January 2026

Powerlink 2027-32 Revenue Proposal

Project Pack

CP.02400 Alan Sherriff Secondary Systems Replacement

Project Status: Unapproved

Network Requirement

Alan Sherriff substation was built in 2002 as a two-transformer 132/11kV substation, replacing the 132kV switching functions at Garbutt substation in 2004. Alan Sheriff substation is located on the Dalrymple Rd, Mount Louisa, approximately 5km off Woolcock St in Townsville. The substation comprises one switchyard, shared between Ergon Energy (EQL) and Powerlink. The switchgear at Alan Sherriff comprises PASS M0 modules.

A condition assessment indicates that most secondary systems devices are reaching the end of their technical asset life, recommending replacement by 2025. It further notes that the field cables are suitable for a further 15 to 20 years of service and that the secondary systems panels are in good condition and may be retained [1]. The driver for replacing secondary systems is the obsolescence and end of manufacturer support for the existing relays. Ageing secondary systems, which are no longer supported by the manufacturer are increasingly at risk of failing to comply with Schedule 5.1.9(c) of the National Electricity Rules, AEMO's Power System Security Guidelines and the reliability standard included in Powerlink's Transmission Authority.

While the PASS M0 modules at Alan Sheriff Substation are now obsolete the planned replacement of the three PASS M0 modules at Ingham South Substation (Project CP.02860) will provide a valuable source of additional spares to maintain this equipment in service.

Powerlink's 2025 Central scenario forecast confirms there is an enduring need to maintain electricity supply in the Townsville area. The removal or reconfiguration of the Alan Sheriff 132/11kV Substation due to secondary system failure/obsolescence would violate Powerlink's N-1-50MW/600MWh Transmission Authority reliability standard and significantly impact electricity supply within the Townsville area [2].

Recommended Option

As this project is currently 'Unapproved', project need and options will be subjected to the public RIT-T consultation process to identify the preferred option closer to the time of investment.

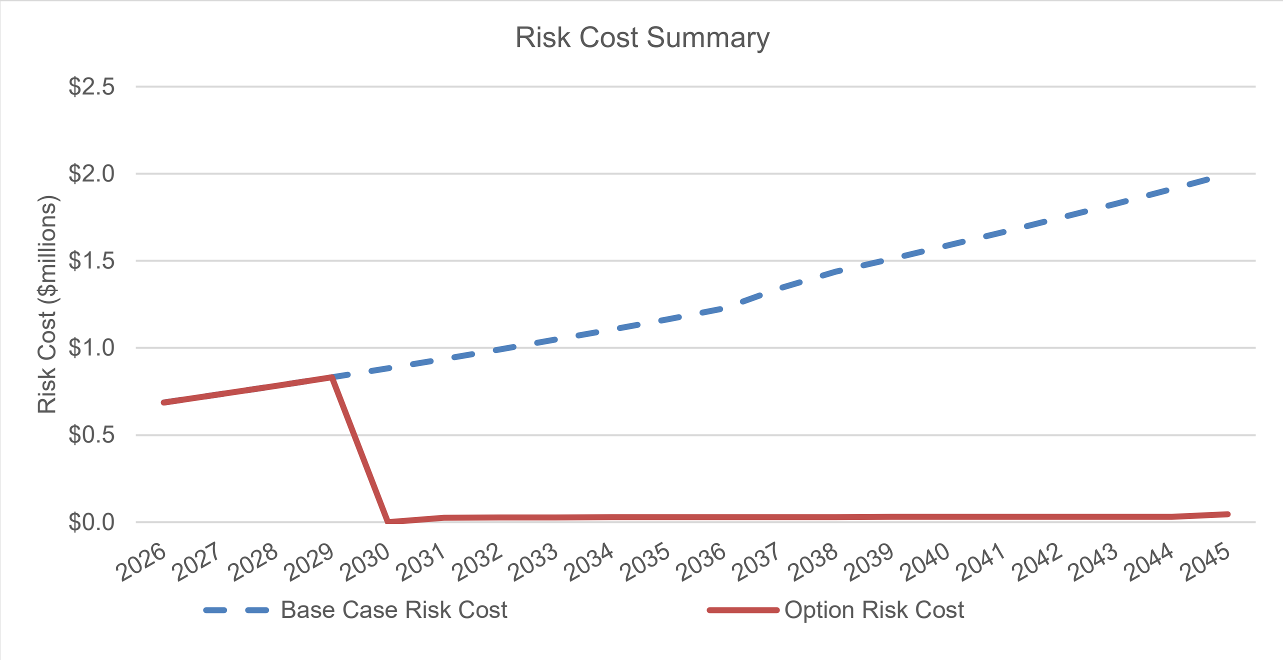
The current recommended option is for in-panel replacement of all secondary systems in the existing control building by 2028 [3].

Options considered but not proposed include:

- Replacement of all secondary systems in a new demountable building expected to be greater overall cost.

Figure 1 shows the current recommended option reduces the forecast risk monetisation profile of the Alan Sheriff Substation secondary systems from around $0.83 million per annum in 2029 to less than $0.03 million from 2030 [5].

Figure 1 Annual Risk Monetisation Profile ($ Real, 2025/26)



Cost and Timing

The estimated cost to replace secondary systems at Alan Sherriff substation is $19.9m ($2025/26) [4].

Target Commissioning Date: October 2028.

Document in CP.02400 Project Pack

Public Documents

1. T150 Alan Sherriff Secondary Systems Condition Assessment Report
2. CP.02400 Alan Sherriff Secondary Systems Replacement – Planning Statement
3. CP.02400 Alan Sherriff Secondary Systems Replacement – Project Scope Report
4. CP.02400 Alan Sherriff Secondary Systems Replacement – Concept Estimate
5. CP.02400 Alan Sherriff Secondary Systems Replacement – Risk Cost Summary Report

T150 Alan Sherriff 132kV Substation

Secondary Systems Condition Assessment Report

Document Details			
Version Number	1.0	**Principal Author**	[redacted]
Objective ID	A4477169	**Authorised by**	[redacted]
Issue Date	20/11/2020	**Team**	Sec Sys and Telecom Strategies
Previous Document	N/A		

Date	Version	Nature of Change	Author	Authorisation
20/11/2020	1.0	Final	[redacted]	[redacted]

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1. Introduction

Alan Sherriff substation was built in 2002 as a two transformer 132/11kV substation, and replaced the 132kV switching functions at Garbutt substation in 2004. A condition assessment in 2020 indicates that condition driven risks associated with existing secondary systems equipment should be addressed by 2025 in order to maintain the current network reliability and availability.

Alan Sherriff substation is located on Dalrymple Rd, Mount Louisa, about 5 km off Woolcock St in Townsville. The substation is comprised of one switchyard, shared between Ergon Energy and Powerlink.

The main purpose of this report is to assess the condition of secondary systems assets associated with the primary plants, as shown in Table 1, and to recommend the optimal reinvestment timing for these assets. Recommendations in this report have been formulated based on asset conditions only, excluding considerations for network reconfigurations, network-enduring needs, economic options, engineering solutions and delivery methodologies.

Alan Sherriff substation primary bays and network elements are listed in Table 1:

Table 1 – Alan Sherriff Substation Network Elements

Local Substation (T150 Alan Sherriff)					Remote Substation
	Voltage (kV)	Quantity	Bay Designation	Operational Element	
Feeder	132	6	=D04-A10	7151/2	Ross / Dan Gleeson
			=D07-A10	7144/2	Ross / Dan Gleeson
			=D10-A10	7277	Yabulu South
			=D11-A10	7240	Garbutt
			=D13-A10	7276	Townsville GT Switchyard
			=D14-A10	7239	Garbutt
			=D01-A10	CB 4412	Alan Sherriff T1 TFMR (Ergon)
			=D02-A10	CB 4422	Alan Sherriff T2 TFMR (Ergon)
Cap Bank		0			
Reactor		0			
Transformer		0			
Bus Coupler	132	1	=D03-A10	CB 4012	
Busbar	132	2	=KD1	1 Bus	
			=KD2	2 Bus	

Alan Sherriff substation pictorial aerial view and electrical single line diagram are shown in Figure 1 and Figure 2 respectively.

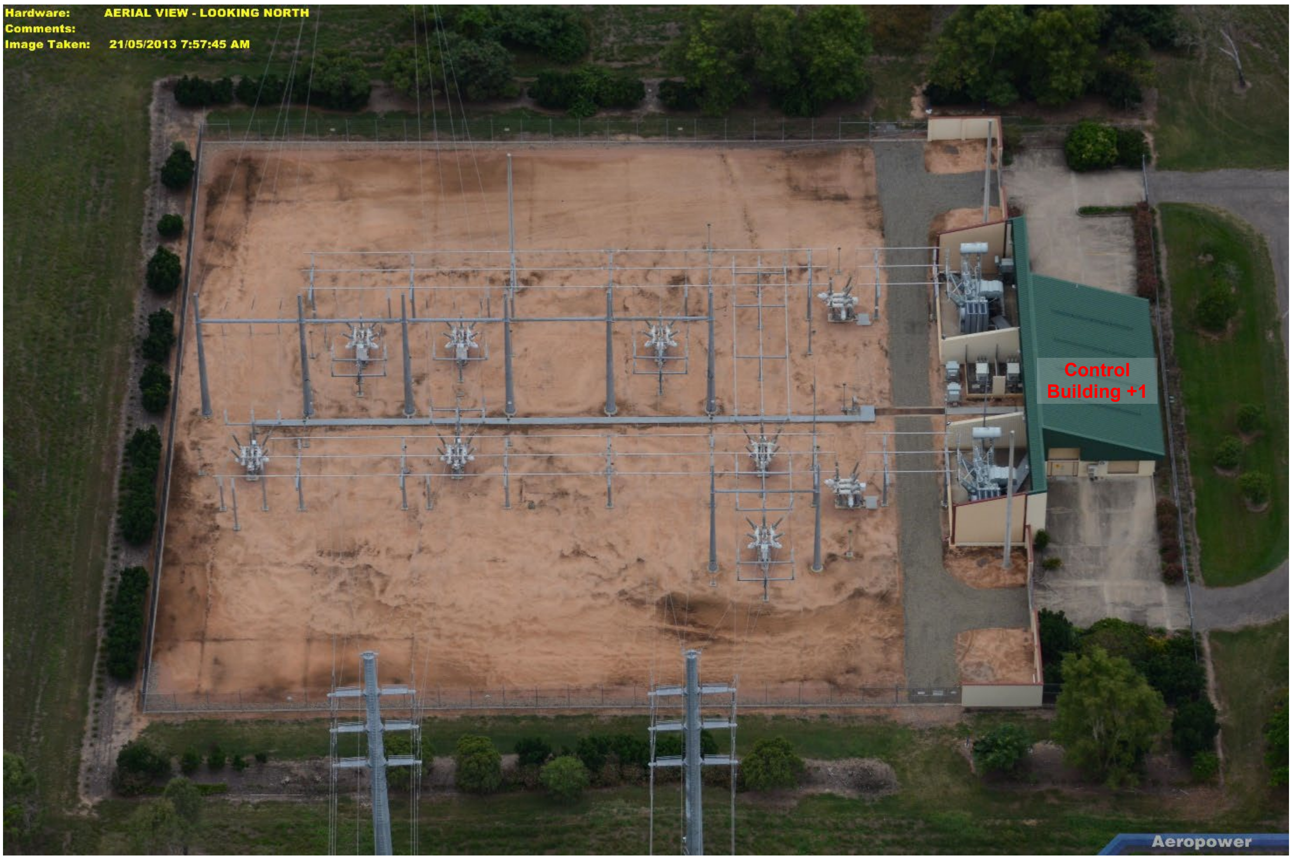


Figure 1 – 132kV Alan Sherriff Substation Aerial View

[redacted]

Figure 2 – 132kV Alan Sherriff Substation Electrical Single Line Diagram

2. Inclusions and Exclusions

2.1 Inclusions

Secondary systems and associated equipment provide monitoring, supervision, control and protection functions. The condition assessment of the following systems and equipment will be covered in this report.

- Secondary system cables – All cables that are associated with secondary systems and equipment, including:
  - Cables between control and protection panels and termination racks,
  - Cables between termination racks and yard marshalling kiosks, AC and DC kiosks.
- OpsWAN panels, system and equipment,
- Secondary system AC and DC supply – Low voltage (LV) AC Panel heaters and lights, DC batteries and chargers,
- Secondary system panels and associated ancillary parts, including links, terminals, Input / output modules, signal converters, transducers and power supplies.
- Indoor and outdoor secondary systems marshalling kiosks, AC and DC kiosks, termination racks, including internal links, terminals, MCBs and fuses,
- Indoor and outdoor control cables to outdoor secondary systems kiosks or cables from indoor secondary systems panels directly connected to primary equipment control kiosks,
- Secondary system equipment and systems, including protection relays, HMI computers, RTUs, data acquisition units, Programmable Logic Controllers (PLCs), Intelligent Electronic Devices (IED).
- Available space in existing control buildings to accommodate new secondary system panels.

2.2 Exclusions

The condition assessment of the following assets are not in scope of this report:

- Condition of control buildings and associated light and power circuits,

  Civil structures, cable trenches and foundations,
- AC auxiliary supply systems (> 230VAC), including transformers, diesel generators and building power and light circuits,
- Substation flood lights,
- Primary equipment and associated components e.g. transformer and circuit breaker control cubicles,

- Primary equipment kiosks and associated components, e.g. Power transformer, circuit breaker control kiosks.
- Cables from secondary systems outdoor kiosks (e.g. bay marshalling kiosks) to primary plant control kiosks,
- Cables from primary plant control kiosks to primary plant equipment,
- Telecommunication assets, including 50VDC batteries and chargers.

3. Condition Assessment Principles and Methodology

Principles of secondary systems condition assessment were based on Powerlink' s Secondary Systems Asset Risk Model developed in [1], and "Powerlink – Asset Risk Management – Framework" in [2]. The methodology consists of two main parts – Desktop assessment based on [1, 2] and site visual inspection.

The desktop assessment is limited only to assets recorded in SAP asset database, e.g. protection relays, RTUs and IEDs. It is important to note that a significant number of secondary systems equipment, including cables, kiosks, terminals, links, panels, termination racks, auxiliary equipment and some IEDs are not recorded in SAP. The condition assessment of these depends solely on the site visual inspection. Site visual inspection also provides moderation and manual update of desktop assessments to reflect the actual condition of operational equipment at site.

The desktop assessment models the equipment health indices based on the optimisation of risk, cost and performance of Powerlink's secondary assets since 1999. The health index is the key condition measurement for each equipment in service. The model takes into account equipment failure rates calculated based on operational data, environmental conditions where the equipment is installed and the mean physical ages of a group of equipment at bay and system (fleet) levels.

Health indices are modelled in the range from zero (0) to ten (10), where zero represents newly installed equipment and ten indicates equipment that have reached the end of their technical service life. Equipment with a health index close to ten represents only a moderate increased risk of functional failures, but significantly longer outage duration and higher risk of impacting system's availability and reliability.

The key outcome of this report is the recommended replacement timing for secondary systems assets and equipment detailed in the Appendix section based on their health indices and condition assessment data. It also takes into account of the criticality of equipment that are (or are not) directly associated with the performance of secondary systems. For example, OpsWAN equipment with health indices are close to ten, but may not need to be replaced urgently because their functions are considered to be non-critical to the secondary systems performance. In this case, they should only be opportunistically replaced as part of the secondary system replacement project to optimise cost.

4. Buildings

4.1 Substation Secondary Systems Buildings

The substation secondary systems are housed in the brick control building +1, which is shared between Ergon Energy and Powerlink. This control building is air-conditioned and clean. It is located within the substation perimeter fence.

Details of the substation control building are shown in Table 2.

