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POWERLINK QUEENSLAND REVENUE PROPOSAL

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Mudgeeraba 110kV
Primary and Secondary Systems Replacement

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STRATEGY & PLANNING

INVESTMENT OPTIONS PAPER

Reinvestment Options for Mudgeeraba 110kV Secondary Systems

May 2015

Document Control

Issue Date	Responsible Person	Objective Document Name	Background
	[redacted]	A2170693	

Approval

	Name	Position	Signature	Date
Endorsed	[redacted]	Manager – Network Integration		
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Executive Summary

During the next five years the Mudgeeraba No.2 and No.3 275/110kV transformers, and selected 110kV primary plant and secondary systems are reaching the end of serviceable life.

The condition assessment of the secondary systems conducted in July 2014 (A883977) identified condition and performance driven issues that will require reinvestment in the 110kV secondary systems equipment in the next five years

This report sets out the investment recommendation to address the end of life strategies for the 110kV secondary systems. A separate investment option paper discusses the investment recommendations regarding the 110kV switchyard and 275/110kV transformers (A2181751 & A2164540).

Three options to address end of life drivers were considered:

1. Minimal relay level replacement in 2017;
2. Partial bay replacement in 2017; and
3. Full secondary system replacement in 2017.

Each of the above options were considered against a range of criteria to identify the most suitable action to address the end of life drivers for this transmission line. These included:

- the need for a reliable electricity supply into the future and to comply with the National Electricity Rules and mandated reliability of supply standards;
- economic (NPV) analysis;
- operational risks; and
- other technical assessment parameters.

Option 2 which involves a partial panel level replacement by October 2017, is the preferred option for implementation.

Background

Mudgeeraba Substation is one of two major 275/110kV injection points into the major Gold Coast and Northern New South Wales load centres. Mudgeeraba Substation is located towards the southern end of the Gold Coast and consists of 275kV and 110kV switchyards connected via three 275/110kV 250MVA transformers. The 110kV Mudgeeraba switchyard provides critical supply into the Energex and Essential Energy distribution networks and connection to the Directlink interconnector.

The single line representation for the existing Gold Coast system, including Mudgeeraba Substation, is shown in Figure 1.

[redacted]

The 110kV switchyard was originally established in 1971 with six bays associated with five circuits to Beenleigh, Burleigh and Terranora and a bus section breaker. Further extension and reinvestment due to load growth, rising fault levels and condition based issues have resulted in primary plant from the 1980s, 1990s and 2000s. The 110kV switchyard is an isolator selectable bus configuration and currently consists of:

- Three 275/110kV 250MVA transformers and associated 110kV transformer bays;
- Ten 110kV feeder bays associated with circuits to Robina (1), Nerang (1), Merrimac (2), Burleigh Heads (2), Varsity Lakes (2) and Terranora (2);
- One 110/33kV 100MVA transformer bay and associated 110kV transformer bay;
- Three 50MVAr capacitor bank and associated 110kV bays; and
- Two bus section breakers.

A recent condition assessment of the Mudgeeraba 275kV and 110kV secondary systems equipment indicated that due to collective consideration of the condition and obsolescence issues, and the related risk of these assets remaining in service, the continued operation of selected secondary systems equipment needs to be considered in the next 3 to 5 years.

This Investment Options Paper examines strategies around the end of life options for the selective 110kV secondary systems, and has been developed as a result of the investigations of the Mudgeeraba 110kV Substation Rebuild team, established under the Terms of Reference identified in Attachment 1.

Investment Need

Assessment of Condition

The condition assessment of the secondary systems conducted in July 2014 (A883977) identified the following condition and performance driven issues with the 110kV equipment in the next 5 years:

Bus zone protection panels

- Bus zone protection devices and CT supervision have been in service over 20 to 30 years and have become obsolete with no spares available and identified higher failure rates on aging relays;
- Current master-check design is not fully redundant (non-compliance with NER). Failure of the check scheme will cause all bus zone protection schemes to block and to clear a bus fault will rely on remote end distance protection with slow clearance time (non-compliance with NER) resulting in the entire 110kV bus being switched out; and
- Replacement with a modern relay will require major logic and wiring modification resulting in longer outage window.

DC Supply Circuitry

- All 110kV protection and control are supplied by “X” DC system. Failure of X DC supply will result in increased risk of loss of all protection and control functions on all 110kV systems.

Feeder protection panels – Feeder 706, 754, 755, 757 and 758

- Pilot wire relays have been in service between 20 to 30 years;
- These relays have experienced reliability issues and manufacturers have ceased to provide technical support and supply. There are only limited system spares for these relays and it will be expected these spares will be consumed in three years; and
- Replacement with a modern relay will require major logic and wiring modification resulting in longer outage window.

Corridor construction type panels

- The above mentioned panels are of construction with separate protection and auxiliary panels. This type of construction is vulnerable to human error on causing protection system operation when maintenance is conducted and it is also expensive to modify because of the inter panel wiring; and
- Increased safety risk due to the exposed wiring terminals and constrained spaced for maintenance on the tunnel control panel.

Local control

- Obsolete HMI for the local control and there are no spares available. A virtualized solution is being developed to replace this obsolete Sun Workstation equipment throughout the state.

The overall condition of the remaining 110kV secondary systems equipment (approximately 50% of total equipment) at Mudgeeraba has been assessed as fair. The majority of this equipment was installed during expansion of the site in the 2000s and is relatively new with replacement being recommended within the next ten years.

This condition assessment also reviewed the 275kV secondary systems equipment indicating replacement is required within the next 5 to 7 years. During this outlook there are related end of life drivers for the 275kV transmission lines that supply the substation and the third 275/110kV transformer. It has been identified that there may be opportunities to consolidate the 275kV network. It is recommended that the end of life strategy for the 275kV primary plant and secondary systems equipment be reviewed together. Hence the majority of 275kV secondary systems risks have not been included as part of this option assessment.

However it was identified that the electro-mechanical 275kV bus zone protection relay DAD3 has been in service for more than 20 years, and is at an age where high failure rates have been observed. These relays have limited system spares and are projected to be consumed in the next few years. There will be no like for like replacement if the relay fails as there are no spares and the manufacturer has ceased manufacturing this type of device. The modern relay used for replacement will require major logic modification and wiring circuitry modification. It is recommended that replacement of this relay be considered within the next 1 to 3 years at the same time as reinvestment of the 110kV secondary systems.

Asset Risk

The following risks have been identified associated with the deteriorated condition and reliability concerns of the 110kV secondary systems equipment.

- Maintainability risks – Limited or no spare parts, requiring extended outages for replacement;
- Reliability risks – Equipment aging leads to increased failures of protection equipment and long outages of protection systems will be expected;
- Availability risk - Master/check bus zone scheme could fail to operate for any failure on the check scheme;
- Safety risks – Exposed wiring terminals and constrained spaced for maintenance on the tunnel control panel;
- Operational risks – Obsolete HMI for the local control.

The current level of risk for the secondary systems at Mudgeeraba substation is moderate. Relay failure will result in a loss of monitoring and remote control of primary plant and associated SCADA. Failure of the obsolete HMI device will result in a lack of local control for a prolonged period. The DC bus is over head and exposed, any maintenance work on site needs to be undertaken slowly to meet the level of caution required to reduce the safety risk.

Mudgeeraba substation is an essential component of the transmission network supplying the Gold Coast region and a secondary systems upgrade is required by October 2017 to maintain reliability of supply to the area.

Assessment of Options

Option 1: Minimal relay replacement in situ by October 2017

Option Overview	Option 1 includes the replacement of the obsolete bus and feeder protection relays only, and replacement of the DC battery and partial replacement of the DC circuitry.
Estimated Cost ($14/15)	$5.2M
Basis of Cost	Planning level estimate
Completion Date	Expected project completion is by October 2017. However site work and project progress will depend on MSP resources and latent conditions of the existing secondary system.
Key Assumptions	Safe work practices will be assessed and implemented as part of project delivery.
Risk Level Post Implementation of Option	The current moderate reliability and safety risk remains unchanged after implementation of this option as the majority of aged equipment and tunnel panels with exposed terminals remain in service. This option carries the highest risk of reliability and failure compared to options 2 and 3.
Benefits of Option	Option 1 defers the requirement for a full secondary system replacement until 2025.
Drawbacks of Option	As this option involves minimal relay replacement, overall reliability at the site is only marginally improved, due to the aged assets remaining. The functionality of the master/check bus protection design remains unchanged. The X supply circuity continues to be the only source of supply. The control system relies heavily on a single RTU. Should control fail, the majority of the site would be lost. The DC bus is over head and exposed. Work will be slow because of the additional level of caution that is required to mitigate the safety risk and may take longer than anticipated if unexpected situations arise e.g. inaccurate drawings. It is assumed that wirings associated with all original control panels will be experiencing cracking and brittleness by 2025 which presents an increased safety risk to personnel. Option 1 does not comply with the requirements of the National Electricity Rules in relation to design redundancy and fault clearance times as the single bus zone protection scheme is not replaced.
Operational Impacts	Option 1 has the highest effect on the network compared to Options 2 and 3. Longer outages may be required for construction and commissioning works.
Delivery Risks & Constraints	Protection panels have separate auxiliary panels. In the current design, there is no electrical isolation between panels and significant inter-panel wiring to be re-installed presents high operational risks during commissioning. Significant rear panel modification would be required to make provisions for Protection

