PowerWater

Power and Water Corporation
Preliminary Business Case – Category B

PRD32117
Secondary systems upgrade of 132kV DKTL substations

Proposed:	Approved:	
Jim McKay Senior Manager Network Development & Planning, Power Networks Date: 6/2/2018	Michael Thomson Chief Executive & Chair Investment Review Committee Date: 23/02/2018	
Endorsed:	Endorsed:	Endorsed:
	Refer to email D2018/72353	Refer to email D2018/59547
Djuna Pollard Executive General Manager Power Networks Date: 15/2/2018	Finance review Date: 06/02/2018	PMO QA Date: 08/02/2018

1 RECOMMENDATION

It is recommended that the Chief Executive approve PRD32117 secondary systems upgrade of 132kV DKTL (Darwin-Katherine Transmission Line) substations for an estimated cost [redacted] and a corresponding completion date of June 2021.

Approval is sought for expenditure of up to $0.4M of the total forecast expenditure to undertake the necessary work to proceed to the next approval gateway (Business Case Approval), including:

- Functional/Concept design and preliminary investigations on site; and
- Project Management.

Since the preparation of the BNI, additional scope items have been included into this business case, including:

- Following more holistic review of the DA-KA transmission line secondary system, additional obsolete and end-of life relays and systems were identified at connected substations; and
- Inclusion of a substation LAN to allow remote access and configuration to secondary protection systems.

The project has a 95% likelihood of being delivered [redacted]

2 PROJECT SUMMARY

Project Title:	Darwin - Upgrade DKTL Secondary Systems		
Project No.:	PRD32117	**SAP Ref:**	
Anticipated Delivery Start Date:	October 2019	**Anticipated Delivery End Date:**	June 2021
Business Unit:	Power Networks		
Project Owner (GM):	Djuna Pollard	**Phone No:**	898 58431
Contact Officer:	Jim McKay	**Phone No:**	8924 5204
Date of Submission:	23/02/18	**File Ref No:**	D2015/625668
Submission Number:		**Priority Score:**	
Primary Driver:	Renewal/Replacement	**Secondary Driver:**	Commercial Efficiency
Project Classification:	Capital Category B		

2.1 Prior Approvals

Document Type	Sub Number	Approved By	Date	Capex Value
BNI	8704	Michael Thomson	25/02/2016	[redacted]

2.2 Related projects

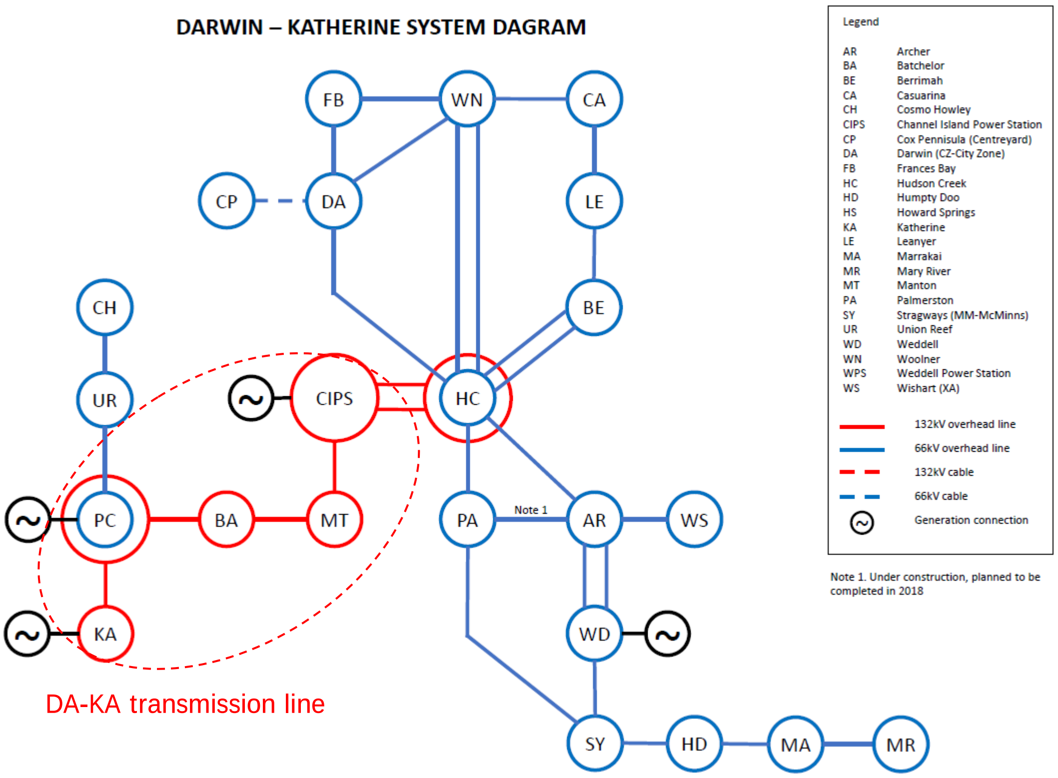
- NPR Protection Relay Replacement
- NPR SCADA and Comms Obsolete Asset Replacement

3 INVESTMENT NEED

3.1 Background

The Darwin to Katherine 132kV Transmission Line (DKTL) runs from Channel Island Power Station to Manton, Batchelor, Pine Creek and Katherine Zone Substations. It was constructed in 1986 and predominantly contains original secondary systems equipment.

Figure 1: System diagram



The DKTL is the main supply for the townships of Pine Creek and Katherine. It is also used by power producers such as EDL and Territory Generation for connection of their generation plant into the Darwin-Katherine system. As the DKTL is a single transmission line only, failure to replace aging, unsupported assets on this essential transmission line will expose PWC and its customers to system security risk, and unplanned outages. The likelihood of extended unplanned outages will be higher due to the unavailability of spare parts for the aged secondary system assets.