Table 2 – Alan Sherriff Substation Secondary System Building

Building Description	Designation	Functional Use	Spare Sec Sys Panel Spaces
Substation Secondary System Building +1	+1	Busbar Protections =KD1, = KD2 (1 and 2 BZ CBF BT) Sec Sys Bays =D01, =D02, =D03, =D04, =D07, =D10, =D11, =D13 and =D14 T1 and T2 TFMR Revenue Meters Mux Communications Protection Signalling Station SCADA (NSC, LCF), Common RTU & OpsWAN 125V X&Y Batteries and Chargers	3

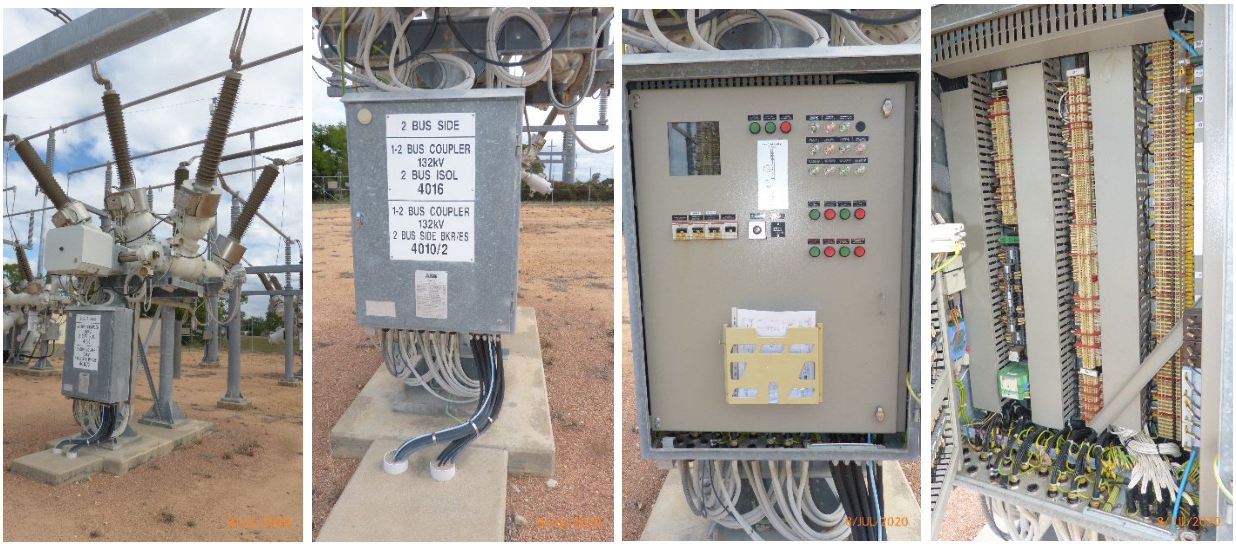
Figure 3 – T150 132kV Alan Sherriff Substation Secondary Systems Building +1

5. Condition Assessment

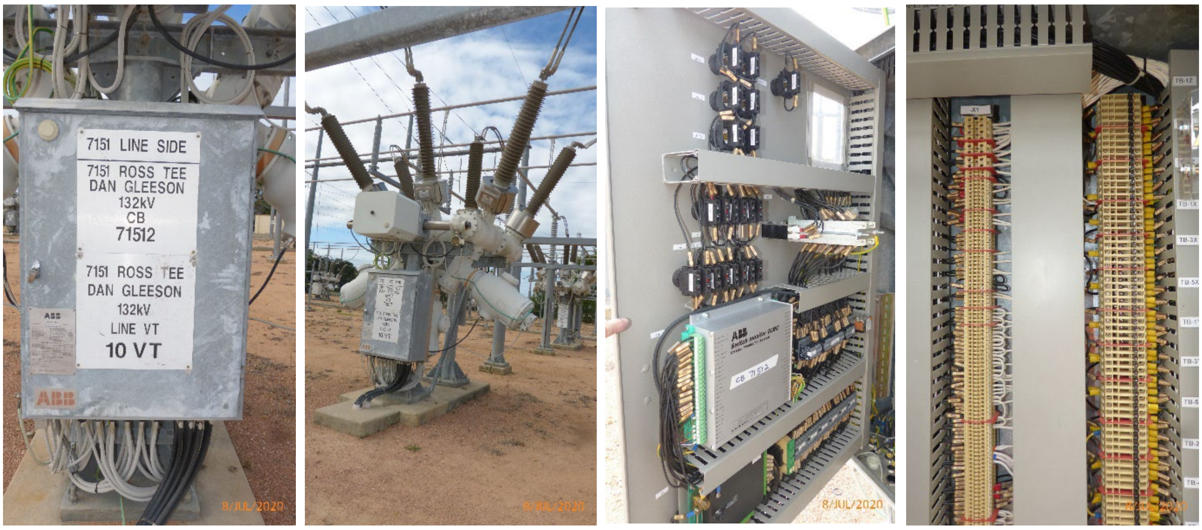
5.1 Secondary System Outdoor Marshalling Kiosks

Switchgears at Alan Sherriff substation are PASS-M0 modules. Generally, PASS-M0 switching bays do not have standalone bay marshalling kiosks. The PASS-M0 control cubicle performs as the switching bay marshalling kiosk and switchgear control cubicle.

The condition assessment of PASS-M0 control cubicles, which belong the primary plant, is not in scope of this report. Photos of PASS-M0 switchgear control cubicle / marshalling kiosks are illustrated in Figure 4 below for information only.



(a)132kV 1-2 Bus Coupler – PASS-M0 Switchgear Control / Marshalling Cubicle (+D03-A10)



(b)132kV Feeder 7151 – PASS-M0 Switchgear Control / Marshalling Cubicle (+D04-A10)

Figure 4 – Physical appearance of 132kV PASS-M0 Outdoor Control (and Marshalling) Cubicles

5.2 Outdoor Secondary System Cables

Control and protection cables were terminated directly between indoor panels and primary plant PASS-M0 control cubicles, i.e. no building termination racks. Visual inspection of these cables indicated they are still in good condition, as shown in Figure 5, and can be kept in service until 2043.

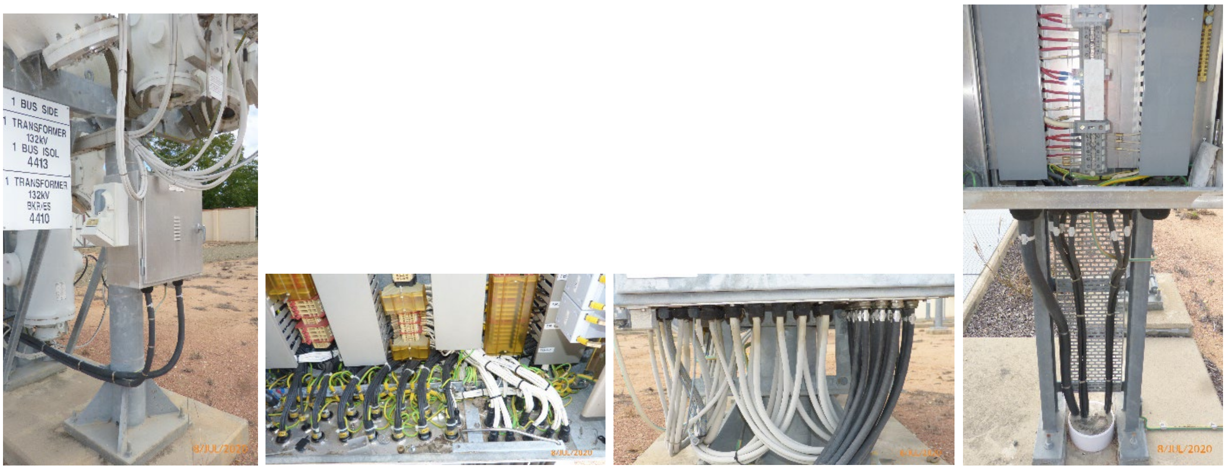


Figure 5 – Physical appearance of typical outdoor secondary system cables

5.3 Indoor Termination Racks / Yard Interface Cubicle

There are no termination racks at Alan Sherriff substation. Secondary system cables were installed directly between the indoor panels and outdoor primary plant control cubicles.

5.4 Indoor Secondary System Cables

All cables inside the control buildings are considered to be in good condition as they have been in clean and air-conditioned environment since there were installed around 2003 / 2004. The replacement of indoor cables is deemed unnecessary until 2043.

5.5 Control and Protection Systems

Condition assessment of Alan Sherriff Substation control and protection systems, including cubicles, equipment, internal components such as links, terminals, wirings, MCBs, fuses, cables is summarised in **Appendix A**.

5.5.1 Secondary Systems Panels

All secondary systems panels, including auxiliary parts e.g. links, terminals and internal wiring were installed between 2003 – 2004, except the Power Quality Monitoring System (ANALYSER UNIPOWER UP-2210) was installed in 2013, are currently still in good condition. Secondary systems panels as shown in Figure 6, including internal wirings, links and terminals can be left in service until 2043.

=D10 Feeder 7277

=D03 1-2 Bus Coupler

=D14 Feeder 7239

=D13 Feeder 7276

=D11 Feeder 7240

=KD1 – 1 Buszone

Power Quality Monitoring

=D07, Feeder 7144

Figure 6 – Typical Indoor Secondary Systems Panels at Alan Sherriff Substation

5.5.2 Control, Protection, Auxiliary, Ancillary, Metering and OpsWAN Equipment

5.5.2.1. Control, Protection, Auxiliary, Ancillary Equipment

Alan Sherriff substation secondary system comprises mostly microprocessor based control and protection equipment. There is a small number of modern solid state and electro-mechanical relays being used e.g. CB Fail Bus Trip relays and high impedance bus zone relays. Health indices and recommended replacement timeframe for substation secondary system equipment and associated ancillary equipment are tabled in Appendix A. Typical indoor secondary systems equipment are illustrated in Figure 7 below.

Figure 7 – Alan Sherriff Substation Typical Indoor Secondary System Equipment (2003 - 2004)

5.5.2.2. Revenue Metering Panel

Alan Sherriff substation revenue-metering panel as shown in figure 8, including auxiliary parts e.g. links, terminals and internal wiring was installed around 2002 and is currently in good condition. Panels, internal wirings, links and terminals can be left service until 2043.

Figure 8 – Alan Sherriff Substation Typical Revenue Metering Panels

5.5.2.3. Revenue Metering Equipment

Alan Sherriff Substation metering equipment as shown in Figure 9 were installed in 2002. Revenue meters should be replaced as part of the secondary system replacement project by 2025.

Figure 9 – Alan Sherriff substation typical revenue meters

5.5.2.4. OpsWAN Systems and Equipment

OpsWAN systems and equipment at this site were installed between 2003-2010 as illustrated in Figures 10 and 11 below. OpsWAN systems are still functioning and have an important role in operation and maintenance efficiencies. They are considered as auxiliary components of the power system. Their condition and performance generally do not have material impacts on the performance, reliability and availability of secondary systems and the power system.

Indoor OpsWAN systems and equipment should only be replaced opportunistically as part of the secondary systems replacement project. OpsWAN cameras (outdoor OpsWAN equipment) should only be replaced under corrective maintenance when they fail and shall be excluded from secondary system refurbishment projects.

Figure 10 – Alan Sherriff Substation OpsWAN Panel

Figure 11 – Alan Sherriff Substation Typical OpsWAN Equipment

5.5.3 Auxiliary Supply

5.5.3.1. AC Auxiliary Supply

AC auxiliary supplies, including station transformers and backup diesel generator/s are not in scope of this report. AC heaters and lights servicing secondary system panels should only be replaced as part of secondary systems panels.

5.5.3.2. DC Batteries and Chargers

Alan Sherriff substation 125VDC X and Y batteries and associated chargers were installed in 2003, illustrated in Figure 12 below. Both X & Y batteries are overdue for replacement, they should have been replaced in 2015. Replacement of these battery banks needs to be replaced urgently, as per recommendation in Appendix A to ensure reliable DC supply to the control and protection systems.

Batteries, chargers and DC monitoring systems should only be replaced at the same time with the secondary systems, as per recommendations in Appendix A.

Figure 12 – Alan Sherriff Substation 125VDC Batteries and Chargers

6. Secondary Systems Asset Strategies Recommendations

Recommendations shown in Table 3 below have been strategically optimised based on the replacement timing (condition based timing) of individual equipment Health Indices (HIs) in Appendix A. It is important that the responsible project team considers these recommendations in light of Powerlink delivery solutions, staging, resources and network outages to achieve safe and sustainable project delivery cost.

Table 3 – Recommended Asset Replacement Timing and Options – Building +1										
Indoor Sec Sys Panels (3 spare panel spaces)						Possible Options	Outdoor Kiosks (Excl. Primary plant)			
ID	Functions		Panel	Equipment	Cables		ID	Functions	Panel	Cables
+1A1	132kV 1 Buszone X & Y PROT CB Fail Bus Trip		2043	2025	2043	A, C				
+1A2	132kV 2 Buszone X & Y PROT CB Fail Bus Trip		2043	2025	2043	A, C				
+1A8	132kV Bay =D03-A10, Bus Coupler CB 4012		2043	2025	2043	A, C	+D03-A10	Hybrid	PASS M0	2043
+1A6	132kV Bay =D01-A10 - TFMR T1 C & P, CB 4412, 1VT, 3VT		2043	2025	2043	A, C	+D01-A10	Hybrid	PASS M0	2043
+1A7	132kV Bay =D02-A10 - TFMR T2 C & P, CB 4422, 2VT, 4VT		2043	2025	2043	A, C	+D02-A10	Hybrid	PASS M0	2043
+1A11	Feeder 7144/2 (Ross/Dan Gleeson), =D07-A10, CB 71442, 9VT		2043	2025	2043	A, C	+D07-A10	Hybrid	PASS M0	2043
+1A9	Feeder 7151/2 (Ross/Dan Gleeson), =D04-A10, CB 71512, 10VT		2043	2025	2043	A, C	+D04-A10	Hybrid	PASS M0	2043
+1A16	Feeder 7239 (Garbutt), =D14-A10, CB 72392, 5VT		2043	2025	2043	A, C	+D14-A10	Hybrid	PASS M0	2043
+1A14	Feeder 7240 (Garbutt), =D11-A10, CB 72402, 8VT		2043	2025	2043	A, C	+D11-A10	Hybrid	PASS M0	2043
+1A15	Feeder 7276 (Townsville GT SY), =D13-A10, CB 72762, 6VT		2043	2025	2043	A, C	+D13-A10	Hybrid	PASS M0	2043
+1A13	Feeder 7277 (Yabulu South), =D10-A10, CB 72772, 7VT						+D10-A10	Hybrid	PASS M0	2043
+1A3	132kV TFMR 1 and 2 Revenue Meters		2043	2025	2043	A, C				
+1A4	132kV Power Quality Monitoring		2043	2025	2043	A, C				
+1A21	Building +1 - Substation SCADA and Master OpsWAN		2043	2025	2043	A, C				
+1A17 +1A18	Building +1 - 125VDC (X & Y) Batteries, Monitors and Chargers	X Battery	2015 – Replace under maintenance ASAP			B,C				
		Y Battery								
		X DC Monitor & Charger	2025			B,C				
		Y DC Monitor & Charger								
		DC Distribution board								

Notes:

(i). *Option A: In-Situ (Equipment) Replacement - Replace equipment in existing panel.*
(ii). *Option B: Install new panels in existing building.*
(iii). *Option C: Install new panels in new building.*
(iv). *Unless specified, e.g. Transformer PLCs and some SICUs, all electronic equipment installed inside primary plant control cubicles (e.g. SICU, PASS M0 OLMs) are considered as integral parts of primary plant assets and are not in scope of this report.*
(v). *Innovative replacement solutions should be considered to maximise the use of available spaces in existing building to save cost.*
(vi). *Replacement timing for PASS M0 switchgear and its control cubicles depends on primary plant strategy.*
(vii). *Panel includes chassis, links, terminals and internal wirings.*

7. Conclusion

This report details the conditions of Alan Sherriff substation secondary systems and equipment. The primary objective of the optimal replacement timeframe is to maintain the current network reliability and availability and to minimise operational and compliance risks associated with secondary systems assets. Alan Sherriff substation secondary systems are recommended to be replaced by the end of calendar year 2025, as per secondary systems asset strategies recommendations.

8. Attachments

- **Appendix A** – T150 132kV Alan Sherriff Substation Secondary Systems Equipment Health Indices and Recommended Asset Placement Replacement Timeframe.

- CIGRE 2018 - B3 - 205 - Modelling Substation control and Protection Asset Condition for Optimal reinvestment Decision Based on Risk, Cost and Performance.

- Powerlink – Asset Risk Management – Framework, ASM-I&P-FRA-A2417558, Powerlink Queensland, 2019.

9. References

[1] "Modelling Substation control and Protection Asset Condition for Optimal reinvestment Decision Based on Risk, Cost and Performance", CIGRE PARIS 26-31 August 2018, T Vu, M. Pelevin, D. Gibbs, J.Horan, C. Zhang.

[2] "Powerlink – Asset Risk Management – Framework", ASM-I&P-FRA-A2417558, Powerlink Queensland, 2019.

10. Appendix A

APPENDIX A - T150 ALAN SHERRIFF 132KV SUBSTATION SECONDARY SYSTEMS - EQUIPMENT HEALTH INDICES AND RECOMMENDED REPLACEMENT TIMEFRAME

Notes:
(a): Subject to Powerlink's O&M Safety Requirements, Current Standard Solutions and Implementation Methodologies, it may be more beneficial to align with the recommended replacement timeframe of sedondary systems equipment
(b): Recommended Timeframe is based on majority of Equipment Health Indices
(c): Based on Visual Inspection and Subject to the decision of the Control Building and Secondary Systems Panels. A number of New Cables may be requried if location of control building or secondary systems panels is changed.
(d): As a minimum requirement, Rubber Seals, Air filter and Terminals and Links are required to be repalced by the recommended timeframe. New Marshalling Kiosks should be considered if Exsiting Cables are to be reaplaced.

