SUBSTATION MANAGEMENT SYSTEMS

BUSINESS CASE

Transpower New Zealand Limited

May 2014

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

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1 Executive Summary

In 1990 Transpower embarked on a modernisation project to implement a new North Island Control Centre, a National SCADA system, RTUs at all substations, and a nationwide serial network to provide communications. This represented a major strategic step change in the way we managed the National Grid. Substations were de-manned and we switched to centralised computer control.

Need

Almost 20 years later the prevalence of these older RTUs has numerous day-to-day and longer term implications for delivery of a robust and reliable transmission service. Over 30% of the deployed RTUs no longer have the capacity to transfer the increasing volume of data required from today's substations (e.g. time-tagged data for Protection flaggings) and over 25% are obsolete and no longer supported by the manufacturer. These functional limitations are impeding both existing and desired business functionality. In addition, over 60% of the existing fleet of RTUs are also approaching their end of life.

The current functionality associated with the existing RTU fleet presents a significant safety issue for local operations with inconsistent and poor situational awareness during local field operations. There is the potential for reduced network reliability and availability due to obsolescence of the existing RTU's.

This document outlines the initial options considered to replace the existing RTUs and address our future substation telemetry requirements. It describes how we reduced the initial options to a short list of two viable options and then how we have identified our preferred option using cost-benefit analysis.

Initial Options

The list of initial options considered is as follows:

1. Option 1: RTU Replacement Only (no additional Functionality)
2. Option 2: RTU & I/O Peripheral Replacement with additional Functionality
3. Option 3: SMS Deployment

Viable Options

The initial three options were reduced to two **viable options** where further cost benefit analysis was undertaken. The two viable options are as follows:

- Option 2: RTU & I/O Peripheral Replacement with additional Functionality
  This option replaces the existing RTUs and its I/O peripheral modules with modern equivalents (like for like replacement) and also includes additional functionality like installation of substation LAN networks, HMIs and migrates existing third party data exchanges to National SCADA's ICCP service. The additional functionality enables a portion of current technology to be utilised i.e. allows modern Ethernet-based IEDs to be connected on to the substation LAN, but it will not easily allow for implementation of remote engineering access or substation automation.

- Option 3: SMS Deployment
  This option replaces the existing RTUs with a SMS deployment that allows for implementation of advance remote engineering access, situational awareness at adjacent sites, improved resilience and tolerance to faults on grid management and control systems, etc. This option will modernise our existing telemetry system to the latest technology and also enables implementation of future technology like substation automation.

Recommendation

The results of the cost benefit analysis are summarised in the table below:

Table 1 - Summary of Costs and Benefits of Selected Options

Option	Net Present Capital Costs ($m) [A]	Net Present Benefits ($m) [B]	Net Benefit($m) [B] – [A]	Net Benefit relative to Option 2
RTU & I/O peripheral replacement with additional functionality	46.5	1.7	-44.7	0.0
SMS deployment	55.8	17.0	-38.8	5.9

The cost benefit analysis shows that Option 3 has a higher net benefit. There are significantly higher benefits associated with a full SMS deployment.

In addition to the quantified benefits included in the cost benefit analysis, Option 3 has further benefits over Option 2 which we have not quantified:

- Improved timeliness and quality of asset condition information
- Increased SCADA and control system availability
- Improved situational awareness through adjacent site visibility
- Reduced commissioning costs and risks through the use of REA to provide support during commissioning of new equipment
- Ability to effectively manage parts of the National Grid via the HMIs during emergencies
- Enhanced asset information to enable improved utilisation of primary assets

In addition, Option 3 provides readiness for substation automation and further developments should such developments prove economic to implement.

Option 3 is therefore our preferred option.

Delivery and Programme Management

From experience gained in RCP1, a SMS project team that includes a Programme Manager, Project Director, Technical Expert, Project Administrator and at least 3 Project Managers will be set in place to ensure the timely delivery of the SMS deployment programme in RCP2.

SCADA facing RTUs are RTUs which connect the substation to National SCADA (some sites may have more than one SCADA facing RTU). The majority of configuration work in a SMS deployment at a site is the migration of information from the existing SCADA facing RTUs to the SMS gateway. They represent a large proportion of work required at each site and will provide an indication of resources required to deliver the work.

In RCP1, we are averaging approximately 15 SCADA facing RTUs migrated per year across 2012/13, 2013/14 and 2014/15. In RCP2, there are 73 SCADA facing RTUs to be configured and replaced across 57 sites. This averages to approximately 14 SCADA facing RTUs migrated (or approximately 11 sites commissioned) per year in RCP2. With our experience and resources in RCP1, we can deliver an average of 14 SCADA facing RTUs in a year.

The annual volumes of work (14 SCADA facing RTUs migrated per year) proposed for RCP2 are consistent with those being delivered (to date) in RCP1. On this basis we are confident that the proposed RCP2 volumes are deliverable.

2 Background

In 1990, we embarked on a modernisation project to automate Transpower substations, de-manning sites. This initiative required the implementation of a new North island control centre, a National SCADA[1] system, the installation of Remote Terminal Units (RTUs) at all substations, and the rollout of a nationwide serial network to provide communications. Prior to this all Grid management and control was performed by onsite station operators receiving instructions by telephone from Control Centres in the North and South Islands. As a result of the modernisation project the operator workforce was reduced to a smaller group of 'roving' operators and with the introduction of centralised remote control we established the ability to manage our assets in 'real time'.

2.1 Problem Definition/Needs Case

A significant number of RTUs have functional and capacity limitations that are impeding both existing and desired business functionality. For example, over 30% of the deployed units no longer have the capacity to transfer the increasing volume of data required by today's substations, such as time-tagged data for protection flaggings. Over 25% of the existing fleet are obsolete and are no longer fully supported by the manufacturer. The prevalence of these older technologies has numerous implications for both day-to-day operations and our ability to deliver the robust and reliable transmission service for our customers defined in our Asset Management Strategy and objectives. In addition, over 60% of the existing fleet of RTUs are approaching their end of life, requiring replacement.

As set out in Transmission Tomorrow (and elsewhere) we are increasingly aiming to utilise innovative technologies and solutions where these provide value to electricity consumers. This includes initiatives on variable line ratings; special protection schemes; dynamic reactive power equipment (e.g. STATCOM, FACTS); demand side load control & forecasting; visualisation and situational awareness technologies; intelligent monitoring and pre-emptive control technologies such as "self-healing" networks and Grid intelligence that can be achieved through substation management systems. The effectiveness and viability of the initiatives (to greater and lesser extents) will depend on the capability and capacity of our telemetry systems. The existing fleet of RTUs will significantly constrain our ability to achieve these initiatives.

In replacing the obsolete RTUs we need to account for the functionality that will be required to support future network innovations. Although we do not know exactly what those will be, allowing for these future network innovations and new functionality is an important consideration in our analysis. In many respects the current situation resembles that of the early 1990s as the business once again faces a technological step change in the way substations are managed.

The options for replacing existing RTUs that we considered were assessed against the issues and risks set out in the following sections (A to H).

A. Ageing RTUS

The majority of the existing fleet of RTUs are reaching the end of their useful lives e.g. over 60% of the existing RTUs are over 10 years of old. Their ages are such that they are very

[1] SCADA – Supervisory Control and Data Acquisition. Provides supervisory control of remote stations as well as data acquisition from those stations over a bidirectional communications link.

limited in terms of processing capability for modern applications. The majority of the input/output (I/O) peripheral modules are also reaching end of life, they are currently replaced on failure. This leads to the following issues and risks.

- Risk of increased device failure rates;
- Over 30% of the existing devices are incapable of leveraging Ethernet-based technology used in our IP enabled TransGo network;
- Operational maintenance costs of the units are steadily increasing e.g. we are currently experiencing one RTU failure per month; we were experiencing one RTU failure every 2 months only 2 to 3 years ago; and
- Device outages are resulting in prolonged losses of functionality with potential for complete loss of visibility and control of sites.

