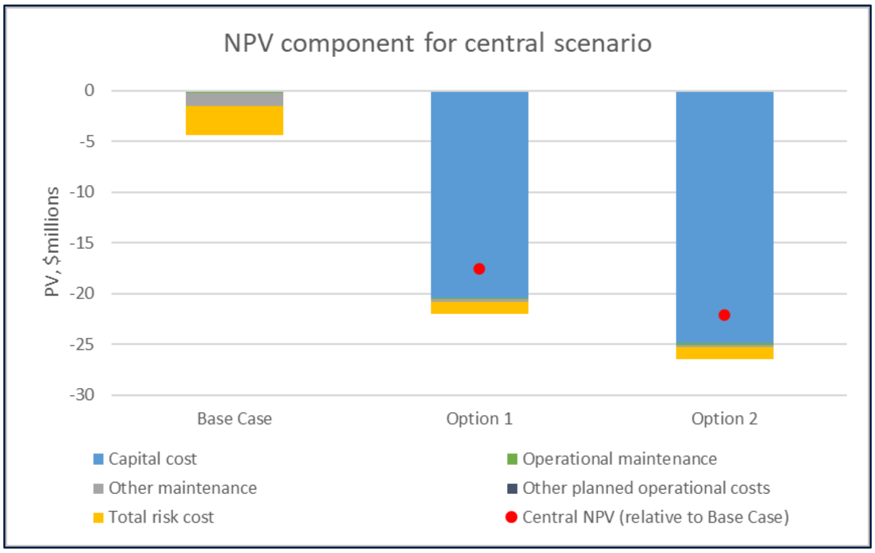


Figure 9.1 illustrates that both credible options will reduce the risk cost compared to the base case. Due to the lower capital cost component, Option 1 results in the highest NPV outcome relative to the base case when compared to other credible options. Sensitivity analysis also concluded that Option 1 is preferred to Option 2 (see Appendix 2).

9.2. Conclusion

The result of the cost-benefit analysis indicates that Option 1 provides the highest net economic benefit (lowest cost in NPV terms) over the 20-year analysis period. Sensitivity testing shows the analysis is robust to variations in the capital cost, risk cost and discount rate assumptions. Powerlink therefore considers Option 1 satisfies the requirements of the RIT-T and is the proposed preferred option.

10. Draft Recommendation

Based on the conclusions drawn from the NPV analysis and regulatory requirements relating to the proposed replacement of transmission network assets, it is recommended that Option 1 be implemented to address the risks associated with the deteriorated condition of the aged and obsolete secondary systems and primary plant infrastructure at Ingham South Substation. Implementing this option will also ensure ongoing compliance with relevant standards, applicable regulatory instruments and the NER.

Option 1 involves the replacement of hybrid switchgear modules in-situ with air insulated switchgear and replacement of secondary systems in a new control building on existing substation platform by 2028. The indicative capital cost of this option is $25.60 million in 2024/25 prices.

Under Option 1, design work will commence in 2025, with installation and commissioning of the new primary plant and secondary systems completed by 2028.

11. Submission Requirements and Next Steps

Powerlink invites submissions and comments in response to this PSCR from Registered Participants, AEMO, potential non-network providers and any other interested parties.

This is not a tender process – submissions are requested so that Powerlink can fulfil its regulatory obligations to analyse non-network options. In the event that a non-network option appears to be a genuine and practicable alternative that could satisfy the RIT-T, Powerlink will engage with that proponent or proponents to confirm cost inputs and commercial terms.

11.1. Submissions from non-network providers

Submissions should be presented in a written form and should clearly identify the author of the submission, including contact details for subsequent follow-up if required. If parties prefer, they may request to meet with Powerlink ahead of providing a written response.

Submissions from potential non-network providers should contain the following information:

- details of the party making the submission (or proposing the service);
- technical details of the project (capacity, proposed connection point if relevant, etc.) to allow an assessment of the likely impacts on future supply capability;
- sufficient information to allow the costs and benefits of the proposed service to be incorporated in a comparison in accordance with AER’s RIT-T Application Guidelines;

- an assessment of the ability of the proposed service to meet the technical requirements of the NER;
- timing of the availability of the proposed service; and
- other material that would be relevant in the assessment of the proposed service.

Powerlink will publish a PADR if submissions to this PSCR identify other credible options not yet considered, and which could provide a more cost efficient outcome for customers. The PADR will also summarise and provide comment on any submissions received in response to the PSCR.[39]

Powerlink will publish submissions on the PSCR, subject to any claim of confidentiality by the person making the submission. Where confidentiality over part or all of a submission is made, this should be clearly identified. Powerlink may also explore whether a redacted or non-confidential version of the submission can be made available.[40]

Powerlink has a general obligation to use all reasonable endeavours not to disclose any confidential information it receives. The obligation is subject to a number of exceptions, including that disclosure may be made:

- with the consent of the person providing the information; or
- to the AER, Australian Energy Market Commission or any other regulator having jurisdiction over Powerlink under the NER or otherwise.[41]

It should be noted that Powerlink is required to publish the outcomes of the RIT-T analysis. If parties making submissions elect not to provide specific project cost data for commercial-in-confidence reasons, Powerlink may rely on cost estimates from independent specialist sources.

11.2. Next steps

Powerlink intends to carry out the following process to assess what action, if any, should be taken to address future supply requirements.