	Signalling, OPSWAN, and Control system interfacing. Bus VT Changeover circuitry is required to switch the feeder protection voltage reference over to the correct bus. The Bus protection scheme (Master/Check) is in separate panels and there is also a separate location to the CBF multi-trip rack. A detailed investigation to safely modify this scheme has not been analysed. There are a significant number of exposed terminals which would need to be brought to current safety/standards if any work is undertaken in these panels. This presents a safety and operational risk when wiring and modifying panels beside in-service panels (falls due to false floor, open space, trip hazards etc) The wiring leaves the panels into the cable basement. The cable basement has historically filled up with water during periods of rain. This has caused many Earth On Battery faults and other cabling integrity issues over recent years. Outage conditions and lengths will be significant and require additional temporary relays to facilitate the work – effectively doubling or tripling outage windows. There is significant panel work, rewiring, cabling and testing required. Depending on the panel, to safely replace, test and configure new protection systems would be significant time per protection system. This would also require significant time and effort into engineering design, a Safety in Design review, extended lengths onsite, which ultimately compromise the remaining systems security and integrity.

Option 2: Partial Secondary Systems replacement in situ (SDM9) by October 17

Option Overview	Option 2 includes the replacement of the obsolete bus protection panels, replacement of five feeder protection panels for 706, 754, 755 757 and 758 installation of new batteries and wiring the Y DC supply, marshalling kiosks associated with Terranora feeders and HMI workstation.
Estimated Cost ($14/15)	$8.0M
Basis of Cost	Planning level estimate
Completion Date	Expected completion is by June 2017. However site work and project progress will depend on MSP resources and latent conditions of the existing secondary system
Key Assumptions	Safe work practices will be assessed and implemented as part of project delivery. SDM9 technology can be implemented on this site.
Risk Level Post Implementation of Option	This option *overall* has reduced the reliability risk to low. However a moderate safety risk still remains after implementation of this option due to the aged equipment and tunnel panels with exposed terminals which will remain in service requiring ongoing maintenance, with a remaining service life of 10 years.
Benefits of Option	Option 2 defers significant secondary system replacement until 2025 and has the second lowest long run cost in the NPV analysis, albeit not greatly dissimilar to Option 1.
Drawbacks of Option	Overall reliability at the site may be problematic due to the risk associated with other aged assets remaining (e.g. existing cabling).
Operational Impacts	Standard outages of approximately two weeks per panel for commissioning works will be required.
Delivery Risks & Constraints	Wiring of the Y DC supply into the existing panels. There are a significant number of exposed terminals which would need to be brought to current safety/standards if any work is undertaken in these panels. This presents a safety and operational risk when wiring and modifying panels beside in-service panels (falls due to false floor, open space, trip hazards etc)

Option 3: Majority Bay Replacement (SDM9) by October 2017

Option Overview	Option 3 includes the full replacement of all secondary systems and control equipment on site
Estimated Cost ($14/15)	$15M
Basis of Cost	Planning level estimate
Completion Date	Expected completion is by June 2017. However site work and project progress will depend on the latent conditions of the existing secondary system.
Key Assumptions	SDM9 technology can be implemented on this site.
Risk Level Post Implementation of Option	Option 3 has the lowest overall level of risk compared to options 1 and 2. In particular the safety risk moves to very low once implemented. However for options 1 and 2, the safety risk remains moderate post implementation due to the tunnel panels with exposed terminals which remain in service.
Benefits of Option	Option 3 has the lowest level of risk compared to all options. This option removes the safety risk associated with the exposed terminals and will have a lower effect on the network compared to options 2. As the scope of this option requires staged cut-overs due to a new SDM9 control building already FAT tested, there will be minimum risk of unplanned forced outages. Dependence on MSP resources is significantly less than option 1 & 2. FAT will be carried out before cut-over commences and as a result, cut-over works can be planned accurately as this option is not reliant on the existing condition of the secondary system.
Drawbacks of Option	This option has the highest write-off costs approximately 50% of secondary systems in this option are 10 years old. This option has the highest upfront costs and NPV. This would require replacement of secondary systems that may not be required under future scenarios.
Operational Impacts	Standard outages of approximately two weeks per panel for commissioning works will be required.
Delivery Risks & Constraints	There is a dependence on the availability of MSP resources; however it is significantly less than option 1 & 2.

Economic Assessment of Options

NPV Parameters

Discount Cash Flow Rate	Period of NPV Assessment
8.61%	50 years

NPV Components of Option 1: *Minimal relay replacement in situ by October 2017*

Action	Date	Value
Minimal relay replacement	2017	$5.2M
Full secondary systems replacement	2025	$15M

NPV Components of Option 2: *Partial Secondary Systems panel replacement by October 17*

Action	Date	Value
Partial secondary systems replacement	2017	$8M
Partial secondary systems replacement	2025	$8M

NPV Components of Option 3: *Full Secondary Systems Replacement by October 2017*

Action	Date	Value
Full secondary systems replacement	2017	$15M

NPV Results

		Present Value	Rank
Option 1	Minimal relay replacement in situ	$12.0M	1
Option 2	Partial secondary systems replacement in new building	$12.7M	2
Option 3	Full secondary systems replacement	$16.0M	3

The information above and financial analysis shows that Option 1 offers the lowest cost solution in NPV terms.

Recommended Options

Having taking into consideration

- the NPV results which identify Option 1 as the most economic option, but having the highest level of reliability and safety risks remaining and a significant reliability and safety risk during commissioning;
- greater reliability benefits of Option 2 compared to option 1, and lower NPV and upfront costs compared to Option 3; and
- operational capability in accordance with the National Electricity Rules.

Option 2, Partial Panel level replacement by October 2017, is the preferred option for implementation.

It is recommended that Option 2 Partial Panel level replacement to be progressed to approval, including the following scope:

- Replace all the secondary system panels associated with the following bays:
    - Bus Zone panels
    - Feeder 706
    - Feeder 754
    - Feeder 755
    - Feeder 757
    - Feeder 758
- Replace the 275kV Bus Zone DAD3 protection relay;
- The introduction of new technology SDM9 requires an MPLS network at providing 100 Mbps. For future secondary system replacements at Mudgeeraba Substation to proceed with SDM9, an alternative cable path will need to be investigated;
- Any new buildings should be located such to accommodate the ultimate substation layout;
- Replace the marshalling kiosks for the Terranora bays;
- Wiring the Y DC supply circuitry; and
- Replace the HMI workstation.

Related Area Plan

The Gold Coast Area Plan studies have confirmed there is an ongoing need for an 110kV substation at Mudgeeraba and as such the proposed secondary system replacement is consistent with the longer term plans for the area.

Regulatory Matters

The Mudgeeraba Secondary Systems Replacement project was included in Powerlink's 2010 Non Load Driven Plan as part of the 110kV rebuild and does not require RIT-T consultation.

Strategies and Policies

Powerlink strategies and policies are overarched by the National Electricity Rules (NER). Policies of particular relevance to Mudgeeraba Substation Secondary Systems include:

(1) AM-POL-0463 Protection Design
(2) AM-POL-0970 Secondary Systems Design
(3) AM–POL–0164, SCADA Requirements for Operational Purposes
(4) AM-POL-0169 Secondary Systems Maintenance Policy
(5) AM-POL-0053 AC and DC Supplies

As noted in Powerlink policy, protection systems should be designed to ensure system security is consistent with NER requirements (Table 1 – Maximum Fault Clearance Times NER Table S5.1a.2).

Relevant Stakeholders

DT Strategies	[redacted]	[redacted]
HV Strategies	[redacted]	[redacted]
Network Customers	[redacted]	[redacted]
Portfolio Management	[redacted]	[redacted]
Network Integration	[redacted]	[redacted]

Attachments

No.	Associated Reference Report	Objective ID
1	Mudgeeraba 110kV Rebuild Strategy NISC Team TOR	A1951689
2	Condition Assessment Report	A883977
3	Gold Coast Area Plan	A1377581
4	Project Scope Report CP.01679 – Mudgeeraba 110kV Selected Replacement OR.02025 – Mudgeeraba Primary and Secondary systems refurbishment	 A131589 A131514

STRATEGY & PLANNING

INVESTMENT OPTIONS PAPER

Reinvestment in the Mudgeeraba 110kV Switchyard

May 2015

Document Control

Issue Date	Responsible Person	Objective Document Name	Background
11/05/15	[redacted]	A2181751	Initial Issue

Approval

	Name	Position	Signature	Date
Endorsed	[redacted]	Manager – Network Integration		
Approved	[redacted]	Group Manager – Strategy & Planning		

Executive Summary

During the next five years the Mudgeeraba No.2 and No.3 275/110kV transformers, and selected 110kV primary plant and secondary systems are reaching the end of serviceable life.

