Attachment 13.1

SA Power Networks:
A Smarter Network Strategy 2014-2025

September 2014

A Smarter Network Strategy 2014-2025

A workstream of the Smart Grid strategy

26 September 2014

SA Power Networks

www.sapowernetworks.com.au

EXECUTIVE SUMMARY

Strategic content

The 2026 Future Operating Model (FOM) was released in 2011 setting the vision and high-level roadmap for SA Power Networks' strategic direction. Included in this vision was the adoption of smart grid technology in the 2015-20 and 2020-25 regulatory periods.

In 2012 a high-level smart grid strategy was developed by Network Management in response to the FOM. It refined and translated the vision set out in the FOM into a number of smart grid specific strategic work streams.

This document

The 2012 smart grid strategy set out the high level rationale and 15 year roadmap for SA Power Networks' future network. It described a future network that utilised technology and other strategic interventions to manage network performance, support operational efficiency, increase customer interaction and mitigate potential impacts on network prices.

This was to be achieved through the extension of monitoring and control capabilities, improvements in planning facilitated by systems and data, developing a network that would connect to and interact with customers and their energy technologies, expanding cost reflective tariffs, and utilising non-network solutions where effective.

This document sets out a key work stream of the strategy called "A Smarter Network" and has been revisited in the light of the 2028 Future Operating Model (update of the 2026 FOM). The purpose of this document is to describe the grid side strategies and initiatives that will integrate intelligent equipment and systems to manage risk, optimise asset investment, manage reliability and enable the two-way network.

This Smarter Network Strategy document forms part of a set of related strategy documents developed by the wider business such as the Operational Telecommunications Strategy, Tariff and Metering Business Case, Customer Engagement Model, Flexible Load Strategy, Customer and Retailer Engagement Strategy and the Integrated Technology & Systems Plan that collectively sets out SA Power Networks' comprehensive Smart Grid strategic direction.

A Smarter Network drivers of change

SA Power Network is positioning itself to respond to unprecedented change over the next 5 to 15 years driven by:

- **Asset age** - the age and maturity of the network, and a slowdown in demand growth, requires an increasing focus on asset management and declining emphasis on constructing new assets.
- **Bushfire risk management** – around 220,000 customers are supplied by lines which traverse high bushfire risk areas (HBFRA). Where a line must be isolated or placed into non-auto setting and no remote control is present, a crew must be dispatched to undertake this work.
- **Response to rising prices** – customers are reducing energy consumption in response to rising electricity retail prices. They are also investing in local generation which has, until recently, been accelerated by generous government incentives. This has led to a reduction in average energy consumed from the network, but has had a smaller impact on peak demand.
- **Deteriorating power quality** – distributed energy resources (DER) such as solar photovoltaic (PV) are leading to increased power quality issues in the low voltage (LV) network. At times of peak solar output and low demand, local voltage levels can become unacceptably high, causing some customers' inverters to disconnect and cease exporting energy to the grid.

- **Emerging technologies** – technological developments create alternative options for consumers, but they also create opportunities for improvements to the network through new and cheaper ways to manage reliability for SA Power Networks' worst served customers and reduce augmentation.
- **Customer expectations and behaviour** – SA Power Networks' customers have expressed a desire for more interaction, higher value for money, accurate information and better control of their electricity use. Continued high expectations from customers mean that SA Power Networks will be under continued pressure to deliver services cost-efficiently.

The Smarter Network Strategy

The technologies proposed under this strategy will provide the ability to remotely monitor network performance and asset condition, detect network faults and issues, control critical switches and equipment and provide data and analysis of the network automatically.

The Smarter Network Strategy comprises three major elements:

- **Foundations** – further developing the core business capabilities that underpin the realisation of a 'smarter' network, including ADMS development, operational telecommunications and effective data and configuration management.
- **Network monitoring and control** - building on existing capabilities to increase the penetration and functionality of remote monitoring and control in the network to manage reliability, continue bushfire risk management, optimise asset investment and enable the two-way network.
- **Planning a 'smarter' network** – providing the necessary network standards, planning and management to facilitate the elements of this strategy.

Figure 1 below shows the vision and key goals of this strategy.

Maximised customer and shareholder value

VISION

Expanded monitoring and control capabilities to optimise long term network investment, performance and risk

Key Goals

Future Operating Model

'Network of the Future'

KRA	DESCRIPTION
Manage risk	Enhance bushfire risk mitigation through deployment of smart technologies.
Optimise asset investment	Increased strategic monitoring to maximise asset life and optimise capacity expenditure.
Manage reliability	Deployment of new techniques including automation and micro-grids to address poorly performing areas of the network and help mitigate the impact of extreme weather events.
Enable the two-way network	Preparing the network to allow connection of additional embedded generation and new energy technologies.