There is an increasing lack of manufacturer support for over 25% of RTUs currently deployed. This has made it difficult to source spare parts, additional units and peripherals and has also led to an increased rate of failures in RTUs during repairs.

This means an inability to meet business expectations in terms of reliability, restoration times, and the ability to integrate new devices.

B. Limited RTU & Communications Capability

The existing RTU population coupled with low speed serial communication links are heavily constraining more modern devices in our substations e.g. over 30% of the existing fleet of RTUs do not have Ethernet capability, requiring the use of low speed serial links. This prevents the use of fast and reliable communications between modern protection relays (or IEDs – Intelligent Electronic Devices) like GOOSE messaging[2]. The following issues are being encountered:

- Existing RTUs are lacking Central Processing Unit (CPU) and memory capacities.
- Repeated loss or non-delivery of the Sequence of Events (SOE) data that is required for power system incident investigation and resolution.
- Very limited ability to extract new/additional telemetry from substations.
- No capability or capacity to appropriately utilise station condition monitoring devices.

These issues have led to the following risks:

- The loss of records, or excessive latency in information retrieval, leads to delays in restoring supply and/or security following a tripping incident.
- As new additional devices are commissioned bringing back even basic data is becoming problematic, this will be exacerbated by larger datasets for PI Historian[3].
- The inability to communicate with asset condition monitoring devices undermines our ability to measure asset performance in a timely manner or in real time.

[2] GOOSE – Generic Object Oriented Substation Events. This is a communications protocol defined in IEC 61850 for the purpose of distributing event data quickly and reliably over entire substation networks.

[3] PI Historian is a SCADA database application that provides historical storage and analysis of time-based process data. Historian software is used to record trends and historical information of substation operations and events for future reference. It captures plant management information about status, performance, and condition with data capture, data compression, and data presentation capabilities

C. Reduced Resilience to Faults and Failures

The lack of redundancy of our existing RTUs has led to a lack of tolerance and resilience to faults and failures in substations. The age of our existing RTUs will only lead to a higher rate of failure of RTUs and I/O peripheral modules. The issues are as follows:

- The loss (whether planned or unplanned) of any existing RTU, I/O peripheral, or other critical device will result in a loss of visibility and control of the primary assets at National SCADA.
- The Electricity Industry Participation Code require specific telemetry to be made available to the System Operator by back-up means should the RTU system be unavailable.

These issues have led to the following risks:

- The loss of an RTU at any substation results in a partial or complete loss of visibility and control. As a result, RTU outages are at times difficult to obtain. In some cases, sites have to be manned for prolonged RTU outages.
- The availability of resources to provide this manning is limited given the current level of contractor workload.
- Any configuration changes to the existing RTU result in an outage for the time it takes to implement new settings.

D. Limited Situational Awareness

The present technology and design of Transpower substations means that local mimic facilities are inconsistent and often hard to maintain. The service providers at a site therefore only have limited and often disparate[4] systems and methods for obtaining situational awareness of the operational status of the assets and the power system. The information they use is typically obtained by visually checking individual panels, direct observation in the switchyard or by talking directly to regional operators. There are currently very few sites with systems for providing local SCADA functionality.

Having limited situational awareness has led to the following risks:

- The absence of local visibility and control poses a risk to both the safety of onsite staff and to security of supply. Near miss events have arisen as a result i.e. personnel working on a site may inadvertently work on the incorrect switchgear or relay panel due to a lack of situational awareness for that particular site.
- Safety and security of supply risks arise due to lack of awareness of the status of electrically adjacent sites as events at one site can have direct and indirect consequences at one or more adjoining substations.

These risks are inconsistent with the Transpower stated Grid Asset Management Policy to strive "*for zero harm to employees and members of the public*" and also to provide "*an enduring, reliable and efficient transmission network to meet New Zealand's present and future needs.*"

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[4] There are different ways of displaying situational awareness across all our substations. For substations with HMIs there are up to 4 different systems e.g. Realflex, Survalent, Coopers and Data Display Panels. For other sites, there are mimic panels that are sometimes not maintained and for the rest of the sites the indications and control for switchgear are located on multiple protection panels in the relay room.

E. Lack of Remote Engineering Access

Remote engineering access (REA) is not available to provide operation support or maintenance of devices in substations. The issues associated with this are as follows:

- All work must be conducted onsite, even for the simplest of tasks. For example, a remote systems engineer is required to be on site to configure the RTU for any changes on site like a protection relay replacement, commissioning or decommissioning of equipment, etc.
- Immediate support for system incidents cannot be provided to assist rapid diagnosis of underlying causes. For example in the event of a tripping, being able to look at the protection flags and events data[5] would provide information as to whether the fault is transient or permanent. In some circumstances, this would have allowed quicker decision making on whether it is safe to restore supply.
- A similar issue applies for our customers (i.e. Lines Companies) who require access to event data from our feeder protection relays for feeder faults. Essentially, there is also a cost associated to our customers who will either have to send a technician to site or request for us to send a technician to site.

These issues lead to the following risks:

- The need to go to site results in both primary delays (time lost while waiting for the task to be completed) and secondary delays (time lost on other tasks as a result of resource diversion).
- Aside from the time-based impacts there are also direct cost implications e.g. average of $1,000 per visit for maintenance contractors to download data from IEDs or $1,500 for a Remote Systems Engineer to do configuration work on site, arising from the direct costs associated with the site visit itself.

F. No Automatic Extraction of Data from Substations following fault events

Current RTUs have no mechanism for the automatic extraction of event related data from substation devices. The issues with this problem are as follows:

- It is generally necessary to arrange for protection maintenance contractors to visit sites following a power system event and manually download data from relays at an average cost of $1,000 per visit.
- Intelligent Electronic Devices (IEDs) have limited local storage, so initial fault information may already be lost (as a result of overwriting) by the time a contractor arrives on site to attempt a manual download of the records.
- Rather than splitting off the data and sending it to PI Historian directly from the substation data has to be sent through National SCADA. This undermines the latter's role as an operational tool.

These issues have led to the following impacts:

- Investigation of power system events relies on interpretation of protection system operations. This requires the capture, storage and evaluation of data from protection

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[5] Currently, we do have a limited number of protection flags being brought back as alarms via National SCADA. However, event data being captured in protection relays are not being brought back and requires a technician to download this from site.

relays. If this data is not retrieved or is only partially retrieved then such investigations cannot be efficiently undertaken.

- The root causes of particular events causing a tripping or loss of supply may remain unclear and cannot be resolved i.e. having timely data to identify the root cause of events could lead to a setting or design change which can prevent a repeat of the same event that could have led to a loss of supply or a decrease in reliability of the Grid.
- There are increased SCADA licences and support costs to cater for the data intended for PI Historian.

G. Lack of Capability to Enable Substation Automation

The use of existing RTUs prevents the adoption of future technologies such as IEC61850[6]. This will lead to difficulty in adopting new technology such as Non-Conventional Instrument Transformers (NCIT's) including optical current transformers, merging units and special protection schemes and interlocking schemes using software that could lead to significant savings in time and costs. The impact of this issue is as follows:

- The current SCADA modelling[7] process is labour intensive. For example, it takes 8 hours to implement a single IED in the current environment and the modelling team currently produces hundreds of such configurations per annum. The use of IEC 61850 provides a form of 'plug and play' functionality which could reduce this time to as little as 10 minutes per configuration.
- Our current site implementations are heavily dependent on copper-based cabling between IEDs and switchyard equipment, RTUs and between the IEDs themselves. This results in an inefficient and highly complex 'mesh' of cabling that is difficult and costly[8] to implement, maintain and document. The use of IEC 61850 allows all of these communications to be abstracted on to a simple IP-based network topology which will result in installing significantly less copper cabling (fibre cabling is cheaper).
- IEC 61850 is the basis of all current and emerging technology and operational innovations. This is increasingly being adopted by Australian utilities. Features such as interlocking, substation automation, device management and configuration are all converging on IEC 61850 as the 'default' industry standard. The inability to appropriately leverage this standard will impede our ability to adopt these innovative approaches.