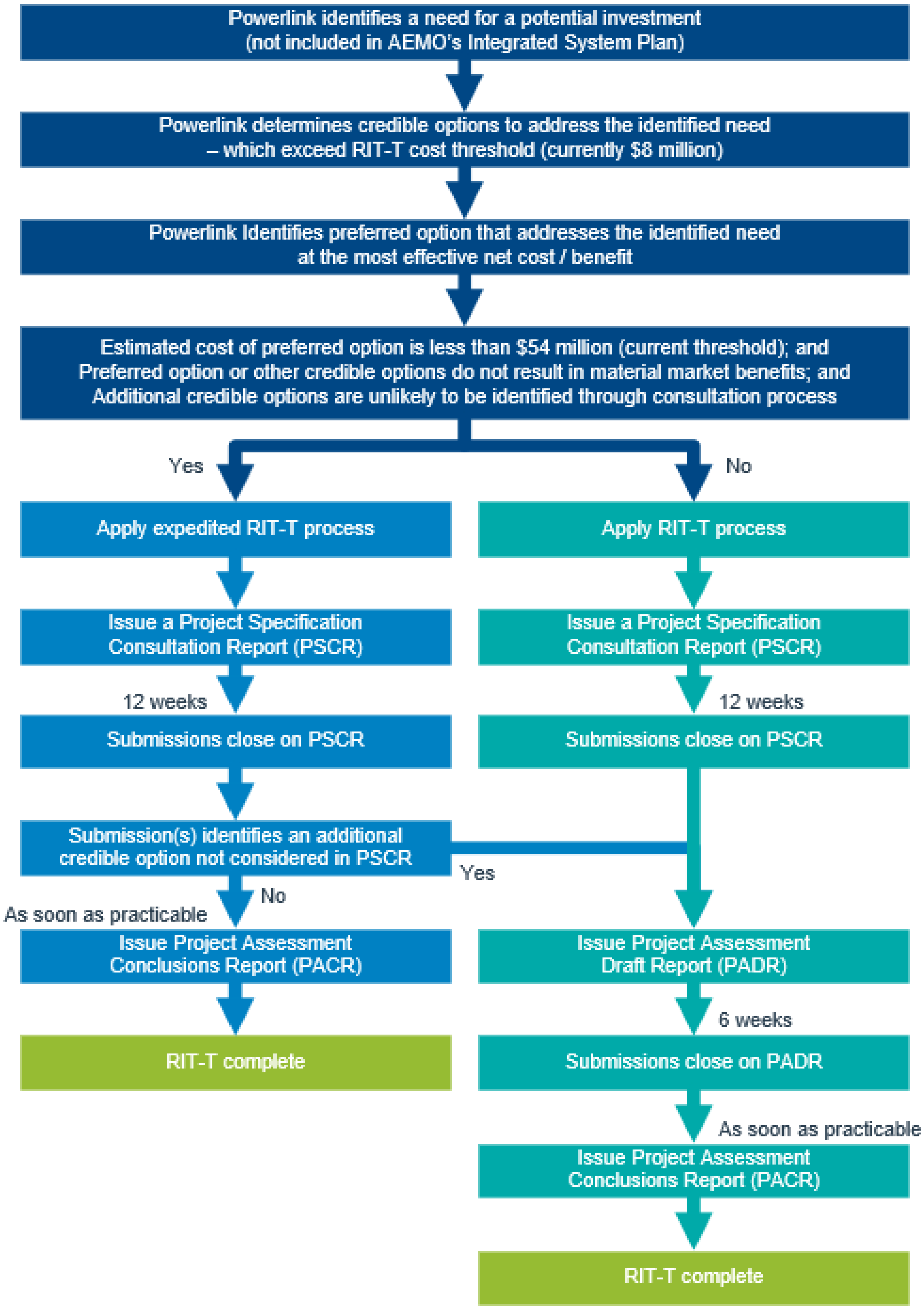
Part 1	PSCR Publication	June 2025
Part 2	Submissions due on PSCR Have your say on the credible options and propose non-network options	September 2025
Part 3	Publication of PACR Powerlink's response to any further submissions received and final recommendation on the preferred option for implementation	November 2025

Powerlink reserves the right to amend the timetable at any time. Amendments to the timetable will be made available on the Powerlink website (www.powerlink.com.au/rit-t-consultations).

[39] National Electricity Rules, clause 5.16.4(k)(2).
[40] AER, *Application Guidelines, Regulatory Investment Test for Transmission*, November 2024, page 70.
[41] National Electricity Rules, rule 8.6.

Appendix 1: RIT-T Process

The flow chart below illustrates the RIT-T process where the need is not identified as an actionable project in AEMO's ISP.



As stated, this PSCR is the first step in the RIT-T process. The PSCR:

- describes the reasons why Powerlink has determined that investment is necessary (the identified need), together with the assumptions used in identifying this need, including whether the need is as an actionable project in AEMO's latest ISP;
- provides potential proponents of non-network options with information on the technical characteristics that a non-network solution would need to deliver, in order to assist proponents to consider whether they could offer an alternative solution;
- describes the credible options that Powerlink currently considers may address the identified need;
- discusses why Powerlink does not expect specific categories of market benefit to be material for this RIT-T;
- presents the NPV assessment of each of the credible options compared to a base case, as well as the methodologies and assumptions underlying these results;
- identifies and provides a detailed description of the credible option that satisfies the RIT-T, and is therefore the preferred option;
- provides information about Powerlink's estimation of costs for each credible option;
- describes how customers and stakeholders have been engaged with regarding the identified need; and
- provides stakeholders with the opportunity to comment on this assessment so that Powerlink can refine the analysis (if required) as part of the PACR.

Powerlink will adopt the expedited process for this RIT-T, as allowed for under the NER for investments of this nature.[42] Specifically, Powerlink will publish a PACR following public consultation on this PSCR and apply the exemption from publishing a PADR as:

- the preferred option has an estimated capital cost of less than $54 million;[43]
- none of the credible options have material market benefits, other than benefits associated with changes in involuntary load shedding, which have been catered for in the risk cost modelling and consequentially represented in the economic analysis of the options;
- Powerlink has identified its preferred option in this PSCR (together with the supporting quantitative cost-benefit analysis);
- Powerlink does not envisage that additional credible options, which could deliver material market benefits, will be identified through the submission process given the nature of this replacement project; and
- Powerlink is currently not aware of any non-network options that could be adopted. This PSCR provides a further opportunity for providers of feasible non-network options to submit details of their proposals for consideration.

As stated, Powerlink will however publish a PADR if submissions to this PSCR identify other credible options that have not yet been considered, and which could provide a material market benefit or a more cost-efficient outcome for customers.

[42] National Electricity Rules, clause 5.16.4(z1).

[43] National Electricity Rules, clause 5.16.4(z1)(1) sets the threshold at $35 million. The AER's latest cost threshold review increased the value to $54 million for three years from 1 January 2025.

Appendix 2: Sensitivity Analysis

Powerlink has investigated the following sensitivities on key assumptions:

- a range from 3.63% to 10.37% discount rate;
- a range from 75% to 125% of base capital expenditure estimates;
- a range from 75% to 125% of base risk cost estimates; and
- a range from 75% to 125% of base operational maintenance expenditure.

As illustrated in Figures A2.1 – A2.4, sensitivity analysis for the NPV relative to the base case shows that varying the discount rate, capital expenditure, operational maintenance expenditure and total risk costs has no impact on the identification of the preferred option. Option 1 is the preferred option under all scenarios tested.