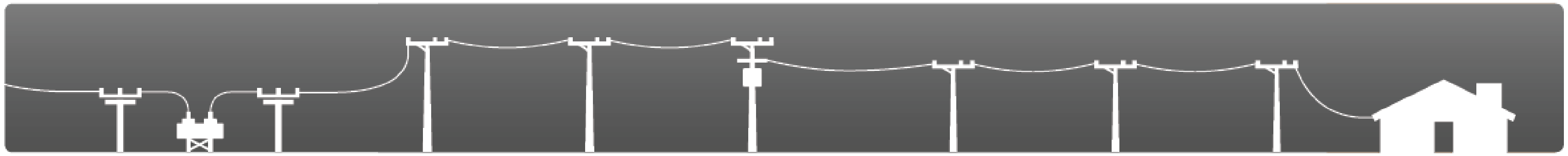
Figure 1: *A Smarter Network* vision and goals

Key initiatives of the Smarter Network Strategy

The key initiatives of the Smarter Network Strategy are:

- **Substation remote monitoring and control** - deployment of monitoring and control to all zone substations over the next 10 years in order to manage the risk of critical asset failure and optimise asset investment. Additional standardisation will also be introduced into the development of future zone substation technology to simplify design, re-configuration and upgrades in the future.
- **HV Switches** - a coordinated program to install HV switches to: manage reliability in the worst performing areas of the network; enhance our management of bushfire risk through deployment of SCADA in bushfire risk areas, and ensure back-up protection coverage. These switches will also be leveraged for their load monitoring capabilities to provide greater visibility of the network beyond the zone substation.
- **LV monitoring** - proactive and selective monitoring of the LV network using a combination of transformer monitoring and telecommunications-enabled meters, to enable more accurate forward-planning of LV capacity upgrades, and to monitor voltage in the LV network in a world of rapidly evolving technology.
- **Voltage control** – providing more responsive control of network voltage levels to allow the network to be flexible to increased penetration of customer side technologies, such as solar PV, battery storage and electric vehicles.

Figure 2 sets out the consolidated roadmap of the network monitoring and control capabilities.



	Substations		HV network		LV network		Customers	
	# of smart device/number of points							
2015	SCADA substations[1]	229	SCADA switches[2]	466	TF monitoring	200	Comms-enabled meters	2,000
2020		274		821		2,120		50,000
2025		319		1,066		2,120		63,000
	Foundations							
Systems	SCADA/ADMS		SCADA/ADMS		ADMS		MMS	
Tel	Fibre/NBN		4G/Private		4G/Mesh radio		4G/Mesh radio	
Data	Historian		Historian		Historian		MMS	
	Initiatives							
	SCADA to substations		Feeder automation		Padmount monitoring		Comms-enabled meters	
	Communications standard		Back-up protection		Power quality monitoring			
	Bushfire risk mitigation				EOL monitoring			
	Rural monitoring		Micro-grid					
	Voltage Regulation							

[1] Number of SCADA substations with monitoring and control (i.e. excludes substations with monitoring only).

[2] Number of SCADA HV switches (includes load switches and reclosers - excludes circuit breakers and air disconnects) with monitoring and control (i.e. excludes switches with monitoring only).

Figure 2: Consolidated monitoring and control roadmap

TABLE OF CONTENTS

SIGNATURES

The following Stakeholders have reviewed and accepted the details within this document. Any changes to the document may only be made with the formal agreement of the signatories.

REVIEWERS	POSITION	SIGNATURE	DATE
	Manager Network Standards & Performance		
	Acting Manager Network Control		
	Manager Customer Solutions		
	Manager Network Planning		
	Manager Network Investment Strategy and Planning		
	Manager Network Asset Management		

APPROVED	POSITION	SIGNATURE	DATE
	GM Network Management		

CHANGE HISTORY

Version	Date	Author	Comments

1 INTRODUCTION

1.1 Purpose

This document sets out the "A Smarter Network" stream of the 2012 smart grid strategy. The purpose of this document is to define the grid side strategies which integrate intelligent equipment and systems into the network in order to manage risk, optimise asset investment, manage reliability and enable the two-way network. *A Smarter Network* builds on current remote monitoring and control capabilities by expanding the ability to remotely monitor parameters and asset condition, detect network faults and issues, control critical switches and equipment and provide data and analysis of the network automatically. This is underpinned by capitalising on the improvements in management and planning of the distribution network that are made possible by technological development.

This strategy is intended to be a living document and will be subject to further reviews and updates as SA Power Networks' and customers' requirements change.

1.2 Strategic context

The electricity industry is undergoing profound and unprecedented transformation, driven by fundamental changes in the way electricity is distributed, generated, controlled and consumed. It is now well accepted throughout the industry that in order to manage these changes and continue to operate effectively, efficiently and safely, electrical networks need to become 'smarter'.

In 2011 SA Power Networks developed its *2026 Future Operating Model* (FOM) [1], which set out the organisation's strategic direction and defined a high-level roadmap for business transformation through, amongst other things, the adoption of smart grid technology.

In response to this, Network Management commenced the development of an overarching smart grid strategy in 2012, which refined and translated the vision set out in the FOM into a number of smart grid specific strategic work streams. The strategy set out a strategic roadmap to a future where:

- power quality, load and asset health can be monitored at thousands of points in the distribution network from the substation to the customer premises;
- the next generation of 'smart' devices can be controlled remotely to automatically reconfigure the network or shed load in response to changing demand; and
- customers can directly access the information they need to manage their own load on the network more effectively.

This document sets out the *Smarter Network* work stream, which primarily applies to grid-side technologies and addresses the development of increased remote monitoring, control and management of grid side technologies over the next 10 years in order to increase customer and shareholder value.