RECOMMENDED REPLACEMENT TIMMING (Based on Trigger Conditions only, Exclude considerations for Solutions, implementation methodologies)

BAY	C&P PANEL				SECONDARY SYSTEMS EQUIPMENT							X-PROT		Y-PROT		AUX & CTRL		REVENUE METERING		OPSWAN		CABLES (HI)	YARD MARSHALLING KIOSKS (HI)	C&P PANELS (Chassis)	Sec Sys Eqiupment	CABLES	YARD MARSHALLING KIOSKS
Function	Panel Descripion	Panel No.	Year	HI	Functional Loc.	Description	Manufacturer	Model number	Obsolescence (Yes / No)	Spare Qty	Material	Eff. Age	HI	Eff. Age	HI	Eff. Age	HI	Eff. Age	HI	Eff. Age	HI	C&P Panels to HV Yard Marshalling Kiosks (CB, MK, CT, VT, AC, DC, COOLING)	Yard Marshalling Kiosks (CB, MK, CT, VT, AC, DC, COOLING)	C&P Panels	Sec Sys Equipment & Auxiliary Components	C&P Panels to HV Yard Marshalling Kiosks (CB, MK, CT, VT, AC, DC, COOLING)	Yard Marshalling Kiosks (CB, MK, CT, VT, AC, DC, COOLING)
132kV 1 Buszone X & Y PROT CB Fail Bus Trip	132kV 1 Buszone X & Y PROT CB Fail Bus Trip, Common RTU 1	+1A1	2003	4.25	T150-SSS-1BU4-BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	25	27350					16.93	8.47					4.25	4.25	2042-2043	2024/25 (b)	2042-2043	2042-2043
					T150-SSS-1BU4-XPROT	RELAY BUS ZONE GE B30	GE	[redacted]	No	3	32781	16.93	8.47														
					T150-SSS-1BU4-XPROT	RELAY CB FAIL BUS TRIP RACK	RMS	[redacted]	No	3	29800	16.93	8.47														
					T150-SSS-1BU4-YPROT	RELAY BUS ZONE GE B30	GE	[redacted]	No	3	32781			16.16	8.08												
					T150-SSS-1BU4-YPROT	RELAY CB FAIL BUS TRIP RACK	RMS	[redacted]	No	3	29800			16.93	8.47												
132kV 1 Buszone X & Y PROT CB Fail Bus Trip	132kV 1 Buszone X & Y PROT CB Fail Bus Trip, Common RTU 2	+1A2	2003	4.25	T150-SSS-2BU4-BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	25	27350					16.93	8.47					4.25	4.25	2042-2043	2024/25 (b)	2042-2043	2042-2043
					T150-SSS-2BU4-XPROT	RELAY BUS ZONE GE B30	GE	[redacted]	No	3	32781	16.93	8.47														
					T150-SSS-2BU4-XPROT	RELAY CB FAIL BUS TRIP RACK	RMS	[redacted]	No	3	29800	16.93	8.47														
					T150-SSS-2BU4-YPROT	RELAY BUS ZONE GE B30	GE	[redacted]	No	3	32781			16.93	8.47												
					T150-SSS-2BU4-YPROT	RELAY CB FAIL BUS TRIP RACK	RMS	[redacted]	No	3	29800			16.93	8.47												
132kV Bay =D03-A10, Bus Coupler CB 4012, CTRL and PROT	132kV Bay =D03-A10, Bus Coupler CB 4012, CTRL and PROT	+1A8	2003	4.25	T150-SSS-401--BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	25	27350					16.93	8.47					4.25	4.25	2042-2043	2024/25 (b)	2042-2043	2042-2043
					T150-SSS-401--XPROT	RELAY CB MGMT GE C60 (VER 2.82)	GE	[redacted]	Yes	4	25383	16.93	8.47														
					T150-SSS-401--YPROT	RELAY CBMAN SEL-351-1 (1A)	SCHWEITZER	[redacted]	Yes	11	25466			16.93	8.47												
132kV Bay =D01-A10 - TFMR T1 CTRL and PROT, CB 4412, 1 VT, 3 VT	132kV Bay =D01-A10 - TFMR T1 CTRL and PROT, CB 4412, 1 VT, 3 VT	+1A6	2003	4.25	T150-SSS-441--BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	25	27350					16.93	8.47					4.25	4.25	2042-2043	2024/25 (b)	2042-2043	2042-2043
					T150-SSS-441--XPROT	RELAY CB MGMT GE C60 (VER 2.82)	GE	[redacted]	Yes	4	25383	16.93	8.47														
					T150-SSS-441--YPROT	RELAY CBMAN SEL-351-1 (1A)	SCHWEITZER	[redacted]	Yes	11	25466			16.93	8.47												
132kV Bay =D02-A10 - TFMR T2 CTRL and PROT, CB 4422, 2VT, 4VT	132kV Bay =D02-A10 - TFMR T2 CTRL and PROT, CB 4422, 2VT, 4VT	+1A7	2003	4.25	T150-SSS-442--BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	25	27350					16.93	8.47					4.25	4.25	2042-2043	2024/25 (b)	2042-2043	2042-2043
					T150-SSS-442--XPROT	RELAY CB MGMT GE C60 (VER 2.82)	GE	[redacted]	Yes	4	25383	16.93	8.47														
					T150-SSS-442--YPROT	RELAY CBMAN SEL-351-1 (1A)	SCHWEITZER	[redacted]	Yes	11	25466			16.93	8.47												
Feeder 7144/2 (Ross/Dan Gleeson), =D07-A10, CB 71442, 9 VT, CTRL and PROT	Feeder 7144/2 (Ross/Dan Gleeson), =D07-A10, CB 71442, 9 VT, CTRL and PROT	+1A11	2003	4.25	T150-SSS-7144-BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	25	27350					16.93	8.47					4.25	4.25	2042-2043	2024/25 (b)	2042-2043	2042-2043
					T150-SSS-7144-XPROT	RELAY CURR DIFF DISTANCE MICOM P546	SCHNEIDER	[redacted]	Yes	14	28746	9.61	4.80														
					T150-SSS-7144-YPROT	RELAY CURR.DIFF ABB RED670 DNP3	ABB	[redacted]	No	4	35967			4.55	2.28												
Feeder 7151/2 (Ross/Dan Gleeson), =D04-A10, CB 71512, 10 VT, CTRL and PROT	Feeder 7151/2 (Ross/Dan Gleeson), =D04-A10, CB 71512, 10 VT, CTRL and PROT	+1A9	2004	4	T150-SSS-7151-BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	25	27350					16.93	8.47					4.00	4.00	2043-2044	2025/26 (b)	2043-2044	2043-2044
					T150-SSS-7151-XPROT	RELAY CURR DIFF DISTANCE MICOM P546	SCHNEIDER	[redacted]	Yes	14	28746																
					T150-SSS-7151-YPROT	RELAY CURR.DIFF ABB RED670 DNP3	ABB	[redacted]	No	4	35967																
Feeder 7239 (Garbutt), =D14-A10, CB 72392, 5 VT, CTRL and PROT	Feeder 7239 (Garbutt), =D14-A10, CB 72392, 5 VT, CTRL and PROT	+1A16	2004	4	T150-SSS-7239-BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	0	26047					15.64	7.82					4.00	4.00	2043-2044	2025/26 (b)	2043-2044	2043-2044
					T150-SSS-7239-PSDITA	DEWAR DM1200 PROT SIG DIG 90-320V SUPPLY	DEWAR	[redacted]	Yes	5	17308																
					T150-SSS-7239-PSDITB	DEWAR DM1200 PROT SIG DIG 90-320V SUPPLY	DEWAR	[redacted]	Yes	5	17308																
					T150-SSS-7239-XPROT	RELAY CURRENT DIFF GE L90 (2 TERM)	GE	[redacted]	Yes	9	25209	15.63	7.81														
					T150-SSS-7239-YPROT	RELAY DISTANCE SEL 311C 1A	SCHWEITZER	[redacted]	Yes	28	25388			15.63	7.81												
Feeder 7240 (Garbutt), =D11-A10, CB 72402, 8 VT, CTRL and PROT	Feeder 7240 (Garbutt), =D11-A10, CB 72402, 8 VT, CTRL and PROT	+1A14	2004	4	T150-SSS-7240-BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	0	26047					15.65	7.82					4.00	4.00	2043-2044	2025/26 (b)	2043-2044	2043-2044
					T150-SSS-7240-PSDITA	DEWAR DM1200 PROT SIG DIG 90-320V SUPPLY	DEWAR	[redacted]	Yes	5	17308																
					T150-SSS-7240-PSDITB	DEWAR DM1200 PROT SIG DIG 90-320V SUPPLY	DEWAR	[redacted]	Yes	5	17308																
					T150-SSS-7240-XPROT	RELAY CURRENT DIFF GE L90 (2 TERM)	GE	[redacted]	Yes	9	25209	15.65	7.82														
					T150-SSS-7240-YPROT	RELAY DISTANCE SEL 311C 1A	SCHWEITZER	[redacted]	Yes	28	25388			15.65	7.82												
Feeder 7276 (Townsville GT SY), =D13-A10, CB 72762, 6 VT, CTRL and PROT	Feeder 7276 (Townsville GT SY), =D13-A10, CB 72762, 6 VT, CTRL and PROT	+1A15	2004	4	T150-SSS-7276-BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	0	26047					15.65	7.82					4.00	4.00	2043-2044	2025/26 (b)	2043-2044	2043-2044
					T150-SSS-7276-PSPIT	DEWAR DM1200 PROT SIG DIG 90-320V SUPPLY	DEWAR	[redacted]	Yes	5	17308																
					T150-SSS-7276-XPROT	RELAY CURRENT DIFF GE L90 (2 TERM)	GE	[redacted]	Yes	9	25209	15.65	7.82														
					T150-SSS-7276-YPROT	RELAY DISTANCE SEL 311C 1A	SCHWEITZER	[redacted]	Yes	28	25388			15.65	7.82												
Feeder 7277 (Yabulu South), =D10-A10, CB 72772, 7 VT, CTRL and PROT	Feeder 7277 (Yabulu South), =D10-A10, CB 72772, 7 VT, CTRL and PROT	+1A13	2004	4	T150-SSS-7277-BAYCONT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO	[redacted]	Yes	0	26047					15.62	7.81					4.00	4.00	2043-2044	2025/26 (b)	2043-2044	2043-2044
					T150-SSS-7277-PSDIT	DEWAR DM1200 PROT SIG DIG 20-60V SUPPLY	DEWAR	[redacted]	Yes	5	17308																
					T150-SSS-7277-PSPIT	DEWAR DM1200 PROT SIG DIG 90-320V SUPPLY	DEWAR	[redacted]	Yes	5	17308																
					T150-SSS-7277-XPROT	RELAY CURRENT DIFF GE L90 (2 TERM)	GE	[redacted]	Yes	9	25209	15.64	7.82														
					T150-SSS-7277-YPROT	RELAY DISTANCE SEL 311C 1A	SCHWEITZER	[redacted]	Yes	28	25388			14.08	7.04												

APPENDIX A - T150 ALAN SHERRIFF 132KV SUBSTATION SECONDARY SYSTEMS - EQUIPMENT HEALTH INDICES AND RECOMMENDED REPLACEMENT TIMEFRAME

Notes:
(a): Subject to Powerlink's O&M Safety Requirements, Current Standard Solutions and Implementation Methodologies, it may be more beneficial to align with the recommended replacement timeframe of sedondary systems equipment
(b): Recommended Timeframe is based on majority of Equipment Health Indices
(c): Based on Visual Inspection and Subject to the decision of the Control Building and Secondary Systems Panels. A number of New Cables may be requried if location of control building or secondary systems panels is changed.
(d): As a minimum requirement, Rubber Seals, Air filter and Terminals and Links are required to be repalced by the recommended timeframe. New Marshalling Kiosks should be considered if Exsiting Cables are to be reaplaced.

RECOMMENDED REPLACEMENT TIMMING (Based on Trigger Conditions only, Exclude considerations for Solutions, implementation methodologies)

BAY	C&P PANEL				SECONDARY SYSTEMS EQUIPMENT							X-PROT		Y-PROT		AUX & CTRL		REVENUE METERING		OPSWAN		CABLES (HI)	YARD MARSHALLING KIOSKS (HI)	C&P PANELS (Chassis)	Sec Sys Eqiupment	CABLES	YARD MARSHALLING KIOSKS
Function	Panel Descripion	Panel No.	Year	HI	Functional Loc.	Description	Manufacturer	[redacted]	Obsolescence (Yes / No)	Spare Qty	Material	Eff. Age	HI	Eff. Age	HI	Eff. Age	HI	Eff. Age	HI	Eff. Age	HI	C&P Panels to HV Yard Marshalling Kiosks (CB, MK, CT, VT, AC, DC, COOLING)	Yard Marshalling Kiosks (CB, MK, CT, VT, AC, DC, COOLING)	C&P Panels	Sec Sys Equipment & Auxiliary Components	C&P Panels to HV Yard Marshalling Kiosks (CB, MK, CT, VT, AC, DC, COOLING)	Yard Marshalling Kiosks (CB, MK, CT, VT, AC, DC, COOLING)
132 kV Reveue Meters	132kV TFMR 1 and 2 Revenue Meters	+1A3	2002	4.5	T150-SSS-METR-REVMET1	TRANSF 1 WH/VARH METER (REVENUE)	EDMI		Yes	45	15879							17.55	8.77			4.50	4.50	2041-2042	2023/24 (b)	2041-2042	2041-2042
					T150-SSS-METR-REVMET1	TRANSF 1 WH/VARH METER (CHECK)	EDMI		Yes	45	15879							17.55	8.77								
					T150-SSS-METR-REVMET2	TRANSF 2 WH/VARH METER (REVENUE)	EDMI		Yes	45	15879							17.55	8.77								
					T150-SSS-METR-REVMET2	TRANSF 2 WH/VARH METER (CHECK)	EDMI		Yes	45	15879							8.46	4.23								
132kV Power Quality Monitoring	132kV Power Quality Monitoring	+1A4	2013	1.75	T150-SSS-NBAY-PWRQUAL1	PQ ANALYSER UNIPOWER UP-2210 VT & REF IN	UNIPOWER		Yes	0	33423											1.75	1.75	2052-2053	2034/35 (b)	2052-2053	2052-2053
Substation SCADA and Master OpsWAN	Substation SCADA and Master OpsWAN	+1A21	2003	4.25	T150-SSS-NBAY-INVERT	INVERTER	LATRONICS		No	2	25941									16.93	8.47			2042-2043	2024/25 (b)		
					T150-SSS-NBAY-LCF	LOCAL CONTROL FACILITY SUN ULTRA 25	SUN		Yes	8	29069					7.45	6.21										
					T150-SSS-NBAY-LCFINT	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO		Yes	2	28781					16.93	8.47										
					T150-SSS-NBAY-NSCLINK1	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO		Yes	2	28781					16.93	8.47										
					T150-SSS-NBAY-NSCLINK2	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO		Yes	2	28781					16.93	8.47										
					T150-SSS-NBAY-TIMING	GPS CLOCK - TEKRON TCG01	TEKRON		Yes	0	25933					16.93	8.47										
					T150-SSS-NBAY-OWNTWK	SERVER PORT 48VDC PERLE 04030450 -OPSWAN	PERLE		No	2	27733									9.36	7.80						
					T150-SSS-NBAY-OWNTWK	SWITCH E/NET 32PRT RUGGED RSG2300 OPSWAN	RUGGEDCOM		No	3	30818									9.36	7.80						
					T150-SSS-NBAY-OWNTWK	ROUTER CISCO 2811 48VDC - OPSWAN	CISCO		Yes	0	27651									9.36	7.80						
					T150-SSS-NBAY-OWSERV	TERMINAL SERVER	ICP ELECTRONICS		Yes	2	30335									10.43	8.69						
Comms RTU and Miscelanuous OpsWAN Equipment	Comms RTU and Miscelanuous OpsWAN Equipment		2003	4.25	T150-SSS-NBAY-OWTERM	LOCAL CONTROL FACILITY PC X TERMINAL	WYSE		Yes	0	29180									10.52	8.77			2042-2043	2024/25 (b)		
					T150-SSS-NBAY-RTUCOM	REMOTE TERMINAL UNIT FOXBORO C50	FOXBORO		Yes	17	27353					16.93	8.47										
					T150-SSS-NBAY-OWCAM1	CANON ETHERNET CAMERA	CANON		Yes	0	27074									10.66	8.89						
					T150-SSS-NBAY-OWPRINT	PRINTER	HEWLETT PACKARD		Yes	0	26840									9.36	7.80						
132kV BLDG +1 DC AUXILIARY SUPPLY	BUILDING +1 125V DC X BATTERY	+1A17	2003	10.00	T150-SIN-DCSU-125DCX	BUILDING +1 125V DC X BATTERY - 300AH	EXIDE																		2015		
	BUILDING +1 125V DC X BATTERY MONITOR AND CHARGER	+1A18	2003	8.50		BUILDING +1 125V DC X BATTERY MONITOR AND CHARGER	RECTIFIER TECHNOLOGIES																		2025		
	BUILDING +1 125V DC Y BATTERY	+1A17	2003	10.00	T150-SIN-DCSU-125DCY	BUILDING +1 125V DC Y BATTERY - 300AH	EXIDE																		2015		
	BUILDING +1 125V DC Y BATTERY MONITOR AND CHARGER	+1A18	2003	8.50		BUILDING +1 125V DC Y BATTERY MONITOR AND CHARGER	RECTIFIER TECHNOLOGIES																		2025		
	BUILDING +1 125V DC DISTRIBUTION BOARD	+1A18	2003	8.50		BUILDING +1 125V DC DISTRIBUTION BOARD																			2025		

Planning Statement	30/07/2025
Title	CP.02400 T150 Alan Sherriff Secondary Systems Replacement – Planning Statement
Zone	Ross
Need Driver	Emerging compliance risks arising from condition and obsolescence of Alan Sherriff ageing secondary systems.
Network Limitation	Alan Sherriff Substation is required to meet Powerlink Queensland's N-1-50MW/600MWh Transmission Authority reliability standard.
Pre-requisites	None

Executive Summary

Alan Sherriff Substation is a bulk supply point for Energy Queensland load located in the north western suburbs of Townsville.

Ageing and obsolete secondary system are increasingly at risk of failing to comply with Schedule 5.1.9(c) of the National Electricity Rules and AEMO's Power System Security Guidelines[1].

The 2025 Central scenario load forecasts confirm an enduring need for the supply of electricity to loads in Townsville.

Emerging secondary system condition risks at T150 Alan Sherriff Substation require Powerlink to take action in order to continue to meet its Powerlink's N-1-50MW/600MWh Transmission Authority reliability standards for Townsville.

The preferred network solution for Powerlink to continue to meet its statutory obligations is the replacement of the at-risk secondary systems.