H. Limited Ability to Manage RTU Fleet

The use of existing RTUs will limit the ability to reliably and efficiently manage the RTU fleet. The issues with this are as follows:

- All existing configuration and settings data for substation devices must be managed through an unwieldy set of (4,000) Excel spread sheets and binary configuration files.

The impact of these issues are as follows:

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[6] IEC61850 is a substation automation standard that specifies a defined data model, a standard naming convention and an engineering process that integrates prescribed format input files into a design. It will standardise communications between devices inside a substation via network connections. This will enable time and cost savings by avoiding the current manual design, allowing ease of configuration and using less secondary copper cabling.

[7] SCADA modelling is the process of mapping control, digital or analogue indications from any new IEDs or newly commissioned/decommissioned primary plant to National SCADA.

[8] For a greenfield site, having fibre instead of copper cabling can save between $3,000 to $40,000 per bay, depending on the size of the site.

- In the absence of a robust tool for the centralised management of substation devices, a number of bespoke applications have been developed to store configuration metadata, facilitate workflow, provide configuration file management and consistency checking. These applications must now be continuously maintained and extended as requirements evolve.
- The configuration and management of devices is time consuming and as a result costly, as is the management of the resulting documentation (around 4000 spreadsheets).
- Device maintenance is currently a risk-prone undertaking as the maintenance of existing RTUs can often lead to a failure of the RTU (increase rate so failures after repair). This is increasingly failing to deliver the service levels that are needed to meet business demands.

3 Options Analysis

3.1 Assumptions

The ‘do nothing’ option has not been considered in detail as it is not deemed viable. In this case, ‘do nothing’ would leave RTUs until they fail and then over time, substations would be re-manned. The cost of re-manning would be prohibitive and is inconsistent with our safety approach, hence is unacceptable.

3.2 Options Considered

Option 1: RTU Replacement Only (No additional Functionality)

This option would see the existing RTUs replaced with modern equivalent RTUs (like for like replacement) to provide the same functionality they provide now, but make no further changes. This option provides no functionality as it will essentially be a like for like replacement of the RTUs without replacing the I/O peripheral modules. This option also does not include any additional functionality such as Local Area Networks[9] (LAN), Human Machine Interfaces (HMIs) or allow for REA. The scope of this work at an Internet Protocol or IP-enabled substation is to:

- Maintain serial connection to an IP-based Wide Area Network (WAN) connection;
- Implement new RTU (excluding legacy IO modules - replace these if/when they fail);
- Make necessary National SCADA changes.

This is a solution that would need to be reworked if other capabilities are required in the future i.e. serial connections would need to be upgraded to Ethernet connections to LAN networks.

This option will only partially resolve the issues and risks defined in Chapter 2.1, it only addresses the need to replace RTUs that are ageing, or which have reduced manufacturer support and have limited communications capability. This option provides limited operational, maintenance or strategic benefits for Transpower or its customers.

Option 2: RTU & I/O Peripheral Replacement with additional Functionality

This option would see the replacement of existing RTUs and I/O peripheral modules with modern equivalents (like for like replacement) and also enables additional RTU functionality over the existing RTUs including the installation of substation LAN networks, installation of local HMIs and migrates existing third party (i.e. lines companies or generators) data exchanges to National SCADA’s Inter-Control Centre Communications Protocol (ICCP) service. The additional functionality enables a portion of current technology to be utilised i.e. having a substation LAN will allow modern IEDs (Ethernet based devices) to be connected via a LAN network allowing for more efficient transfer of data with less copper cabling installed in the control room.

The scope of this work at an IP-enabled substation is to:

- Install equipment to provide a secure IP-based WAN connection;
- Implement LAN1/LAN2 substation networks;

[9] Modern IEDs are all Ethernet-based and will need to be connected to each other via a LAN network.

- Review substation data to ensure policy and standards compliance;
- Implement Distributed Network Protocol over IP (DNP3i protocol) within substation;
- Implement new RTU including legacy IO Module replacements;
- Implement new HMI; and
- Make necessary National SCADA changes.

This particular upgrade has already been undertaken at a number of sites as an emergency short term measure when it became obvious that replacement of the existing RTU was necessary.

This option will resolve most of the immediate essential issues and risks defined in Chapter 2.1. However, it will not improve on the RTUs lack of tolerance and resilience of faults and failures in substations, there is no REA capability, it will not enable substation automation and it will not improve our ability to reliably and efficiently manage the RTU fleet.

Option 3: Full Substation Management System (SMS) Deployment

The deployment of a fully-fledged SMS system would deliver the highest level of functionality of all of the options, delivering the scope of Option 2 while also adding additional value in the form of fully integrated and advance REA solution, centralised configuration and management, automated functionality and reporting, data segregation at source to reduce SCADA point consumption, adjacent substation situational awareness and control, and the efficient integration of enhanced functionality (e.g. Phasor Measurement devices, Asset Condition Monitoring appliances, Distributed Temperature Sensing monitors etc.).

3.3 Analysis of Options

The table below provides an indication of the range of costs per substation of Options 1 to 3, depending upon the size of the substation. These costs were assessed using data obtained during previous substations upgrades and can be considered to be robust estimates.

Table 2 - Range of estimated costs for Options 1 to 3

Option	Cost
1 – RTU Replacement Only (No Additional Functionality)	$70,000 to $120,000
2 – RTU & I/O Peripheral Replacement with additional Functionality	$250,000 to $880,000
3 – SMS Deployment	$220,000 to $1,240,000

In order to evaluate the feasibility of the options, we have developed criteria based on the functionality each option will deliver. These functionalities address one or more of the issues/risks discussed in Chapter 2.1. Each functionality has been categorised as either:

- *Mandatory* – Those which must be addressed regardless of the option selected (e.g. the existing RTUs must be replaced with something before the onset of widespread failures).
- *Optional* – Those which provide enhanced functionality and would be worth investing in only if the extra benefits exceed the extra cost.

The functionalities are described below:

Table 3 – Mandatory and Optional Functionalities

Item		Issues & Risks	Type of Functionality	Description
I.	*RTU Replacement*	A B	*Mandatory*	Ageing RTUs must be replaced with a newer generation of device of some description. This new device can be generically termed the "Station Master". RTU Replacement (no added functionality) - This only covers the installation of a new Station Master and its commissioning. RTU & I/O Peripheral Replacement (with added functionality) - This covers the installation of a new Station Master and its commissioning, including installation of LAN1/LAN2 substation networks, data rationalisation and the replacement of I/O modules.
II.	*Localised Situational Awareness (HMI)*	D	*Mandatory*	The delivery of interactive situational awareness and control tools for the management of the substation. Having better situational awareness and control of equipment from the HMI (in the relay room) would enhance the safety of field personnel working on equipment in a substation. This functionality delivers a platform from which onsite engineers can achieve operational awareness of the operational status of the site including equipment status, recent events and active alarms. Selected equipment can be operated and/or isolated from the HMI. This can also allow for removal of existing mimic boards/control panels freeing up space in the relay room.
III.	*Data Standardisation*	G	*Mandatory*	Information sourced from substations will be standardised such that a common data set is gathered for every device of a given type, classified and named in a consistent manner. This will also enable the use of technology such as 61850, increasing efficiency in configuring RTUs and allow for better interpretation of alarms. This functionality ensures that all data-related aspects at a given site comply with the appropriate standards (e.g. TP.DC 29.04).
IV.	*Migration of Third Party Communications*	B G	*Mandatory*	All existing third party data exchanges are delivered using RTU-to-RTU connections. With the replacement of the RTU these connections should be migrated i.e. any existing RTU-based third party connections is to be migrated to National SCADA's ICCP (Inter-Control Centre Communications Protocol) service. This will allow us to provide data to our customers more efficiently i.e. quicker receipt of data allowing for faster restoration of faulted equipment.
V.	*Substation LAN1/LAN2 networks*	G	*Mandatory*	New devices are generally Ethernet-based and will need to be connected to each other and the Station Master via an Ethernet LAN. This is required to enable new technology to be implemented like 61850 which saves costs i.e. less copper cabling. This functionality implements Ethernet-based LAN1/LAN2 networks at a site and connects all devices over IP.
VI.	*Secure WAN Connection*	G	*Mandatory*	The delivery of Ethernet capability to the substation enables communications to be migrated from existing serial bearers onto high speed IP networks. This provides the infrastructure that is required to provide a secure and robust connection to the Transpower WAN for the purposes of carrying all substation network traffic. This also enables an IP connection from the Station Master to National SCADA.
VII.	*Secure REA Connection*	E F	*Mandatory*	Secure REA connection - The delivery of REA capability is to be secure and each site is required to be isolated from other sites i.e. someone accessing IEDs in substation X should not be able to access IEDs in substation Y, unless they pass the security requirements to access another substation.