1.3 Early start initiatives

In 2013 a number of early start initiatives were kicked off across the business as SA Power Networks progressed towards a ‘smarter’ network. In particular, 2013/14 saw:

- The establishment of the **Smart Grid Steering Committee**;
- The business undertaking an evaluation of SA Power Networks’ broader direction;
- The release of the **Operational Telecommunications Strategy**;
- Publication of SA Power Networks’ **Customer and Retailer Engagement Strategy**;
- Design work in preparation for the first phase of the **Feeder Automation** Project;
- **Stage 1 SCADA/ADMS** implementation progressed with factory acceptance testing completed;
- Execution of SA Power Networks’ 2012/13 **Capacity Tariff Trial** in North Adelaide and expansion of this trial in the lead up to the 2013/14 summer period ;
- Engagement of external stakeholders on tariff reform and the two-way network through the **TalkingPower** stakeholder engagement program;
- A refinement of **LV Planning** practices and continuation of **LV monitoring** trials;
- Evaluation of **bushfire risk management** options in the wake of the Victorian bushfires in 2009;
- Initial **assessment of IEC 61850** for zone substations; and
- The development of a **Common Data Model for specific asset classes** through the data governance committee.

1.4 Structure of the document

The body of the report is structured as follows:

- **Section 2** summarises the **drivers** leading to changes in the network including its current state, bushfire risk, embedded generation, the challenge around emerging technologies and the change in SA Power Networks’ customers’ expectations and behaviours.
- **Section 3** outlines SA Power Networks’ **response** to the opportunity to increase owner and customer value.
- **Section 4** examines the **foundations** for the *Smarter Network* strategy, these being the implementation of the Advanced Distribution Management System (ADMS), operational telecommunications infrastructure and data management solutions.
- **Sections 5** outlines the strategy for additional network **monitoring and control** in the high voltage (HV) network, increased monitoring of the low voltage (LV) network and enabling the two-way network.
- **Section 6** considers the requirement for **planning** and implementation of these solutions.
- **Section 7** gives a brief overview of the **impact on key roles**.
- **Section 8** contains a consolidated **roadmap** of the smarter network initiatives over the next 10 years.

2 THE CASE FOR CHANGE

2.1 Asset Age

SA Power Networks' electricity network is large and is dispersed over a wide area. However, customer density in greater Adelaide is much higher than in country areas, with approximately 30% of the network infrastructure servicing 70% of the customer base. The network is also old, with much of the network constructed during the 1950s and 1960s, primarily above ground.

The age of the network means that SA Power Networks will have to continue to focus on asset management in order to maintain the existing network and meet mandatory service standards. The scale of the network required to service regional areas of the state combined with low customer numbers in these remote areas makes it expensive to maintain the entire network. This is a primary driver which has lead to considering smarter and more cost-efficient ways of managing the network.

The following table provides a summary description of the current network scale and condition.

Table 1: Current network scale and condition

Characteristic	Description
Asset age profile	Substantially built in the 1950s and 60s
Network	Covers 178,200 square kilometers
Route length	88,000 km
Number of substations	407 zone substations[1]
Number of distribution transformers	72,000 distribution transformers
Customers	840,000
Peak demand >3,000 MW and load factor	40%
Number of SCADA connected HV switches [2]	• 453 out of 3,168 devices have control and monitoring • 128 out of 3,168 devices have monitoring only
Number of SCADA connected zone substations	• 229 of 407 zone substations have control and monitoring • 87 of 407 zone substations have monitoring only

[1] A substation is an asset with a SSD number (ie excludes rural pole top HV/HV transformers single customer sites and regulator stations).
[2] Including load switches and reclosers (i.e. excludes circuit breakers and air disconnects).

2.2 Bushfire risk management

Approximately 220,000 of SA Power Networks' customers are supplied by a line/feeder which traverses a HBFRA. In cases of extreme bushfire risk weather, SA Power Networks has the legislative authority to switch off electricity supply to minimise the risk of a bushfire starting from its assets. However, disconnecting power may adversely affect communities and bushfire safe precincts may be left without power.

SA Power Networks has a number of older reclosers in service located within HBFRAs and MBFRAs (medium bushfire risk area) with no remote control or monitoring capability, and hence are unable to be remotely operated during extreme fire danger events. This requires either upstream devices to be operated (which can impact a greater number of customers some of whom may not be inside a bushfire risk area), or mobilising field staff to manually operate reclosers, which could potentially compromise their safety.

In 2009, devastating bushfires in Victoria caused the deaths of 173 people and the widespread destruction of many rural communities, farmland and the environment. As a result the Victorian Bushfires Royal Commission (VBRC) was established, which concluded that the estimated losses from these fires were over $4 billion.

The VBRC found that five of the fires, including the Kilmore East fire which led to 119 fatalities, were caused by electricity assets[3]. Evidence shows that the probability of bushfires starting from electricity assets rises dramatically on extreme fire risk weather days. Additionally, the VBRC made specific recommendations about the need for flexibility in protection settings associated with devices protecting bushfire risk areas.

2.3 Response to rising prices

In the face of higher prices, there is a strong incentive for consumers to reduce consumption in order to minimise the impact on household costs. This has generally meant initiatives to reduce the consumption of electricity (but not necessarily at peak periods) have been acted upon. SA Power Networks' customers have invested in local generation in response to generous government incentives and energy efficiency as a means of reducing their electricity bills.