Figure A2.1: Discount rate sensitivity

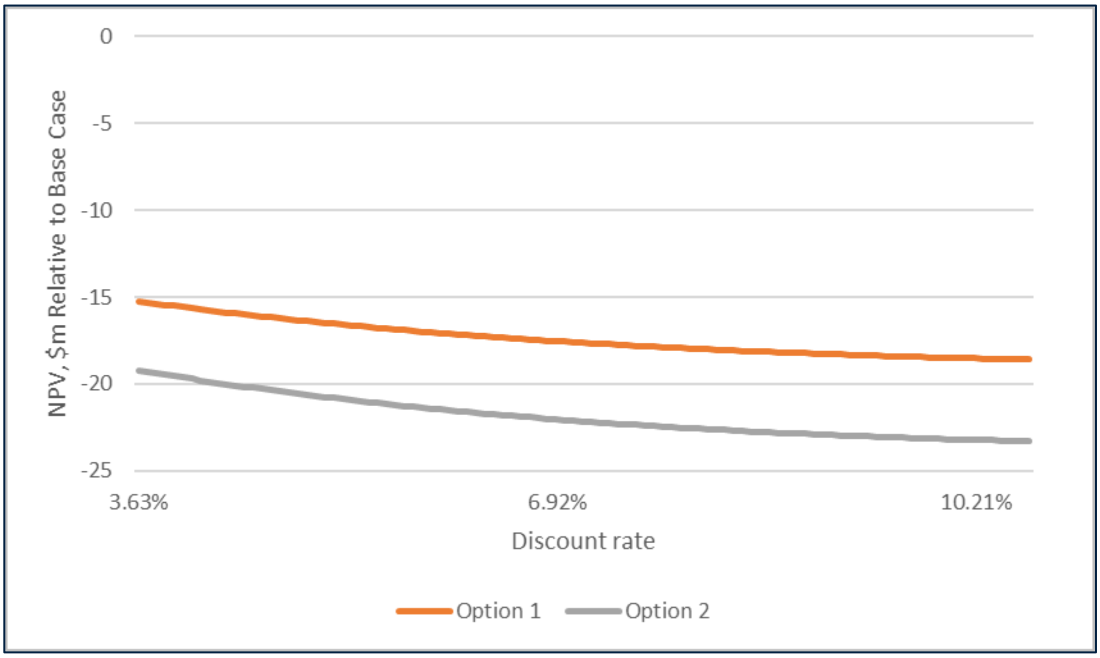


Figure A2.2: Capital cost sensitivity

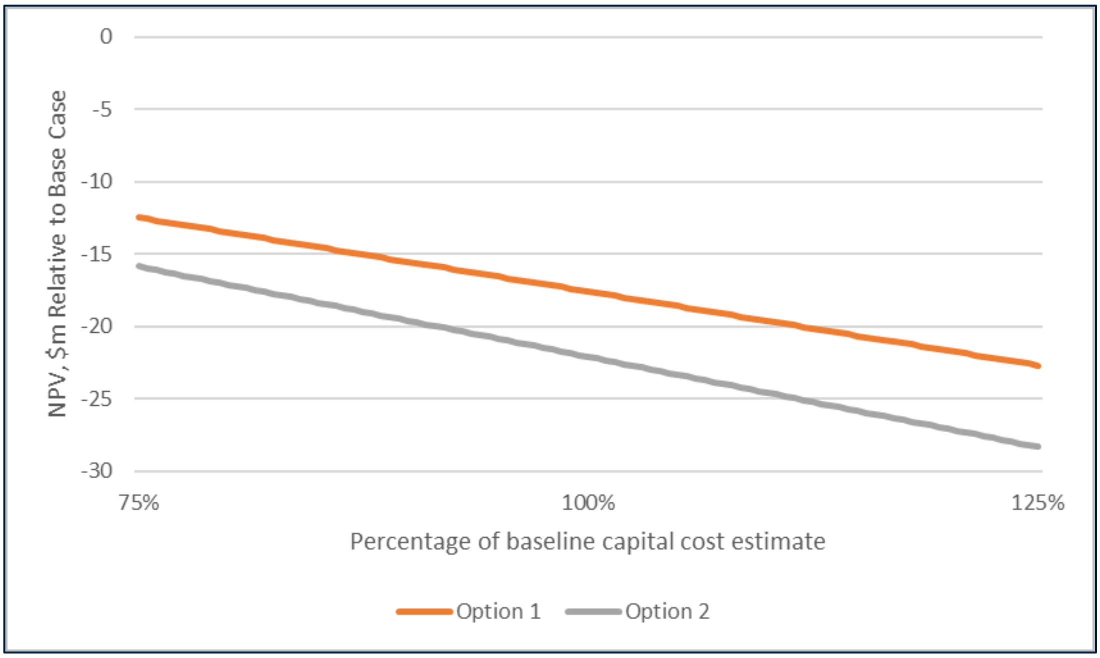


Figure A2.3: Risk cost sensitivity

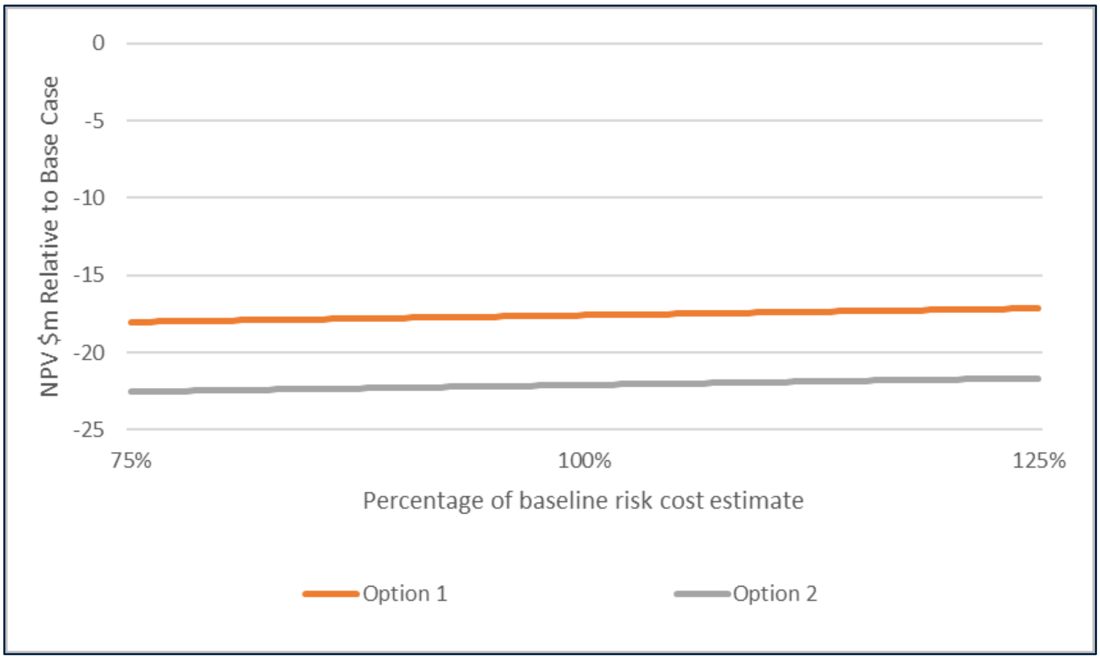
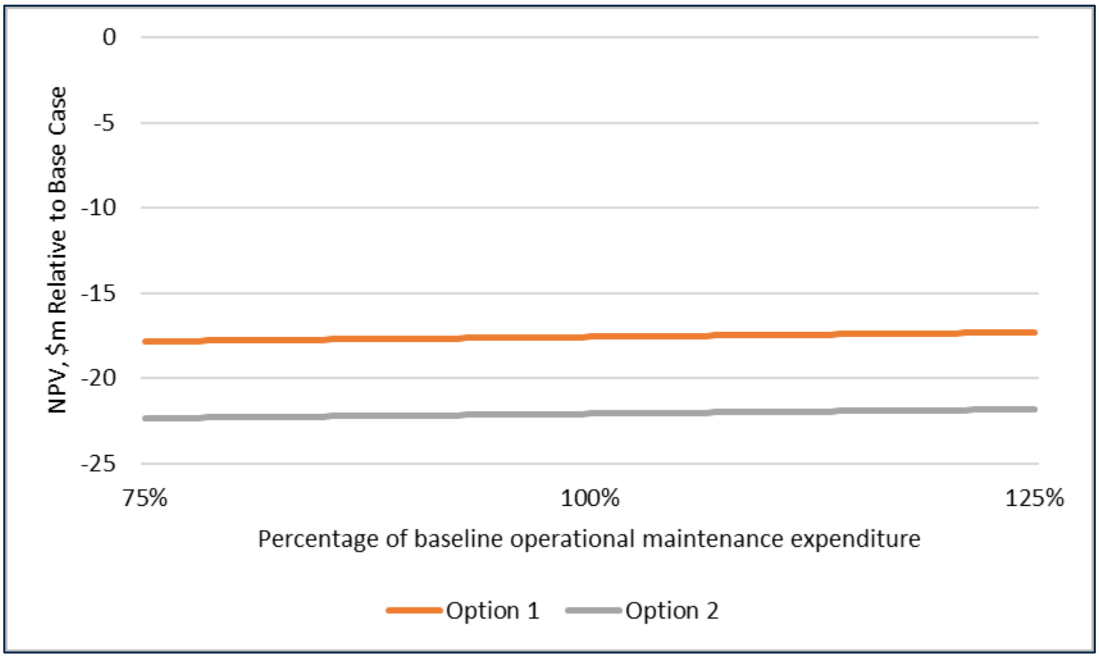
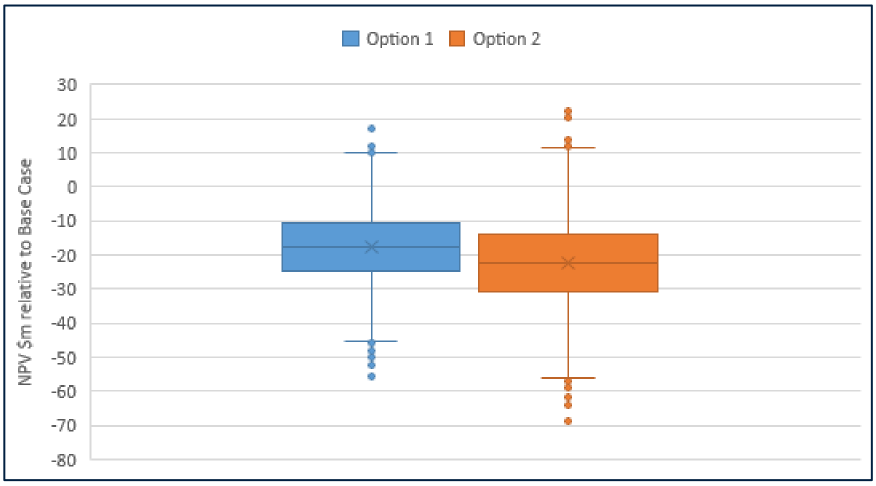


Figure A2.4: Maintenance cost sensitivity



Powerlink also performed a Monte Carlo simulation with multiple input parameters (including capital cost, discount rate and total risk cost) generated for the calculation of the NPV for each option. This process was repeated over 5,000 iterations, each time using a different set of random variables from the probability function. The sensitivity analysis output is presented as a distribution of possible NPVs for each option, as illustrated in Figure A2.5.

Figure A2.5: NPV sensitivity analysis of multiple key assumptions relative to the base case



Note: The box represents the interquartile interval, where 50% of the data is found. The horizontal line through the box is the median and the mean is represented by the cross (X). The two lines outside the box extend to 1.5 times the interquartile range. Data points that are outside of this interval are shown as dots on the graph.

The Monte Carlo simulation results identify that Option 1 has similar statistical dispersion in comparison to the other credible option, and its mean and median is the highest of the two credible options. This confirms that Option 1 is robust over a range of input parameters in combination.

Appendix 3: NER Compliance Checklist

This appendix outlines Powerlink's compliance with PSCR content requirements set out in sub-paragraphs (1) to (6) of clause 5.16.4(b) of the NER.

Table A3.1: NER Compliance Checklist

Sub-para	Requirement	Section of PSCR
(1)	Description of identified need	3.2
(2)	Assumptions used to identify the identified need	3.3