Item		Issues & Risks	Type of Functionality	Description
VIII.	*Situational Awareness at Adjacent substation (HMI)*	D	*Optional*	This functionality builds on (II) that provides improved situational awareness and control for maintainer/switcher for local and nearby substations e.g. a circuit outage will not require personnel to be sent to the far end substation
IX.	*Basic REA*	E	*Optional*	The delivery of basic console-only connections to substation equipment from a remote location. This allows users logically located on Transpower's network to make remote connections to equipment located in substations. It provides an identical level of service to that available when onsite technicians connect to any given device using a laptop.
X.	*Advanced REA*	F	*Optional*	The delivery of advanced remote engineering functions to a substation from a remote location. This delivers the features of the basic service, but also allows for the automated extraction of event files, waveforms and disturbance records, delivery of automatic reporting, and support for centralised configuration and management.
XI.	*Fault Tolerance*	A C	*Optional*	Provides for resilient operation of all Grid Management and Control systems ensuring that the loss of a single component does not lead to a loss of visibility or control. The failure/outage of a RTU does not lead to a loss of visibility or control for the particular plant or site.
XII.	*Improved Data Management*	B C F H	*Optional*	Data from substations will be classified as operational or non-operational. Only operational data is sent to National SCADA, while all data is sent to PI Historian. This functionality helps to determine the appropriate segregation of data and implements the necessary infrastructure to support a data feed directly from the Station Master to PI Historian. The appropriate segregation data helps to reduce the burden of having all non-operational data from being sent to National SCADA, there is a cost associated to maintaining each point of data that is brought back to National SCADA.
XIII.	*Centralised Configuration Management*	F H	*Optional*	The configuration and ongoing management of electronic devices in substations can be centrally managed. This functionality integrates the substation with the centralised infrastructure such that management, inventory control, and configuration of substation devices can all be undertaken remotely.
XIV.	*Implementation of IEC61850*	G	*Optional*	Provides automated configuration functionality and other enhanced features to provide near "plug and play" management and integration of substation devices. This is a key enabler for future substation automation.
XV.	*Advanced Device Integration*	A B F G	*Optional*	Provides for the most cost effective integration of advanced substation devices such as Phasor Measurement Units, Asset Condition Monitoring appliances, Distributed Temperature Sensors, Power Quality Meters etc.
XVI.	*Effective Asset Management*	E F H	*Optional*	The ability to obtain condition monitoring data permits planned replacement of assets and planned periodic maintenance activities to be deferred until required. At the moment, age and results of periodic maintenance provides an indicator on when assets should be replaced.

The table below compares each of the three options, defined in Chapter 3.2, with the functionalities that they enable.

Table 4 – Mandatory & Optional Functionalities of each option

Functionality			Option 1 RTU Only	Option 2 RTU & I/O Peripherals	Option 3 SMS Deployment
I.	RTU Replacement	Mandatory	✓	✓	✓
II.	Localised Situational Awareness (HMI)	Mandatory	✘	✓	✓
III.	Data Standardisation	Mandatory	✘	✓	✓
IV.	Migration of Third Party Communications	Mandatory	✘	✓	✓
V.	Substation LAN1/LAN2 networks	Mandatory	✘	✓	✓
VI.	Secure WAN Connection	Mandatory	✓	✓	✓
VII.	Secure REA Connection	Mandatory	N/A	N/A	✓
VIII.	Situational Awareness at adjacent substation (HMI)	Optional	✘	✘	✓
IX.	Basic REA	Optional	N/A	N/A	✓
X.	Advanced REA	Optional	N/A	N/A	✓
XI.	Fault tolerance	Optional	✘	✘	✓
XII.	Improved Data Management	Optional	✘	✘	✓
XIII.	Centralised Configuration Management	Optional	✘	✘	✓
XIV.	Implementation of IEC 61850	Optional	✘	✘	✓
XV.	Advanced Device Integration	Optional	✘	✘	✓
XVI.	Effective Asset Management	Optional	✘	✘	✓

The table shows that only Options 2 and 3 deliver all of the mandatory functionalities. Therefore Option 1 is eliminated and not considered further.

In more detail, Option 1 is dismissed for the following reasons:

- Only addresses the need to replace RTUs that are ageing, have reduced manufacturer support and have limited communications capability.
- While this option replaces the existing RTUs with modern equivalents, it does not include the replacement of I/O peripheral modules which are also nearing end of life.
- This option does not meet all the mandatory functionalities required i.e. does not implement substation LAN1 and LAN2 networks, local HMIs, etc. Having better situational awareness and control of equipment from the HMI (in the relay room) would enhance the safety of field personnel working on equipment in a substation.
- This option does the “bare minimum” in maintaining the current level of technology and is an option that does not easily enable implementation of new technologies.
- Further enhancement of the substation telemetry systems would be required at a future time to implement other functionalities.
- Option 1 is not considered further.

3.4 Viable Options

The three options outlined in Chapter 3.2 can be reduced to two viable options:

- Option 2: RTU & I/O Peripheral Replacement with additional Functionality; and
- Option 3: SMS Deployment.

From the two viable options, we can see that there are two distinct paths for our telemetry systems.

Option 2 (RTU & I/O Peripheral Replacement with additional Functionality) is a solution that will continue the previous approach to managing our RTU telemetry assets by replacing RTUs that are ageing and no longer supported by the manufacturers with modern equivalent units. This will maintain the current level of technology as before without enabling technology advances like REA or substation automation. With this option, further investment will be required in the future to accommodate new functionality that will be required in the network.

Option 3 (SMS Deployment) will enable new technological advances to be incorporated in our telemetry systems, that allow for additional future functionality. This will allow for secure REA to be implemented that will unlock significant benefits in being able to return assets to service a lot quicker, allow for RTU configurations to be done remotely and enable us to implement future technology such as substation automation i.e. implement IEC61850 in Transpower substations.

The remainder of this document will focus on the two viable options, Option 2 (RTU & I/O Peripheral Replacement with additional Functionality) and Option 3 (SMS Deployment).

4 Cost Benefit Assessment

4.1 Baseline

In considering the relative cost benefit implications of the two viable options a number of key assumptions apply. The two main assumptions are that:

- costs have been determined through a volumetric building block approach based on average costs for each site. Typically small and medium sites will require one RTU/SMS each, while large sites will require two RTUs/SMSs each and very large sites will require two or more RTUs (only two SMSs required at very large sites); and
- relative benefits of the two viable options are determined by assessing impacts on current operating costs and the quantification of any additional gains.

Further assumptions are documented below.