[1] *AEMO, Power System Operating* Procedure *SO_OP_3715*, *Power System Security Guidelines (the Rules require AEMO to develop and publish Power System Operating Procedures pursuant to clause 4.10.1(b) of the Rules, which Powerlink must comply with 4.10.2(b)).*

Table of Contents

1. Introduction

Alan Sherriff substation was built in 2002 as a two transformer 132/11kV substation, replacing the 132kV switching functions at Garbutt substation in 2004. The substation is comprised of one switchyard, shared between Ergon Energy and Powerlink. The switchgear at Alan Sherriff comprises PASS M0 modules.

This substation provides a link between H056 Yabulu South, T145 Townsville Switchyard, T092 Dan Gleeson and T046 Garbutt substations and supplies 11kV load on the Ergon Energy network.

Figure 1 shows a geographical view of Townsville South's location within the Townsville area. The figure shows the existing 275kV,132 kV and 66kV transmission networks in the Townsville area.

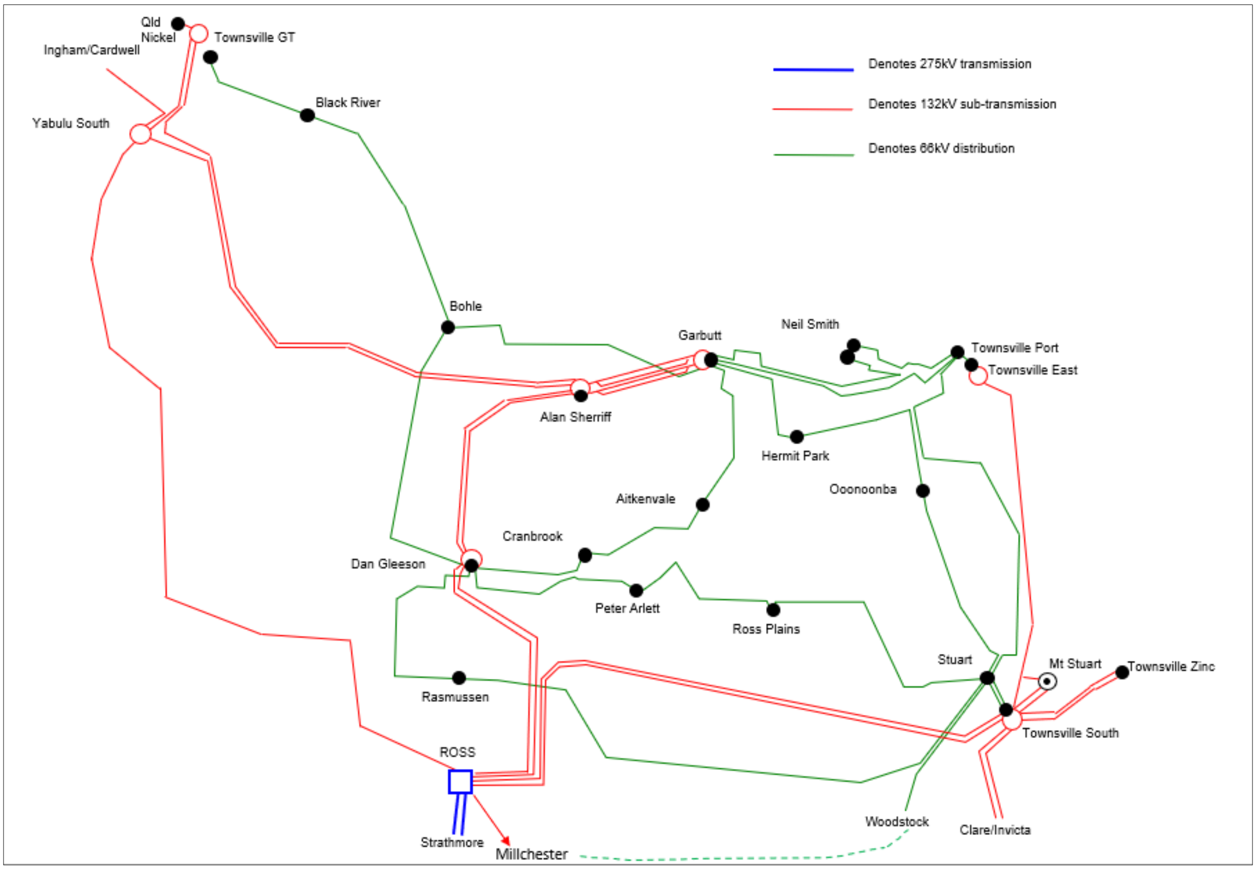


Figure 1. Geographical view of the Townsville transmission network

The condition assessment [1] of the secondary system plant at T150 Alan Sherriff Substation has concluded many of the original assets are reaching the end of their operational life and recommends that action is taken to address the compliance risks arising from the condition and obsolescence of the at-risk plant.

In addition to the site-specific impacts of obsolescence at Townsville 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. Running multiple secondary systems to failure across the network increases the likelihood of concurrent systemic faults with significant implications on network reliability and safety.

This report assesses the impact that removal of the functionality enabled by the at-risk secondary systems would have on the performance of the network and Powerlink's statutory obligations. It also establishes the indicative requirements of any potential alternative solutions to the current services provided by Alan Sherriff Substation.

2. T150 Alan Sherriff Substation configuration

Figure 2 shows the operational diagram for the Alan Sherriff Substation and the plant in scope.

[redacted]

Figure 2. Line Diagram of Alan Sherriff Substation

3. Alan Sherriff Demand Forecast.

Figure 3 shows diagrammatically the interconnected 66kV network.

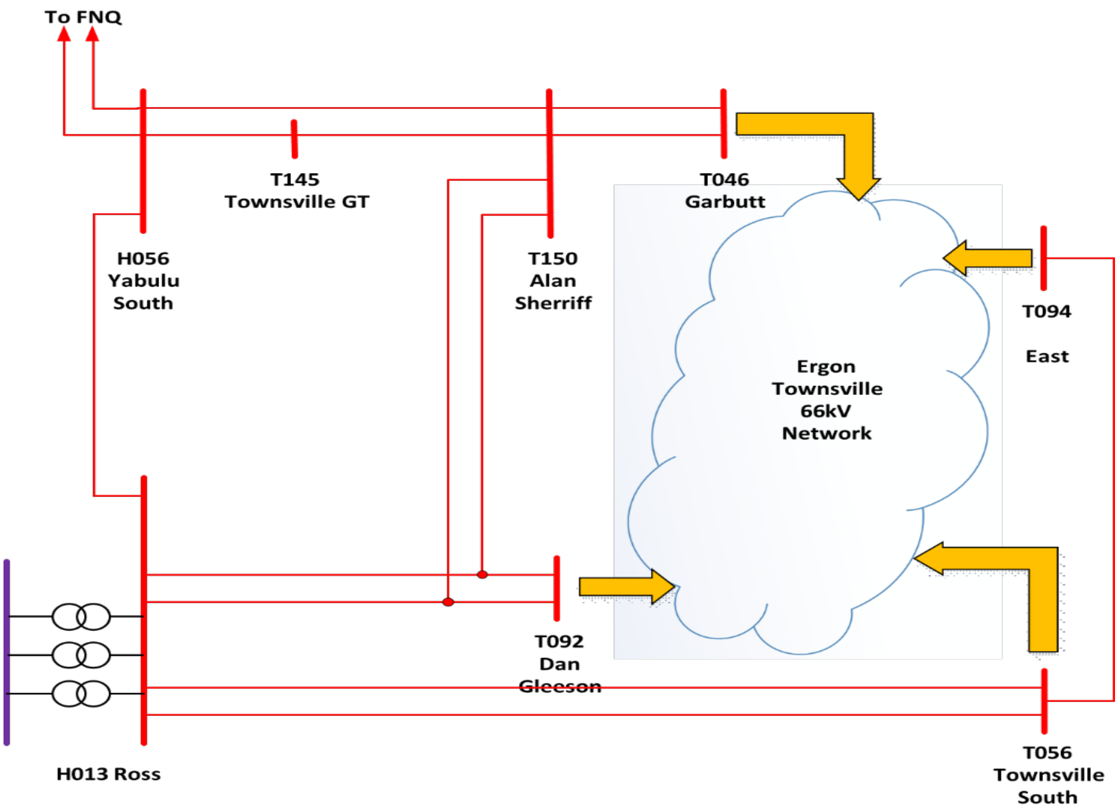


Figure 3. Townsville Distribution Network (Schematic Overview)

Historical and forecast maximum demand for the Alan Sherriff loads is shown in Figure 4 and 5. Over the planning period, the maximum demand is forecast to remain relatively steady.

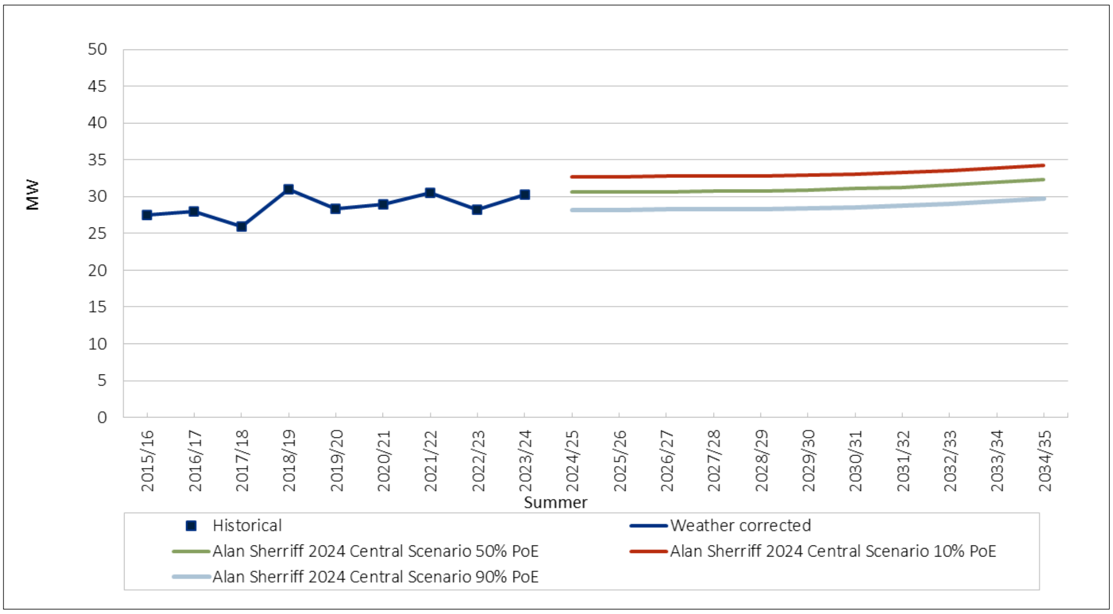


Figure 5: Alan Sherriff 11kV Load History and Forecast

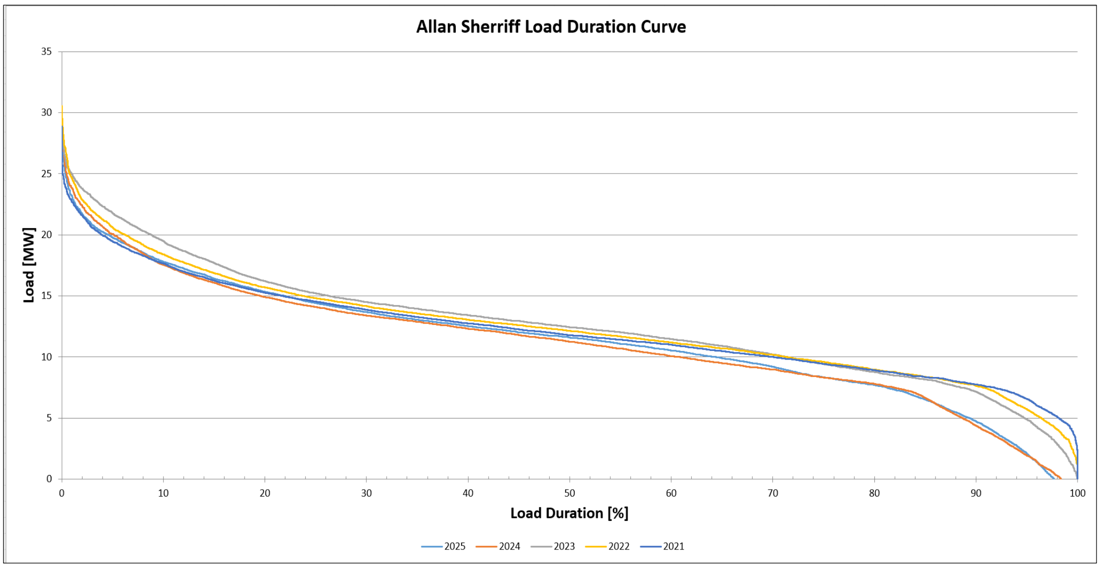


Figure 6. Allan Sherriff 11kV Load duration curves

With consideration of rooftop PV within the Ergon Energy network supplied from Alan Sherriff the maximum customer load is significantly higher. Figure 7 shows that rooftop PV meets up to 5MW of underlying demand.

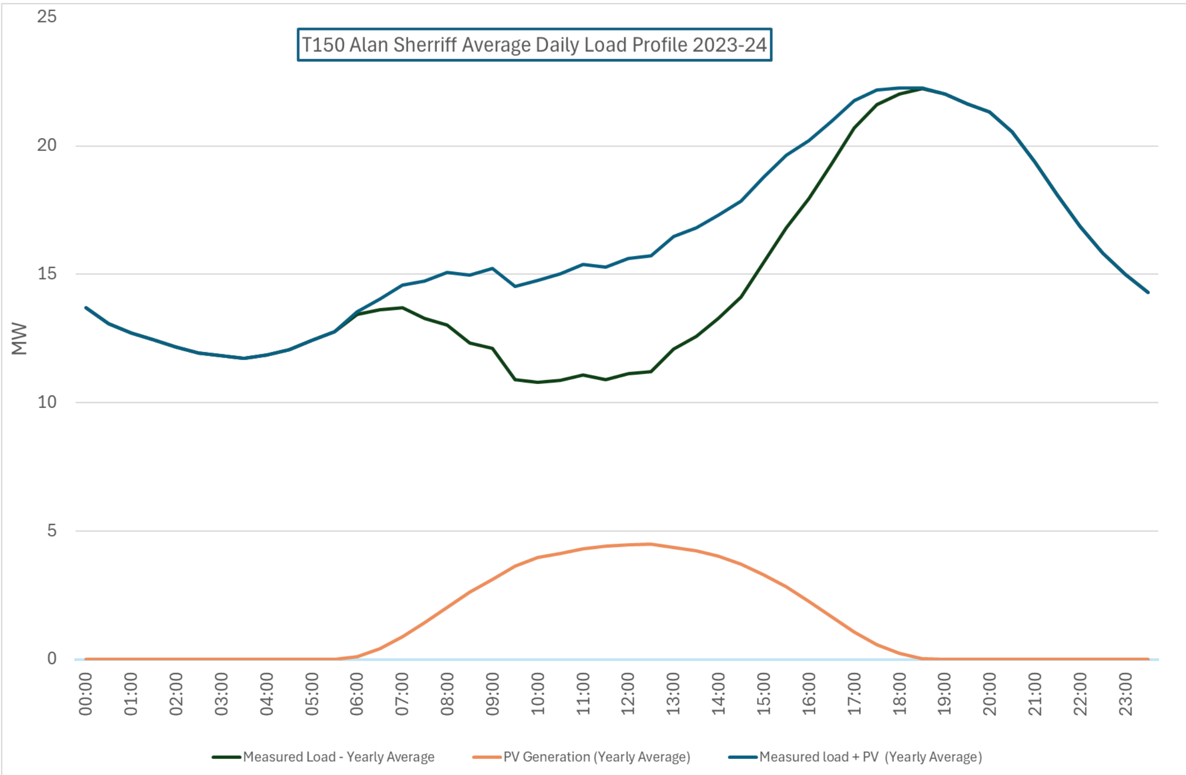


Figure 7. Alan Sherriff 11kV Summer Average Load Day profile 2023/24 (PV in service).

Historical and forecast maximum demand for the Garbutt loads is shown in Figures 8 and 9. Over the planning period, the maximum demand is forecast to steadily grow.

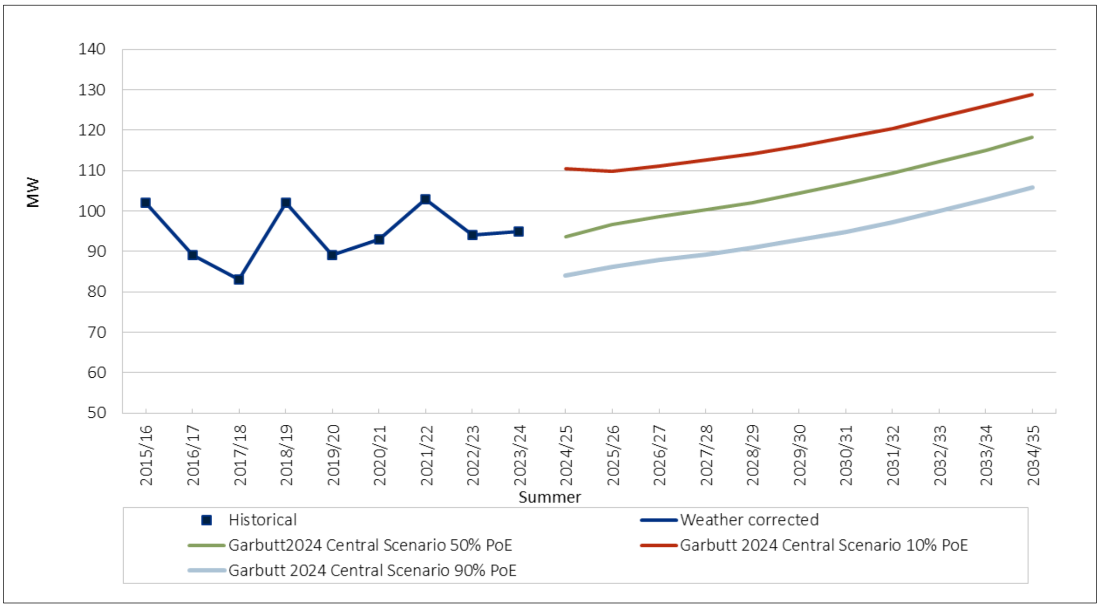


Figure 8. Garbutt 66kV Load History and Forecast

The annual load duration curves from 2021 are shown in Figure 8.