(3)	Technical characteristics of the identified need that a non-network option would be required to deliver	4.1
(4)	Discussion of identified need or credible options to meet the identified need in most recent ISP	N/A
(5)	Description of credible options	5
(6)	For each credible option, information about: (i) technical characteristics of the option; (ii) whether the option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefit that are likely / not likely to be material (iv) estimated construction timetable and commissioning date (v) indicative capital and operating and maintenance costs	 5 5 6.1 – 6.2 5 5

N/A denotes not applicable.

Appendix 4: RIT-T Application Guidelines Compliance Checklist

This appendix outlines Powerlink's compliance with binding requirements included in the RIT-T Application Guidelines.

Table A4.1: RIT-T Application Guidelines Compliance Checklist

Section of Guidelines	Topic	Requirements	Section of PSCR
3.5.3	Social licence costs	Provide the basis for any social licence costs, including any reference to best practice	N/A
3.5A.1	Cost estimation accuracy	Outline cost estimation process (as applicable to stage of the RIT-T)	8.4
3.5A.2	Cost estimation information	Details of inputs, assumptions and methodologies for each credible option (as applicable to the stage of the RIT-T)[44]	8.4
3.7.3	Market benefits	Calculation of changes in Australia's greenhouse gases	N/A
3.8.2	Sensitivities	Sensitivity analysis on all credible options	Appendix 2
3.11.2	Concessional finance	Provide sufficient detail about a concessional finance agreement	N/A
4.1	Community engagement	Description of assessment of requirement for community engagement and, as applicable, how engagement has been undertaken and any relevant concerns sought to be addressed, and how the proponent plans to engage with stakeholder groups.	2.5

Notes:

N/A denotes not applicable.