4.1.1 Key Cost-Related Assumptions

The following assumptions are made in relation to the determination of costs:

1. That one-off establishment costs can be excluded from the determination of per-site costs[10];
2. That the projected SMS costs are based on a 'full' rather than reduced scope of delivery; and
3. That the cost of providing a secure connection to our WAN can be excluded from all calculations as it applies equally to all approaches and is funded elsewhere.

4.1.2 Key Benefit-Related Assumptions

The following assumptions are made in relation to the determination of benefits:

1. That the functionality, and therefore benefits, delivered by common work blocks is essentially identical regardless of the option;
2. That the determination of benefits can be based on a 'future state' scenario in which every substation is upgraded in accordance with the option under consideration.
3. That a per-site benefit can be determined on a simple pro rata basis by dividing the total annual benefit by the number of substation sites.
4. Generally, unquantified benefits have been excluded from the cost benefit analysis and may understate the advantages and benefits of the recommended option.

4.2 Option 2 - RTU & I/O Peripheral Replacement with additional Functionality

4.2.1 Costs

Costing is based on existing RTU replacements, substation LAN implementations, HMI deployments and the estimated cost of delivering a secure network connection to the site. The cost estimates are based on the size of the site as follows:

[10] This includes the costs for establishing any centralised management tools and related services that may apply to a particular option. Such costs are often borne by the first site but can then be subsequently leveraged at little or no charge by future deployments.

Table 5 – RTU Replacement costs for different size sites

Site size	Cost estimate per site (RTU installation)
Small	$249,300
Medium	$329,100
Large	$599,200
Very large	$875,500

A breakdown of the costs in Table 5 is provided in Appendix B.

The RTU Replacement option would be installed as per the programme indicated in the table below.

Table 6 – RTU Replacement Programme, RCP1 to RCP3

Year	Sites				
	Small	*Medium*	*Large*	*Very large*	*Total*
12/13[11]	7	3	0	0	10
13/14	7	1	0	0	8
14/15	12	6	1	0	19
RCP1 subtotal	**26**	**10**	**1**	**0**	**37**
15/16	7	6	0	0	13
16/17	3	3	4	1	11
17/18	2	3	4	1	10
18/19	2	2	4	2	10
19/20	3	3	5	2	13
RCP2 subtotal	**17**	**17**	**17**	**6**	**57**
20/21	3	13	7	2	25
21/22	10	9	1	1	21
22/23	9	7	19	1	27
RCP3 subtotal	**22**	**29**	**18**	**4**	**73**
TOTAL[12]	**65**	**56**	**36**	**10**	**167**

[11] This includes the two trial sites at Kaiapoi and Owhata implemented in 2011/12.

[12] The total figures exclude the effect of divestments.

The estimated cost of the RTU Replacement programme is provided below.

Table 7 – RTU Replacement Total Costs

Year	Sites	RTU	GPS Clocks, HMIs & DNP3i	Total
12/13	10	$2,983,100	-	$2,983,100
13/14	8	$4,516,200	$35,000	$4,551,200
14/15	19	$5,565,400	$48,000	$5,613,400
RCP1 subtotal	37	$13,064,700	$83,000	$13,147,700
15/16	13	$3,719,700	$80,200	$3,799,900
16/17	11	$5,007,500	$56,100	$5,063,600
17/18	10	$4,758,200	$64,100	$4,822,300
18/19	10	$5,304,600	$120,300	$5,424,900
19/20	13	$6,482,200	$72,200	$6,554,400
RCP2 subtotal	57	$25,272,200	$392,900	$25,665,100
20/21	25	$10,971,600	$80,200	$11,051,800
21/22	21	$6,929,600	$96,200	$7,025,800
22/23	27	$11,414,900	$128,300	$11,543,200
23/24	0	-	$112,300	$112,300
24/25	0	-	$112,300	$112,300
RCP3 subtotal	73	$29,316,100	$529,300	$29,845,400
Total	**167**	**$67,653,000**	**$1,005,200**	**$68,658,200**

4.2.2 Benefits

Benefits under this option relate to reduced maintenance costs realised through having a 'younger' telemetry system fleet and reduced diversity.

Table 8 - Benefits for RTU & I/O Peripheral Replacement Option

Benefit category	Description	Full RTU - benefits	Notes
Reduction in RTU Maintenance Costs	Present direct spend on preventive and corrective maintenance of existing RTU's is approximately $260,000 p.a. Assume a new fleet of RTUs requires only 3/4 of this cost to maintain due to reduced diversity and lowered age.	$65,000	Maintenance callouts will be reduced due to newer RTUs. (estimate a 25% reduction of maintenance costs).
Total	These are annual benefits following rollout to all sites. As project is completed, the benefits will be realised on a pro-rata basis. E.g. if the project is 20% complete, annual benefits will be 20% of this value.	$65,000	

There are also unquantified benefits for this option that is common for both Options 2 and 3 i.e. Improved Situational Awareness through Local Site Visibility. These unquantified benefits, common for both options, have not been included in the benefits assessment.

4.3 Option 3 - SMS Deployment

Under this option, RTUs will be replaced with an SMS in a staged manner under a closely controlled programme management approach in a defined programme timeframe over several years. The priority order that determines which RTUs are replaced is determined by when:

- The RTU and I/O peripheral modules at a site is technically obsolete or reaching end of life;
- The RTU reaches its reliability or capacity limit;
- functionality is limited at the site due to the existing RTU; and
- Aligning work at a site with other protection projects that will see the installation of new modern IEDs.

The SMS roll-out programme is a high priority for Transpower and as such will be closely managed using a “programme management” approach. Based on experience in RCP 1, potential substation projects have been prioritised in line with the principles described previously, detailed design and planning will be undertaken to ensure that the programme is deployed effectively, meeting high level objectives for cost control and project timing. Integration with existing refurbishment and other medium term replacement programmes and short term integration with existing operations and maintenance programmes will ensure a high level of programme effectiveness achieving maximised benefits in the shortest possible time-frames.

4.3.1 Costs

The per site cost estimates for the RCP1 period were based on actual detailed estimates because these sites are included in the present SMS project in execution phase. Cost estimates for RCP 2 are based on robust and up-to-date information where feasible, using experience gained in RCP 1 programmes. However, for the purposes of project justification, and given that many Transpower substations are based on similar overall design, cost estimates for RCP2 and beyond are based on volumetric cost estimates as follows:

Table 9 - SMS Costs for different size sites

Site size	Cost estimate per site (SMS installation)
Small	$220,200
Medium	$259,000
Large	$671,700
Very large	$1,242,400

A breakdown of the costs is provided in Appendix A.

The SMS Deployment option would be installed as per the programme indicated in the table below.

Table 10 - SMS rollout Programme, RCP1 to RCP3

Year	Sites				
	Small	*Medium*	*Large*	*Very large*	*Total*
12/13[13]	7	3	0	0	10
13/14	7	1	0	0	8
14/15	12	6	1	0	19
RCP1 subtotal	**26**	**10**	**1**	**0**	**37**
15/16	7	6	0	0	13
16/17	3	3	4	1	11
17/18	2	3	4	10	10
18/19	2	2	4	2	10
19/20	3	3	5	2	13
RCP2 subtotal	**17**	**17**	**17**	**6**	**57**
20/21	3	13	7	2	25
21/22	10	9	1	1	21
22/23	9	7	19	1	27
RCP3 subtotal	**22**	**29**	**18**	**4**	**73**
TOTAL[14]	**65**	**56**	**36**	**10**	**167**

Besides the supply and installation of a new SMS at each site, the costs below also include:

- Software needed to provide a centralised interface to the SMS;
- Software needed to enable remote access to IEDs (IMS);
- Retrofitting REA in SMS sites installed during RCP1 (without REA); and
- Replacement of GPS Clocks, installation of a full HMI system at critical sites and remaining DNP3i conversion works to be done in RCP2.