This has tended to reduce average electricity consumption more than reducing peak demand. As a consequence, the amount of electricity used from the grid on a year on year basis has declined – the first time this has happened in the history of the industry in Australia[4].

Although there has been a decline in the total amount of energy delivered by the grid in South Australia, distribution network assets are still required to meet peaks in demand and to enable customers to export surplus energy from embedded generation. Today's network tariffs, which recover the cost of the network largely in proportion to the amount of energy consumed from the grid, are no longer appropriate, as they lead to increasing costs per unit of energy delivered and reinforce the feedback loop that has been referred to as the "energy death spiral" [12].

Further to this, electricity prices have raised the profile of the electricity industry to the point where customers are willing to participate in the market to reduce costs, and governments and regulators are supportive of changes that could reduce customer prices and enhance the customer experience.

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[3] A sixth fire, the Murrindindi fire, is under investigation by Victorian Police and suspicion surrounds the failure of an electricity line.
[4] Source: AEMO

2.4 Deteriorating power quality

The large penetration of solar PV in South Australia is dramatically changing the load profile of our network. For example, a new “off peak” time now occurs in the middle of the day, with a number of suburbs acting as generators at this time. This causes problems in the static LV network that was not designed to deal with the large fluctuation between peak load in the late afternoons during heatwaves and local small scale generation in the middle of the day on mild spring/autumn days.

These fluctuations create power quality issues as a high level of energy exported to the grid can cause an excessive increase in local voltage. This in turn causes the inverters of small scale solar systems to operate to shut down until voltage levels have normalised.

2.5 Emerging technologies

Emerging technological developments create alternative options for consumers, but they also create opportunities for improvements to the network through new and cheaper ways of managing reliability and reducing the need for augmentation. These emerging technologies include:

- ‘Smarter’ switches;
- Cheaper permanent LV monitoring and telecommunication solutions;
- ‘Smart’ meters;
- Battery storage; and
- Equipment with remote management capabilities.

In particular, the predicted reduction in the cost of battery storage has the potential to significantly alter energy flows across the distribution network. Such emerging customer-side technologies increase the complexity of managing the network and heighten the need for better control and monitoring.

2.6 Customer expectations and behaviour

Consumer behaviour has changed over recent years in response to rising electricity prices, an increased focus on climate change impacts and government incentives for distributed energy resources (DER). This has also translated into high media coverage and a changing political, environmental and regulatory landscape. In particular consumers are using less electricity, opting for more energy efficient appliances and considering the uptake of alternative supply options.

Customer expectations around the range and levels of services are increasing continually in response to their experiences with other services such as phone and internet service providers. Customers expect more detailed, accurate and timely information, with fewer limitations on location or time, and a greater degree of control over their energy use. Meeting these expectations will involve increased customer interaction and the provision of higher value information to inform customer choice.

At the same time, the community demands infrastructure that is more aesthetically pleasing with reduced impact on the environment.

2.7 TalkingPower™

In order to understand the concerns and expectations of South Australian electricity consumers, SA Power Networks developed a stakeholder engagement program in the lead up to the 2015-2020 regulatory period.

During 2013, SA Power Networks undertook numerous customer workshops and an online survey as part of this consumer engagement program to listen to and explore consumer sentiments and opinions on key topic areas. Key observations from these workshops which pertain to the Smarter Network Strategy include:

- Support for continued asset management and investment to drive reliability, manage risk and support economic growth. Asset management initiatives that have a direct impact on reliability and/or prevent potential safety hazards were rated most important.
- Consumers are ready for the installation of smart meters.
- Support for continued upgrades to support a two-way network to enable the increasing uptake of new technologies.
- Education will increase customer satisfaction; consumers clearly expressed a need for education on new technologies and changes to the industry.
- Consumers support hardening the network against storms.

3 STRATEGIC RESPONSE

3.1 The network today

SA Power Networks' network spans from the bulk supply points of the transmission network down to the LV networks which connect the majority of customers (a small number of industrial and commercial customers connect directly to the HV network). Typically, the network comprises sub-transmission lines interconnecting zone substations located throughout the metropolitan area, towns and other locations throughout the state. HV feeders then radiate from these substations for suburb and town level distribution and branch into LV networks via transformers.

A typical urban zone substation can serve between 5,000 and 15,000 customers, with an urban HV feeder generally suppling between 1,000 and 3,500 customers. LV networks are supplied via the HV feeder and a typical urban feeder can have 40-70 distribution transformers, each with its own LV network. The network in total has approximately 72,000 distribution transformers of which 17,000 are located in urban areas with multiple small customers or a single commercial customer.

Each metropolitan transformer typically has between 40 and 60 customers on up to 4 different circuits (LV feeders) from the transformer. These LV circuits extend around 200m to 400m from the transformer and connect single phase and three phase customers to the network. Rural customers are also supplied from transformers directly connected to the sub-transmission lines, or single wire earth return (SWER) lines supplied from these lines or HV feeders.

3.2 The Smarter Network Strategy

A Smarter Network is a strategy that sets out a coordinated approach to integrating intelligent equipment and systems into the network to manage risk, optimise asset investment, manage reliability and enable the two-way network in order to maximise customer value.

A 'smarter' network will remotely detect network faults and issues as well as control critical switches and equipment. It will also provide data and analysis of the network automatically as well as tools to assist network planning decision making.