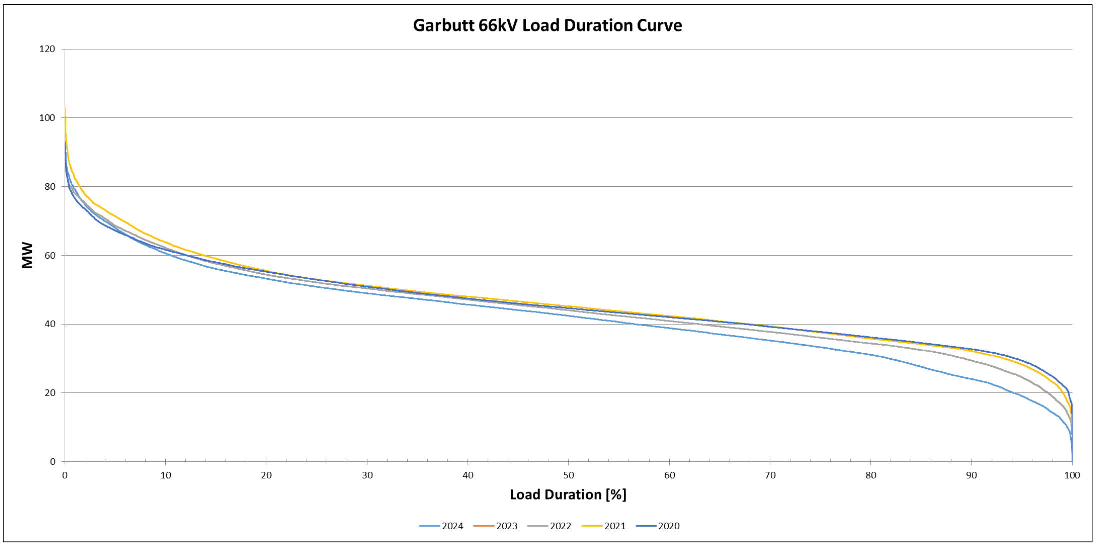


Figure 9. Garbutt 66kV Load duration curves

With consideration of rooftop PV within the Ergon Energy network supplied from Garbutt Substation the maximum customer load is significantly higher. Figure 10 shows that rooftop PV meets up to 60MW of underlying demand.

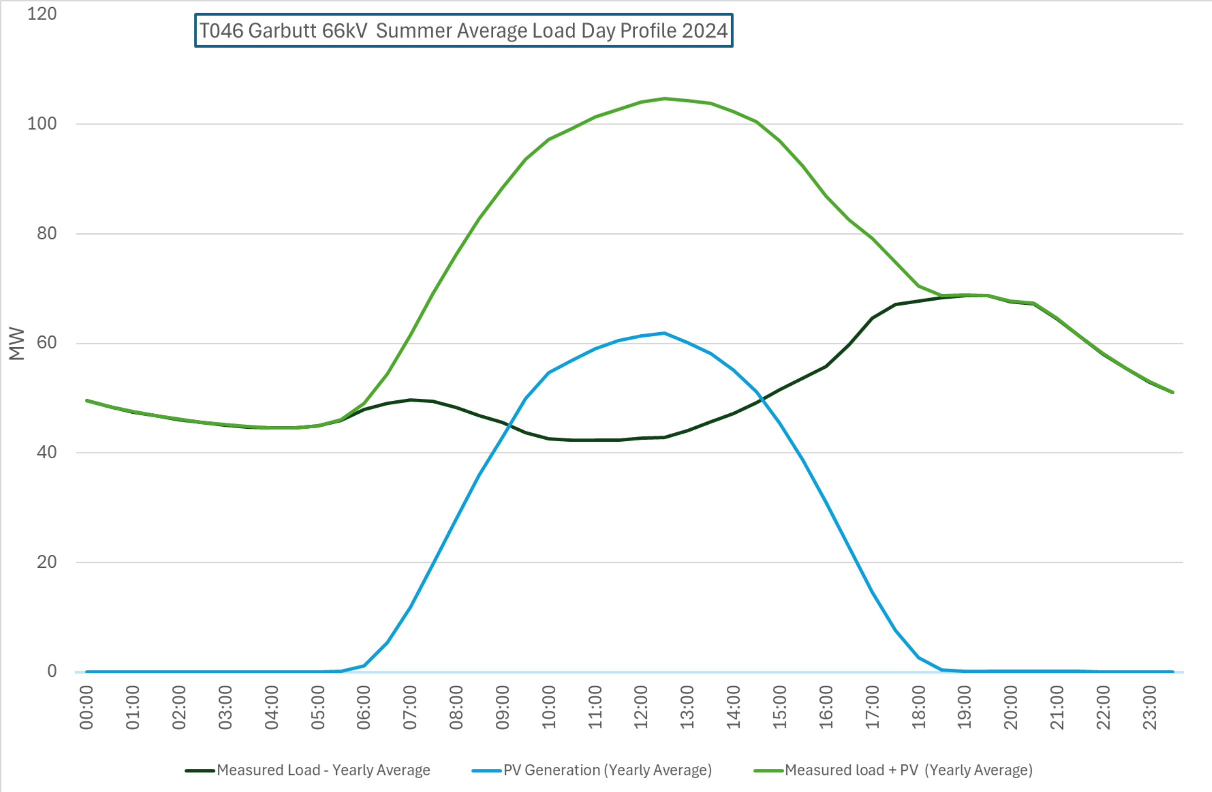


Figure 10. Garbutt 66kV Summer Average Load Day profile 2023/24 (PV in service)

4. Statement of Investment Need

There is an enduring need for all network elements connected to T150 Alan Sherriff Substation.

T150 Alan Sherriff substation supplies Ergon Energy through load groups at voltage levels of 11kV and 66kV. The 11kV load is supplied through the 132/11kV transformers at T150 Alan Sherriff. The 66kV load is injected via feeders 7239 & 7240 to T046 Garbutt Substation and 7144 & 7151 to T092 Dan Gleeson Substation. Alan Sherriff Substation is therefore pivotal for two of the four injection points into Ergon Energy's 66kV network (refer Figures 1 and 3).

Removing the functionality of this substation due to the secondary system condition would result in the loss of support from Alan Sherriff to T092 Dan Gleeson, Alan Sherriff to T046 Garbutt, Alan Sherriff to Yabulu South and T145 Switch yard.

The loss of supply to Garbutt substation would shift approximately 97 MW of load to the Ergon Energy 66 kV network. This would result in increased power flows across the 66 kV lines connecting T092 Dan Gleeson and T046 Garbutt, as well as higher flows from Townsville Port towards Garbutt and Dan Gleeson. In this scenario under system normal conditions, the Ergon Energy 66 kV is overloaded.

Additionally, during N-1 contingency scenarios, the Powerlink transformers supporting the EQL network would be overloaded.

This would eliminate operational windows for planned maintenance activities.

Further the feeder connecting Alan Sherriff to Yabulu South and T145 Townsville Switchyard will be de-energised without reinvestment. This will reduce the reliability supply to T145 Townsville Switchyard and Townsville PS.

Therefore, addressing the risks associated with the deteriorating condition of the secondary systems by decommissioning Alan Sherriff Substation is not a viable option, as it serves as a critical supply point for the local load and maintaining a reliable electricity supply to the area.

A failure to maintain supply due to secondary system issues would overload Energy Queensland network under System normal conditions, which can lead to breach of 600MWh limit and violation of N-1 reliability standard and eliminate opportunities for planned maintenance.

4. Network Risk

Table 1 summarises the maximum load (MW) and energy (MWh) at risk for 11kV and 66kV loads assuming that a network element is removed from service due to a failure of Alan Sherriff Substation secondary system element.

The table below presents the maximum load at risk and energy at risk for loads connected to the 132/11kV transformers at T150 Alan Sherriff and loads directly connected to T046 Garbutt substation (which is supplied from T150 Alan Sherriff). The load and energy at risk are calculated based on historical data for FY2023/24.

Alan Sherriff Substation is the supply point for Ergon loads in the northern area. The local load is supplied from two132/11kV transformers at Alan Sherriff Substation. The substation load is forecasted to be increased steadily in the next 10years (refer to Figure 5). The loss of both 132/11kV transformers would result in loss of 31MW of load under peak conditions.

Similarly, de-energising the feeders from Alan Sherriff to Garbutt due to aging secondary assets would result in the loss of approximately 97 MW of support from the 132 kV network under peak conditions resulting in load being transferred to alternate 66kV feeders.

Table 1. Load and energy at risk

At Risk	Contingency	Metric	2024 (Delivered)
66kV Ergon Load	Outage of feeder 7329 OR 7240	Max (MW)	61
		Average (MW)	0.13
		24h Energy Unserved Max (MWh)	245.5
		24h Energy Unserved Average (MWh)	3.3
11kV Ergon Load supplied from Alan Sherriff	Outage of 132/11kV (1T and 2T at Alan Sherriff)	Max (MW)	31
		Average (MW)	11
		24h Energy Unserved Max (MWh)	489
		24h Energy Unserved Average (MWh)	264
66kV Ergon Load	Outage of feeder 7329 and 7240	Max (MW)	97
		Average (MW)	38
		24h Energy Unserved Max (MWh)	1639
		24h Energy Unserved Average (MWh)	916
66kV Ergon Load	Loss of feeder 7144/2 and 7151/2	Max (MW)	29.4
		Average (MW)	11.68
		24h Energy Unserved Max (MWh)	493.5
		24h Energy Unserved Average (MWh)	280.32
66kV Ergon Load	Loss of feeder 7277 and 7325	Max (MW)	30.0
		Average (MW)	0.040
		24h Energy Unserved Max (MWh)	85.5
		24h Energy Unserved Average (MWh)	0.963

5. Market impact

The Townsville Power Station (GT) connects to Yabulu South and Alan Sherriff substations via circuits 7276 and 7325 respectively. Failure of associated secondary system equipment at Alan Sherriff Substation coincident with a planned or unplanned outage of 7325 will result in the trip (unavailability) of the Townsville Power Station (GT and ST). The combined capacity of the GT and ST is 230MW.

Table 2 defines the maximum and average difference in total system costs (including emission reduction benefits) per 24-hour period with the Townsville Power Station removed from service. The analysis assumes that there is not impact on the generation investment pathway as a result of this outage.

The methodology used to assess these market impacts is outlined in Appendix A.

Table 2 defines the maximum and average difference in total system costs (including emissions) per 24-hour period with the Townsville Power Station removed from service.

The methodology used to assess these market impacts is outlined in Appendix A.

Table 2. Market impact of removing Townsville Power Station from service

At Risk	Contingency	Metric	$M
Townsville Power Station (Gas + Steam turbines)	Outage of 7276 (sec sys) followed by outage of 7325 (planned or unplanned)	Max 24h incremental system cost ($m)	0.173
		Average 24h incremental system cost ($m)	0.0005

6. Non-Network Options

Potential non-network solutions would need to provide supply to the 132kV network at Alan Sherriff as per Table 1. Up to 128 MW and 2128 MWh per day for 11kV and 66kV network in 2024 excluding rooftop PV.

These figures are expected to increase over time in line with projected load growth in 2034. The non-network solution would be required on a continuous basis and be able to meet reliability criteria under contingencies, i.e. N-1-50MW/600MWh.

Powerlink is not aware of any non-network solutions, including demand side management solutions, in the area. 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 prior to project approval.

7. Network Options

7.1 Proposed Option to address the identified need

To address network transfer capability due to failure of secondary system at Alan Sherriff it is recommended that the secondary system reaching end of life to be replaced at an appropriate time as recommended by asset strategies ensuring reliability, availability and minimal operational and compliance risks associated with secondary systems assets.

This option ensures that all reliability of supply and asset condition criteria are met.

7.2 Option Considered but Not Proposed

This section discusses alternative options that Powerlink has investigated but does not consider technically and/or economically feasible to address the above identified issues and thus are not considered credible options.

7.2.1 Do Nothing

"Do Nothing" would not be an acceptable option as the primary drivers (primary system condition) and associated safety, reliability and compliance risks would not be resolved. Furthermore, the "Do Nothing" option would not be consistent with good industry practice and would result in Powerlink breaching their obligations with the requirements of the Technical Rules and its Transmission Authority.

8. Recommendations

Powerlink has reviewed the condition of the secondary systems at Alan Sherriff Substation and anticipates they will reach end of technical service life.

It is recommended the secondary system be replaced to ensure Powerlink's ongoing compliance with the Electrical Safety Act 2002, Electrical Safety Regulation 2013 and to meet its required reliability obligations (N-1-50MW/600MWh).

Powerlink is currently unaware of any feasible alternative options to minimise or eliminate the load at risk at Alan Sherriff but will, as part of the formal RIT-T consultation process, seek non-network solutions that can contribute to reduced overall investment needs whilst ensuring Powerlink continues to meet its reliability of supply obligations.

9. References

1. T150 Alan Sherriff Secondary Systems Condition Assessment Report - 20 Nov 2020
2. 2025 Transmission Annual Planning Report (A6049612)
3. Asset Planning Criteria - Framework (ASM-FRA-A2352970)
4. Powerlink Queensland's Transmission Authority T01/98

10. Appendix A – Network Risk methodology

Feeder 7144/2 AND 7151/2, to resecure for a contingency 7326

De-energising feeder 7144/2 and 7151/2 would result overloading in EQL network and the network is not secure for the next contingency (e.g trip of feeder 7326). To resecure the network within next 30 minutes, load reduction is required to reduce EQL demand and maintain security under any subsequent contingency as summarised in table 1.

Feeder 7277 and 7325 to resecure for a contingency 7144/1 or 7151/1

De-energising feeders 7277 and 7325 would result overloading in EQL network and the network is not secure for the next contingency (e.g trip of feeder 7144 overloading 7151/1), as this feeder is trying to support the network of Garbutt, Dan Gleeson and Alan Sherriff. To resecure the network within next 30 minutes, load reduction is required to reduce EQL demand and maintain security under any subsequent contingency as summarised in table 1.

EQL Bulk Supply Points: Outage of feeder 7329 and/or 7240

Garbutt is one of the four connection point to support Townsville region EQL 66kV network Without 132/66kV Garbutt transformer, EQL and potentially PLQ network will experience voltage and thermal issues for the next credible contingency. This requires EQL network to manage load for a single contingency or run split for double circuit contingency to in order to maintain network security. During summer, the split may require load management pre-contingency for network security. The split also means significant portion of EQL load is “at risk”, as reflected in Table 1 with “single and “two” elements out of service.

11. Appendix B – Market Impact Assessment

Market modelling was used to assess the operational market impact of constraining off the Townsville Power Station due to an outage of the 132kV connection circuits with Alan Sherriff and Yabulu South substations.

The market modelling approach is consistent with the regulatory investment test for transmission requirements that a market benefit “must be a benefit to those who consume, produce and/or transport electricity in the market, that is, the change in producer plus consumer surplus.” Critically, a market benefit must not “include the transfer of surplus between consumers and producers”.[2]

As such, the market impact is assessed by comparing the changes in costs for market participants due to the differences in the operational and maintenance costs (including fuel costs), changes in involuntary load shedding (at the value of customer reliability [VCR] [3]), and changes in greenhouse gas emissions (at the value of emissions reduction [VER] [4])

The market modelling simulations considered committed and anticipated generators were commissioned on time, coal units closed according to their announced dates (as of December 2025), and modelled generation and storage projects consistent with the Queensland Energy Roadmap 2025.[5] The profiles of demand and energy available for variable energy resources followed the 2015 weather reference year as published by AEMO, as being a year found to result in ‘median’ outcomes.

A schedule of generator planned outages was modelled. However, generator forced outages were not considered. Instead, a reserve requirement is maintained via a reserve constraint equation, and therefore unserved energy may be underestimated in some circumstances.

Appropriate network detail (in the form of network constraints or sub-regional transfer limits) was added to adequately represent the network capability across major grid sections.

The outage (Townsville Power Station) was modelled as occurring in perpetuity to approximately capture the effect of this occurring at any time.

The market impact was then quantified as the differential total system cost (as above) for each hour between a base case with Townsville Power Station available against the state of the world with an outage of the power station. Both the hourly and a moving 24-hour differential cost were determined.

The values in the report tables capture the maximum differential total system cost for any 24-hour period (averaged over the 5-year analysis period) and the average differential total system cost for a 24-hour period (over the 5-year analysis period).