[13] This includes the two trial sites at Kaiapoi and Owhata implemented in 2011/12.

[14] The total figures exclude the effect of divestments.

The estimated total cost of the SMS rollout programme is provided below.

Table 11 - SMS Total Costs

Year	Sites	SMS	Centralised Interface Software	IMS	REA[15]	GPS Clocks, HMIs & DNP3i	Total
12/13	10	$2,983,100	-	-	-	-	$2,983,100
13/14	8	$4,516,200	-	-	-	$35,000	$4,551,200
14/15	19	$4,873,800	-	-	-	$48,000	$4,921,800
RCP1 subtotal	37	$12,373,100	-	-	-	$83,000	$12,456,100
15/16	13	$3,096,000	$750,000	$750,000	$1,059,100	$627,300	$6,282,400
16/17	11	$5,386,600	$250,000	$250,000	$1,610,300	$607,600	$8,104,500
17/18	10	$5,166,400	$250,000	$250,000	$1,156,400	$258,200	$7,081,000
18/19	10	$6,149,800	$250,000	$250,000	$756,400	$493,100	$7,899,300
19/20	13	$7,305,600	-	$250,000	$702,500	$266,400	$8,524,500
RCP2 subtotal	57	$27,104,400	$1,500,000	$1,750,000	$5,284,700	$2,252,600	$37,891,700
20/21	25	$11,249,400	$1,000,000	-	-	$139,800	$12,389,200
21/22	21	$6,452,900	-	-	-	$215,400	$6,668,300
22/23	27	$11,803,700	-	-	-	$307,000	$12,110,700
23/24	0	-	-	-	$302,600	$112,300	$414,900
24/25	0	-	-	-	$302,600	$112,300	$414,900
RCP3 subtotal	73	$29,506,000	$1,000,000	-	$605,200	$886,800	$31,998,000
Total	**167**	**$68,983,500**	**$2,500,000**	**$1,750,000**	**$5,889,900**	**$3,222,400**	**$82,345,800**

4.3.2 Benefits

A description of the benefits to be provided by SMS telemetry systems are detailed below:

- REA - the ability to interrogate substation IEDs without staff or contractors having to attend on-site. This helps to reduce expected unserved energy by having faster event analysis and reduced restoration times, better assessment of root causes and remedial actions with improved information availability;
- Reduction in telemetry installation and configuration costs. Configuration will be less time consuming compared to existing RTU telemetry systems;
- Reduced maintenance costs; and
- Reduced SCADA system loading resulting in improved availability of operational systems and lower SCADA licensing costs. Non-operational data will be split from operational data.

[15] This is for the 37 sites scheduled to be commissioned in RCP1 that have not had REA implemented.

Table 12 – Benefits of Full SMS Deployment Option

Benefit category	Description	Quantity	Rate	SMS annual benefits	Notes
Remote engineering access	Avoided system minutes @0.5 /annum (0.5 @ 6917MW-min @ $20k/MWh) resulting from faster event analysis and reduced restoration times[16]	0.5	$2,305,667	$1,152,800	Unplanned outage costs.
	Lower cost in REA based on $1,000 per site visit for Transpower & customers; 4 incidents per week. Presently, site visits are required to retrieve event data.	208	$1,000	$208,000	
	Lower cost in remote configuration & commissioning based on $1,500 per site visit; 7 configurations required per week.[17]	364	$1,500	$546,000	
Reduction in telemetry installation and configuration costs	Reduced project capital costs -$70k per site on hardwired IO on 2 large projects p.a.	2	$70,000	$140,000	Simplified design, IO nearer source, less wiring costs
	Reduced project delivery times: 2wks design, 2wks commissioning.	2	$16,800	$33,600	Efficiencies in simplified design
	Automatic configuration of SCADA and REA systems, saving 1 man-wk per project, conservatively 2 projects per month.	24	$3,400	$81,600	Template based designs
	Efficiency gains in reducing the time it takes to do a configuration for an IED from 8 hours to approximately 1 hour (with SMS); with an estimated 10 IEDs per week.	52	$5,950	$309,400	
Reduction in RTU Maintenance Costs	Present spend on preventive and corrective maintenance is around $260,000 p.a. Assume a new fleet of SMS requires only 3/4 of this cost for maintenance due to reduced diversity and lowered age.	0.25	260,000	$ 65,000	
Reduced SCADA system loading	Improved availability of operational systems through reduced CPU loadings and disk usage. With SMS, SCADA will no longer be the dumping ground for data used by engineers outside of the control centres. Instead the data will be diverted to a historian system freeing up SCADA (SCADA point license costs @$50k/annum).	1	50,000	$ 50,000	Saving in license costs for 10% growth per annum of SCADA database points.
Total	These are annual benefits following rollout to all sites. As project is completed, the benefits will be realised on a pro-rata basis. E.g. if the project is 20% complete, annual benefits will be 20% of this value.			**$ 2,586,400**	Benefit of having all sites converted to SMS. Annual benefits are pro-rated based on how many are done each year.

[16] For the last 10 years, there has been an average of 14 system minutes lost per year. REA functionality could help in reducing restoration time following an outage. Our assumption for this analysis is that REA would reduce system minutes lost per year by 0.5 system minute. By way of an example, in a recent event in 2013, STK T8 tripped unexpectedly via differential protection. Event data had to be requested from site to confirm if this was due to a sympathetic inrush tripping or if it was a more permanent fault. If REA had been available, we could have restored T8 in half the time. Approximately 0.3 system minutes were lost in this event, so 0.15 system minutes could have been saved in just one event. Savings of 0.5 system minute a year is a conservative estimate.

[17] A Remote Systems technician is required to configure the RTU on site in the event that settings are changed, equipment commissioned or decommissioned at any of our sites. In the 2011/12 year alone, there were just over 360 site visits by the System Modelling group to configure RTUs at various sites around the country. This has increased to over 400 site visits in the 2012/13 year.

4.4 Discussion of preferred option

Cost benefit analysis has been undertaken between the two viable options:

1. Option 2 – RTU & I/O Peripheral Replacement with additional Functionality; and
2. Option 3 - SMS Deployment.

The results of the cost benefit analysis is summarised in the table below:

Table 13 - Summary of Cost Benefit Analysis

Option #	Option name	Net Present Capital Costs ($m) [A]	Net Present Benefits ($m) [B]	Net Benefit ($m) [B] – [A]	Relative to Option 2
2	RTU & I/O Peripheral replacement with additional Functionality	46.5	1.7	-44.7	0.0
3	SMS deployment	55.8	17.0	-38.8	5.9

The cost benefit analysis indicates that Option 3 (SMS Deployment) has a higher net benefit compared to Option 2. Although the cost of Option 3 is higher than Option 2, Option 3 has significantly more benefits compared to Option 2.

The original submission had a net benefit of -$4.8m (SA Substation Management Systems (Telemetry System) Fleet Strategy). The net benefit above is $5.9m. The main reason for the difference is the addition of quantified benefits for Option 3 i.e. lower cost in remote configurations & commissioning with REA and significant reduction in the time it takes to do a configuration for an IED.

In addition to the quantified benefits included in the cost benefit analysis, Option 3 has further benefits over Option 2 which cannot be readily quantified:

1. Improved Asset Condition Information
   SMS will facilitate retrieval of asset condition information, which will allow faster fault identification, and savings through targeted maintenance rather than routine time base strategies. There is potential for fewer routine inspections of primary equipment through the use of on line condition monitoring and the potential for implementation of Condition-Based maintenance (CBM). This has the potential to extend the life of high value assets such as transformers, deferring capital expenditure.

2. Increased SCADA and Control System Availability
   The deployment of an SMS system with appropriate levels of design redundancy (in large and very large sites) ensures outages to primary assets will be minimised through both routine maintenance (of the SMS) and unexpected events (failure of a SMS module). There will also be reduction in required resources during site works which may otherwise be required if there was no redundancy.