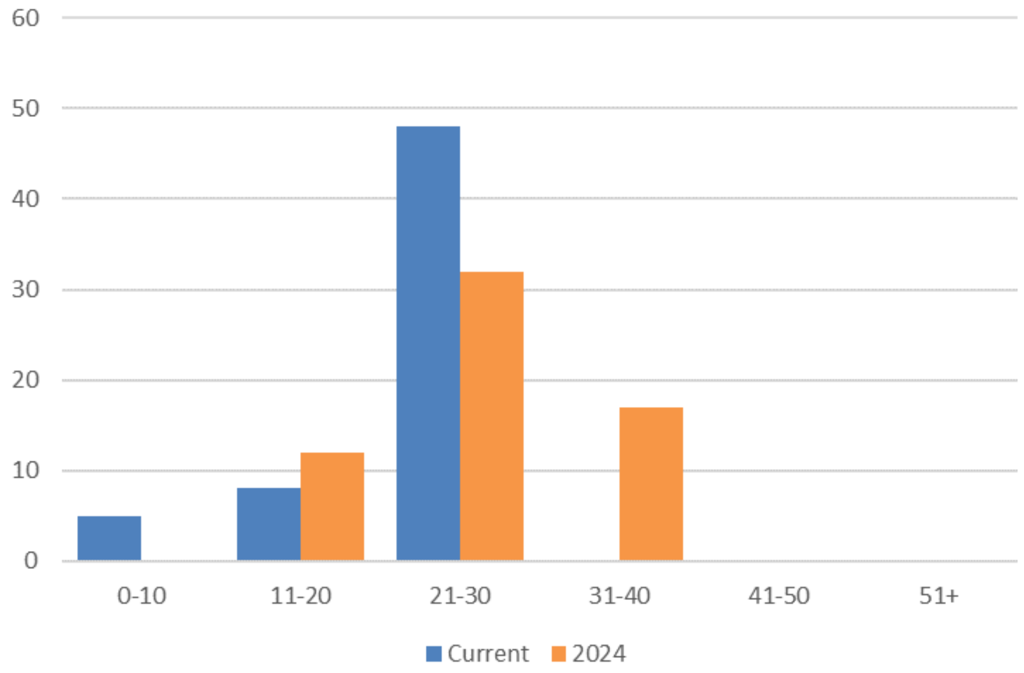
3.2 Asset details

The majority of the secondary systems assets installed at substations along the DKTL have been in service since commissioning. At 30+ years, these assets have not only exceeded their operational life but are obsolete models, no longer supported by the Original Equipment Manufacturer (OEM).

Unlike the primary equipment that has an expected life of 40+ years, the design life for the electronic and digital technology of the secondary systems installed on the DKTL is 20 years. PWC is experiencing increasing failures[1] [2] and without OEM support, it is increasingly difficult to technically and economically repair these devices[3].

The age profile is shown in Figure 2, illustrating the extent of secondary systems on the DKTL that exceed the design life of 20 years. By 2024, 17 relays will be in excess of 30 years of age.

Figure 2. Asset age profile – DKTL secondary systems



[1] Investigation Report AVR, Synchronisation and ARC on 132kV substations rev 2, PSC Consultants, PWC Ref: D2015/625643

[2] Asset History – Protection defects reports, PWC Ref: F2006/7416

[3] Woodward Controller (synchroniser), Feb 2016, PWC Ref: D2016/78999

3.3 Management strategy & investigation outcomes

Piecemeal secondary system component replacement and replacement on failure has been undertaken to date and where required. Due to the criticality of this transmission line, and the interdependent nature of the systems, continuing this strategy is no longer prudent or efficient. For example, modern relays interface directly with SCADA and communications systems, rather than via hard wiring. As such, communications system must be upgraded to accommodate the new relay requirements whilst maintaining an obsolete technology for relays not being replaced, adding complexity to the operation of the system, increased level of risk to failure of components, and increased cost.

3.4 Current and emerging issues

Secondary systems are critical to maintaining the security and reliability of the electricity network and supply to customers. As the secondary systems continue to age, the ability for the systems to maintain their functions within acceptable limits decline significantly. This has a direct impact on the ability to maintain reliable electricity supplies to customers, and protect against exposing the public and workers to unsafe conditions following failure of plant.

As identified in the secondary systems asset management plan, the current and emerging issues include[4]:

- Secondary systems and relays operating well beyond the design life of 20 years.
- Complex static relays are often found to be operating outside the rated tolerance or are non-functional. The cause of failure is difficult to identify, and the relays are typically not repairable.
- The older digital relays have reached the end of their expected serviceable life and they have been made obsolete by the manufacturers. They also have poor communication interface which makes them harder to work with and diagnose.
- To maximise the useful life of relays made obsolete by manufacturers, PWC replaces some relays in the fleet to generate spares for the remaining fleet. These are used to perform like-for-like replacements when relays fail in-service.
- Component failures in digital relays such as current elements, output contacts, communications module faults and power supplies failure can result in relay replacement. Some relays are modular and only the failed component module requires replacement. Approximately three digital relays per year are replaced due to these common failures.

[4] Condition Assessment Report – DKTL secondary systems

A summary of the issues identified in the DA-KA transmission line secondary system are highlighted in Table 1 below. The Pine Creek, Manton and Katherine ZSS sites require the majority of corrective works.