The Smarter Network Strategy is comprised of **three** major elements:

- **Foundations** (outlined in section 4) – core business capabilities that underpin the realisation of a 'smarter' network, including Advanced Distribution Management System (ADMS) development, operational telecommunications and effective data and configuration management.
- **Network monitoring and control** (outlined in section 5) - building on existing capabilities to increase the penetration and functionality of remote monitoring and control.
- **Planning a 'smarter' network** (outlined in section 6) – providing the necessary suite of network standards, planning and management to facilitate the elements of this strategy.

Maximised customer and shareholder value

VISION

Expanded monitoring and control capabilities to optimise long term network investment, performance and risk

Future Operating Model

'Network of the Future'

Key Goals

KRA	DESCRIPTION
Manage risk	Enhance bushfire risk mitigation through deployment of smart technologies.
Optimise asset investment	Increased strategic monitoring to maximise asset life and optimise capacity expenditure.
Manage reliability	Deployment of new techniques including automation and micro-grids to address poorly performing areas of the network and help mitigate the impact of extreme weather events.
Enable the two-way network	Preparing the network to allow connection of additional embedded generation and new energy technologies.

Figure 3: *A Smarter Network* vision and goals

4 SMART GRID FOUNDATIONS

This strategy has been founded upon three critical elements which are as follows:

- The implementation of the ADMS;
- Strategic development of the operational telecommunications infrastructure; and
- Effective and comprehensive data management solutions.

These elements are described in more detail below and form the basic foundation required to underpin the other elements of this strategy and are key to benefit realisation and deployment efficiency.

4.1 Advanced Distribution Management System (ADMS)

In 2012, SA Power Networks commenced the implementation of a project to deploy a new SCADA system and an ADMS. These systems allow remote monitoring, operation and control of the electricity network. The ADMS will be the technological platform to be utilised for future smarter network capabilities across the business.

The project is being delivered in three stages, being:

- Stage 1 – SCADA Replacement
- Stage 2 – ADMS Phase 1
- Stage 3 – ADMS Phase 2

The current Citect SCADA system is at the end of its useful life and is being replaced as part of the SCADA Replacement Phase (Stage 1). ADMS Phase 1 involves the delivery of the core Distribution Management System (DMS) functionality including the creation of the Network Operational Model (NOM) and switching management capabilities. ADMS Phase 2 will deliver basic network analysis functions. These elements are expected to be completed by the end of 2015.

ADMS leverage is a strategy to implement additional ADMS functionality beyond the current phases to allow for greater exploitation of smart technologies. Figure 4 shows the roadmap for the ADMS. More detail can be found in the ADMS Technical Roadmap document [6].

The implementation of a SCADA/ADMS solution is fundamental to achieving the full benefits of a ‘smarter’ network. The systems will allow greater exploitation of smart technologies while the advanced capabilities of ‘smart’ devices will be optimised by the full suite of functions provided by the ADMS.

It is also important to note that the ADMS will also be required to interface with nominated SA Power Networks applications over the life of the project.