This report sets out the investment recommendation to address the end of life strategies for the 110kV switchyard. Separate reports discuss the investment recommendations regarding the 275/110kV transformers and secondary systems (A2164540 & A2170693).

The Gold Coast Area Plan has identified:

- There is an ongoing requirement for the Mudgeeraba 110kV switchyard to provide reliable supply to the Gold Coast; and
- A reinvestment strategy for the Mudgeeraba 110kV switchyard that involves the renewal of the substation and the related transmission lines around 2025-2030.

Three options to address end of life drivers were considered:

1. Minimal selective reinvestment in 2017, followed by full rebuild in 2025
2. Minimal bay level reinvestment in 2017, followed by full rebuild in 2025
3. Minimal bay level reinvestment in 2017, followed by staged rebuilds in 2025 and 2030

Each of the above options were considered against a range of criteria to identify the most suitable action to address the end of life drivers for this transmission line. These included:

- the need for a reliable electricity supply into the future and to comply with the National Electricity Rules and mandated reliability of supply standards;
- economic (NPV) analysis;
- operational risks; and
- other technical assessment parameters.

Option 1 is the recommended option, which involves the minimal selective reinvestment of identified equipment in 2017, targeting a more extensive rebuild in approximately ten to fifteen years, which will be subject to business justification at that time.

Background

Mudgeeraba Substation is one of two major 275/110kV injection points into the major Gold Coast and Northern New South Wales load centres. Mudgeeraba Substation is located towards the southern end of the Gold Coast and consists of 275kV and 110kV switchyards connected via three 275/110kV 250MVA transformers.

The 275kV switchyard is currently supplied from Greenbank Substation by two 275kV single circuit transmission lines. Transmission line F835 was constructed in 1974 and F836 in 1975 with single Martin conductor rated at 550MVA. When initially constructed these lines were configured as transformer ended through two 275kV circuit breakers. A third transformer was established in 1993, a fully switchable 275kV bus arrangement in 2001, and installation of a 275kV 120MVAr capacitor bank in 2002. The 110kV Mudgeeraba switchyard provides critical supply into the Energex and Essential Energy distribution networks and connection to the Directlink interconnector.

The single line representation for the existing Gold Coast system, including Mudgeeraba Substation, is shown in Figure 1.

[redacted]

The 110kV switchyard was originally established in 1971 with six bays associated with five circuits to Beenleigh, Burleigh and Terranora and a bus section breaker. Further extension and reinvestment due to load growth, rising fault levels and condition based issues have resulted in primary plant augmentation and replacement in the 1980s, 1990s and 2000s. The 110kV switchyard (see Figure 2) currently consists of nineteen 110kV circuit breakers outlined below:

- Three 275/110kV 250MVA transformers and associated 110kV transformer bays;
- Ten 110kV line bays associated with circuits to Robina (1), Nerang (1), Merrimac (2), Burleigh Heads (2), Varsity Lakes (2) and Terranora (2);
- One 110/33kV 100MVA transformer bay and associated 110kV transformer bay;
- Three 50MVAr capacitor bank and associated 110kV bays; and
- Two bus section breakers.

[redacted]

A condition assessment of Mudgeeraba 110kV switchyard was completed in 2014. It identified emerging condition and obsolescence issues, which if not addressed, will present an increasing related risk for continued operation of these assets. The collective strategy to address these risks needs to be considered including the No.2 and No.3 275/110kV transformers and selected primary plant and secondary systems equipment. This Investment Options Paper examines strategies around the end of life options for the 110kV switchyard and has been developed as a result of the investigations of the Mudgeeraba 110kV Substation Rebuild team, established under the Terms of Reference identified in Attachment 1.

Investment Need

A site condition assessment was completed at Mudgeeraba Substation in 2014 for the 110kV switchyard including structural components. The condition and reliability of the 110kV Mudgeeraba Substation is routinely assessed to assist with determining the appropriate strategies for maintenance, refurbishment and replacement.

The future reinvestment strategy of the Mudgeeraba 110kV switchyard has considered the following plant and load driven issues:

Plant driven issues

- The original establishment of Mudgeeraba 110kV substation was in 1971 and consisted of six 110kV bays associated with a bus coupler, Beenleigh (1), Burleigh (2) and Terranora (2). A significant program of primary plant replacement occurred at Mudgeeraba 110kV Substation in 2006 which involved the upgrade of 110kV circuit breakers and other switchgear in order to address critical fault rating and continuous current rating limitations. The scope was to replace selected primary plant using the existing structures and foundations, with the majority being from the original installation in the 1970s. A significant proportion of the original bays have been renewed, however the remaining equipment requires selective replacement;

- Further extension of the switchyard occurred in a period from the mid-1970s to the 2000s. The bays established from the mid-1970s to early 1980s have been assessed as requiring selective reinvestment in the primary plant in the next five years (as shown in Table 1);
- The original 110kV isolator and earth switches in all 110kV bays are in a deteriorated condition, but with additional maintenance can remain in service for another 10 years. The original isolators have a contact arrangement which is a centre make and break type, this type of arrangement has caused problems when high currents are flowing. Eventual replacement will be necessary due to lack of spares, condition and inadequate rating;
- The switchyard is an isolator selectable bus configuration with the isolator insulated support posts supporting the solid bus. The eventual replacement of these support structures may require bus reconfiguration or full replacement;
- Observations have been made of atypical rates of corrosion on structures and primary plant throughout the switchyard possibly due to the prevailing salt laden coastal winds. Structures in the 110kV yard have been the subject of structural assessment with the estimated remaining service life around 15 to 20 years. However, the condition of the hold down bolts within the yard need to be continuously monitored to assess the level of corrosion and the impact on structural integrity;
- The switchyard resides on a low lying site which is flood prone and the ground very slow to dry out. The area surrounding the substation has been developed for residential purposes. The development around the site has resulted in significant drainage issues which may impact the total useable area of the site. Redevelopment and construction will be constrained within the existing perimeter and flood free areas; and
- The communications systems are microwave, PLC and Pilot wire based systems located in the communications room and common user's room. Existing communications systems can accommodate the requirements of the substation and are suitable for continued use. Optical fibres will need to be installed for replacement of the secondary systems with SDM9 technology and eventually eliminate the pilot wires and PLC systems.

Load driven issues

- Planning analysis has shown there is a continuing long term need for the 110kV switchyard at Mudgeeraba to meet reliability of supply obligations to the Gold Coast load centre under all demand projections. It provides critical supply into other electricity networks such as Energex and Essential Energy and provides 110kV connection to Directlink;
- At this stage, the long term 110kV ultimate layout requirements are not known as it will depend on the reinvestment strategy for the end of life drivers for the Gold Coast 275kV network to be addressed around 2025. However the present viewpoint is that the existing 110kV configuration would be sufficient for the subdued load growth outlook in the TAPR 2014 load forecast. There may be a future opportunity to reduce the number transformers, bus sections and ongoing requirement for bus select ability;
- The minimum plant rating for fault levels is 25kA with the existing fault level at 23kA. The fault level on the 110kV system is approximately 23kA and the minimum plant rating is 25kA. It is not expected that the fault levels will exceed the minimum plant ratings under the TAPR 2014 load forecast. In the future, operational measures may be available to manage fault levels within equipment rating to some degree. However to ensure safe operation of plant during faults the fault level ratings need to be considered in any long term redevelopment strategy;

- The overhead strung bus sections have been assessed to be in fair condition and the minimum rating of 2000 Amps is adequate on the basis of actual load and the current TAPR 2014 load forecast which is flat; and
- The Commonwealth Games will be held on the Gold Coast in April 2018. Project staging and outage coordination must ensure supply availability and reliability during this period.

Investment Strategy

Previous strategies for the reinvestment of the 110kV switchyard were integrated with the expected augmentation requirements to meet the forecast increase in Gold Coast load (resulting in higher fault levels and continuous current rating requirements). However on the basis of subdued load growth in the TAPR 2014 load forecast, the age profile throughout the switchyard and site specific considerations as above, these options were discounted on the critical review of the changed drivers and the significant capital expenditure for these solutions and high asset write off costs. Further, these solutions did not allow the flexibility to align to future end of life replacement options, i.e. locking Mudgeeraba to partial equipment replacement strategies into the future, nor do they allow the future opportunity to optimise the number of transformers, bus sections and ongoing requirement for bus select ability.

The proposed reinvestment strategy in this Investment Options Paper involves minimalist reinvestment over the next 10 years to address the condition driven risks. This achieves alignment of broader end of life drivers for the majority of the 110kV switchyard and targets an extensive rebuild in 10 to 15 years.

The installation of GIS technology has been evaluated in consideration of the advantages of this technology over conventional AIS switchgear relevant to the aforementioned constraints of this site. It is recommended that the use of GIS technology be considered as an option for a future rebuild on this site offering the following advantages:

- Compact design requiring less space requirements for extensive redevelopment scope within the existing perimeter;
- Longer service life;
- Low visibility buildings can be designed to blend in with local surroundings in highly developed residential area;
- Less sensitivity to pollution and salt laden winds;
- Increased availability, lower life cycle costs and reduced maintenance costs;
- Modules are factory assembled and taken to site for final assembly, significantly reducing installation times for replacement; and
- Reduced routine maintenance due to reduction in required planned outages and outage costs.