Table 1. Summary of secondary system issues identified on DKTL

Secondary system	Channel Island PS	Manton ZSS	Batchelor ZSS	Pine Creek ZSS	Katherine ZSS
Sychronisation				x	x
Grid / island detection				x	
AVR relay		x	x	x	x
Transformer protection relay				x	
Line protection relay	x	x	x	x	x
Auto reclose	x	x	x	x	x
CB management relay		x		x	x
RTU		x		x	
Substation Lan	x	x	x	x	x

3.4.1 Obsolete synchronisation system at Pine Creek and Katherine ZSSs

The reliability of the current synchronisation system at Pine Creek and Katherine ZSS is unacceptably low because:

(i) The tone signalling units, which facilitate communication between the power station and substation, have previously malfunctioned and have recently been repaired. However, the units are no longer supported by the OEM and given the age, are prone to failure making them unreliable[5]; and

(ii) The synchronisation system and PLC is now obsolete and has been superseded by a new design.

The power stations at Pine Creek and Katherine are islanded several times per year[6] as a result of outages on the single line connecting Manton and Katherine. At the Pine Creek end, a simple scheme is in place consisting of a local PLC that reviews information at the CB to determine if the system is islanded and sends a signal to the power station to change its operating

[5] Email "Review of Syncheck Settings in Power Network" dated 08/09/2016 sent by W. Chan. Trim reference D2016/410770

[6] Ibid

mode. At Katherine there is no active system in place to match voltage and frequency. Instead, a power station PLC relies on information from Pine creek and status of the local CB.

This system has become increasingly unreliable in its operation, causing local outages. There are no spare units available, and the manufacturer has declined to repair existing units.[7]

3.4.2 Obsolete system for grid/island detection at Pine Creek

The single line between Manton and Katherine experiences several interruptions during the year due to thunderstorms, scheduled maintenance or other issues. This results in Pine Creek and Katherine systems being islanded numerous times a year.[8] During islanding, Katherine Power Station switches its operating mode from frequency droop (when grid connected) to isochronous mode, reverting back to frequency droop mode only when connection to the grid is restored. The grid/island detection, located at Pine Creek Power Station, is currently performed by an [redacted] PLC) which is due to be discontinued in 2017. In addition, there have been reported communication issues between the PLC, Pine Creek Power Station and Katherine Power Station resulting in local power outages.[9]

These relays are operating beyond their design life, and there is insufficient knowledge within PWC to maintain the ladder logic used in the PLC for these functions.

3.4.3 Obsolete transformer Auto-Voltage Regulating (AVR) and tap control relays (Manton, Batchelor, Pine Creek and Katherine ZSSs)

Transformer tap change in the transmission and sub-transmission system is performed automatically or in remote manual control mode by the power system controller to manage voltage regulation. The transformers along the DA-KA transmission line are fitted with [redacted] auto voltage regulating (AVR) relays. This relay is no longer supported by the OEM and has proven to be unreliable in the past,[10] with an increasing failure rate.

An obsolete [redacted] unit performs the tap-change control function, which is also no longer supported by the OEM.

Both relays are operating beyond their design life. PWC has commenced a relay replacement function for [redacted] AVR across other ZSS sites, including Hudson Creek, Berrimah and Palmerston[11].

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[7] Ibid

[8] Condition Assessment Report – DKTL Secondary Systems

[9] Ibid

[10] Refer to Trim container F2006/7416: "TECHNOLOGY INFRASTRUCTURE SERVICES - ASSET HISTORY - Asset Management - NT Northern Territory Protection Defect Reports" for defect reports

[11] Hudson Creek, Berrimah, Palmerston

3.4.4 End of life transformer protection relays (Pine Creek ZSS)

The existing transformer protection relays at Pine Creek Switching Station are outdated and are operating beyond their design life. A previous test report has also indicated likely relay failure in the future[12].

After detection of several defects, the same relay has been replaced at Katherine 132kV Zone Substation.

3.4.5 Obsolete line protection relays (Channel Island, Manton, Pine Creek and Katherine ZSSs)

The line protection system between Channel Island, Manton, Pine Creek and Katherine Zone Substations currently comprises of obsolete protection relays [redacted] protection relays. These relays have surpassed their expected asset design life, are no longer supported by the manufacturer and, with spares unavailable, unplanned outages are likely to be several weeks while replacement relays are installed and commissioned.

The line protection on the Channel Island end of the transmission line was recently upgraded to [redacted] protection relays in 2014 due to augmentation of the 132kV switchgear due to installation of new generators. However the remote end of this line at Manton still consists of the outdated relays.

3.4.6 End of life and obsolete Auto Reclose (ARC) function

The auto-reclose function is typically employed for overhead lines to enable automatic reclose of circuit breakers following non-critical outages (momentary spurious outages caused by flying animals, trees and branches, etc.). Currently this function is performed by [redacted] PLC units. These relays have surpassed their expected asset design life, are no longer supported by the manufacturer and, with spares unavailable, unplanned outages are likely to extend for several weeks while a replacement relay is installed and commissioned.

3.4.7 End of life and obsolete circuit breaker management relays (Manton, Pine Creek and Katherine ZSSs)

The circuit breaker (CB) management protection relays for each of the circuit breakers at Manton, Pine Creek and Katherine Zone Substations consists of aged, outdated and inefficient electro-mechanical relays. For example, at Pine Creek, the circuit breaker management function is currently performed by four relays operating beyond their design life and exposed to failure. This may result in system instability and physical damage to equipment from failure to properly isolate faults. In modern protection schemes this function is undertaken by one Intelligent Electronic Device (IED) protection relay.

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[12] Refer to Trim document D2010/192470: "20100527 132PC01-03 Transformer REF MFAC14 M3017026 MH KK DL Relay Defect Report"

The relay technology is no longer supported by the manufacturer, and spare relays are no longer available. Whilst repairs may be possible by making use of components from salvaged relays, the risk of failure of other components continues to increase.[13]

3.4.8 *Obsolete and non-standard RTU configuration (Manton and Pine Creek ZSSs)*

Current substation design philosophy incorporates duplicate/redundant RTUs for increased reliability, however, the existing installation at MT and PC ZSSs only include single RTUs which do not meet PWC's design philosophy[14].