3. Improved Situational Awareness Through Adjacent Site Visibility
   Being able to monitor adjacent sites using a local HMI provides maintainer/switchers critical information about the surrounding Grid, providing additional certainty that primary assets (i.e. transmission circuits, line side disconnectors) are safe to be

worked on during site works or maintenance. This is a critical function if the National SCADA system is not available.

4. Reduced Commissioning Costs and Risks
Devices being installed in substations are increasingly more complex and specialised. Field technicians do not have the capacity to be experts on all devices. REA will allow increased specialised support to field staff during commissioning of new equipment.

5. Ability to Effectively Manage Parts of the National Grid by 'Manning Sites' during emergencies.
In the event of an emergency (communications link to National SCADA is severed), the provision of a local HMI coupled with the ability to monitor and control adjacent sites provides a viable option for temporarily manning sites to manually control the local and adjacent sites.

6. Improved Utilisation of Primary Assets
Deferred capital expenditure may be possible through closer to the limit operation of primary assets; for example, deferring investment in a new GXP (Grid Exit Point) or deferring uprating a transformer through continuous monitoring by running it closer to the limit.

In addition, Option 3 provides readiness for substation automation and further developments. We will be in a better position to leverage both industry best practice and future technologies (e.g. smart grid, IEC61850) should such developments prove economic to implement.

Our preferred option is therefore the SMS deployment option (Option 3).

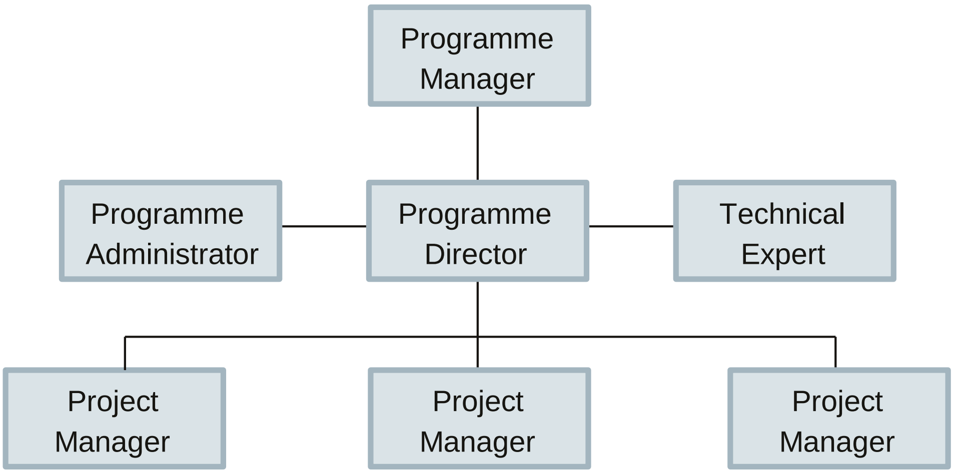
4.5 Deliverability

This chapter explains our approach to delivering the SMS work programme. It discusses the structure of the project team, progress to date, and our plans for delivering the programme during RCP2.

4.5.1 Project Team

Figure 1 below shows the structure of the project team delivering the SMS deployments in RCP2..

Figure 1 - Structure of the SMS Project Team



From experience gained in RCP1, this structure will be in place to ensure the timely delivery of the SMS deployment programme in RCP2.

The Programme Manager has overall programme oversight in RCP2 and is accountable for the delivery of the programme within time and budget. The Programme Manager reports to Transpower's Senior Management on progress of the overall programme.

The Programme Director will be responsible for day-to-day consistency and co-ordination of the site works and manage the Project Managers who are delivering SMS at specific sites. The Programme Director will be supported by a Technical Expert to resolve any technical issues during SMS implementation and a Programme Administrator will be available to help with project documentation and contract management of the various projects within the programme.

The Project Managers will ensure the delivery of SMS deployments at specific sites nationwide.

4.5.2 Scope of Works and Progress to date of RCP1 Works Programme

Table 14 below sets out the number of sites planned for SMS deployment in RCP1, RCP2 and RCP3.

Table 14 - Planned number of sites for SMS Deployment in RCP1, RCP2 and RCP3

Year	Sites					SCADA Facing RTUs
	Small	Medium	Large	Very large	Total	
12/13[18]	7	3	0	0	10	12
13/14	7	1	0	0	8	9
14/15	12	6	1	0	19	20
RCP1 subtotal	**26**	**10**	**1**	**0**	**37**	**41**
15/16	7	6	0	0	13	14
16/17	3	3	4	1	11	13
17/18	2	3	4	1	10	16
18/19	2	2	4	2	10	14
19/20	3	3	5	2	13	16
RCP2 subtotal	**17**	**17**	**17**	**6**	**57**	**73**
20/21	3	13	7	2	25	29
21/22	10	9	1	1	21	21
22/23	9	7	19	1	27	30
RCP3 subtotal	**22**	**29**	**18**	**4**	**73**	**80**
TOTAL[19]	**65**	**56**	**36**	**10**	**167**	**194**

SCADA facing RTUs are Remote Terminal Units (RTUs) which connect the substation to National SCADA (some sites may have more than one SCADA facing RTU). The majority of configuration work in a SMS deployment at a site is the migration of information from the existing SCADA facing RTUs to the SMS gateway. They represent a large proportion of work required at each site and will provide an indication of resources required to deliver the work.

In RCP1, we would have commissioned a total of 23[20] sites by the end of 2013/14 (End of June 2014) with another 19 sites planned to be commissioned by the end of RCP1 (2014/15). This means an average rate of 14 sites commissioned per year, or approximately 15 SCADA facing RTUs migrated per year, across 2012/13, 2013/14 and 2014/15. With our experience and resources in RCP1, we can deliver an average of 14 SCADA facing RTUs in a year.

In RCP2, there are 73 SCADA facing RTUs to be configured and replaced across 57 sites. This averages to approximately 14 SCADA facing RTUs migrated (or approximately 11 sites commissioned) per year in RCP2.

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[18] This includes the two trial sites at Kaipoi and Owhata implemented in 2011/12.

[19] The total figures exclude the effect of divestments.

[20] This number also includes 5 new substations where SMS have been commissioned e.g. Hobson Street (large), Kimberley (small), Penrose new control room (large), Piako (small) and Wairau Road (large). These new substations are not included in Table 14.

4.5.3 RCP2 Programme Planning

The annual volumes of work (14 SCADA facing RTUs migrated per year) proposed for RCP2 are consistent with those being delivered (to date) in RCP1.

This view is further supported by the following:

- We are gaining experience in deploying SMS sites in RCP1 that will allow us to be more efficient in how we deliver these sites i.e. drawing templates, technical experience.
- We are utilising better tools (e.g. DNP3 conversions are now much faster using protocol converters and automated configuration) than were available when SMS was initially deployed in RCP1.
- We are committed to begin the design work and project establishment work earlier in 2014/15 (RCP1), in order to start delivering sites in RCP2 to meet our scheduled targets.

On this basis we are confident that the proposed RCP2 volumes are deliverable.