The implementation of a GIS strategy would also need to investigate any matters regarding ongoing technical support, design, spares, training competency and other issues arising from introduction of a new technology.

A high level overview of potential condition driven timings and overarching issues of assets throughout the 110kV switchyard is shown in Table 1. The recommendations from the site condition assessment are the basis within 1 to 5 years and discussed in detail in the following sections. Beyond 10 years, this high level overview is based on health and replacement indices and the age profile of each 110kV bay.

Table 1 Overview of 110kV switchyard profile

Overview of 110kV switchyard renewal drivers			
1 to 5 years	5 to 10 years	10 to 15 years	Beyond 15 years
F779 bay - Merrimac - excluding disconnectors	1 Tx Bay - 110kV	F838 bay - Varsity Lakes	F794 bay - Robina
F780 bay - Merrimac - excluding disconnectors	3-4 Bus coupler bay	F839 bay - Varsity Lakes	F754 bay - Burleigh
3 Capacitor Bank bay - CT, VT	3 Tx Bay - VT	F706 bay - Nerang	F755 bay - Burleigh
1 Capacitor Bank bay - CB	No.3 275/110kV Transformer	1 Capacitor Bank bay	F839 - Varsity Lakes
2 Tx Bay - VT		1 Bus, 2 Bus, 3 Bus , 4 Bus bay	F757 bay - Terranora
1 Bus, 2 Bus, 3 Bus , 4 Bus - VTs		1-3 Bus bay	F758 bay - Terranora
Spare 1 Bay - disconnectors		1-4 Bus bay	2 Capacitor Bank bay
3-4 Bus coupler bay - CT		2 Tx Bay - 110kV	3 Capacitor Bank bay
No.2 275/110kV Transformer		Yard - lights	4 Tx bay - 110/33kV
Yard - Fence		Secondary systems (partial 110kV)	3 Tx Bay - 110kV
DC Supply			No.1 275/110kV Transformer
Secondary Systems (partial 110kV)			Building
			AC Supply
			General Structures
			Yard - trench
Fault levels - existing fault levels are 23kA, limited equipment 25kA			
Accelerated corrosion of structures and drainage/localised flooding			
Hold Down Bolts			

The site condition assessment conducted in 2014 identified condition and safety issues over the next 1 to 5 years for the following assets:

- Merrimac 110kV line bays;
- No.1 and No.3 Capacitor bank bay;
- Selected instrument transformers;
- DC supply;
- Structures;
- Perimeter Fence;
- 110kV Secondary systems; and
- No.2 & No.3 275/110kV 250MVA Transformers.

Each these components are discussed in turn.

Reinvestment Needs 0 to 5 years

Merrimac Line Bays

The Mudgeeraba to Merrimac 110kV distribution lines are owned by Energex, and form part of supply to the critical northern Gold Coast bulk supply points including the Surfers Paradise and Broadbeach tourist and commercial precincts. These 110kV lines are aligned with the ongoing strategy by Energex to provide supply to the major tourist centres. [redacted]

An outage of a single Mudgeeraba to Merrimac 110kV line is unlikely to involve the loss of supply except under extenuating circumstances (such as prior outages or co-incident multiple failures of the parallel lines supplying the load area).

The components in the 110kV line bays are experiencing aged condition issues such as oil contamination, moisture ingress, low insulation resistance readings, failures of the closing coil and structural corrosion.

The condition of the circuit breaker, CTs and VTs pose moderate safety, network and compliance risks in the short to medium term which increase over time. There are age associated risks for oil filled VTs and CTs of an explosive failure mechanism. The existing controls are considered to be partially effective in mitigating the risk. The replacement of the line bay reduces risk levels to low or very low.

The structure corrosion and foundation condition pose low safety, network and compliance risks in the short to medium term which increase over time. The existing controls are considered to be partially effective in mitigating the risk. The replacement of the line bay reduces risk levels to low or very low.

50MVAr No.1 and No.3 Capacitor Bank Bays

An outage of two 110kV capacitor banks will not result in loss of supply or voltage stability limits on power transfer into the Gold Coast.

The components in the 110kV capacitor bank bay are experiencing aged condition issues such as the circuit breakers are in poor condition with the number of operations exceed rating for operating mechanisms and are mal-operating, there are age associated reliability issues of the voltage transformer and structural integrity issues due to corrosion.

The condition of the circuit breaker and VT pose moderate to significant safety, network and compliance risks in the short to medium term which increase over time. The existing controls are considered to be partially effective in mitigating the risk. The replacement of the line bay reduces risk levels to low or very low.

The structure corrosion and foundation condition pose low safety, network and compliance risks in the short to medium term which increase over time. The existing controls are considered to be partially effective in mitigating the risk. The replacement of the line bay reduces risk levels to low or very low. It is recommended to decommission these bays as the network operation risks associated with decommissioning both the No.1 and No.3 capacitor bank bays and removing the voltage support to the system are very low.

Selected instrument transformers

The condition of selected instrument transformers poses moderate to significant safety, network and compliance risks in the short to medium term which increase over time. The existing controls are considered to be partially effective in mitigating the risk. The replacement of the following instrument transformers reduces risk levels to low:

- [redacted] CTs are over 45 years old and have an age associated risk of failure with an explosive failure mechanism beyond 40 years old; and
- Identified electromagnetic porcelain housed voltage transformers have age associated risks beyond 35 years of age with an explosive failure mechanism.

DC supply

The 125 volt batteries were installed in 2000 and have been assessed to be at end of serviceable life. The chargers were installed in 2009 but are subject to a high failure rate of switched mode rectifiers. Both X and Y protection is connected to the X DC supply system and failure of the X DC supply poses moderate network and compliance risks in the short to medium term which increase over time. It is recommended it be replaced reducing the ongoing risk to low.

Structural and Foundations

There are minor works identified to rectify poor site drainage and to ensure the remaining equipment support structures and their foundations remain in a safe and functional state. Visual monitoring and periodic ultrasonic testing for structural corrosion and corrosion of the hold down bolts is recommended under maintenance and existing control procedures are in place. The transformer firewalls associated with No.2 and No.3 transformer have been assessed with an estimated remaining life of 5 years and will be considered as part of the transformer replacement projects in the same timeframe.

Perimeter Fence

The original fencing section displays extensive corrosion at steel posts with increased risk to structural integrity. Sections of the fence are below the minimum design standard of 3 metres, with no concrete kerbing and utilises a rail at the top which can be used as a climbing aid. The observed condition poses a significant safety risk related to unauthorised entry. It is recommended that this fence be replaced compatible with the security standard R2 and aligned with the scope of future substation security projects as per Powerlink Policy AM-POL-0234.

110kV Secondary systems

The protection and control relays installed in late 1990s are obsolete with limited manufacturer support and spares. There are inherent risks related to reliability of equipment, master/check bus zone design, DC supply circuitry and potential safety issues related to the tight work environment within the corridor panels and proximity to exposed live parts. The internal panel wiring cables appear in reasonable condition. The strategies for reinvestment of the 110kV secondary systems have been considered in an Investment Options Paper (A2170693).

No.2 & No.3 275/110kV 250MVA Transformers

There is increased risk of in-service failure of the No.2 and No.3 275/110kV 250MVA Transformers due to the following condition and design issues:

- The oil tests for both transformers indicated aged paper insulation, oil contamination and external corrosion/oil leaks with an increased risk of moisture ingress;
- There are aged condition and design concerns that clamping pressures will not be adequate to restrict axial movement of windings; and
- The No.2 275/110kV transformer bushings tested outside acceptable limits.

The strategies for reinvestment of these transformers have been considered in an Investment Options Paper (A2164540).

An assessment of the associated condition based asset risks of the 110kV switchyard assets was conducted with reference to Powerlink's Corporate Risk Assessment Matrix Checklist (RSK-FBP-CKL-A1165080). Appendix 1 summarises the existing level or risk and potential asset risks in 5 years.

The existing level of risk in the 110kV switchyard on the Mudgeeraba site has been assessed to be moderate risk level. The risk profile confirms the need to take action to address a significant safety risk which is expected to arise beyond 2017. The principle drivers are safety, compliance and financial risks related to the degrading condition of instrument transformers with an explosive failure mechanism and the condition of the security fence.