The RTUs installed at both sites are C2025 modules which are no longer in production and unsupported by the manufacturer. Additionally, spare parts are becoming difficult to source.

3.4.9 *Substation LANs*

Substation LANs are not currently installed at substation sites on this transmission line, which does not meet PWC's design standard and inhibits any remote access to the protection relays. The response time required to investigate faults and system events is therefore extended due to lengthy travel times involved in attending site.

3.5 Peak demand and capacity forecasts

There are no identified demand-driven drivers for this project.

3.6 Risk analysis

Figure 2 shows the current rating, inherent rating (in 2024, i.e. if no action is taken in the interim), and the residual (post-treatment) risk ratings associated with the condition of secondary system assets on the DKTL.

(i) *Current rating:* The Current rating (2017) is assessed to be 'High' due to the aggregate service delivery, compliance and financial risk posed to PWC from disruptions arising from failure of the secondary system assets to a 'moderate' level. The likelihood of extended outages is rated as 'likely'. There would also likely be adverse media attention and compliance breaches.

(ii) *Inherent rating:* If the assets are not replaced by 2024, the consequence increases from 'moderate' to 'major', incurring long term interruptions financial loss and compliance breaches. The inherent risk rating is therefore 'Very High'.

(iii) *Residual rating:* The proposed project will mitigate the condition and obsolescence risks through replacement of the secondary system assets. The likelihood of disruptions is considered 'unlikely'. The consequence of the risk

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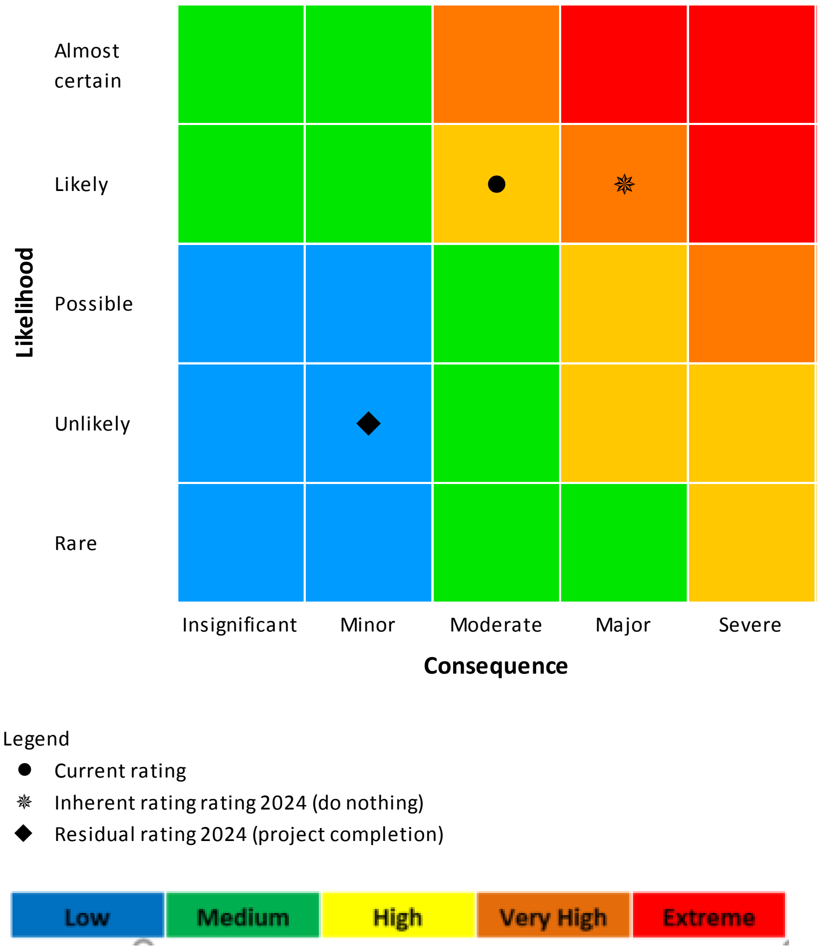
[13] Condition assessment report – DKTL

[14] Power and Water substation design manual

will be a temporary and minor disruption to the electricity supply. The residual rating is therefore 'Low'.

Figure 2: DKTL secondary systems risk assessment[15]



It is Power and Water's current practice to take action on risks that have an inherent rating of 'HIGH' or above. The PBC summarises the proposed response to this impending risk.

4 STRATEGIC ALIGNMENT

This project aligns with the Corporation's key result areas of operational performance and customer centricity, where the goals are to be an efficient provider of services and delivering on customers' expectations.

This project will allow PWC to provide safe, reliable power supply in line with our stakeholder expectations.

[15] Based on Power Network's Risk Assessment Guide

5 TIMING CONSTRAINTS

This project will need to be completed by June 2021 to limit risk to the system and manage assets at the end of life. The protection relays and associated secondary systems are no longer supported by manufacturers and spares are difficult to source. Based on our current estimates of requirements for spares, components are not likely to be available to use for breakdown failures within 3 years (i.e. 2020/2021). The project must be completed before this time.

This project has already been deferred; however there is no further opportunity to defer this project due to unavailability of replacement items and spares.

6 EXPECTED BENEFITS

Driver/Objective	Benefit	Current State	Future State
Asset renewal	Reduced asset failure. Increase reliability of network.	Currently assets are outdated and failure rates are high.	This project will replace outdated and failing assets with new supported and easy to maintain assets. It will reduce asset failure rates
Commercial efficiency	Reduced failure rate, maintenance cost, duration of outages	Currently maintenance costs are high due to high asset failure rates and low available system information.	Reduced failure rate, trouble shooting time shortened. Reduced corrective maintenance cost.