[44] Although the provisions in section 3.5A.2 of the RIT-T Application Guidelines are not included in the table of binding requirements at Appendix C of the Guidelines, Powerlink has added them to the compliance checklist as the provisions are expressed as being binding in section 3.5A.2 of the Guidelines.

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CP.02860 T157 Ingham South Substation Reinvestment

Project Management Plan

Version History

Version	Date	Section(s)	Summary of amendment

Table of Contents

1. Executive Summary

Ingham South Substation (T157) is fed via 132kV feeders from Cardwell and Yabulu South and is critical to supplying the Ergon 66kV Ingham Substation and the subsequent Ingham load centre. Ingham South substation was established in 2005 to replace the original Ingham substation equipment. It consists of a 132 kV switchyard with two 132/66kV transformers connected via underground cables to the adjacent Ergon 66kV Ingham Substation (T047).

The objective of this project is to replace all PASS M0 modules, install new metering equipment and address condition driven risks associated with the secondary systems at T157 Ingham South Substation by October 2027. This is not achievable due to approval timeframes, RIT-T, long lead procurement, wet season and outage constraints. The proposed commissioning date is **February 2028**.

This project will follow the two-stage approval process.

The Class 3 (Stage 1) proposal remains valid until the Class 2 (Stage 2 / Full Approval) proposal is submitted, or until the conditions, assumptions, exclusions contained in this document change.

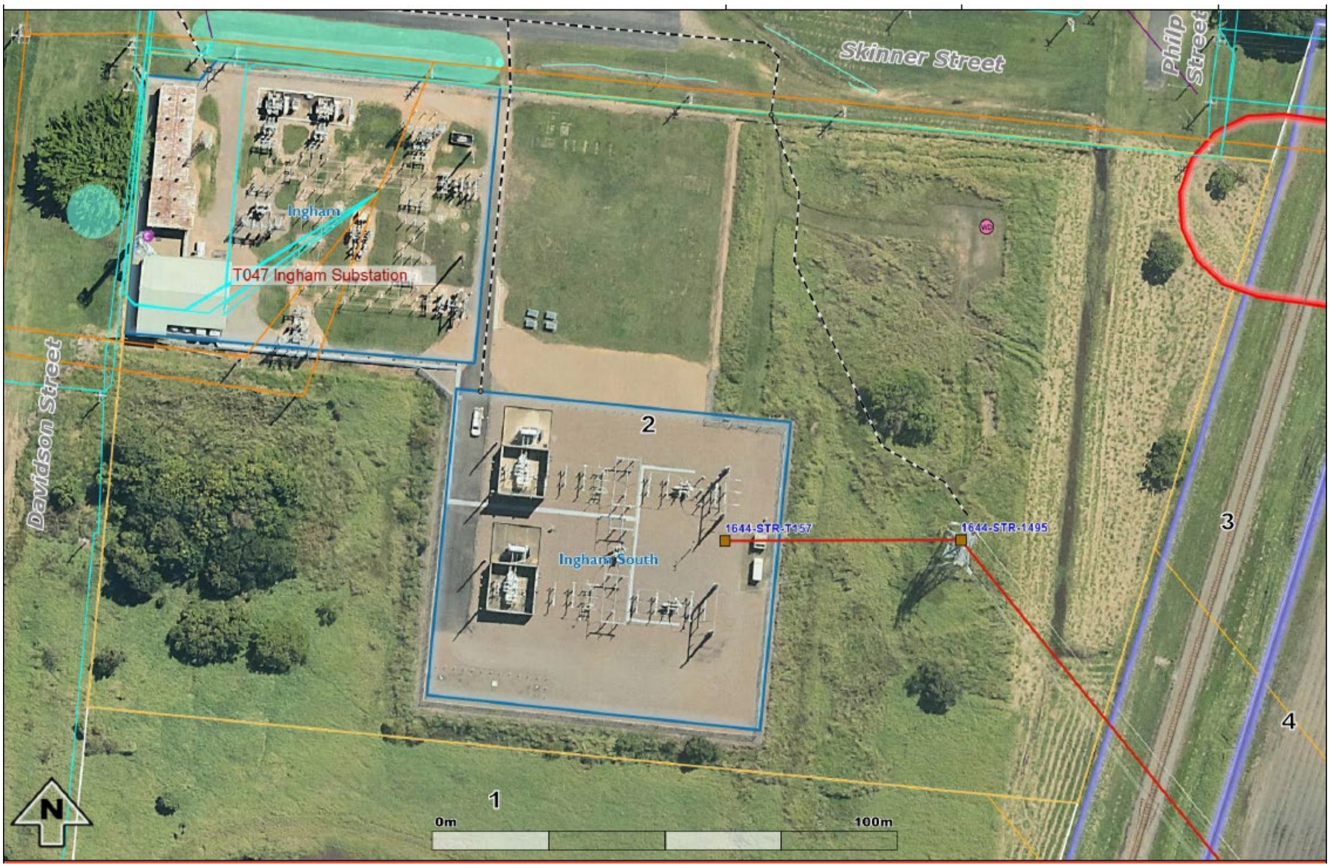

Figure 1: Ingham South Substation view

	Date
Project Proposal and Project Estimate - date submitted	6 December 2024
Stage 1 Project Approval Advice (PAA) – date received	23 July 2025
Stage 2 / Full Approval Project Approval Advice (PAA) - date received	15 April 2026

1.1 Overview of Estimated Costs

The following table summarises the breakdown of the project estimate for the Stage 1 Project Proposal.