Options to address end of life drivers

Three options to address end of life drivers have been developed which offer various levels of investment risk and cost of works:

1. Selective bay reinvestment in 2017, followed by full rebuild in 2025
2. Selective bay level reinvestment in 2017, followed by full rebuild in 2025
3. Selective bay level reinvestment in 2017, followed by a staged rebuild in 2025 and 2030

Option 1: Minimal selective reinvestment in 2017, Full Rebuild 2025

Option Overview	This option involves the replacement of 2 bays and selective replacement of equipment in 2017. This option has a more significant replacement project in 10 to 15 years including the bays which were refurbished in 2017.	
Estimated Cost (2014/15)	2017 - $6.8M 2025 - $29.1M	
Project Delivery Dates	Expected Commissioning	October 2017
Key Assumptions	The replacement in 2017 would include: • In-situ replacement of the Merrimac line 779 and 780 primary plant equipment excluding bus disconnectors 7806, 7805, 7796 and 7795 • Decommission the spare bay D09, No. 3 Capacitor bank bay and No.1 Capacitor bank bay • Selective replacement of instrument transformers • Replace the existing site perimeter fence • Replace the DC distribution systems Followed by full substation replacement of the remainder of the switchyard (excluding the 2 Merrimac bays) in 2025	
Benefits of Option	• This option presents the minimal initial capital cost outlay and results in deferral of the large capital expenditure associated with the full substation replacement options, while managing the majority of the condition drivers and asset risks in the identified bays for the next 5 years • Flexibility to deal with future 110kV switchyard requirements in future is maintained • Aligns more significant reinvestment with broader substation drivers in 10 to 15 years • Provides benefits related to the use of GIS technology on this site	
Drawbacks of Option	• Write off of selective instrument transformers in 10 to 15 years	

Option 2 - Minimum bay level reinvestment in 2017, Full Rebuild 2025

Option Overview	Option 2 involves the replacement of 4 bays in 2017 and replacement of selective equipment. This option has a more significant replacement project in 10 to 15 years excluding the bays replaced in 2017.	
Estimated Cost 2014/15	2017 - $9.8M 2025 - $29M	
Project Delivery Dates	Expected Commissioning	October 2017
Key Assumptions	The replacement in 2017 would include: • Full replacement of 4 line bays in 2017 • Decommission the spare bay D09, No. 3 Capacitor bank bay and No.1 Capacitor bank bay • Selective replacement of instrument transformers • Replace the existing site perimeter fence • Replace the DC distribution systems Followed by the full replacement of the remainder of the switchyard including buildings and general yard condition in 2025 (13 bays)	
Benefits of Option	• Minimises the condition drivers and asset risks in the identified bays for the next 5 years • Flexibility to deal with future 110kV switchyard requirements in future is maintained	
Drawbacks of Option	• Does not align with the strategy to use of GIS technology on this site, or would require higher write of costs to achieve strategy • Higher upfront costs and deliverability concerns to achieve a 2017 commissioning date • Longer outage and staging requirements required for subsequent replacement work	

Option 3 - Minimum bay level reinvestment in 2017, Staged Rebuild 2025 & 2030

<table>
<tr><td>Option Overview</td><td colspan="2">This option is the same as Option 2 except it involves a staged replacement of future works in in 10 to 15 years.</td></tr>
<tr><td>Estimated Cost 2014/15</td><td colspan="2">2017 - $9.8M
2025 - $13M
2030 - $19.8M</td></tr>
<tr><td>Project Delivery Dates</td><td>Expected Commissioning</td><td>October 2017</td></tr>
<tr><td>Key Assumptions</td><td colspan="2">The replacement in 2017 would include:
• Full replacement of 4 line bays in 2017
• Decommission the spare bay D09, No. 3 Capacitor bank bay and No.1 Capacitor bank bay
• Selective replacement of instrument transformers
• Replace the existing site perimeter fence
• Replace the DC distribution systems

Followed by the staged replacement of the remainder of the switchyard including buildings and general yard condition in 2025 (incl. 5 bays) and 2030 (incl. 8 bays)</td></tr>
<tr><td>Benefits of Option</td><td colspan="2">• Minimises the condition drivers and asset risks in the identified bays for the next 5 years
• Flexibility to deal with future 110kV switchyard requirements in future is maintained</td></tr>
<tr><td>Drawbacks of Option</td><td colspan="2">• Does not align with the strategy to use of GIS technology on this site, or would require higher write off and implementation costs to achieve strategy
• Higher upfront costs and deliverability concerns to achieve a 2017 commissioning date
• Longer outage and staging requirements required for subsequent replacement work</td></tr>
</table>

ASSESSMENT OF OPTIONS

An assessment of the associated asset risks for this project was conducted with reference to Powerlink's Corporate Risk Assessment Matrix Checklist (RSK-FBP-CKL-A1165080) and is shown in Appendix 1. Table 2 below summarises the broader decision criteria and risk option analysis considered on the basis of the identified asset risks in Appendix 1.

Table 2 Option Analysis for reinvestment in Mudgeeraba 110kV Switchyard

Option Assessment - Decision Critieria	Key Risk Category	Existing 2015	2020	2025	Option 1: Selective equipment/Full Rebuild $21.2M	Option 2: Selective bays / Full Rebuild $23.5M	Option 2a: Selective bays / Staged rebuilds $23.3M
Safety - security fence	Harm to public or personnel occurs due to unauthorised entry into substation	Significant (Ex6)	Significant (Ex6)	Significant (Ex6)	Moderate (Fx6)	Moderate (Fx6)	Moderate (Fx6)
Safety - primary plant	Harm to public or personnel occurs due to explosion	Significant (Ex6)	High (Cx6)	High (Cx6)	Moderate (Fx6)	Moderate (Fx6)	Moderate (Fx6)
Network Operations	Network constraints or loss of supply due to plant failure or planned outages	Moderate (Ex4)	Moderate (Ex4)	Significant (Cx4)	Low (Fx4)	Low (Fx4)	Moderate (Ex4)
Financial / People	Critical staff required to respond to equipment failures or investigation. Extended outages during commissioning.	Low (Fx3)	Low (Ex3)	Moderate (Dx3)	Low (Fx3)	Low (Fx3)	Moderate (Dx3)
Stakeholder	Failure of equipment resulting in loss of supply at a critical load centres or within other TNSPs, constraint on Directlink operation. Event during Commonwealth Games.	Moderate (Dx4)	Moderate (Dx4)	Moderate (Dx4)	Low (Fx4)	Low (Fx4)	Low (Fx4)
Regulatory	Aligned with joint planning and regulatory requirements	N/A	N/A	N/A	Low (Fx4)	Low (Fx4)	Low (Fx4)
Deliverability	Ability to deliver project in required timeframe	N/A	N/A	N/A	Low (Fx4)	Moderate (Ex4)	Moderate (Ex4)
Strategic alignment	Aligned with broader long term asset management and network requirements	N/A	N/A	N/A	Low (Fx4)	Low (Fx4)	Low (Fx4)

The overall economic assessment over a 40 year assessment period using a discounted cash flow rate of 8.61%.

Discounted Cash Flow Results | NPV of Capital and Operating Costs		Present Value	Rank
Option 1	Selective bay reinvestment in 2017, followed by a full rebuild in 2025	$21.2M	1
Option 2	Selective bay level reinvestment in 2017, followed by full rebuild in 2025	$23.5M	3
Option 3	Selective bay level reinvestment in 2017, followed by a staged rebuild in 2025 and 2030	$23.3M	2

The information above and financial analysis shows that Option 1 offers the lowest cost solution in NPV terms and a prudent level of asset and network risk.

Recommendation

On the basis of this analysis and having considered the benefits and risks of each option, it is recommended that Option 1, involving selective replacement of equipment in 2017 followed by a full substation rebuild in 10 to 15 years dependent on the assessment of the plant condition at that time and project justification.

It is recommended that the investment option 1 for replacement of selective equipment in the 110kV switchyard to be progressed to approval, including the following scope:

- In-situ replacement of all the Merrimac line 779 and 780 primary plant equipment including civil works, but excluding bus disconnectors;
- Replace the existing site perimeter fence compatible with Powerlink Policy for future substation security projects;
- Replace the DC distribution systems;
- Decommission the spare bay D09, No. 3 Capacitor bank bay and No.1 Capacitor bank bay;
- All primary plant associated with operation of the transformer be capable of withstanding the normal and emergency ratings of the new 250MVA transformer; and

- Selective replacement of the following instrument transformers

Bay	Replacement Items	
	Current Transformers	Voltage Transformers
2 Cap (D06)		Y
2 TX (D12)		Y
3-4 Bus (D17)	Y	
KD2 (2 Bus)		Y
KD3 (3 Bus)		Y
KD4 (4 Bus)		Y

Related Area Plan

The Gold Coast Area Plan studies have confirmed there is an ongoing need for an 110kV substation at Mudgeeraba and as such the proposed replacement is consistent with the longer term plans for the area.

Regulatory Matters

The Mudgeeraba 110kV Switchyard Replacement project was included in Powerlink's 2010 Non Load Driven Plan and does not require RIT-T consultation.