[2] AER, November 2024, “Regulatory investment test for transmission”, p4

[3] AER, December 2024, “Values of customer reliability: Final report on VCR values” available at

[4] AER, May 2024, “Valuing emissions reduction: AER guidance and explanatory statement”

[5] The State of Queensland (Queensland Treasury), October 2025, “Energy Roadmap”

Project Scope Report

CP.02400

T150 Alan Sherriff Secondary Systems Replacement

Concept – Version 3

Document Control

Change Record

Issue Date	Revision	Prepared by	Reviewed by	Approved by	Background
12/12/20	1	[redacted]	[redacted]	[redacted]	Initial Draft
19/03/25	2	[redacted]	[redacted]	[redacted]	
4/6/25	3	[redacted]			Added telecommunications replacement/consolidation of SDH/PDH and OpsWAN (works previously scoped under CP.02811 & CP.02513)

Related Documents

Issue Date	Responsible Person	Objective Document Name
20/11/20	[redacted]	Project Initiation Form - CP.02400 - Alan Sherriff Secondary Systems Replacement (T150) - 20 Nov 2020 (A4477453)
20/11/20	[redacted]	T150 Alan Sherriff Secondary Systems Condition Assessment Report - 20 Nov 2020 (A4477169)

Document Purpose

The purpose of this Project Scope Report is to define the business (functional) requirements that the project is intended to deliver. These functional requirements are subject to Powerlink's design and construction standards and prevailing asset strategies, which will be detailed in documentation produced during the detailed scoping and estimating undertaken by DTS (or OSD), i.e. it is not intended for this document to provide a detailed scope of works that is directly suitable for estimating.

Project Contacts

Project Sponsor	[redacted]
Connections Manager (Energy Queensland)	[redacted]
Strategist – HV Asset Strategies	[redacted]
Planner - Main/Regional Grid	[redacted]
Manager Projects	[redacted]
Project Manager	TBA
Design Manager	TBA

Project Details

1. Project Need & Objective

Alan Sherriff substation was built in 2002 as a two transformer 132/11kV substation, replacing the 132kV switching functions at Garbutt substation in 2004. Alan Sherriff substation is located on the Dalrymple Rd, Mount Louisa, approximately 5 km off Woolcock St in Townsville. The substation is comprised of one switchyard, shared between Ergon Energy and Powerlink. The switchgear at Alan Sherriff comprises PASS M0 modules.

Townsville is supplied by a 132kV transmission network to the south and west of the greater load area injecting into an interconnected 66kV distribution system owned and operated by Ergon. Connection points are located at the Townsville South 132/66kV, Dan Gleeson 132/66kV, Garbutt 132/66kV, and Alan Sherriff 132/11kV Substations.

A condition assessment indicates that the majority of secondary systems devices are reaching the end of their technical asset life, recommending replacement by 2025. It further notes that the field cables are suitable for a further 20 to 25 years of service and that the secondary systems panels are in good condition and may be retained. The driver for the secondary systems replacement is the obsolescence and end of manufacturer support for the existing relays.

The objective of this project is to undertake selective replacement of secondary systems equipment at Alan Sherriff substation by October 2028.

This project will follow the two (2) stage approval process and be subject to a RIT-T consultation process.

2. Project Drawing

Figure 1 – Location of Alan Sherriff Substation

Figure 2 – Aerial view of T150 Alan Sherriff

[redacted]

Figure 3 - Block Diagram of T150 Alan Sherriff

3. Deliverables

The following deliverables are to be provided in response to this Project Scope Report. The requirement dates for these deliverables will be communicated separately.

This project will follow the two stage approval process. The following deliverables are to be provided for the purposes of options analysis as required under the RIT-T:

1. A report (e.g. Concept Estimate Report) detailing the works to be delivered, high level staging, resource requirements and availability, and outage requirements and constraints for each option

2. A class 5 estimate (minimum) for each option

3. A basis of estimate document and risk table, detailing the key estimating assumptions and delivery risks for each option

4. Outline staging and outage plans for each option

5. Provide high level schedule and funding requirements to meet proposed commissioning date. Any requirement for pre-approval funding should be clearly identified.

6. For Option 1, undertake a feasibility assessment to confirm suitability of the in-panel replacement methodology including confirmation of sufficient space in the existing building and usability of existing cables (including condition and rating confirmation) and panels. Provide recommendations, including any alternate options identified, with clear justification

7. A comparison of the two options, including outage durations, resource requirements (MSP, contractors etc), return to service times, risks and any other relevant considerations

4. Project Scope

The following scope presents a functional overview of the desired outcomes of the project. The proposed solution presented in the estimate must be developed with reference to the remaining sections of this Project Scope Report, in particular *Section 7 Special Considerations*.

Briefly, the project will upgrade selected 132kV secondary systems equipment at T150 Alan Sherriff.

Powerlink has identified two credible options to address the identified need, as presented in Table 1 below. Concept estimates are required for each option to inform feasibility and cost assessments.

Table 1 - Options summary

Option	Works	Comm Date
Option 1	Single stage in-panel selective replacement of 132kV secondary systems in existing building	October 2028
Option 2	Single stage replacement of 132kV secondary systems into new demountable building	October 2028

The scope requirements for each of the options are described in the following sections.

4.1. Option 1 - In-Panel Replacement

Phase 1 (to be done as part of the Concept Estimate):

Undertake site assessment to confirm feasibility of utilising the in-panel replacement methodology currently being developed under CP.02929 Sumner Secondary Systems Replacement project.

Note: The in-panel replacement methodology has not yet been proven under CP.02929. If the Alan Sherriff site assessment determines the in-panel methodology is feasible, this is to be assumed for estimating purposes, however, the project will not be approved until this methodology is approved.

<u>Phase 2 (to be done following project approval):</u>

- Design, procure, construct and commission the in-panel replacement of selected 132kV secondary systems including:
  - 132kV 1 & 2 Bus
  - 132kV Bay (1T) =D01-A10
  - 132kV Bay (2T) =D02-A10
  - 132kV Bay (Bus Coupler) =D03-A10
  - Feeder 7144/2 (Ross/Dan Gleeson) =D07-A10
  - Feeder 7151/2 (Ross/Dan Gleeson) =D04-A10
  - Feeder 7239 (Garbutt) =D14-A10
  - Feeder 7240 (Garbutt) =D11-A10
  - Feeder 7276 (Townsville GT SY) =D13-A10
  - Feeder 7277 (Yabulu South) =D10-A10
  - 132 kV Transformer 1 & 2 Revenue Metering
  - Substation SCADA and OpsWAN

- The existing Power Quality Monitoring panel was installed in 2013 and can be retained. No HSM or WAMPAC equipment is required;

- New metering for Garbutt feeders 7239 and 7240 has been installed under CP.02825 T046 Garbutt Configuration Change. This metering can be retained;

- Replace DC supplies for both protection and telecommunications equipment (note the 125V battery banks were replaced in 2022 and therefore, do not require replacement under this project);

- Replace OpsWAN equipment and relocate devices (except the camera) from the OpsWAN camera housing at the top of the pole to the camera patch box at the base of the pole;

- Modify customer interface kiosks as required;

- Review the existing AC and DC supply arrangements, modify as required to accommodate new secondary systems;

- Replace screw type CT links as required where modifying existing CT secondary circuits;

- Modify and upgrade telecommunications equipment as required to support the new secondary systems; and

- Decommission and recover all redundant equipment, and update drawing records, SAP records, config files, etc. accordingly.

4.2. Option 2 – Full Replacement in a New Demountable Building

- Design, procure, construct and commission new 132kV secondary systems in a new control building, including secondary systems for:
  - 132kV 1 & 2 Bus
  - 132kV Bay (1T) =D01-A10
  - 132kV Bay (2T) =D02-A10
  - 132kV Bay (Bus Coupler) =D03-A10
  - Feeder 7144/2 (Ross/Dan Gleeson) =D07-A10

- Feeder 7151/2 (Ross/Dan Gleeson) =D04-A10
- Feeder 7239 (Garbutt) =D14-A10
- Feeder 7240 (Garbutt) =D11-A10
- Feeder 7276 (Townsville GT SY) =D13-A10
- Feeder 7277 (Yabulu South) =D10-A10
- 132 kV Revenue Metering for Transformers 1 and 2 and Feeders 7239 and 7240 (feeder metering relocated from Garbutt Substation under CP.02825)
- Substation SCADA and OpsWAN equipment (except the camera) and relocate devices (except the camera) from the OpsWAN camera housing at the top of the pole to the camera patch box at the base of the pole;
- Power Quality Monitoring (existing functionality to be retained. No HSM or WAMPAC equipment is required)

- Undertake all civil works to facilitate installation of the new control building and secondary systems including foundations, structures, drainage, trenches, conduits, roads etc;
- Install new and modify existing cabling, kiosks and termination racks as required to facilitate installation of the new control building and secondary systems;
- Replace DC supplies for protection and telecommunications equipment;
- Modify and upgrade AC and DC distribution as required to facilitate replacement of secondary systems;
- Replace screw type CT links as required when modifying existing CT secondary circuits;
- Modify and upgrade telecommunications equipment as required to support the new secondary systems;
- Upgrade fire and security systems as required to incorporate the new control building; and
- Decommission and recover all redundant equipment, and update drawing records, SAP records, config files, etc. accordingly.

4.3. H013 Ross Substation Works

Modify protection, control and communications systems for feeders 7144 and 7151 as required to accommodate the new secondary systems at Alan Sherriff.

4.4. T092 Dan Gleeson Substation Works

Modify protection, control and communications systems for feeders 7144 and 7151 as required to accommodate the new secondary systems at Alan Sherriff.

4.5. T046 Garbutt Substation Works

Secondary systems at Garbutt are to be upgraded under CP.02841 Garbutt Secondary Systems Replacement in conjunction with this project.

4.6. T145 Townsville GT PS Substation Works

Modify protection, control and communications systems for feeder 7276 as required to accommodate the new secondary systems at Alan Sherriff.

Secondary systems at Townsville GT PS are currently being upgraded under CP.02966 Townsville GT PS Secondary Systems Replacement. The new secondary systems are expected to be commissioned by December 2026.

4.7. H056 Yabulu South Substation Works

Modify protection, control and communications systems for feeder 7277 as required to accommodate the new secondary systems at Alan Sherriff.

4.8. Telecoms Works

As per sections 4.1 to 4.7, review and upgrade telecommunications equipment as required to support the new secondary systems at Alan Sherriff.

This includes replacement of the PDH and SDH equipment with a single consolidated device in coordination with CP.02811 Telecommunication Network Consolidation RAN 2.

In addition to this, the new OpsWAN solution determined under CP.02512 OspWAN Replacement Stage 1 is to be implemented. This solution will replace the functionality currently provided by the IP/MPLS and OpsWAN routers and allow the migration of all services to IP (OpsWAN will become a service over the network rather than a network in its own right). This work is to be coordinated with CP.02513 OpsWAN Replacement Stage 2.

4.9. Easement/Land Acquisition & Permits Works

Not applicable.

4.10. Key Scope Assumptions

The following assumptions should be included in the estimating of this scope:

- This project will be executed in conjunction with CP.02841 Garbutt Secondary Systems Replacement. All works at Garbutt will be done under CP.02841; and
- In-panel replacement methodology will be successfully implemented under CP.02929 Sumner Secondary Systems Replacement prior to project approval.

4.11. Variations to Scope (post project approval)

Not applicable

5. Key Asset Risks

Asset risk management shall be in accordance with the Asset Risk Management Process Guideline (A4870713).

6. Project Timing

6.1. Stage 1 Approval Date

The anticipated date for Stage 1 approval is November 2025.

6.2. Site Access Date

Site access is immediately available for Powerlink construction works to commence.

6.3. Commissioning Date

The latest date for the commissioning of the new assets included in this scope and the decommissioning and removal of redundant assets, where applicable, is 31st October 2028.

7. Special Considerations

- The substation secondary systems are housed in a brick control building (+1) which was built in 2002. This building is owned by Powerlink and shared with Ergon Energy.
- Switchgear at Alan Sherriff substation are PASS M0 modules and do not have standalone bay marshalling kiosks.
- There have been issues on previous projects where PASS M0 CTs have failed commissioning testing and have required replacement. It is recommended to have at least three spare CT cores available onsite (including contingency design if required) when undertaking commissioning works to facilitate replacements if required.
- Control and protection cables were terminated directly between indoor panels and primary plant PASS M0 control cubicles i.e. no building termination racks. Visual inspection of these cables indicated they are still in good condition and can be kept in service until 2043.
- All secondary systems panels, including auxiliary parts e.g. links, terminals and internal wiring were installed between 2003 – 2004 (except for the Power Quality Monitoring System [redacted] which was installed in 2013) and are still in good condition. Secondary systems panels, including internal wiring, links and terminals can be left in service until 2043.
- All cables inside the control building are considered to be in good condition as they have been in a clean and air-conditioned environment since they were installed in 2003/2004.

8. Asset Management Requirements

Equipment shall be in accordance with Powerlink equipment strategies.

Unless otherwise advised Sarah Gilmour will be the Project Sponsor for this project. The Project Sponsor must be included in any discussions with any other areas of Network and Business Development including Asset Strategies & Planning.

Jay Tencate will provide the primary customer interface with Energy Queensland. The Project Sponsor should be kept informed of any discussions with the customer.

9. Asset Ownership

The works detailed in this project will be Powerlink Queensland assets.

The asset boundary with Ergon is the HV terminals of the 132/11kV transformers.

10. System Operation Issues

Operational issues that should be considered as part of the scope and estimate include:

- interaction of project outage plan with other outage requirements;
- likely impact of project outages upon grid support arrangements; and
- likely impact of project outages upon the optical fibre network.

11. Options

As per section 4.

12. Division of Responsibilities

A division of responsibilities document will be required to cover the changes to the interface boundaries with Ergon. The Project Manager will be required to draft the document and consult with the Project Sponsor who will arrange sign-off between Powerlink and the relevant customer.

13. Related Projects

Project No.	Project Description	Planned Comm Date	Comment
Pre-requisite Projects			
CP.02929	Sumner Secondary Systems Replacement	Sept 2026	Related to Option 1 only Planned to be the first project to utilise the in-panel replacement methodology
CP.02825	Configuration Change Request – T046 GARBUTT	May 2025	Execution
CP.02151	Townsville GT PS Secondary Systems Replacement	Dec 2026	Execution
Co-requisite Projects			
CP.02841	T046 Garbutt Secondary Systems Replacement	October 2028	Definition
CP.02811	Telecommunication Network Consolidation RAN 2	Dec 2027	Definition
CP.02513	CP.02513 OpsWAN and MPLS Replacement RAN 2	Aug 2027	Definition
Other Related Projects			

CP.02400 T150 Alan Sherriff Secondary Systems Replacement

Concept Estimate

Table of Contents

1. Executive Summary

The purpose of this report is to provide a high-level options analysis for the replacement of the secondary systems equipment at T150 Alan Sherriff Substation.

The concept report considers two options:

- **Option 1:** Single-stage in-panel selective replacement of 132kV secondary systems in existing building. The proposed commissioning date is October 2028, as stated in the project scope report.
- **Option 2:** Single-stage replacement of 132kV secondary systems into a new demountable building. The proposed commissioning date is October 2028, as stated in the project scope report.

This project will follow the two (2) stage approval process and be subject to a RIT-T consultation process.

[redacted]

Figure 1:T150 Alan Sheriff Substation Line Diagram

2. Project Information

2.1 Options Comparison Table

	Option 1	Option 2
Cost (total escalated incl risk)	[redacted]	[redacted]
Proposed Commissioning	October 2028	October 2028
Outages	Nine separate outages required (33 weeks in total)	Eight separate outages required (28 weeks in total)
Delivery	Requires careful integration with existing panels, risk of space and CT links constraints	Requires new building construction, avoids integration risks, but higher upfront cost.
Design Risks	Potential issues with PASS M0 and CT Links compatibility	Avoid asbestos risk, with minimal impact on existing cabling
Dependencies	Relies on CP.02929 (Sumner) as a pilot for in-panel methodology	Executed with CP.02841 and CP.02513 for SIP/MPLS integration

2.2 Dependencies & Interactions

This project is dependent on the completion and delivery of the following projects:

Project No.	Project Description	Planned Commissioning Date	Comment
Dependencies			
CP.02929	Sumner Secondary Systems Replacement	November 2025	Related to Option 1 only. Planned to be the first project to utilise the in-panel replacement methodology.
CP.02825	Configuration Change Request – T046 GARBUTT	April 2026	Execution
Interactions			
CP.02966	Townsville GT PS Switchyard Secondary Systems Replacement	December 2026	Execution – Two-stage approval
CP.02841	T046 Garbutt Secondary Systems Replacement	October 2028	Definition
CP.02811	Telecommunication Network Consolidation RAN 2	December 2027	Definition
CP.02513	OpsWAN and MPLS Replacement RAN 2	August 2027	Definition

2.3 Site-Specific Issues

Figure 2: T150 Alan Sheriff Substation

- Alan Sherriff substation was built in 2002 as a two-transformer 132/11kV substation, replacing the 132kV switching functions at Garbutt substation in 2004. Alan Sherriff substation is located on the Dalrymple Rd, Mount Louisa, approximately 5km off Woolcock St in Townsville. The substation comprises one switchyard, shared between Ergon Energy (EQL) and Powerlink. The switchgear at Alan Sherriff comprises PASS M0 modules.