7 REQUIREMENTS

The solution must resolve the need to renew the existing secondary assets currently in service at the DKTL zone substations to minimise the risk of failure that will result in extended unplanned outages to customers.

8 OPTIONS

8.1 Options Development

A feasibility options study[16] considered the main issues and proposed solutions. This study has been drawn upon in the presentation of options below.

[16] PSC, January 2016, Investigation into synchronisation, auto reclose, AVR and tap control functions at Manton, Pine Creek and Katherine 132kV substation (provides as Appendix A of the PRD32117 BNI, PWC Ref D2015/625643)

8.1.1 Option 1 – Do nothing (replace on failure)

The deferral/do nothing option is essentially “run to failure”; parts and equipment are replaced only upon failure.

Option 1a: Repair on failure

In limited cases, a repair on failure option may be available. However, since the existing equipment is outdated and no longer supported by the manufacturer, spares are no longer available or are extremely difficult to source for breakdown work. In some cases, the spares can cost more than replacement/upgrade cost.

This option is likely to incur extended outages of the impacted systems, and consequential impact to the security and reliability of the power system. For each of the secondary systems identified, the propose scope is detailed in Table 2 below.

Table 2 – Included scope – Option 1a

Secondary system	Scope
Synchronisation	The current synchronisation relay has been superseded by a new design, and no longer supported by the manufacturer. In the event of failure of these units, alternate hardware would need to be sourced and commissioned for this system.
Grid / island detection	The current PLC will be discontinued in 2017. In the event of failure of this unit, a supported version of PLC would be sourced, new logic tested with the existing communications link. The compatibility of the repaired systems is untested.
Transformer AVR and tap control relay	The current relays are obsolete and no longer supported by the manufacturer. In the event of failure of these units, a new supported PLC would need to be configured (non-standard design).
Transformer protection relay	The relays have been superseded, and no longer supported by the manufacturer. In the event of failure of these units, PWC would utilise any existing spare parts available to repair the system by replacing components. Spare components are limited from previously removed units.
Line protection relay	The relays have been superseded, and no longer supported by the manufacturer. In the event of failure of these units, PWC would utilise any existing spare parts available to repair the system by replacing components. Spare components are limited from previously removed units.
Auto reclose	The current relays are obsolete and no longer supported by the manufacturer. In the event of failure of these units, a new supported PLC would need to be configured (non-standard design).
CB management relay	The relays have been superseded, and no longer supported by the manufacturer. In the event of failure of these units, PWC would utilise any existing spare parts available to repair the system by replacing components. Spare components are limited from

	previously removed units.
RTUs	The current RTU has been superseded by a new design, and no longer supported by the manufacturer. In the event of failure of these units, PWC would utilise any existing spare parts available to repair the system by replacing components. No redundancy is provided for this unit, and availability spare components are limited from previously removed units and will quickly be exhausted.
Substation LAN	Maintain current systems - do not install
Master station	Maintain current systems - do not replace

Option 1b: Upgrade on failure

As an alternate to the above repair approach, upgraded units could be purchased in advance of failure (as system spares), preparatory work undertaken in advance of change-over and final integration and testing not undertaken until time of failure. Whilst this has the advantage of migrating to the current design standard, the time involved in installation, testing and commissioning would be in response to an unplanned failure event and likely to incur additional time and cost. The time at site would likely be increased with multiple mobilisation and de-mobilisation costs.

Summary

Options 1a and 1b expose PWC's customers to an increased risk of extended unplanned outages. With an increasing equipment failure rate, the reliability of the protection system becomes compromised, leading to an increased risk to personal safety.

Options 1a and 1b are not consistent with the secondary systems asset management strategy or good industry practice. They are not considered technically or commercially feasible, due to the existing technical obsolescence of these devices and shortage of spares (Option 1a) and difficulty to upgrade technology in response to an unplanned event (Option 1b).

8.1.2 Option 2 – Targeted replace/upgrade of secondary systems (Preferred option)

In this option, the highest risk secondary systems (outdated and unsupported systems) will be replaced with modern systems that meet current design standards. The advantages are new up-to-date systems with improved reliability, enhanced site remote monitoring and control capabilities, and reduced frequency and duration of unplanned outages.

The systems upgrade is expected to reduce maintenance cost due to a reduced rate of equipment failure. Consequently, there will be a significant reduction in the number and duration of unplanned outages. The enhanced system and equipment information can also be utilised to improve equipment monitoring and reduce testing time on site.

For each of the secondary systems identified, the proposed scope is detailed in Table 3 below.