Strategies and Policies

Powerlink strategies and policies are overarched by the National Electricity Rules (NER). Policies of particular relevance to Mudgeeraba 110kV primary plant include:

(1) AM-POL-0057 & AM-PR-0237 Instrument transformers (CTs, VTs, CVTs)
(2) AM-POL-0407 Disconnectors
(3) AM-POL-0402 and AM-PR-0403 Circuit Breakers

Relevant Stakeholders

HV Strategies	[redacted]	[redacted]
DT Strategies	[redacted]	[redacted]
Main Grid Planning	[redacted]	[redacted]
Regional Grid Planning	[redacted]	[redacted]
Network Customers	[redacted]	[redacted]
Portfolio Management	[redacted]	[redacted]
Network Integration	[redacted]	[redacted]

ATTACHMENTS

No.	Associated Reference Report	Objective ID
1	Mudgeeraba 110kV Rebuild Strategy NISC Team TOR	A1951689
2	Condition Assessment Report	A2003046
3	Gold Coast Area Plan	A1377581
4	Project Scope Report CP.01679 – Mudgeeraba 110kV Selected Replacement OR.02025 – Mudgeeraba Primary and Secondary systems refurbishment	 A131589 A131514

APPENDIX 1

An assessment of the associated asset driven risks for these assets was conducted with reference to Powerlink's Corporate Risk Assessment Matrix Checklist (RSK-FBP-CKL-A1165080). The following table identifies the potential asset risks associated with each of the options considered in the options analysis.

[redacted]

Note1: This risk accounts for existing practices of regular routine maintenance. Network Operations advised to operate Capacitor Bank No.2 before operation of No.1 and No.3.

Note2: This risk is reduced to moderate once temporary repairs (barbed wire underneath and replacement of 4 grade corroded fence posts) have been completed.

CAPITAL/OPERATIONAL PROJECT ENDORSEMENT SHEET

Project: **CP.01679**	Description: **Mudgeeraba 110kV Primary and Secondary Systems Replacement**

In order to ensure that all the issues associated with network operational works are addressed, it is desirable to have all relevant Managers within Powerlink Queensland endorse project approval submissions prior to financial approval being received.

Endorsement by responsible parties ensures that the proposed project scope achieves Powerlink's requirements. The following parties endorse this project and recommend its approval, specifically:

1. there is an ongoing need for the project and the project scope is consistent with the intended objective of the project;

2. the project scope (including the timing) and associated estimate are consistent, and appropriate budget has been identified for the required works to ensure a deliverable outcome;

3. there is sufficient budget provision to undertake this operational refurbishment project and the project is allowed for within the overall portfolio of works; and

4. the proposed scope is technically acceptable and complies with all current plant strategies.

[redacted]

[redacted]

INVESTMENT & PLANNING

BUSINESS CASE

CP.01679 Mudgeeraba 110kV Primary and Secondary Systems Replacement

25 May 2015

Document Control

Issue Date	Responsible Person	Objective Document Name	Background
25/05/2015	[redacted]	Business Case CP.01679 Mudgeeraba 110kV Primary and Secondary Systems Replacement	Initial Issue

CONTENTS

SUMMARY

This report sets out the business case to justify a capital project to replace selected primary and secondary systems at the Mudgeeraba 110kV switchyard. It discusses the reasons for partial replacement of the asset and also recommends the proposed scope as the preferred option that addresses the issues associated with the primary and secondary systems at Mudgeeraba Substation.

It is therefore recommended that approval be sought for CP.01679 Mudgeeraba Primary and Secondary Systems Replacement to replace approximately 10% of the primary plant assets and approximately 30% of the secondary systems equipment. The estimated capital expenditure required is $15.6 million escalated to completion ($14.14 million plus 10% contingency) and the works are to be completed by 28 February 2018.

As a result, it is also recommended that $726,682 of accelerated depreciation be applied to the existing primary plant.

1. INTRODUCTION

As a transmission network service provider, Powerlink undertakes works to meet its obligations contained in the *National Electricity Rules* (the Rules) to plan, design, operate and maintain the transmission network to allow the efficient transfer of electrical energy from producers to users. In addition, under its *Transmission Authority* obligations set out in the *Electricity Act*, Powerlink must make appropriate investments to ensure continuity of supply (refer Attachment 1).

These obligations give rise to a program of capital expenditure to develop the network to ensure efficient transfer of electrical energy and to replace assets to maintain reliability of supply. This business case describes a capital project to replace selected 110kV primary and secondary systems plant at Mudgeeraba.

2. BACKGROUND

Mudgeeraba Substation is one of two major 275/110kV injection points into the critical Gold Coast and Northern New South Wales load centres. Mudgeeraba Substation is located towards the southern end of the Gold Coast and consists of 275kV and 110kV switchyards connected via three 275/110kV 250MVA transformers. The 110kV switchyard currently provides critical supply into other electricity networks including Energex, Essential Energy and Directlink.

The 110kV switchyard was originally established in 1971 including six bays associated with five circuits to Beenleigh, Burleigh and Terranora and a bus section breaker. Further extension and reinvestment due to load growth, rising fault levels and condition based issues resulted through the 1980s, 1990s and 2000s. The 110kV switchyard is an isolator selectable bus configuration and currently consists of:

- Three 275/110kV 250MVA transformers and associated 110kV transformer bays;
- Ten 110kV feeder bays associated with circuits to Robina (1), Nerang (1), Merrimac (2), Burleigh Heads (2), Varsity Lakes (2) and Terranora (2);
- One 110/33kV 100MVA transformer bay and associated 110kV transformer bay;
- Three 50MVAr capacitor bank and associated 110kV bays; and
- Two bus section breakers.

A significant program of primary plant replacement occurred at Mudgeeraba 110kV Substation in 2006 that involved the upgrade of 110kV circuit breakers and other switchgear in order to address critical fault rating and continuous current rating limitations. The scope included replacement of selected primary plant using the existing structures and foundations.

As a result of the previous partial replacements at Mudgeeraba and revised demand outlook the scope of work now proposed by the suite of Mudgeeraba replacement and refurbishment projects form part of a strategic solution to maximise use of the assets while minimising asset write downs and future rework.

3. NEED

3.1. Condition Driver

A site condition assessment was completed at Mudgeeraba Substation in 2014 for the 110kV primary plant including structural components. The condition assessments have identified that while a significant proportion of the original bays have been renewed, the remaining equipment requires selective replacement.

Similarly, a condition assessment was completed in 2014 for both the 275kV and 110kV secondary systems. The condition assessment identified selective replacement of the 110kV secondary system is required within the 1 to 5 year timeframe.

The site condition assessments for the 110kV assets recommend equipment to be replaced or refurbished within 1 to 5 years due to reliability and safety risks. Beyond 10 years, the proposed plant and equipment replacements are a high level overview, based on health and replacement indices and the age profile of each 110kV bay. Table 1 identifies the assessed and assumed condition driven timings for the 110kV switchyard, and a description of the issues follows.

Table 1 Overview of 110kV switchyard replacement profile

Overview of 110kV switchyard renewal drivers			
1 to 5 years	5 to 10 years	10 to 15 years	Beyond 15 years
F779 bay - Merrimac - excluding disconnectors	1 Tx Bay - 110kV	F838 bay - Varsity Lakes	F794 bay - Robina
F780 bay - Merrimac - excluding disconnectors	3-4 Bus coupler bay	F839 bay - Varsity Lakes	F754 bay - Burleigh
3 Capacitor Bank bay - CT, VT	3 Tx Bay - VT	F706 bay - Nerang	F755 bay - Burleigh
1 Capacitor Bank bay - CB	No.3 275/110kV Transformer	1 Capacitor Bank bay	F839 - Varsity Lakes
2 Tx Bay - VT		1 Bus, 2 Bus, 3 Bus , 4 Bus bay	F757 bay - Terranora
1 Bus, 2 Bus, 3 Bus , 4 Bus - VTs		1-3 Bus bay	F758 bay - Terranora
Spare 1 Bay - disconnectors		1-4 Bus bay	2 Capacitor Bank bay
3-4 Bus coupler bay - CT		2 Tx Bay - 110kV	3 Capacitor Bank bay
No.2 275/110kV Transformer		Yard - lights	4 Tx bay - 110/33kV
Yard - Fence		Secondary systems (partial 110kV)	3 Tx Bay - 110kV
DC Supply			No.1 275/110kV Transformer
Secondary Systems (partial 110kV)			Building
			AC Supply
			General Structures
			Yard - trench
Fault levels - existing fault levels are 23kA, limited equipment 25kA			
Accelerated corrosion of structures and drainage/localised flooding			
Hold Down Bolts			

Refer to the Investment Options Papers - Reinvestment in the Mudgeeraba 110kV Switchyard and Reinvestment Options for the Mudgeeraba 110kV Secondary Systems for detailed descriptions.

110kV Primary Plant

The principal primary plant issues are:

- Merrimac Line Bays.

  The Mudgeeraba to Merrimac 110kV distribution lines are owned by Energex, and form part of supply to critical northern Gold Coast bulk supply points including the Surfers Paradise and Broadbeach tourist and commercial precincts. Components in the 110kV line bays are experiencing aged condition issues such as oil contamination, moisture ingress, low insulation resistance readings, failures of the closing coil and structural corrosion. The aged status of the circuit breaker, CTs and VTs pose moderate safety, network and compliance risks in the short to medium term which increase over time.