Estimate Components			Base Cost $	Escalated $
Base Estimate (A)			**25,602,542**	**27,697,663**
Contingency (Unknown Risk)	(B)	13%	3,205,727	3,468,060
Mitigated Risk (Known Risk)	(C)	7%	1,914,781	2,071,473
Total Proposed	(B+C)	20%	5,120,508	5,539,533
Total Proposed Approval	**(A+B+C)**		**30,723,051**	**33,237,196**

1.2 Cost Comparison (un-escalated)

CP.02860 Ingham South Substation Reinvestment	(A) Base Cost (Class 5)	(B) Base Cost (Class 5 - 2024 labour rate uplift)	(C) Base Cost (Class 3)	Variance (C - B)	Reason for Variance
PQ Overheads Costs	$ 2,332,996	$ 2,316,681	$ 1,924,825	-$ 391,856	- Internal estimates prepared - Decrease in HSE labour rates across the Class 5 initial estimate and Class 5 2024 labour rate uplift
Design	$ 1,961,619	$ 2,124,566	$ 2,040,498	-$ 84,068	- Design estimates prepared
Procurement	$ 2,589,308	$ 2,647,634	$ 2,933,662	$ 286,028	- Plant summary and estimates received from Design
Construction	$ 12,940,694	$ 15,135,069	$ 13,253,835	-$ 1,881,234	- External cost plan prepared - Construction & Commissioning estimate prepared - Staging plan prepared
Commissioning	$ 3,017,060	$ 5,053,490	$ 4,396,395	-$ 657,095	- Internal estimates prepared - Construction & Commissioning estimate prepared - Staging plan prepared
Post Commissioning	$ 811,152	$ 962,155	$ 736,163	-$ 225,992	- Internal estimates prepared
O&FS / Network Ops	$ 202,122	$ 244,075	$ 317,164	$ 73,089	- Staging / outage plan prepared
Base Estimate Total	***$ 23,854,950***	***$ 28,483,670***	***$ 25,602,542***	***-$ 2,881,128***	

2. Project Definition

2.1 Project Scope

This site utilises PASS M0 gas insulated hybrid modules for all 132kV switching diameters (3 modules in total). There are approximately 140 gas insulated hybrid modules within the Powerlink network and due to the manufacturer no longer supporting them, there are no spares available. As such, these hybrid modules in the Ingham South site are to be replaced with conventional air insulated switchgear to allow for the gas insulated hybrid modules to be utilised as system spares.

The secondary system was installed in approx. 2005, with additional equipment installed between 2005 and 2008. A condition assessment in 2020 indicates that condition driven risks associated with existing secondary systems equipment should be addressed by 2026, to maintain the current network reliability and availability.

The metering on the 132/66kV transformers currently utilises EQL owned equipment on the low voltage side of the transformers. The metering point is to be relocated under this project to align with the Connection Point on the high voltage side of the 132/66kV Transformers.

The objective of this project is to replace all PASS M0 modules, install new metering equipment and address condition driven risks associated with the secondary systems at T157 Ingham South Substation.

2.1.1 T157 Ingham South Substation

Replace PASS M0 modules in-situ and replace secondary systems equipment within a new control building.

Key scope items as follows:

- Design, procure, construct and commission new primary plant (standard air insulated switchgear) and secondary systems equipment for the following bays:
    - D06 Feeder 7388 to Cardwell
    - D03 Feeder 7133/1 to Yabulu South
    - D05 1-2 Bus Coupler
    - New metering for Transformers 1 and 2 is to be installed as close as practicable to the connection point. The connection point is on the high voltage side of the transformers. (Existing metering utilises EQL 66kV CTs and VTs)
- New feeder and coupler bays are to be installed in the same location as the existing bays and use of existing foundations or placement of new foundations should be considered and designed in such a way to reduce required outage durations.
- Design, procure, construct and commission any temporary bypass arrangements that are required to facilitate the bay rebuilds.
- Design, procure, construct and commission new secondary systems for (Refer to Attachment 2 for a summary of the secondary systems condition assessment):
    - D07 Transformer 1 (protection and control devices only)
    - D04 Transformer 2 (protection and control devices only)
    - OpsWAN and SCADA to provide for control and monitoring requirements including replacement of the OpsWAN camera and associated equipment in accordance with ETR 10434041 OpsWAN camera lowing device trial.

- New secondary systems equipment to be installed within a new control building located on the existing Ingham South substation platform, designed to meet Q200 flood levels (telecommunications equipment and amenities to be retained in the existing EQL building).

For full scope details, refer to Project Scope Report V2 under Section 4.

2.1.2 T134 Cardwell Substation

- Modify protection, control, automation and communications systems associated with feeder 7388.

2.1.3 H056 Yabulu South Substation

Modify protection, control, automation and communications systems associated with feeder 7133.

[redacted]

Figure 2: T157 Ingham South Substation Proposed General Arrangement

2.2 Exclusions

- All works external to the substation yard;
- Oil separation tank modifications;
- Any delays, costs or cost increase not within the control of Powerlink;
- Rock or unsuitable material (including asbestos and other contamination);
- Industrial action impact: any increases to other rates by contractors engaged by Powerlink or Powerlink directly engaged personnel;
- All environmental, development, operational works and statutory approvals and any allowances for specific environmental requirements on customer property. EPBC off-set requirements and or any specific project approvals including but not limited to EPBC, including offset requirements;
- Any clearing and access required for access to work areas for construction and prior to construction for mobilisation of all required plant, resources and equipment, including geotechnical and other investigatory works;
- Any work outside of normal working hours;
- Costs associated with expediting manufacturing, delivery of plant, equipment and material;
- Allowances for any cultural heritage requirements;
- Impacts of global logistics issues due to geopolitical tensions, shortage of labour, problems with shipping slots etc;
- Long lead items lead time beyond nominal durations including delays in procuring electronic equipment due to global semi-conductor shortage and any other materials or services;
- SPA design;
- Regulated/hazardous or contaminated waste removal;
- Additional security measures during construction;
- Refurbishment of the recovered PASS M0 units;
- Non-standard foundations; and
- Fluctuation in foreign exchange rates.

2.3 Assumptions

- Access to network and outage management resources are available;
- All existing equipment in good condition and working order, the site is accessible and there are no restricted access zones (RAZ);
- All resources will be available including necessary operational resources are available to complete necessary construction, testing and commissioning activities;
- Availability of site access for works as required;
- Existing ground conditions are suitable for the construction of standard foundations;
- Laydown area is located within the substation yard;
- CP2860 Ingham South Substation Reinvestment will be commissioned prior to CP2665 Rollingstone Solar Farm 132kV Connection;
- Internal design, DSP contractor and MSP resources are available to deliver the entire project scope; and
- No electric security fence upgrade will be required.