Table 3 – Included scope – Option 2

Secondary system	Scope
Synchronisation	The existing tone signalling units and synchroniser will be upgraded to current supported hardware. Total of 2 installations at Pine Creek and Katherine.
Grid / island detection	Utilise the power system control system to perform the grid/island detection. This also provides an opportunity to implement multi area Automatic Generation Control in the future. Total of 1 installation at Pine Creek.
Transformer AVR and tap control relay	Replace both relays with a current supported relay capable of performing both AVR and tap-change control functions. Total of 4 installations at Manton, Batchelor, Pine Creek and Katherine
Transformer protection relay	Replace transformer protection using standard protection relays T60 and 7UT633. Total of 2 installations at Pine Creek and Katherine.
Line protection relay	New standard line protection relays P442 and L90 installed at Channel Island (L90 to replace existing REL670 at CI), Manton (new L90 and P442 at both ends), Batchelor (new L90), Pine Creek (new L90 and P442 at both ends), and Katherine Zone Substations (new L90 and P442),
Auto reclose	To be provided in the feature set of the upgraded line protection relays. The standard line protection relay P442 has the ARC functionality inbuilt. It is planned that when the line protection is upgraded, the Gould PLC units will be decommissioned and the ARC function will be performed by the new line protection relays.
CB management relay	Replace the 4 obsolete schemes with the PWC standard CB management relay C60. Total of 4 installations at Manton (2), Pine Creek and Katherine.
RTUs	The proposed solution is to replace the current RTU system with a dual redundant system, utilising current approved RTU hardware to improve reliability. Total of 2 installations at Manton, and Pine Creek.
Substation LAN	Substation LAN will also be installed at each substation to allow remote access to the protection relays from the major centres like Darwin. This will allow the protection relays to be remotely accessed by engineers in the Darwin office to retrieve fault records and change/modify settings without having to physically drive to the substation. This will significantly reduce response time required to investigate faults and system events. The communications system will also need to be upgraded to cater for the increased data requirements.
Master station	Associated secondary and SCADA works to the system control

	Master Station

The advantage of this option (option 2) is that it replaces the outdated and unsupported systems with new up-to-date systems that improve secondary systems reliability, enhances site remote monitoring and control capability, and reduces the risk and duration of unplanned outages. The current risks associated with lack of available replacement units, spares and training are effectively mitigated, and extended outages due to failures are avoided.

This option has inherent cost advantages when compared with option 1, whereby the projects are treated as a program and complementary projects designed, constructed and commissioning to minimise required outages and maximise efficiency of required resources.

The primary disadvantage is that the option reflects a higher level of expenditure than historically has been incurred at these sites.

The cost breakdown of each component of this option is provided in Table 4 below. Costs shown in the table below are base project costs and do not include the risk-adjusted costs (ie. P_{50}).

Table 4 – Cost estimate for Option 2

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

8.1.3 Option 3 – Replace/upgrade all secondary systems

This option involves a complete upgrade of all secondary systems at all substations along the DA-KA transmission line.

The advantage of this option is that it develops a new secondary system environment based on the current design standard across all sites, and substantially removes the risk to safety and interruption of supplies related to the quality of the installed secondary systems.

The primary disadvantage, is that there is marginal benefit achieved from upgrading all secondary systems at significant additional time and cost, including replacement of systems and relays that have bene recently replaced, and those that are not approaching replacement age.

The cost estimate of this option is [redacted] over the next RCP. This option is not considered commercially feasible.

8.1.4 Option 4 – Non-network solutions and demand management

PWC confirm the ongoing need for these assets to support the function of the secondary systems on the DKTL. Given the stated condition and obsolescence risks associated with these secondary systems, PWC has not identified any non-network or demand management options to meet the objective of this work.

Option 4 is not considered to be technically or commercially viable.

8.2 Comparative cost analysis (including sensitivity analysis)

PWC is currently developing a probabilistic risk-cost methodology which, when completed will be used to compare options and confirm the economically optimum time for investment.

Table 5 summarises the results of a comparative cost analysis, the details of which are included in Appendix A Of the technically viable options, Option 2 – Replace existing substation has the lowest NPC. Costs shown in the table below are base project costs and do not include the risk-adjusted costs (ie. P_{50}).

Table 5: Summary of comparative capital cost analysis

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

8.3 Non-cost attributes

An analysis of the non-cost attributes for each option has been completed using the multi-criteria analysis method. The attributes are selected considering major risks and priorities to achieve Project Objectives. A weighting is allocated to each, totalling 100%. Each attribute is given a score out of 5 (from 1 – Fails to satisfy, to 5 – exceeds requirements); the score is then multiplied by the relevant weighting to give the weighted score that is summarised in the table below.

8.3.1 Evaluation Summary

	Project Objectives		Technical & System Risk		Stakeholder Risk			Env. Risk		Commercial
Criteria	Renewal\Asset Replacement	Commercial Efficiency	Interconnected Secondary Systems	Loss of Supply Event	Safety	Community Impact	Approvals	Vegetation Removal	Visual Amenity	NPV/C
Weighting (%)	15	15	15	15	10	5	5	5	5	10
Option 1a	0.15	0.3	0.15	0.15	0.2	0.1	0.25	0.25	0.25	0.5
Option 1b	0.3	0.3	0.15	0.15	0.2	0.1	0.25	0.25	0.25	0.4
Option 2	0.6	0.45	0.45	0.45	0.4	0.2	0.25	0.25	0.25	0.3
Option 3	0.75	0.3	0.45	0.45	0.4	0.2	0.25	0.25	0.25	0.2

Weighted Scores:

Option 1a: (Repair on failure)	2.40
Option 1b: (Upgrade on failure)	2.35
Option 2: (Targeted replacement)	3.55
Option 3: (Full replacement)	3.65

8.4 Preferred Option

The preferred option (Option 2) is the targeted replacement of the highest risk secondary systems of the DKTL. As part of this work, standard technologies will be applied and relevant substations upgraded to modern PWC design standards for the secondary systems.

This option best fulfils the project objectives of safety and reliability at the same time having minimum impact on system security whilst under construction. It also presents an acceptable level of safety risks during construction.

The design of the secondary systems will be to the existing PWC Substation Standards. This will maximise constructability and reduce design cost risk.

Asset renewal will be achieved through the replacement of existing unsupported outdated assets to current OEM supported models. This in turn will increase commercial efficiency, as the number of unplanned outages and maintenance costs are reduced.

Replacing the outdated and unsupported systems with new up-to-date systems improves secondary systems reliability, enhances site remote monitoring and control capability, and reduces the risk and duration of unplanned outages. The systems upgrade is expected to reduce maintenance cost due to a reduced rate of equipment failure. Consequently, there will be a significant reduction in the number and duration of unplanned outages.