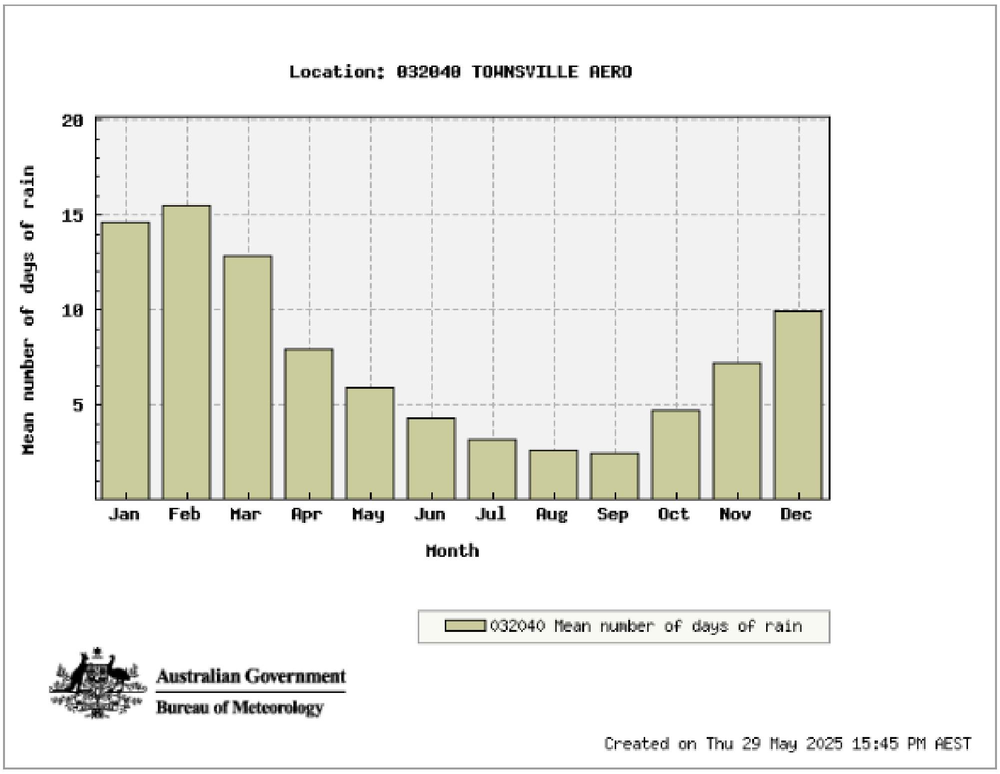
- Townsville is supplied by a 132kV transmission network to the south and west of the greater load area, injecting into an interconnected 66kV distribution system owned and operated by Ergon. Connection points are located at the Townsville South 132/66kV, Dan Gleeson 132/66kV, Garbutt 132/66kV, and Alan Sherriff 132/11kV substations.

- A condition assessment indicates that most secondary systems devices are reaching the end of their technical asset life, recommending replacement by 2025. It further notes that the field cables are suitable for 20 to 25 years of service and that the secondary systems panels are in good condition and may be retained. The driver for replacing secondary systems is the obsolescence and end of manufacturer support for the existing relays.

- The existing cables in the Local Control Cubicles of the PASS M0 Units have been identified to have sun damage. New field cables are required if these cables are not suitable for re-use.

- The presence of PASS M0 Circuit Breakers poses challenges for the switching of assets and the testing of the new secondary systems. Bus outages or Live Substation resources may be required to ensure safety during work.

- T150 Alan Sherriff is located within Townsville and is subject to a six-month “wet season”, November to April, with considerable variation from year to year. Below is rainfall data from the Bureau of Meteorology indicating Mean Rainfall (days) for the Townsville area.



Statistics	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	Years
Mean number of days of rain for years 1800 to 3000	14.6	15.5	12.8	7.9	5.9	4.3	3.2	2.6	2.4	4.7	7.2	9.9	7.6	84

Figure 3: Townsville Area Mean Number of Days of Rain

3. Option 1 – In-Panel Replacement

3.1 Option Definition

3.1.1 Option Scope

T150 Alan Sheriff

- Design, procure, construct and commission the in-panel replacement of selected 132kV secondary systems at T150 Alan Sherriff, including replacement of bushing CTs for PASS M0 units.
- Secondary Systems design based on SDM9.3.
- In-Panel secondary systems replacement and associated common control, protection and monitoring equipment in the existing EQL building for the following assets. Using the In-Panel Replacement methodology for CP.02929 Sumner Secondary Systems Replacement:
  - =D01 CB4412 1T & =D02 CB4422 2T – New X and Y Protection Relays
  - =D03 CB4012 CPLR – New X and Y Protection Relays
  - =D04 F7151 & =D07 F7144 – New X and Y Protection Relays
  - =D10 F7277 – New X and Y Protection Relays
  - =D13 F7276 – New X and Y Protection Relays
  - =D11 F7240 & =D14 F7239 – New X and Y Protection Relays
- Modifications to the following secondary systems:
  - 1 Bus Zone and 2 Bus Zone panels shall be used as a CT marshalling point for the existing cables and new cables run to the new BZ panels.
  - In Metering Panel, upgrade existing meters for 1T & 2T and upgrade communications to IP metering.
  - In PQM Panel, integrate CT/VT/OpsWAN circuits to the new SDM9.3 panels.
  - Replace existing 125V DC Chargers and add radial DC connection to all the panels.
  - The PLQ/EQL Interface kiosk will suit the new transformer interface.
- New secondary systems panels will be installed in the existing EQL building for the following assets:
  - 2 x SIP/MPLS Panels
  - 1 x Network Panel
  - 2 x HZ BZ Panels
- All Current Transformer (CT) link terminals associated with CT circuits will be replaced with a new physical disconnect terminal, per Standards Update, SU0049.
- 5 x New Bay Marshalling Kiosks.
- 2 x Bus Zone Marshalling Kiosks.
- 4 x AC/DC Field Marshalling Kiosks.
- Replacement of Bushing CTs for Pass M0 Units and new secondary cables connected to new Bay MKs.
  - CTs for bays D01, D02, D03, D04, and D07.
  - Replacement of all MK Type 1 PASS CTs with stemars at D01, D02, D03, D04 and D07 and associated civil works to allow us to bypass the existing Local Control Cubicle (LCC). Existing CT will not have enough length to make it to the new Marshalling Kiosk (MK), so we will need to create a Junction Box (JB) type situation at the LCC and install new cables between the JB and

the new MK. The LCC will not have enough width to accommodate the new PT6-type link to enable this. This will leave us stranded on bypassing the existing LCC and utilising the existing CT cables.

- Replace IONS (OpsWAN) equipment (except OpsWAN camera) and relocate all devices (except the camera) from the OpsWAN camera housing at the top of the pole to the camera patch box at the base of the pole. Refer to ASM-FRM-A4982111 and ETR 10434041
- Sponsor has agreed to add telecommunications replacement/consolidation of SDH/PDH and OpsWAN (works previously scoped under CP.02811& CP.02513.
- Undertake civil works as required to facilitate the secondary replacement work
- Install new fibre patch leads between the Telecoms equipment and the Feeder Panel in +1 building
- Migrate SCADA circuits from SDH to be delivered over MPLS
- Decommission redundant SCADA and Metering Circuits
- Design of Cisco MPLS/SIP network
- Implementation of Shared Services Network (OpsWAN)
- Decommission and recover all redundant equipment.
- Update drawing records, SAP records, config files, etc., accordingly.

H056 Yabulu South

The existing secondary systems at H056 Yabulu South shall require modification to integrate with the new SDM9.3 system at T150 Alan Sherriff.

- =D02 F7277
  - Replace X Protection Relay
  - Setting changes Y Protection Relay
  - Remove Y Protection Signalling Units

T145 Townsville GT PS

The existing secondary systems at T145 Townsville GT PS shall require modification to integrate with the new SDM9.3 system at T150 Alan Sherriff.

- =D03 F7276
  - Setting changes Y Protection Relay
  - Remove Y Protection Mirror Bit Interface

3.1.2 Scope Assumptions

The following key assumptions were made for the Project Estimate.

- Powerlink (PLQ) design resources are available as required.
- No Restricted Access Zone will be deployed on this site during construction.
- Access to network and outage management resources are available.
- Outages will be available, and any Return to Service (RTS) requirements will be agreed in a timely manner with Energy Queensland.
- All existing equipment is in good condition and working order.
- MSP and Live Subs resources will be available to complete the work.

- PLQ project and support resources are available to align with the project timing to support meeting the approved commissioning date.
- Access to the site is available.
- Energy Queensland design and construction resources will be available for remote end works when required.
- Timely Division of Responsibility (DOR) agreement between Energy Queensland and Powerlink for all the works involved.
- EQL currently owns the existing Station Services transformer, ACCO and ACDB, and this arrangement will remain as is.
- Field cables are in good condition and suitable for reuse.
- This project will be executed with CP.02841, and all works at Garbutt will be done under CP.02841.

3.1.3 Scope Exclusions

- No allowance is included for any Energy Queensland projects that may impact Powerlink works.
- Easement acquisition works, including permits, approvals, development applications, etc. All works are within Powerlink-owned land.
- Interface between Energy Queensland and Powerlink.
- AC system upgrade.
- PASS M0 refurbishment works.
- This estimate does not include any costs for repairing or modifying the primary plants not listed to be replaced under the scope.
- No asbestos removal is included in the scope of this project.
- Any delays, costs or cost increases not within the control of Powerlink.
- Extreme weather or impacts thereof.
- Fluctuation in foreign exchange rates.

3.2 Project Execution

3.2.1 Project Schedule

A high-level project Schedule has been developed for the project stages:

Milestones	High-Level Timing
Class 5 Project Proposal Submission	July 2025
Request for Class 3 Estimate	September 2025
Class 3 Project Proposal Submission	April 2026
RIT-T (assumed 26 weeks)	July 2026 – January 2027
Stage 1 Approval (PAN1) includes funds for design & procurement	June 2026
Project Development Phase 1 & Phase 2	June 2026 – September 2026
Reconcile Estimate and Submit PMP for Stage 2 Approval	September 2026
Stage 2 Approval (PAN2)	February 2027
Site Mobilisation	April 2027
Project Commissioning	October 2028

3.2.2 Network Impacts

- All feeders to/from Alan Sheriff, which includes Garbutt feeders, will need to be considered. Garbutt's impact is to be considered given these feeds, EQL's new GIS board.
- Previous Garbutt/Alan Sherriff projects, outages are to be scheduled in shoulder and winter periods – Late April;/May to October.
- PLQ Outage Management to negotiate a prolonged bus outage (with a quick RTS) at T150 Alan Sherriff. The plan is to execute CP.02400 and CP.02841 simultaneously, given outages on Feeder 7240 & F7239 at Alan Sherriff will impact Garbutt.

3.2.3 Resourcing

The following resource strategy is proposed:

- Design by PLQ
- MSP (core works including all cutover, testing and commissioning)

3.3 Project Estimate

		Sub Total $	Total $
Estimate Class	5		
Estimate accuracy (+% / -%)	+100% / -50%		
Base Estimate		$19,915,282	
[redacted]		[redacted]	
Proposed Released Budget			[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]		[redacted]
TOTAL			[redacted]

4. Option 2 – Full Replacement in New Demountable Building

4.1 Option Definition

4.1.1 Option Scope

Design, procure, construct and commission the complete replacement of 132kV secondary systems at T150 Alan Sherriff, including replacement of bushing CTs for PASS M0 units.

Establish new secondary systems panels and associated common control, protection and monitoring equipment in a new Control Building. These require:

- New foundations for the new control building and marshalling kiosks.
- Trenching from the control building to the existing trenches in the yard including cable pits.
- Underground conduits where cables are leaving or entering trenches or trenches are not suitable.
- Full Replacement of the T150 secondary systems within the new Control Building, containing the following:
    - 2 x HZ BZ Panels
    - 2 x Transformer Panels
    - 3 x Feeder Panels
    - 1 x Coupler Panel
    - 1 x Metering Panel
    - 1 x Network Panel
    - 2 x SIP/MPLS Panels (to be installed in the existing EQL building)
    - 1 x 125V DC Dual Battery System
    - New fire and security system
    - 2 x FTPs

- There will be new control and fibre cables between the new control building and the bay marshalling kiosks.
- Modifications to the following secondary systems in the existing EQL building:
  - In Metering Panel, upgrade existing meters for 1T & 2T and upgrade communications to IP metering.
  - In PQM Panel, integrate CT/VT/OpsWAN circuits to the new SDM9.3 panels.
  - Replacement of existing DC systems.
  - The PLQ/EQL Interface kiosk will suit the new transformer interface.
- Replacement of Bushing CTs for Pass M0 Units and connected to new Bay MKs.
  - CTs for bays D01, D02, D03, D04, and D07.
  - Replacement of all MK Type 1 PASS CTs with stemars at D01, D02, D03, D04 and D07 and associated civil works to allow us to bypass the existing LCC. Existing CT will not have enough length to make it to the new MK, so we will need to create a Junction Box type situation at the LCC and install new cables between the JB and the new MK. The LCC will not have enough width to accommodate the new PT6-type link to enable this. This will leave us stranded on bypassing the existing LCC and utilising the existing CT cables.
- 5 x New Bay Marshalling Kiosks.
- 2 x Bus Zone Marshalling Kiosks.
- 4 x AC/DC Field Marshalling Kiosks.
- All Current Transformer (CT) link terminals associated with CT circuits will be replaced with a new physical disconnect terminal, per Standards Update, SU0049.
- Replace IONS (OpsWAN) equipment (except OpsWAN camera) and relocate all devices (except the camera) from the OpsWAN camera housing at the top of the pole to the camera patch box at the base of the pole. Refer to ASM-FRM-A4982111 and ETR 10434041.
- Footings for the new control building.
- Structures for all plant and equipment are required for the replacement of secondary systems.
- Drainage system for buildings and surroundings to fall into the existing drainage system or off the substation platform.
- Conduits and cable trench extension to the new demountable control building.
- Minor earthworks, including road base and gravel surfacing, may be required to reinstate or reshape the existing substation platform to the design levels to accommodate the new control building and associated works.
- Modifications/installation of new marshalling kiosks as required.
- Substation roads damaged or modified as part of the works shall be reinstated to good condition.
- New substation internal roads required to provide access to the new demountable building
- All necessary civil and miscellaneous site works, including temporary road works/access for new control building installation, as required.
- Install new 2X MMOF cables between the existing building and the new Control building
- Install U/G CAT 6 Cables between the existing building and the new Control building
- Establish two telephone services to the new Control building
- Migrate SCADA circuits from SDH to be delivered over MPLS

- Design of Cisco MPLS/SIP network
- Implementation of Shared Services Network (OpsWAN)
- Deployment of Site Server with virtualised firewall
- Migration of SCADA circuits from SDH to MPLS/SIP
- Decommission redundant SCADA and Metering Circuits
- Decommission and recover all redundant equipment.
- Update drawing records, SAP records, config files, etc., accordingly.

H056 Yabulu South

The existing secondary systems at H056 Yabulu South shall require modification to integrate with the new SDM9.3 system at T150 Alan Sherriff.

- =D02 F7277
    - Replace X Protection Relay
    - Setting changes Y Protection Relay
    - Remove Y Protection Signalling Units

T145 Townsville GT PS

The existing secondary systems at T145 Townsville GT PS shall require modification to integrate with the new SDM9.3 system at T150 Alan Sherriff.

- =D03 F7276
    - Setting changes Y Protection Relay
    - Remove Y Protection Mirror Bit Interface

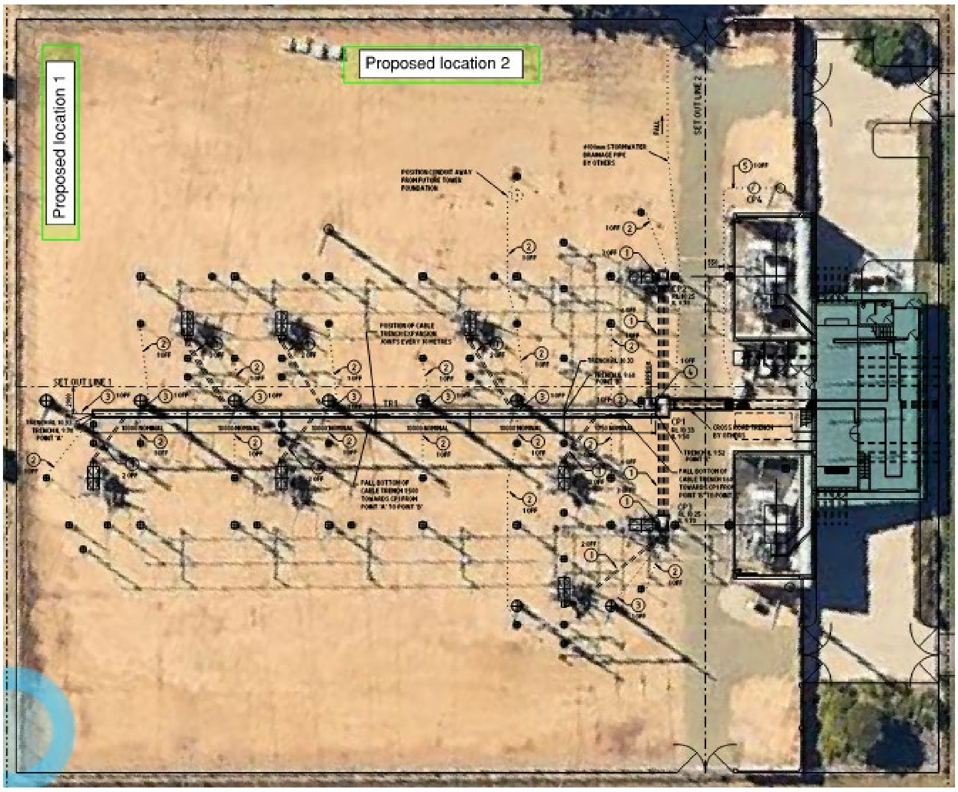


Figure 4: Proposed New Building Location (Preferred Option 1)

4.1.2 Scope Assumptions

The following key assumptions were made for the Project Estimate.