  There are age associated risks of an explosive failure mechanism for the oil filled VTs and CTs. Structure corrosion and foundation condition poses moderate safety, network and compliance risks in the short to medium term which increase over time. The existing controls are considered to be partially effective in mitigating risk however replacement of the line bays reduces risk levels to low or very low. Replacement of both Merrimac feeder bays is recommended.

- DC supply.

  The 125 volt batteries were installed in 2000 and have been assessed to be at end of serviceable life. The associated battery chargers were installed in 2009 but are subject to a high failure rate of the switched mode rectifiers. Both the X and Y protection supplies are connected to the X DC supply system and failure of the X DC supply poses moderate network and compliance risks in the short to medium term which increase over time. It is recommended the DC system be replaced thereby reducing the ongoing risk to low.

- Perimeter Fence.

  The original fencing section displays extensive corrosion at steel posts with increased risk to structural integrity. Clearances exceed design allowances in sections with no concrete kerbing posing a significant safety risk related to unauthorised entry. It is recommended that this fence be replaced to current Powerlink design standards.

110kV Secondary System

The principal secondary systems issues are:

- Bus zone protection panels.

  The current master-check scheme is non-compliant with the NER and can result in the entire 110kV bus being switched out. The bus zone protection devices and CT supervision have been in service 20-30 years and have become obsolete with no spares available. There is a risk of higher failure rates on the ageing relays; replacement with the current Powerlink standard relay will require major logic and wiring modification resulting in significant cost and a long outage window. Replacement of all the bus zone panels adopting the new SDM9 design standard is recommended.

- Protection panels for feeders 706, 754, 755, 757 and 758.

  The pilot wire relays have been in service between 20-30 years and have experienced reliability issues. The manufacturers have ceased to provide technical support and there are only limited system spares. It is expected these spares will be consumed within 3 years. In the event that system spares are no longer available, replacement with the current Powerlink standard relay will require major logic and wiring modification resulting in significant cost and a long outage window. Replacement of these panels is recommended.

- DC Supply Circuitry.

  All of the 110kV protection and control equipment is supplied by the X DC system. Failure of X DC supply results in an increased risk of the loss of all protection and control functions on all 110kV systems. Implementation of an X and Y DC supply system is recommended.

- Corridor Panels.

  This style of panel segregates protection and auxiliary functions into separate panels. This type of construction presents increased safety risks due to exposed terminals, constrained space for maintenance and, by its design, is prone to plant trips due to human error. In addition, panel modifications are costly due to the inter-panel wiring design. Where significant relay replacement is required, replacement of the complete panel is recommended.

- Local control.

  The HMI for the local control is obsolete and no spares are available. Replacement of the local HMI is recommended.

3.2. Network Need

Planning analysis has shown there is a continuing long term need for the 110kV switchyard at Mudgeeraba to meet reliability of supply obligations to the Gold Coast load centre under all demand projections. While the long term 110kV ultimate requirements are not known it is considered that the existing 110kV configuration is sufficient for the subdued load growth outlook as per the TAPR 2014 load forecast.

The fault level on the 110kV system is currently approximately 23kA and the minimum plant rating is 25kA. It is not expected that in the foreseeable future the fault levels will exceed the minimum plant ratings. However, operational measures will be adopted to manage fault levels within equipment rating in the short to medium term should the need arise, and will be considered for long term redevelopment strategy.

Further, the Commonwealth Games will be held on the Gold Coast in April 2018. Project staging and outage coordination must ensure supply availability and reliability during this period

As a result, it is not acceptable to do nothing to address this need due to the ongoing network requirement for this asset and the safety and reliability issues presented by the condition of the primary plant and secondary systems.

4. PROPOSED SOLUTION

4.1. Options Considered - Primary Plant

Initially, a range of primary plant implementation options were considered on the basis that the site inundates, that the equipment presents with significant condition issues, and inadequate fault level ratings to meet rising fault currents. The implementation options included:

- Partial 110kV switchyard replacement with AIS ($60.0m)
- Complete 110kV switchyard replacement with AIS ($64.2m)
- Complete 110kV switchyard replacement with GIS ($59.0m)

Note that each of these options included complete replacement of the 110kV secondary systems.

These options were all discounted on the basis that:

- fault levels are not expected to exceed the minimum plant fault level ratings under the load forecast in the TAPR 2014;
- the solutions did not allow the flexibility to align to future end of life replacement options, thereby locking Mudgeeraba into partial equipment replacement strategies into the future;
- the future opportunity to optimise the number of transformers, bus sections and ongoing requirement for bus select ability was constrained;
- significant capital expenditure could be deferred; and
- high asset write off costs minimised.

On the basis of the condition assessment of the primary plant, the ongoing network requirement for this plant at Mudgeeraba, and minimising long term development constraints, selective primary plant replacement was investigated and determined to deliver the most cost effective solution that provides flexibility for future replacement strategies. This solution is described in the following section.

4.1.1. Selective Equipment Replacement

Three selective equipment 110kV primary plant replacement options were considered (Reference 4). Each was similar but varied to the extent of the number of full bays to be replaced (2 versus 4 bays). The NPV results identify the *minimal* selective replacement scope as the preferred option.

The scope of the preferred option includes the following within the scope of OR.02025 Mudgeeraba Primary and Secondary Systems Refurbishment:

- Decommissioning of spare bay D09, No. 3 Capacitor bank bay and No.1 Capacitor bank bay; and
- Selective replacement of instrument transformers,

and the following within the scope of this project (CP.01679):

- In-situ replacement of the Merrimac feeder 779 and 780 primary plant equipment excluding bus disconnectors 7806, 7805, 7796 and 7795;
- Replacement of the existing site perimeter fence; and
- Replacement of the DC distribution systems.

This option presents the minimum primary plant initial capital cost outlay and results in deferral of the large capital expenditure associated with the full substation replacement options, while managing the condition drivers and asset risks identified in the bays for the next 5 years. It allows the flexibility to align more significant reinvestment with broader substation drivers in 10 to 15 years. However, there will be some write off costs associated with a small amount of equipment that will be installed within the scope of the associated refurbishment project. The overall future primary plant write off cost will have been significantly minimised.

4.2. Options Considered – Secondary Systems

Three options were considered to address the condition drivers for replacement of the 110kV secondary systems at Mudgeeraba.

4.2.1. Option 1 – Minimal Relay Replacement

This option includes the replacement of the obsolete bus and feeder protection relays only, replacement of the DC battery, and partial replacement of the DC circuitry. While this solution defers the requirement for a full secondary system replacement until 2025, overall reliability at the site is only marginally improved due to the aged assets remaining. In addition, safety risks for maintenance personnel remains as does non-compliance with the requirements of the National Electricity Rules in relation to design redundancy and fault clearance times as the single bus zone protection scheme is not replaced. The estimated capital cost of this option is $5.2m. The net present value of minimal relay replacement in 2017 followed by a full secondary systems replacement in 2025 is $12.0m

4.2.2. Option 2 – Partial Secondary Systems Replacement

This option includes replacement of the obsolete bus protection panels and feeder protection panels for 706, 754, 755, 757 and 758 to SDM9 design standard, installation of new batteries including addition of a Y DC supply, and replacement of marshalling kiosks and HMI workstation.

The benefit of this option is deferral of a full secondary system replacement until 2025 and the introduction of the new SDM9 technology. The NPV analysis is comparable to that of Option 1. It offers some improvement to safety risks given some of the original corridor panels remain however moderate risk rating remains. Overall the reliability risk is improved to low risk.

The estimated cost of this option is $8.0m. The net present value of partial panel replacement in 2017 followed by a further partial panel replacement in 2025 is $12.7m. Option 2 is the recommended secondary solution.

4.2.3. Option 3 – Full Secondary Systems Replacement

Option 3 includes the full replacement of all secondary systems and control equipment on site to the SDM9 design standard. Option 3 has the lowest level of risk compared to all options. This option removes the safety risk associated with the exposed terminals and will have a lower effect on the network compared to option 2. As the scope of this option requires staged cut-overs due to a new SDM9 control building already FAT tested, there will be minimum risk of unplanned forced outages. Further, dependence on MSP resources is significantly less than option 1 & 2. However, this option has the highest write-off costs as approximately 50% of secondary systems in this option are 10 years old. This option also has the highest upfront costs and NPV and includes replacement of secondary systems that may not be required under future scenarios.

The estimated cost of this option is $15.0m. The net present value of a full secondary systems replacement by 2017 is $16.0m.

4.3. Recommended Solution

The minimal selective primary plant replacement solution together with partial secondary systems panel replacement (Option 2) is recommended as the most cost effective option that addresses the condition of the primary plant and secondary systems, the ongoing network requirement for this plant at Mudgeeraba, and minimises long term development constraints.