The enhanced system and equipment information can also be utilised to improve equipment monitoring and reduce testing time on site.

8.5 Other Considerations

The DKTL is considered to have an enduring need to maintain the electricity supply to customers and maintain connection to generation in the area, as nominated in the Network Management Plan (NMP) as it is updated from time to time.

The secondary systems Asset Management Plan (AMP) identifies the issues associated with technical obsolescence, lack of spares and failure history of these assets as a priority for treatment in the next RCP.

9 PROJECT OUTLINE

9.1 Project Description

The project encompasses eight components as discussed in detail below.

9.1.1 Scope Inclusions

The following items/works are included in the scope of this project:

- New active synchronisation system at Pine Creek and Katherine ZSSs;
- Grid/Island detection upgrade at Pine Creek Power Station, using the existing power control system;
- New AVR relays at Manton, Batchelor, Pine Creek and Katherine ZSSs;
- New transformer protection relays at Pine Creek and Katherine ZSSs;

- New line protection relays (including ARC) at Channel Island, Manton, Pine Creek and Katherine ZSSs;
- New circuit breaker management relays at Manton, Pine Creek and Katherine ZSSs;
- New redundant RTU at Manton and Pine Creek ZSSs;
- New substation LANs at Channel Island, Manton, Batchelor, Pine Creek and Katherine.
- In addition, associated secondary and SCADA works such as Master Station changes at System Control are included in this project.

9.1.2 Scope Exclusions

Limits of the project should be considered as the minimum work on existing equipment at the relevant sites to achieve the project requirements (as noted above in scope inclusions). Maintenance on existing primary and secondary systems will only be scheduled if it does not affect the project adversely.

9.1.3 Assumptions

The secondary systems associated with the Darwin – Katherine transmission line are complex, and due to the age of the assets, highly sensitive. In developing this project, it has been assumed that no further major upgrades of interconnected equipment are required in order to obtain a functioning system, as per the scope inclusions.

The protection and SCADA equipment are standardised to minimise cost of maintenance and spares. This equipment is sourced through period contracts that are created from competitive tenders. This will ensure that project costs will be minimised.

9.1.4 Dependencies

No project dependencies exist, however construction will be restricted within system availability, particularly being subject to electricity demand and inclement weather. In addition, scheduling/order of works may produce efficiencies such as reduced outage windows.

9.1.5 Key Stakeholders

Name	Title / Business Unit
Internal – Governance Stakeholders	Chief Executive
	Investment Review Committee
	Executive General Manager Power Networks
	Chief Engineer
	Group Manager Service Delivery
Internal – Design Stakeholders	Senior Manager Networks Development and Planning

	Manager Southern Region
	Manager Major Projects
	Senior Manager Network Assets
	Manager Protection
External – Authorities	EDL
External - Other	Local Residents
	Ministers
	Utilities Commission
	Australian Energy Regulator

9.2 Capital Cost

A risk adjusted cost estimate (RACE) was conducted on the preferred option based on latest design, scope and cost information.

Based on the analysis, the project has a 90% likelihood of being delivered between [redacted]. The contingency attributable to risk is calculated as $P_{95} - P_{50}$ =\$0.36M. The calculated P_{50} risk-adjusted cost is the estimated cost of the project.

[redacted]

9.2.1 *Base Capital Cost*

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]
[redacted]	[redacted]

Table 1 – Base Capital Cost Estimate

9.2.2 Risk and Contingency

The current estimate has been developed largely based on PWC estimates considering previous experience with similar works and existing period contract for the supply of protection relays and other equipment. The contingency amount, calculated as the P95 value minus the expected P50 value, is currently $0.36M.

The base cost, P50 and P95 values will be revised at the next gateway (Business Case) after preliminary designs have been completed. This will provide for a more accurate cost estimate for the project.

9.3 Estimated Operating Cost Impact

The ongoing operating cost after the system upgrades is expected to reduce. The preventative and planned maintenance will continue as per existing schedule. However, there is expected to be a marginal decrease in cost due to the need for less unplanned maintenance and better reliability due to newer technology.

Item		Annual Incremental Cost $
Maintenance		
	Protection System	$30,260
	Control and Communication System	$30,000
TOTAL		$60,260

Table 2 – Estimated Operating Cost Impact

9.4 Project Milestones

Project Phase (end)	Investment Planning	Project Development	Commitment	Implementa-tion	Review
Original Plan (BNI)	Feb 2016	Jun 2016	Oct 2016	May 2019	June 2019
Current Forecast	Feb 2016	Jan 2019	Oct 2019	Jun 2021	Sep2021
Actual Completion	Feb 2016	-	-	-	-

10 RISK MANAGEMENT AND COMPLIANCE

Project risks have been developed into the PWC Project Risk Register and will be managed by the Project Manager. Refer to Appendix B for the project risk register.

10.1 Legal Issues

There are no expected legal issues regarding this project.

10.2 Stakeholder and Approval Issues

There are no expected stakeholder and approval issues regarding this project.

10.3 Environment and Sustainability Issues

All replacement or upgrade work will take place entirely within PWC owned zone substations. Decommissioned assets, such as protection relays, will be disposed of appropriately in accordance with good environmental practice.

10.4 Technical and System Issues

Due to the existence of a single transmission line only, the line is a critical interconnection between Darwin, Manton, Batchelor, Pine Creek and Katherine. As such, the existing secondary systems are intricately interconnected. The age of the assets also makes the system highly sensitive to accidental disturbances and thereby all risks must be identified and mitigated to ensure no accidental/unplanned outages result.

All required planned outages on the Darwin-Katherine transmission line will be communicated with System Control as soon as possible for scheduling.