2.4 Project Interaction

Interactions with other projects and Engineering Task Request (ETRs) as follow:

Project Number and Description	Interaction (Pre-requisite/Co-requisite/dependent/Related)	Planned Commissioning Date	Comment
CP.02770	Upgrade of Oil Separation Systems Stage 2	30th June 2030	In estimation Includes installation of a puraceptor at Ingham South
C55.1645	T157 Ingham South PASS M0 Refurbishment	TBA	
CP.02665	Rollingstone Solar Farm 132k Connection	Not Approved	Project is on hold and there is uncertainty around whether this will proceed (assume CP.02860 Ingham South reinvestment will be commissioned before Rollingstone)

2.5 Project Risk

Project risks identified during Project Proposal phase are as follows:

Line Ref	Risk/ Opportunity	Risk Specifics including cost basis of Pessimistic Estimate (PE)	Likelihood of PE occurring	Mitigated Risk
CO2	Contract Validity Period	Contractor Validity expiring due to delay in NTP and subsequent Contract Award. Additional 2.5% of subcontract costs	Unlikely	$12,738
CO3	Scope Definition Issues	Temporary bypass arrangement not defined. Needs detailed design. Assume $800k.	Likely	$300,000
CO4	Variations (EOT etc.)	Variation to fixed price contracts. Assume 10% of total contract values	Possible	$203,812
SS1	Supplier Risks (New, Existing)	Procurement delays due to manufacturing delays. Assume 5% of subcontractor cost due to EOT	Unlikely	$9,168
SS2	Subcontractor Risks	Subcontractor resource capacity with competing projects. Assume 5% of subcontractor costs	Possible	$50,953
FP1	Performance Warranty	Warranty on plant and equipment purchased by PLQ. Assume 10% of procurement	Possible	$73,342
HR1	Subcontractors' industrial agreements/employment issues	Assume increase to subcontractor / supplier EBAs / agreements in line with PLQ new EBA. Assume 5% increase on subcontract wages for SPA.	Unlikely	$50,953

NE1	Abnormal/Exceptional Weather Conditions	Rain events and the effects of these events impacting program above seasonal rainfall, Wind events grounding the use of EWPs and cranes for structure erection resulting in impact to overall program, allow for potential impact of $250k for wind events. Lightning events causing damage to equipment and delays to program. Assume $150k for Lightning events, $100k for other events	Possible	$62,500
IM2	Interfacing with Contractors	Contractor interfaces causing variations and delay claims. Allow $100k to cover interface management and delays	Likely	$37,500
DS1	Maturity of Project Scope/Design Substation	Change in design scope (Ground conditions/ layout). Assume design discrepancies $100k	Possible	$50,000
DS2	Staging / Outages	Additional outage management / ops engineering input required for contingency plan (outage management requirements for RTS)	Likely	$56,250
DL2	Site access	Alternative access to be upgraded for delivery of control building / plant	Possible	$62,500
DL3	Location of Works	Suitability of existing external and internal roads for plant & building delivery.	Possible	$75,000
DL5	Remobilisation	Principal delays or disruptions to work causes Contractors / OSD to remobilise. Assume 100k mob and demob costs	Possible	$50,000
DL6	Testing, Commissioning and Staging	Principal delays for commissioning. Allow 10% of OSD costs	Possible	$203,454
DL8	Material Delivery Delays	Hardware/material delivery late for a tight commissioning timeframe	Unlikely	$6,250
DL9	Outage Availability (Live Line/Live Substation Crew)	Required outage durations are not obtainable. Allow 10% of OSD costs	Likely	$305,181
DL10	Availability of Resources (OSD, MSP)	Required resource for commissioning/ FAT not available. Allow 10% of OSD costs	Likely	$305,181

During Project Execution, project risks are recorded managed in PWA Server.

2.6 Applicable Lessons Learned

Applicable lessons learned that have been identified during the Project Proposal phase are as follows:

No	Project Number & Name	Lesson Title	Expected Outcomes	Actual Outcome	Lesson Category	Recommended Changes
1	CP02721 H013 Ross 132kV Primary Plant Replacement	Primary Civil & Electrical Alignment	Busbars Sections manufactured to Electrical Section Drawings by Aliweld in Brisbane and shipped to site H013 Ross. D19 Bay 15m (standard 10m with 5m extension) D18 Bay standard 10m	During critical 4Bus short duration outage, busbars didn't fit Civil drawing 156300-121 (Downer Stamped) has the bus support foundation INSTH1 in a different location	Design Coordination; Design - Substation Civil; Design - Substation Electrical; Documentation	Need to understand where the error was, to prevent a recurrence. Was there an As Built returned drawing issue? The Downer drawing stamp details are incorrect CP.01546 (Calvale) and Rev B should be Rev A or Rev B? Can’t find where Downer would have provided feedback on electrical bus connections.
2	CP01635 Abermain Secondary Systems Replacement	SPA Construction	Clear communication path between PLQ and SPA Contractor	No clear communication matrix between PLQ and Contractor.	Construction	Communication matrix needs to be established early in the project
3	CP02755 T080 Redbank Plains Primary Plant Replacement	Difference between ITT drawing package & AFC drawing package	Detailed advice about changes from ITT to AFC drawings would be confirmed. This was requested & some detail was provided.	The Contractor highlighted some changes that the Design team didn't advise.	Claims and Variations; Construction; Contract; Design Coordination; Design - Lines; Design - Secondary Systems (Protection and Automation Design); Design - Substation Civil; Design - Substation Electrical; Design	This could be noted in somewhere as a prompt (the Project Schedule, the PLT Meeting Minutes, etc) and SHOULD be included as part of the Design Hand-over.

3. Project Financials

3.1 Project Estimate

3.1.1 Estimate Summary

		Sub Total $	Total $
Estimate Class	3		
Estimate accuracy (+% / - %)	+30% / -20%		
Base Estimate		$25,602,542	
[redacted]		[redacted]	
[redacted]			[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]			[redacted]
[redacted]			[redacted]

3.1.2 Asset Write-Off Table

CP.02860 Asset Write-off. Values current at 30th June 2025							
Functional Location	Description	Asset	Sub-number	Book val.	Write-off %	Write-off Value	Currency
T157-D03-7133	7133 TOWNSVILLE GT 132kV FEEDER BAY	111336	0	572,349.28	95%	$ 543,731.82	AUD
T157-D05-411-	1-2 BUS SECTION 132kV BAY	111338	0	473,192.94	100%	$ 473,192.94	AUD
T157-D06-7388	7388 CARDWELL FEEDER BAY	111339	0	572,349.28	90%	$ 515,114.35	AUD
Asset Class 10003 Sub - Bays				1,617,891.50		$ 1,532,039.11	AUD
T157-SSS-411-	1-2 BUS SECTION 132kV BAY	111344	0	0	100%	$ -	AUD
T157-SSS-441-	1 TRANSFORMER 132Kv BAY	111345	0	0	100%	$ -	AUD
T157-SSS-442-	2 TRANSFORMER 132kV BAY	111346	0	0	100%	$ -	AUD
T157-SSS-7133	7133 TOWNSVILLE GT 132kV FEEDER BAY	111347	0	0	100%	$ -	AUD
T157-SSS-7388	7388 CARDWELL 132kV FEEDER BAY	111348	0	0	100%	$ -	AUD
T157-SSS-METR-REVMET1	TRANSFORMER 1 ENERGY METERING	111349	0	0	100%	$ -	AUD
T157-SSS-METR-REVMET2	TRANSFORMER 2 ENERGY METERING	111350	0	0	100%	$ -	AUD
T157-SSS-NBAY	NON BAY	111351	0	1,121.19	100%	$ 1,121.19	AUD
T157-SSS-441-	1 TRANSFORMER 132Kv BAY	132593	0	691,137.58	100%	$ 691,137.58	AUD
T157-SSS-442-	2 TRANSFORMER 132kV BAY	132594	0	691,137.52	100%	$ 691,137.52	AUD
Asset Class 10007 Sub-Site Second Sys				1,383,396.29		$ 1,383,396.29	AUD
					Total	$ 2,915,435.40	AUD