5. STRATEGIC FIT

This scope of this project is in accordance with the following Powerlink policies:

- AM-POL-0057 Instrument Transformers Maintenance
- AM-POL-0407 Maintenance of Disconnectors
- AM-POL-0402 Maintenance of Circuit Breakers
- AM-POL-0463 Protection - Design
- AM-POL-0970 Secondary Systems Design
- AM-POL-0164 SCADA Requirements for Operational Purposes
- AM-POL-0169 Secondary Systems Maintenance Policy
- AM-POL-0053 AC and DC Supplies

6. PROJECT SCOPE

The scope of work detailed below addresses the primary and secondary systems capital expenditure replacement works associated with the recommendations of the respective investment options papers. Associated refurbishment and decommissioning works will be included in the operational expenditure budget and is addressed by the scope of project OR.02025 Mudgeeraba Primary and Secondary Systems Refurbishment.

6.1. 110kV Primary Plant Replacement

The scope of primary equipment replacement includes:

- In-situ replacement of the Merrimac feeder 779 and 780 primary plant equipment including civil works (bays D07 & D08), but excluding bus disconnectors 7806, 7805, 7796 and 7795;
- Replacement of the existing site perimeter fence compatible with and upgradeable to security standard R2 to complement the scope of future substation security projects per Powerlink Policy AM-POL-0234. Within the scope of work; and
- Replacement of the DC distribution systems for the equipment to be retained in the existing control building.

6.2. 110kV Secondary Systems Replacement

The scope of secondary systems replacement includes:

- Replacement of selected 110kV secondary systems panels including all bus zone panels and panels for feeders 706, 706, 754, 755, 757 and 758 adopting the SDM9 design standard. The new equipment will be installed in a new control building complete with associated auxiliary equipment;

- Replacement of all 110kV marshalling kiosks excluding those associated with the Terranora feeders.
- Modify the X and Y DC supplies in the existing control building to the current protection system requirements;
- Removal of redundant panels and equipment;
- Replacement of the HMI workstation including software upgrade to conform to Powerlink design standards.
- Provision of additional protection system fibre paths.

For a detailed scope, refer to Project Scope Report CP.01679 Mudgeeraba 110kV Selected Replacement.

7. PROJECT COMPLETION

The planned completion date for the project is 28 February 2018.

Timely execution of the project is required to meet this date ahead of the Commonwealth Games that will be held on the Gold Coast in April 2018.

8. DEPENDENCIES

This project is co-dependent upon the timely completion of:

- CP.01543 Mudgeeraba 275/110kV No 2 Transformer Replacement
- OR.02025 Mudgeeraba 110kV Primary and Secondary Systems Replacement

9. COSTS

The project quotation is shown in the Project Proposal for CP.01679 Mudgeeraba 110kV Primary and Secondary System Replacement (Reference 2), and summarised in the table below.

Escalated	**Estimate $k**
Design	[redacted]
Materials Procurement	[redacted]
Construction Contract	[redacted]
Construction Management	[redacted]
Test and Commission	[redacted]
Project Management	[redacted]
Other	[redacted]
Total	**13,740**

The projected cash flows based on an annual escalation of 4.1% are set out below.

	2014/15 $k	2015/16 $k	2016/17 $k	2017/18 $k	Total $k
Real, 2014/15	405	2,880	6,863	2,570	**12,718**
Escalated to completion	405	2,998	7,438	2,899	**13,740**

A contingency amount of 10% should be included to allow for unforeseen scope changes. This brings the total amount to be approved to $15.1 million.

As a result of this project, it is also recommended that accelerated depreciation be applied to the primary plant. The written down value of assets to be replaced by this project is estimated to be $726,682 as at April 2015.

10. FUNDING

The capital expenditure of this project has been reviewed in relation to the financial forecasts and borrowing requirements. Funding of this project is considered appropriate and can be accommodated within the current approved capital budget and as such within Powerlink's borrowing requirements.

11. RETURN ON INVESTMENT

To support Powerlink's capital expenditure to meet its regulatory obligations, the following matters have been considered for the proposed investment:

- the expenditure is demonstrated to be cost effective;
- the requirement for the assets does not diminish in future (i.e. asset stranding does not occur);
- the proposed capital expenditure relative to the allowance in the AER's current Transmission Determination for Powerlink; and
- appropriate consultation and approvals processes are undertaken.

Each of these issues is discussed in turn below.

11.1. Cost Effective Solution

The implementation of selective primary plant replacement and partial secondary systems panel replacement is essential to ensure that the primary plant and secondary system condition issues are addressed to meet the ongoing network requirement for the plant at Mudgeeraba while minimising long term development constraints.

The condition assessments identified that primary equipment replacement could be broadly grouped into 1 to 5 year, 5 to 10 year, 10 to 15 year and beyond 15 year timings. Equipment with timings greater than 5 years based on age related triggers were excluded from the scope of this project. Similarly, the secondary systems condition assessment identified equipment that should be replaced within the scope of this project, the remainder due for replacement circa 2025. Addressing the immediate condition drivers will ensure the continued availability and reliability of Mudgeeraba to supply the Gold Coast area and networks including Energex, Essential Energy and Directlink, in particular during the Commonwealth Games in April 2018.

Further, it minimises and defers capital expenditure, minimises asset write off costs, and allows the flexibility for future network optimisation while aligning future development works at Mudgeeraba.

The recommended option was selected as the lowest cost effective solution to address plant condition and reliability issues, which has a prudent regard for long term business requirements.

The works to be undertaken are also in accordance with Powerlink's Procurement Policy and existing procurement arrangements to ensure effective pricing competition. The expenditure is therefore considered to be cost effective.

11.2. Stranding Risk

The selected Mudgeeraba primary equipment and new secondary systems panels are required for the foreseeable future to provide an essential service for the 110kV substation and associated connections in the Gold Coast area. The stranding risk associated with this proposed investment is therefore not considered to be significantly different to that of Powerlink's other typical prescribed investments.

11.3. Capital Expenditure Allowance

For the regulatory period from 2012/13 to 2016/17, the regulatory arrangements include an ex-ante capital expenditure allowance. Powerlink will receive a full regulated return on, and of, the expenditure, provided the investment required to meet Powerlink's obligations over the five year period is prudent and efficient, and within the capital expenditure allowances in the AER's Transmission Determination for Powerlink.

This project is included in the current capital budget forecast and, therefore, the capital expenditure associated with this project is within the ex-ante capital expenditure allowance.

11.4. Approval and Consultation

The AER requires that all new assets to be rolled into the regulated asset base at the end of the 2012/13 to 2016/17 regulatory period be subjected to the appropriate consultation and approvals processes.

At the time of writing there are no Rules requirements for approvals, public or participant consultation on the replacement of assets such as transformers and other associated works included in this project. However, this project is subject to Powerlink's capital governance process.

In addition to the consultation required under the Rules, the High Voltage Asset Strategist and Digital Asset Strategist have been consulted regarding the requirement, and proposed implementation methodology, for this project and support its approval.

Final approval for a project of this value rests with the Powerlink Board as per financial delegations in Compliance Manual.

12. RECOMMENDATION

It is recommended that approval be sought for CP.01679 Mudgeeraba Selected Replacement. The estimated cost is $15.6 million escalated to completion ($14.14 million plus 10% contingency). The works are to be completed by 28 February 2018.

As a result of this project, it is also recommended that accelerated depreciation be applied to the existing primary equipment. The written down value of assets to be replaced by this project is estimated to be $726,682 as at April 2015.

13. REFERENCES

1. Condition Assessment Report
2. Project Scope Report
3. Project Proposal
4. Investment Options Paper - Reinvestment in the Mudgeeraba 110kV Switchyard
5. Investment Options Paper - Reinvestment Options for Mudgeeraba 110kV Secondary Systems

ATTACHMENT 1 – PLANNING OBLIGATIONS

As a transmission network service provider (TNSP), Powerlink is obliged to meet the requirements of Schedule 5.1 of the *National Electricity Rules* (the Rules) and in particular, clause S 5.1.2.1:

> *"Network Service Providers must plan, design, maintain and operate their transmission network... to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Registered Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called "credible contingency events").*
>
> *The following credible contingency events and practices must be used by Network Service Providers for planning and operation of transmission networks....*
>
> *The credible contingency events must include the disconnection of any single generating unit or transmission line, with or without the application of a single circuit two-phase-to-ground solid fault on lines operating at or above 220 kV".*
>
> *The voltage stability criteria outlined in Clause S5.1.8 of the National Electricity Rules requires 'that an adequate reactive power margin must be maintained at every connection point in a network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point'. In line with this requirement, a reactive margin of 1% of the maximum fault level (in MVA) at each connection point is required.*

Powerlink's transmission authority also includes a responsibility on Powerlink to:

> *".....plan and develop its transmission grid in accordance with good electricity industry practice such that:*
>
> *...*
>
> *(b) if the power quality standards do not specify different obligations during normal and other operating conditions – the power quality standards will also be met by the transmission entity even during the most critical single network element outage; and*
>
> *(c) the power transfer available through the power system will be such that the forecast of electricity that is not able to be supplied during the most critical single network element outage will not exceed:*
>
> *(i) 50 megawatts at any one time; or*
>
> *(ii) 600 megawatt-hours in aggregate....." (Electricity Act 1994).*

These obligations give rise to an ongoing program of capital expenditure to develop the grid and to replace aged assets.