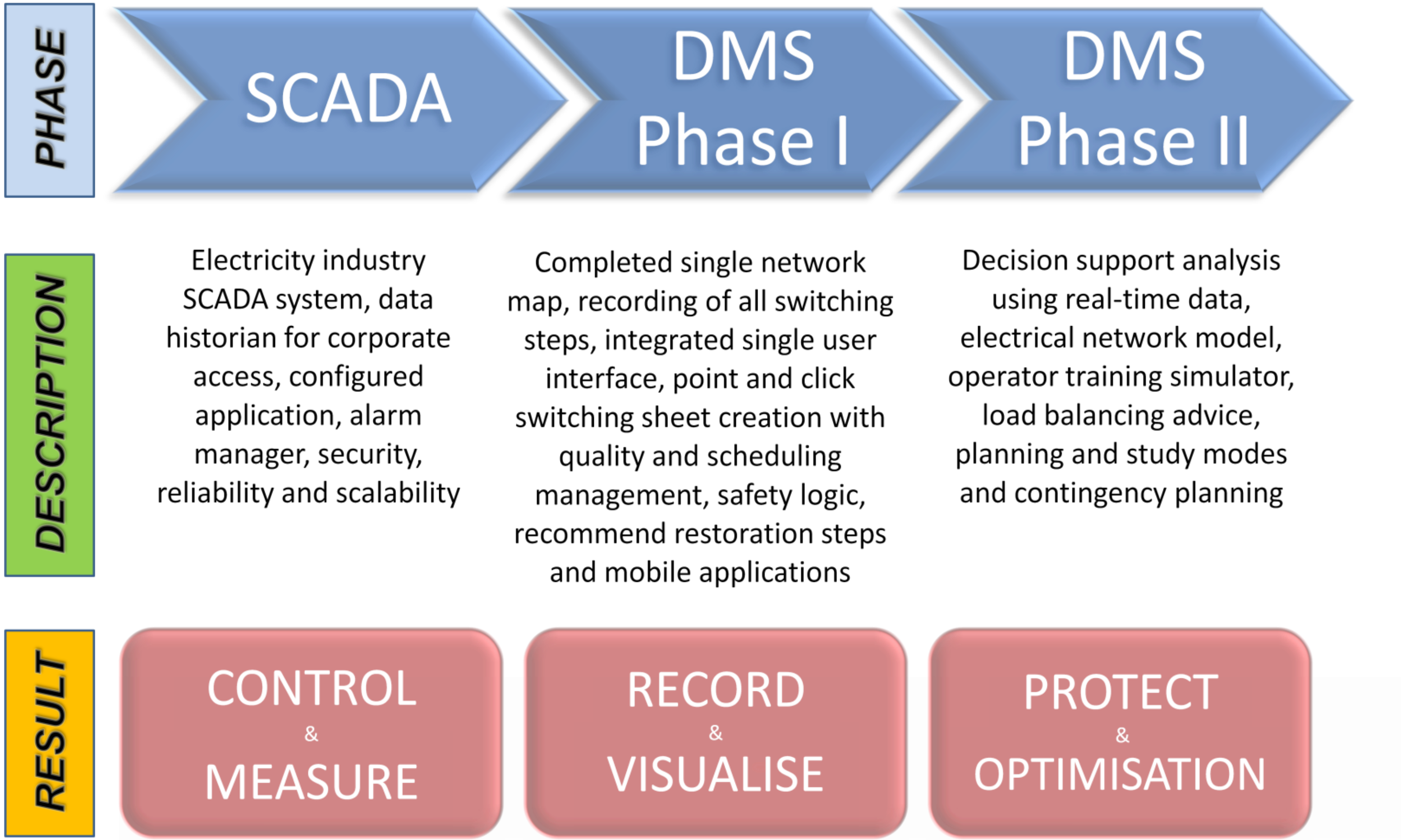


Figure 4: ADMS roadmap

4.2 Telecommunications

Fundamental to the realisation of the smart grid strategy will be the provision of reliable, secure telecommunications to enable and realise the full potential of the new generation of 'smart' devices. This will require capital investment in order to extend SA Power Networks' existing telecommunications systems with new infrastructure required to communicate with potentially thousands of smart network devices in the field and at customer premises, many in rural or remote areas,

Technology in this area is evolving rapidly, particularly in wireless applications. There are fundamental questions around technology choices and issues, such as the availability of radiofrequency spectrum that must be addressed in order to make prudent investment decisions and deliver a reliable, cost-effective, flexible and long-lasting telecommunications platform. The role of carrier services or the National Broadband Network (NBN) as part of an overall solution, and the broader IT and telecommunications requirements of the business are also key considerations

The Operational Telecommunications Strategy[2] has been developed to support the smart grid strategies. It defines the future architecture of SA Power Networks' telecommunications network and sets out a strategic roadmap to deliver this architecture in a timeframe that aligns with the broader smart grid strategy.

4.2.1 The future telecommunications network

The proposed future telecommunications network is shown in Figure 5 below and includes:

- **A high-capacity wireless field-area network** which combines tactical deployment of private LTE (4G) with carrier 3G and 4G networks, to backhaul data from other networks (e.g. local narrowband radio) and provide reliable, secure wireless communications to regional substations and smart field devices such as switches.
- **A transition to all-IP** communications that will enable services to be rolled out rapidly and securely to substations that are without existing telecommunications, using varying IP backhaul methods.
- **A converged, high-capacity core IP/MPLS optic fibre network**. This will provide the necessary capacity to support the new smart grid applications, and will lay the foundation both for a future transition to the IEC 61850 substation communication standard, and for future carriage of the IT network over the operational transport network platform.
- **Connections into the National Broadband Network** enabling the NBN's state-wide optic fibre, wireless and satellite assets to be seamlessly integrated into SA Power Networks' network. This will provide cost-effective, high-capacity links into regional and remote areas for depots, some substations and LTE backhaul, and potentially a range of other applications as the NBN rolls out through to 2023.
- **A new network** for communication with advanced meters, to enable power quality monitoring on the LV network and facilitate demand side participation. This will use carrier 3G/4G telecommunications, potentially in combination with RF mesh technology.