4. Project Planning Strategy

4.1 Milestones

The following milestones are required by the project team to deliver the project:

Milestones	High Level Timing
Stage 1 Approval (PAN1) incl funds for design, procurement & ITT preparation	July 2025
Site Access for design and investigation	August 2025
Project Development Phase 1 & Phase 2	August 2025 – December 2025
RIT-T (assumed 26 weeks)	June 2025 – December 2025
Endorsement for “Going to Tender” from Network & Alternate Solutions	October 2025
ITT Submission (8 weeks)	November 2025 – January 2026
Evaluate Tender, Reconcile Estimate and Update PMP for Stage 2 Approval	February 2026
Stage 2 Approval (PAN2)	April 2026
Execute Delivery (including award of SPA contract)	May 2026
Site Possession for construction	July 2026
Construction & Commissioning (incl allowance for wet season)	July 2026 – December 2027
Decommission & Remove Redundant Panels & Cables	December 2027 – February 2028
Project Commissioning Date	February 2028

4.2 Project Staging

The high-level project staging are as follows:

Activity/Stage Description	High Level Timing
FAT (building install Sep 26)	April 2026 – July 2026
SPA Early Works	July 2026 – November 2026
PSI & Site Integration	September 2026 – November 2026
Decommission, Rebuild & Commission 2Bus + Coupler	April 2027 – August 2027
Decommission, Rebuild & Commission 1Bus	August 2027 – December 2027
Decommission & Remove Redundant Panels	December 2027 – February 2028

Notes:

- The above staging durations are assumptions.
- The high-level timing and wet weather constraints have been considered, based on BOM data for mean rainfall.

For detail staging, refer to the Project Staging Plan.

4.3 Project Schedule

Project timing shall be managed using a Project Schedule. Refer to the Project Schedule in PWA Server.

4.4 Network Impacts and Outage Planning

Accessing the Network for the staging and commissioning of the project works is required to be planned to reduce an impact to the network for the Project commissioning. This is to enable less effect to other Network operational requirements.

An outage plan has been submitted to the Outage Management team to enable discussions with the Network Operations Engineering team. Due to current workloads and ongoing RAZ issues, a response from outage management key stakeholders is not detailed in the Stage 1 Proposal.

Discussions with Powerlink and Energy Queensland Outage Management team will continue from January 2025.

4.5 Project Delivery Strategy

Strategy to deliver the project as follows:

Description	***Responsibility***							
	Main Site				***Remote End(s)***			
	Powerlink	***Contractor***	***MSP – O&SD***	***MSP - Ergon***	***Powerlink***	***Contractor***	***MSP – O&SD***	***MSP - Ergon***
Primary Design Systems (PSD):								
Earthworks	☒	☐	☐	☐	☐	☐	☐	☐
Civil and Structural	☒	☐	☐	☐	☐	☐	☐	☐
Electrical	☒	☐	☐	☐	☐	☐	☐	☐
Secondary Systems Design (SSD):								
Protection	☒	☐	☐	☐	☒	☐	☐	☐
Automation (Circuitry and Systems Configurations)	☒	☐	☐	☐	☒	☐	☐	☐
Telecommunication System Design (TSD):								
Data Networks	☒	☐	☐	☐	☐	☐	☐	☐
Bearer Networks	☒	☐	☐	☐	☐	☐	☐	☐
Construction:								
Earthworks	☐	☒	☐	☐	☐	☐	☐	☐
Civil	☐	☒	☐	☐	☐	☐	☐	☐
Construction (support structures, plant and equipment installation and demolition Works)	☐	☒	☐	☐	☐	☐	☐	☐
Secondary Systems Installation (loose panel's installation, panel modification, IED replacement, etc.)	☐	☒	☐	☐	☐	☐	☐	☐
Telecommunication Construction (including fibres)	☐	☒	☐	☐	☐	☐	☐	☐
Testing and Commissioning:								
Factory Acceptance Test	☐	☐	☐	☒	☐	☐	☐	☐
Site Acceptance Test (partial)	☐	☐	☐	☒	☐	☐	☐	☐

Description	*Responsibility*							
	Main Site				*Remote End(s)*			
	Powerlink	*Contractor*	*MSP – O&SD*	*MSP - Ergon*	*Powerlink*	*Contractor*	*MSP – O&SD*	*MSP - Ergon*
System Cut Over and Commissioning	☐	☐	☐	☒	☐	☐	☐	☒
Other:								
Revenue Metering site works	☐	☐	☐	☒	☐	☐	☐	☐

4.6 Procurement Strategy

The procurement strategy for services and selected items are listed below. All other services and items shall be procured in accordance with Powerlink's Procurement Standard.

Description	Procurement Method
Services:	
SPA – C / CT / DCT / D	ITT - Substation Panel Arrangement (SPA)
Optical Fibre System	Shortform ITT – Standing Offer arrangement with preferred/preapproved suppliers
MSP – OSD	RFQ
MSP – Ergon	RFQ – Service Level Agreement
Primary Plant and Equipment:	
HV Plant and Equipment	Period Contractors
Structures	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Hardware and fittings	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Transformers	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Reactors	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Diesel Generators	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Capacitor Bank	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Secondary Systems Equipment:	
IEDs	Period Contract
Panels, Kiosks, Boards and building fit-out	Shortform ITT – Standing Offer arrangement with preferred/preapproved suppliers
Control Building	Shortform ITT – Standing Offer arrangement with preferred/preapproved suppliers
DC Systems (Battery Banks and Charger)	Period Contract
Fire System	TBA
Security System	TBA
Specify any other items	Specify engagement (air-conditioning for existing building, etc.)

Description	Procurement Method
Specify any other items	Specify engagement

5. References

The following documents are applicable to this Project Management Plan.

Document name and hyperlink		Version
Project Scope Report		**2.0**