5 Glossary

Term	Definition
DNP3	Distributed Network Protocol 3. A communications protocol used in SCADA systems. It provides the packet transmission between remote sensors and a SCADA Master Station. DNP3 is part of the IEEE 1379-2000 standard for best practices in SCADA communications.
DNP3i	As per DNP3, but delivered over IP.
HMI	Human Machine Interface. The user interface in a substation. It provides a graphics-based visualisation of the local site and permits the user to interact with various site elements using the interface. Previously called an "MMI" (man machine interface), an HMI typically resides in a Windows-based computer that communicates with an RTU or SMS device.
ICCP	The Inter-Control Centre Communications Protocol (ICCP or IEC 60870-6/TASE.2) is being specified by utility organizations throughout the world to provide data exchange over WANs between utility control centres, utilities, power pools, regional control centres, and Non-Utility Generators. ICCP is also an international standard: International Electrotechnical Commission (IEC) Telecontrol Application Service Element 2 (TASE.2)
IMS	IED Manager Suite. An umbrella application that provides the necessary security, remote configuration management, automated event data retrieval and the supervision of manufacturers' IED engineering tools for online remote engineering access to substation IED devices. It facilitates device management, data retrieval, event storage and incident reporting.
IP	Internet Protocol. IP is the principal communications protocol used for relaying datagrams (packets) across a network using the Internet Protocol Suite. Responsible for routing packets across network boundaries, it is also the primary protocol that establishes the Internet.
LAN	Local Area Network. A computer network that connects computers and devices in a limited geographical area such as an office building or substation.
LCM	Life Cycle Management. Refers to the strategic portion of Transpower's network services and development programme.
MPLS	Multi-Protocol Label Switching. A mechanism in high-performance telecommunications networks which directs and carries data from one network node to the next with the help of labels. MPLS makes it easy to create "virtual links" between distant nodes. It can encapsulate packets of various network protocols.
PI	Plant Information. Software from OSISoft that is used to capture, process, and provide long term storage of data received from the field. PI applications can monitor and analyze gathered data to find ways to streamline operations.
REA	Remote Engineering Access. A service that provides contractors the ability to remotely undertake engineering functions, avoiding the need to travel to site.
RTU	Remote Terminal Unit. A device that collects data from data acquisition equipment and sends them to the main system over a communications network.
SCADA	Supervisory Control And Data Acquisition. Provides supervisory control of remote stations as well as data acquisition from those stations over a bidirectional communications link.
SEP	Security Enforcement Point. A logical function (often manifested physically) that controls the ingress and egress of data to and from a LAN. It serves to ensure that appropriate controls are applied such that the overall network security and stability is preserved.
SMS	Substation Management System.
TransGo	'TransGo' is our new nationwide communications network that provides high-speed, high-capacity fibre optic communications between our control centres and our substations.
VPN	Virtual Private Network. A computer network that uses public telecommunications infrastructure (such as the Internet) to provide secure access to a network. It encapsulates data transfers between two or more networked devices which are not on the same private network so as to keep the transferred data private from other devices on one or more intervening local or wide area networks. There are many different classifications, implementations, and uses for VPNs.
WAN	Wide Area Network. A computer network that covers a broad area, in Transpower's case the WAN will ultimately encompass all transmission and corporate sites.

A. Detailed SMS Costs

The following tables provide a detailed breakdown (unrounded estimates) of small, medium, large and very large sites for SMS deployment (Option 3).

Table 15 - Breakdown of SMS deployment for a small site

Description	Cost
Project Management & Design Costs	$85,744
Materials	$47,570
Installation	$77,925
Plant & Equipment	$9,000
Total	**$220,239**

Table 16 - Breakdown of SMS deployment for a medium site

Description	Cost
Project Management & Design Costs	$84,242
Materials	$106,783
Installation	$59,040
Plant & Equipment	$9,000
Total	**$259,065**

Table 17 - Breakdown of SMS deployment for a large site

Description	Cost
Project Management & Design Costs	$195,349
Materials	$361,771
Installation	$96,626
Plant & Equipment	$18,000
Total	**$671,746**

Table 18 - Breakdown of SMS deployment for a very large site

Description	Cost
Project Management & Design Costs	$450,180
Materials	$492,784
Installation	$281,500
Plant & Equipment	$18,000
Total	**$1,242,464**

B. Detailed RTU Replacement Costs

The following tables provide a detailed breakdown of small, medium, large and very large sites for RTU replacement (Option 2).

Table 19 - Breakdown of RTU Replacement for a small site

Description	Cost
RTU box, wiring, panels, design, installation and commissioning for each site	$117,200
I/O Peripheral modules	$25,000
Substation LAN	$57,100
HMI (mainly software licenses costs)	$50,000
Total	**$249,300**

Table 20 - Breakdown of RTU Replacement for a medium site

Description	Cost
RTU box, wiring, panels, design, installation and commissioning for each site	$164,100
I/O Peripheral modules	$35,000
Substation LAN	$80,000
HMI (mainly software licenses costs)	$50,000
Total	**$329,100**

Table 21 - Breakdown of RTU replacement for a large site

Description	Cost
RTU box, wiring, panels, design, installation and commissioning for each site	$322,900
I/O Peripheral modules	$68,900
Substation LAN	$157,400
HMI (mainly software licenses costs)	$50,000
Total	**$599,200**

Table 22 - Breakdown of RTU replacement for a very large site

Description	Cost
RTU box, wiring, panels, design, installation and commissioning for each site	$372,900
I/O Peripheral modules	$137,700
Substation LAN	$314,800
HMI (mainly software licenses costs)	$50,000
Total	**$875,500**

The RTU replacement costs for small, medium and large sites are based on actual costs of historical RTU replacement work (pre RCP1).

The small sites were average on the actual cost of RTU replacement for Kaikohe, Kensington and Waipapa.

The medium sites were average on the actual cost of RTU replacement for Rotorua, Brunswick and Motueka.

The large sites were average on the actual cost of RTU replacement for Kawerau and Tarukenga.

The RTU replacement costs for very large sites have been extrapolated from the RTU replacement costs for a large site i.e. addition of $50,000 for additional cable raceways (for fibre cabling) over that of the large site. The addition of a HMI per site is the estimated as the same across all sites at $50,000.

C. Benefits – Sensitivity Analysis

We have undertaken sensitivity analysis on both the costs and benefits of both options to consider the robustness of the economic result.

We varied the cost relativity between the two options by 20% and the benefits relativity between the two options by 50%. The results are reported below.

Base results

Table 23 – Cost Benefit Analysis, Base Results

Option #	Option name	Net Present Capital Costs ($m) [A]	Net Present Benefits ($m) [B]	Net Benefit ($m) [B] – [A]	Relative to Option 2
2	RTU & I/O Peripheral replacement with additional Functionality	46.5	1.7	--44.7	0.0
3	SMS deployment	55.8	17.0	-38.8	5.9

SMS Costs+10%, *RTU replace* Costs-10%

Table 24 - Cost Benefit Analysis, SMS Costs +10%, RTU Replacement Costs -10%

Option #	Option name	Net Present Capital Costs ($m) [A]	Net Present Benefits ($m) [B]	Net Benefit ($m) [B] – [A]	Relative to Option 2
2	RTU & I/O Peripheral replacement with additional Functionality	42.5	1.7	-40.8	0.0
3	SMS deployment	60.7	17.0	-43.7	-2.9

SMS Benefits-25%, *RTU replace* Benefits+25%

Table 25 - Summary of Cost Benefit Analysis

Option #	Option name	Net Present Capital Costs ($m) [A]	Net Present Benefits ($m) [B]	Net Benefit ($m) [B] – [A]	Relative to Option 2
2	RTU & I/O Peripheral replacement with additional Functionality	46.5	2.1	-44.3	0.0
3	SMS deployment	55.8	12.8	-43.1	1.2

These sensitivities show that the Option 3 net benefit is robust to changes in the relativity between the benefits of each option, but is sensitive to changes in the relativity between the costs of each option.

This sensitivity to costs does not change our preference for Option 3, for two reasons:

a) We are comfortable with the cost relativity reflected in our analysis, between the two options. The costs for Option 3 are based on our actual costs installing SMS to date and many of the costs included in the Option 2 estimate are also based on known costs.
b) The net benefit in the cost sensitivity is within 10% of the cost of the alternate option (Option 3). Recognising the inherent uncertainty in cost and benefit estimation, we call Options 2 and 3 *similar*. Similar options are considered economically equivalent and unquantified benefits are used to identify a preferred option. As outlined above, Option 3 has a number of unquantified benefits in its favour compared to Option 2 and we would still prefer Option 3.