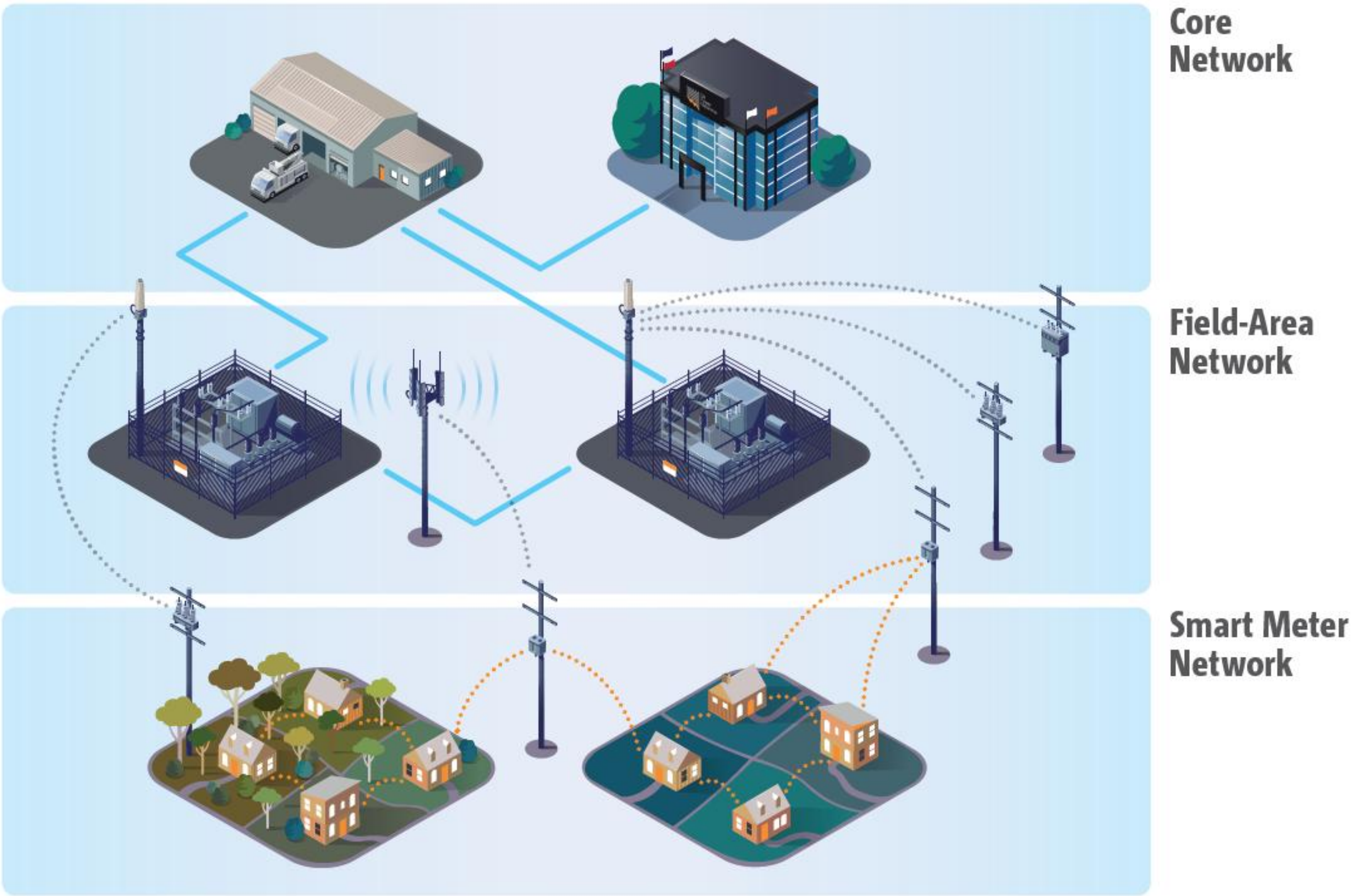


Figure 5: The future operational telecommunications network

4.3 Data management

In order to realise the benefits of a 'smarter' network there is a strong reliance on both timely and accurate data. This data can range from detailed asset information to real time status and performance information over the breadth of the network from distribution substations to the end use customer loading.

To facilitate this, a strong emphasis is being placed on improving the range and quality of the data held by SA Power Networks. The Integrated Technology and Systems Plan (ITSP) identified the need to adopt an industry based standard to ease integration with back office, control and other operational systems and ensure reliable information interchange between systems.

4.3.1 A common data model (CDM)

The ITSP requires that all systems strive to comply with the standard industry data models to which SA Power Networks currently aligns. One in particular is the Utilities Common Information Model (CIM) standard as defined in IEC 61968, IEC 61970 and IEC 62325. This industry-recognised standard provides common data and metadata constructs for many aspects of the energy supply chain from generators to the end use customer applications. The other key industry data models to which the SA Power Networks common data model (CDM) aligns include the Australian Energy Market Operator (AEMO) data model and the Open Geospatial Consortium (OGC) data model. There are currently several data collection projects underway with the major program associated with the collection of asset data.

A CDM aligned with industry standard models reduces data duplication and removes ambiguity. This is achieved by providing a clearly defined format to develop a trusted set of data to allow informed decisions to be made promptly, by personnel and systems, to manage network operations. It is recognised that where systems have data models that are not aligned with the industry standards, integration will require customisation and adapter software.

Operational data will be collected and stored in accordance with the guidelines of the CDM wherever possible. It has also been recognised that there is a requirement to create greater ownership of the data collected by the different areas within SA Power Networks to ensure the quality of data meets the required standard to support business capabilities.

4.3.2 Configuration management

The successful operation of the smart grid relies on the interoperability between the different devices within the network. This ranges from integration between a device and the communications network to requiring devices to physically exchange information in order to facilitate an automated response to changing distribution network conditions.

Management of the configuration of these devices has been identified by the industry as one of the most important processes to ease the implementation and operation of smarter distribution network equipment.

With the increasing penetration of intelligent controls and equipment across SA Power Networks' distribution network and the expected rapid advancement in technology, a new challenge arises around the configuration management of these devices. Configuration includes the operational settings on the equipment, the device firmware that enables the operations and the software applications required to support these devices utilised by our technical teams. These settings, device firmware and support software versions will be dynamic so as to optimise management, device operation and to enable additional functionality.

Industry experience indicates that this aspect of operational management is best achieved via a formalised role(s), operating within a change management process that is responsible for the overall interoperability within the distribution network. To provide for proactive configuration management it is envisaged that a configuration management database would be deployed.