- PLQ design resources are available as required.
- No Restricted Access Zone will be deployed on this site during construction.
- Access to network and outage management resources are available.
- Outages will be available, and any Return to Service (RTS) requirements will be agreed in a timely manner with Energy Queensland.
- All existing equipment is in good condition and working order.
- MSP and Live Subs resources will be available to complete the work.
- SPA contractor is available when required to meet the approved commissioning date.
- PLQ project and support resources are available to align with the project timing to support meeting the approved commissioning date.
- Access to the site is available.
- Energy Queensland design and construction resources will be available for remote end works when required.
- Timely Division of Responsibility (DOR) agreement between Energy Queensland and Powerlink for all the works involved.
- EQL currently owns the existing Station Services transformer, ACCO and ACDB, and this arrangement will remain as is.
- This project will be executed with CP.02841, and all works at Garbutt will be done under CP.02841.
- This project will also be executed with CP.02513 to fabricate combined SIP/MPLS panels.

4.1.3 Scope Exclusions

- No allowance is included for any Energy Queensland projects that may impact Powerlink works.
- Easement acquisition works, including permits, approvals, development applications, etc. All works are within Powerlink-owned land.
- AC system upgrade.
- PASS M0 refurbishment works.
- Interface between Energy Queensland and Powerlink.
- This estimate does not include any costs for repairing or modifying the primary plant not listed to be replaced under the scope.
- No asbestos removal is included in the scope of this project.
- Any platform extension works.
- Any delays, costs or cost increases not within the control of Powerlink.
- Any work outside of regular working hours.
- Extreme weather or impacts thereof.
- Fluctuation in foreign exchange rates.

4.2 Project Execution

4.2.1 Project Schedule

This project will follow the two (2) stage approval process.

A high-level project Schedule has been developed for the project stages:

Milestones	High-Level Timing
Class 5 Project Proposal Submission	July 2025
Request for Class 3 Estimate	September 2025
Class 3 Project Proposal Submission	April 2026
RIT-T (assumed 26 weeks)	July 2026 – January 2027
Stage 1 Approval (PAN1) includes funds for design & procurement, & ITT preparation	June 2026
Project Development Phase 1 & Phase 2	June 2026 – September 2026
ITT Submission (8 Weeks)	September 2026
Evaluate Tender, Reconcile Estimate and Submit PMP for Stage 2 Approval	October 2026
Stage 2 Approval (PAN2)	December 2026
Site Mobilisation	April 2027
Project Commissioning	October 2028

4.2.2 Network Impacts

- All feeders to/from Alan Sheriff, which includes Garbutt feeders, will need to be considered. Garbutt's impact is to be considered given these feeds, EQL's new GIS board.
- Previous Garbutt/Alan Sherriff projects, outages are to be scheduled in shoulder and winter periods – Late April;/May to October.
- PLQ Outage Management to negotiate a prolonged bus outage (with a quick RTS) at T150 Alan Sherriff. The plan is to execute CP.02400 and CP.02841 simultaneously, given outages on Feeder 7240 & F7239 at Alan Sherriff will impact Garbutt. Awaiting response from PLQ Outage Management.

4.2.3 Resourcing

The following resource strategy is proposed:

- Design by PLQ
- SPA – Civil works (Construct only)
- MSP (core works including all cutover, testing and commissioning)

4.3 Project Estimate

			Sub Total $	Total $
Estimate Class	5			
Estimate accuracy (+% / -%)	+100% / -50%			
Base Estimate			$25,864,516	
[redacted]			[redacted]	
Proposed Released Budget				[redacted]
[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]	
Total Risk	**40%**			[redacted]
TOTAL				[redacted]

5. Risks

Description	Impact	Likelihood	Mitigation Strategy
Availability of Resources: • Contractor (Minor Civil) • MSP (OSD)	Major	Moderate	Engage in early and ongoing discussions with Network Operations and Customers.
Change in project delivery strategy due to: • Network Outage Change • Staging Change • Change of design by PLQ to design by SPA • Latent conditions for Civil Works	Medium	Possible	Review Strategy, staging, outage and design on an ongoing basis
Wet weather impacts during construction.	Major	Likely	Project timing is to be planned to minimise work during the wet season (November to early April).
RIT-T process (assumed duration 26 weeks): Any delays to this process will directly impact the commissioning date.	Major	Possible	Maintain communication with the Sponsor during RIT-T so that any foreseeable delay can be managed appropriately.
Delivery Issues: • Delivery strategy change - Outage staging and MSP Changes	Medium	Possible	Engage with EQ early for outage opportunities.

Note: During Project Execution, project risks are recorded and managed in the PWA Server.

6. References

Document	Version	Date
Project Scope Report	2.0	19/03/2025

Risk Cost Summary Report

CP. 02400

Alan Sherriff Secondary Systems Replacement

Document Control

Change Record

Issue Date	Revision	Prepared by
23/12/2025	1.0	Asset Strategies

Related Documents

Issue Date	Responsible Person	Objective Document Name

Document Purpose

The purpose of this model is to quantify the base case risk cost profiles for the secondary systems at Alan Sherriff substation which are proposed for reinvestment under CP.02400. These risk cost profiles are then included as part of the overall cost-benefit analysis (CBA) to understand the economic benefit of the proposed infrastructure upgrades. This process provides a benchmarking and internal gate process to support Powerlink in effectively identifying prioritised infrastructure upgrades.

The CBA was designed to demonstrate and quantify the value to be gained through specific infrastructure investments. To evaluate the CBA, an NPV is derived based on the present values of costs and benefits. The flow chart in Figure 4 below designates the methodology used in designing the CBA process.

Key Assumptions

In calculating the risk cost arising from a failure of the ageing secondary systems equipment at Alan Sherriff substation, the following modelling assumptions have been made:

- Whilst the re-investment scope of secondary system upgrade projects contains a range of supporting devices (i.e network switches, revenue metering, firewalls and human machine interfaces), for simplicity of risk cost modelling only main protection relays, bay controllers and RTUs were considered.

- Spares for secondary system equipment have been assumed to be available prior to the point of expected spares depletion, which coincides with the expected technical asset life (20 years). After this point the cost and time to return the secondary system back to service increases significantly.

- When calculating network risk cost, it has been assumed that after 24 hours of any network element being protected by a single protection system (due to failure of the alternate system) the Australian Energy Market Operator (AEMO) will direct Powerlink to de-energise the network element.

- A site-specific value of customer reliability (VCR) of $29,130 has been applied when calculating network risks.

Base Case Risk Analysis

Risk Categories

For this project, two main categories of risk are assessed as per Powerlink's Asset Risk Management Framework:

- Financial Risk

- Network Risk (including market impact if applicable)

Table 1: Risk categories

Risk Category	Failure Type	Equipment in Scope
Financial Risk	Failure of the equipment resulting in emergency onsite replacement	All equipment
Network Risk	Failure of equipment resulting in de-energisation of network elements after 24 hours	Main protection relays only

Base Case Risk Cost

The modelled and extrapolated total base case risk costs are shown in Figures 1 and 2 below.

Risk costs associated with the equipment in scope are expected to increase from $0.69 million in 2026 to $1.23 million in 2036 and $2 million by 2045. Key highlights of the analysis include:

- Financial risk accounts for approximately 63% of the overall risk cost in 2030 with network risk accounting for the remaining 37%.
- As the probability of failure (PoF) continues to grow over time, the network risk cost grows to become a greater proportion of the overall risk. In the year 2040, financial risk is 49% of the total risk cost (≈$1.6m) compared with network risk which contributes 51%.

Figure 1: Total risk cost

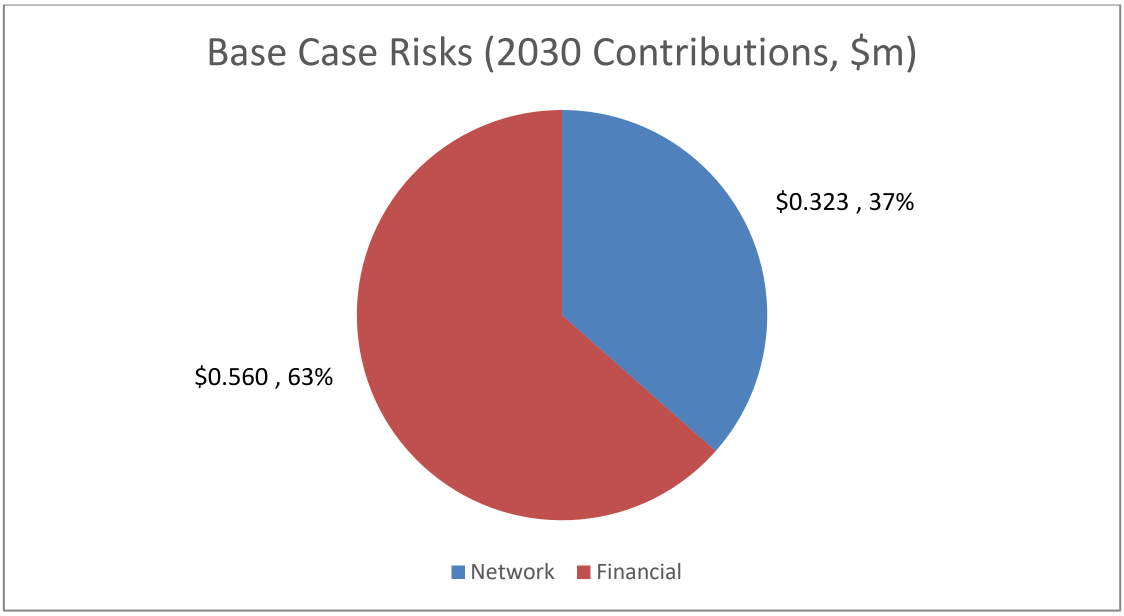


Figure 2: Base case risk cost by contributions (2030)

Option Risk Cost

For modelling purposes, the replacement of equipment at the Alan Sherriff substation reduces the probability of failure to zero in the year after investment, resulting in a lower risk cost.

The figures below set out the total project case risk cost, and associated risk cost savings incremental to the base case.

Figure 3: Project Option Risk Cost (compared to base case)

Following the investment, risk cost grows slowly over time as it is assumed sufficient spares are available resulting in lower responsive costs and shorter outage durations.

Cost Benefit Analysis

The methodology designed for the cost benefit is set out as per Figure 4 below.

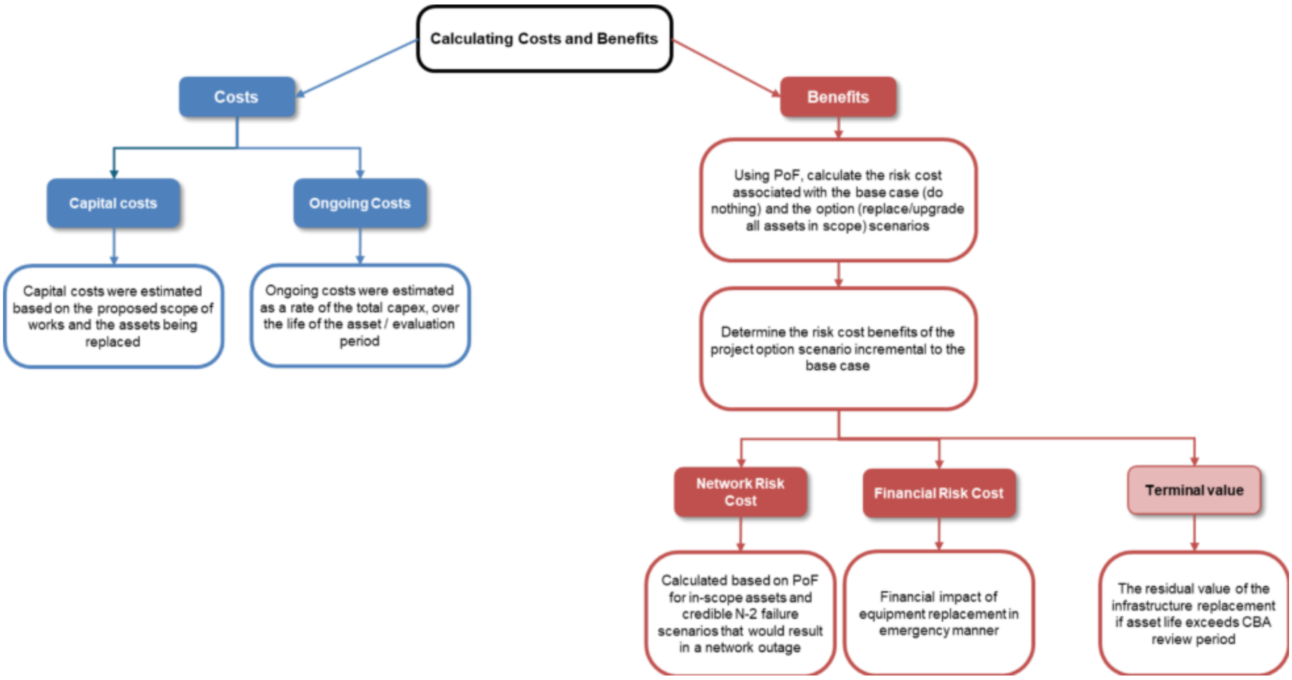


Figure 4: CBA methodology

The project is estimated to cost approximately $19.92 million resulting in a negative NPV and benefit-cost ratio (BCR) less than 1.

Table 2: Net Present Value and Benefit-Cost Ratio

		Present Value Table ($m)		
Discount rate	%	**3%**	**7%**	**10%**
NPV of Net Gain/Loss	$m	-$3.4	-$6.5	-$7.4
Benefit-Cost Ratio	ratio	0.81	0.58	0.47

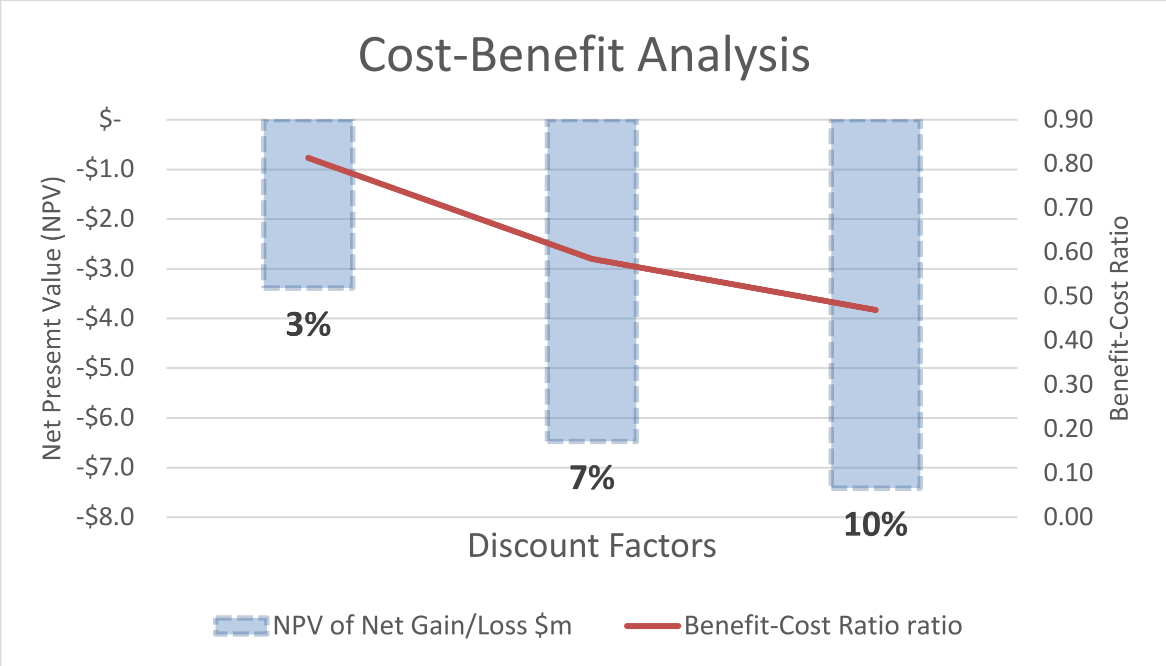


Figure 5: Cost benefit summary

Participation Factors

A sensitivity analysis was undertaken to determine the participation factors for key inputs to the risk cost models (i.e. to identify which inputs are most sensitive to overall risk cost).

The participation factor is defined as the ratio of percentage change in output (i.e. risk cost) to a percentage change in input (e.g. VCR). The participation factors for key model inputs are shown in the table below.

Due to the non-linear nature of the risk cost model (especially network risk costs, which are a function of concurrent failures), the participation factor can change depending on the magnitude of input percentage change.

The model is most sensitive to:

- **changes in the restoration time of a relay with no spares** (halving the restoration time) results in a decrease in risk cost of $0.26 million, or approximately 29.3% of the original base case risk (at 2030).
- **changes in the value of customer reliability** (halving the value) results in a decrease in risk cost of $0.16 million, or approximately 18.3% of the original base case risk (at 2030).
- **changes in bay controller emergency replacement cost** (halving the cost) results in a decrease in risk cost of $0.18 million, or approximately 20.5% of the original base risk (at 2030).

Table 3: Participation Factors

Input	Baseline value	Sensitivity value (-50%)	Change in risk cost at 2030 ($m)	Participation (%)
Network				
VCR ($/MWh)	29130	14565	-0.16	-18.26%
Restoration Time with spares – Relay (days)	2	1	0.00	-0.02%
Restoration Time with no spares – Relay (days)	10	5	-0.26	-29.30%
Financial				
Emergency replacement cost with spares - Relay ($m)	0.02	0.01	0.00	-0.18%
Emergency replacement cost without spares – Relay ($m)	0.09	1.50	-0.10	-11.09%
Emergency replacement cost with spares – Bay Controller ($m)	0.02	0.01	0.00	0.00%
Emergency replacement cost without spares – Bay Controller ($m)	0.20	0.10	-0.18	-20.46%