All construction work on the secondary system will occur inside an energised zone substation. In some cases, work will be adjacent to live cables within the same cabinet/cubicle. PWC has policies and procedures that must be adhered to such as the Access to Apparatus Rules. Additionally, all design and commissioning risks are to be identified in the project risk register and eliminated or mitigated to as low as reasonably possible.

11 PROJECT IMPLEMENTATION

11.1.1 Resourcing Requirements (to next gateway)

Resource Type/Role	How Many?	Internal/ External?	Anticipated Start Date	Duration Required	Allocation (% time or # hrs/days/ wks/mths)
Network Development and Planning, Planning Engineer	1	Internal	Jun 2017	Until project completion	As required for development of governance documents and project support
Project Manager	1	Internal	Jul 2019	Until project completion	4 weeks

Design consultant	2	External	Jul 2019	Until preliminary design and investigation completed	8 weeks

12 FINANCIAL IMPACT

12.1 Funding Arrangements

This project is currently included in the 2017/18 SCI budget for a total approved sum of [redacted], with project scheduled for commencement in the 2018/19 period. It will be rescheduled to start in the next regulatory period starting 2019/20. The reason for the deferral is due to other projects such as the Hudson Creek 132kV third diameter and the Channel Island to Hudson Creek line protection upgrade given a higher priority.

The current project cost estimate is [redacted], which is a direct result of an increase in scope of works and better understanding of the requirements since the development of the Business Needs Identification (BNI). The scope of works has increased to incorporate substation LAN in Channel Island, Manton, Pine Creek and Katherine Zone Substation.

12.2 Capital Expenditure

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]		[redacted]
[redacted]			[redacted]	[redacted]		[redacted]

12.2.1 Variance Coverage

There is no variance in costs between the forecast and SCI.

12.3 Incremental Operating Expenditure

An operating expenditure of approximately $60,260 per annum is expected for the maintenance of the protection and SCADA systems. Upon completion of the project, the operation cost of the secondary systems will be included in the operational budget and forecasted in regulatory processes.

APPENDIX A

Summary of Financial Analysis

Introduction

The purpose of this Appendix is to provide details of the options analysis for Secondary systems upgrade of 132kV DKTL substations.

Table A1 below outlines the estimated capital expenditure for all the options. The operational cost of option 2 and 3 is less due to the newer fleet of equipment. This is reflected in the operational cash flows below.

Table A1 – Estimated Capital & Operating Expenditure

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Assumptions

In modelling the options, technical, economic and cost parameters were included. The technical and cost data was provided by Power Networks and the economic data was sourced from Pricing and Economic Analysis (PEA). Base cost capital expenditure was based on the consultant's feasibility study.

In the assumptions, all costs exclude GST or other government charges.

The common variables employed in the Discounted Cash Flow (DCF) model are presented in Table A2 below.

These variables are consistent with the 2019-24 Regulatory Proposal to the AER and are considered appropriate for use in the detailed commercial analysis.

Table A2 – Common Variables

Variables	
Nominal Pre-Tax WACC	6.96%
CPI – 2017/18	2.42%
CPI after 2017/18	2.42%
Time Horizon of Project	25 years

Option 1a – Deferral – Repair on failure

The analysis for this option does not require any capital expenditure. It assumes that the existing average operational costs of $179,000 per annum will continue into the future. However, it is likely to increase significantly as the frequency of failure will increase.

Option 1b – Deferral – Replace on failure

The analysis for this option assumed that the upgrade works is spread over a 5 year period as the relays fail over time. [redacted]

Option 2 – Targeted replacement

[redacted]

Option 3 – Full replacement

[redacted]

Least cost analysis

Based on the DCF analysis undertaken, the least cost option is Option 1a. However, this option is not technically feasible as the relays are not manufactured and cannot be sourced. The next lowest NPC is Option 2. This is summarised in Table A3 below.

Table A3 – Net Present Cost of Options

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Tariff cover

This project capex (2019/20 and 20120/21 expenditure) will be submitted as part of the 2019 Regulatory Proposal to the AER. The AER’s Final Determination will provide the approved level of net capital expenditure for the 2019-24 period. In so far as the Regulated Networks annual capital expenditure program remains at this level (or lower), Networks will earn a guaranteed rate of return through standard control service charges until the commencement of the next regulatory control period in 2024-25.

APPENDIX B

Project Risk Register

Refer:

PRD32117 Darwin - Secondary systems upgrade of 132kV substations at Manton, Pine Creek and Katherine Project Risk Register

PWC Ref: D2017/8829

APPENDIX C

Project Program Summary

Task	*Baseline*			*2019*				*2020*				*2021*			
	Plan Start	*Plan Duration*	*Percent Complete*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*
Options Study	Mar 17	8 wks	100%												
Concept Design	Mar 17	8 wks	50%												
Planning and Permits	Mar 19	20 wks	50%												
Major Electrical Plant Procurement															
Protection Relays	Oct 19	20 wks													
SCADA & Comms Equipment	Oct 19	20 wks													
Protection Panels	Jan 20	20 wks													
Detailed Design															
Electrical	Oct 19	12 wks													
Electrical Installation															
Synchroniation (Pine Creek)	Apr 20	4 wks													
Grid Island Detect (Pine Creek)	May 20	4 wks													
Transformer AVR Upgrade	Jun 20	8 wks													

Task	*Forecast*			*2019*				*2020*				*2021*			
	Plan Start	*Plan Duration*	*Percent Complete*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*
Line Protection Upgrade	Jun 20	8 wks													
Circuit Breaker Management Protection Upgrade	Jul 20	4 wks													
Testing and Commissioning	Oct 20	12 wks													
Cutover to new systems	Apr 21	4 wks													

APPENDIX D

CONDITION ASSESSMENT REPORT