In addition, the creation of a firmware and application library will provide access to an archive of older versions to ensure that interoperability can be maintained (if required) after field equipment replacement. A comprehensive testing regime and quality control process with suppliers to ensure effective control over configurations allowed onto the distribution network will be also be required. A list of approved devices that may be connected the distribution network and associated assets will be provided as part of configuration management and will be updated as the technology evolves.

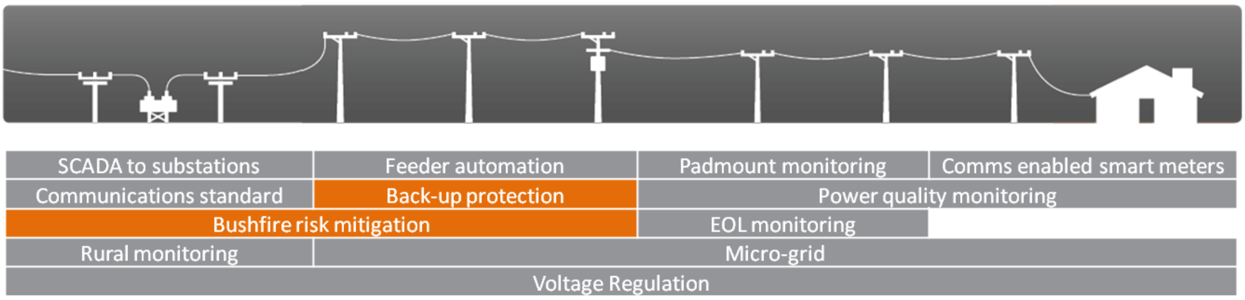
5 NETWORK MONITORING AND CONTROL

The Smarter Network Strategy aims to build on existing capabilities to increase the penetration and functionality of remote monitoring and control in the network in order to manage risk to SA Power Networks' assets and public safety, optimise asset investment and operation, manage reliability and enable the two-way network. This section sets out the technology roadmaps to realise the key result areas of the strategy.

As highlighted in Section 1.1, this strategy is intended to be a living document and will be subject to further reviews and updates as SA Power Networks' requirements and customers' requirements change. The solutions proposed in this section of the document, including precise numbers of devices, will be reviewed during implementation.

5.1 Manage risk

Enhance risk mitigation through deployment of smarter technology.



Advances in protection technology create the opportunity to manage risks in smarter ways. Protection devices in bushfire risk areas can be remotely operated via SCADA to reduce bushfire start risks on extreme fire danger days, thereby improving public safety. Currently some of these devices have to be operated on site by field staff. By installing 'smart' devices, the improved protection technology can be operated remotely, which improves the WH&S of operators and provides greater visibility of the network in rural areas.

5.1.1 SCADA in bushfire risk areas

The VBRC found that the probability of fires starting from powerlines increases significantly if the reclose function of reclosers is not disabled during high Fire Danger Level (FDL) conditions. Reclosing is an important function for the majority of the year for supply reliability to customers and saves significant supply restoration expenditure on the network, especially in rural areas.

The VBRC made several recommendations to help prevent bushfires starting from electrical assets, and accordingly as of 2014 the Victorian Government has committed to funding over $700 million of improvements over the next decade.

SA Power Networks has a number of older hydraulic type reclosers in service located within HBFRAs and MBFRAs with no remote control or monitoring capability, and hence are unable to be remotely operated during extreme fire danger events. This requires either upstream devices to be operated (which can impact on a greater number of customers who may not be inside a bushfire risk area) or field staff to be mobilised to manually operate reclosers, which can potentially compromise their safety.

5.1.1.1 Strategic development

The Bushfire Risk Reduction Strategy [11,15] proposes a number of initiatives, including replacing existing non-SCADA 33kV, 11kV and 19kV reclosers located in HBFRAs and MBFRAs with SCADA controlled devices by 2025. The replacement is based on a priority system which takes into account the feeder fire start history and consequences of a bushfire starting from each feeder.

Some feeders originate in the non-bushfire risk area and supply sections of HBFRA or MBFRA. To avoid unnecessarily isolating customers in the non-bushfire risk area this program also includes completing the installation of additional SCADA enabled reclosers at bushfire risk area boundaries which is designed to limit disconnections to bushfire risk areas only.

The proposed deployment of reclosers is outlined in Table 2 and is detailed in the Bushfire Risk Reduction Strategy [11].

Table 2: Remote switch bushfire risk management solutions roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	• Replacement/upgrade under Feeder Automation Project where applicable.
Period 2 (2015 – 2020)	• Targeted upgrade/replacement program for approximately 151 devices in HBFRA.
Period 3 (2020 – 2025)	• Targeted upgrade/replacement of devices in MBFRA (and remaining HBFRA)[5].

5.1.2 Ground Fault Neutralising Technology

As a result of the VBRC and the subsequent Powerline Bushfire Safety Taskforce, the use of Ground Fault Neutralising (GFN) or Reduced Earth Fault Current Limiting equipment (REFCL) is being investigated by distribution utilities as a new use of existing technology to potentially reduce the occurrence of fire starts.

These devices work by high speed detection of earth faults in three phase systems - the rapid clearing of earth faults reduces the energy fed into a fault which corresponds to a lower possibility of arcing, resulting in a reduction of the potential for ignition.

5.1.2.1 Strategic development

As this is a relatively new approach for bushfire start prevention, it is proposed that GFN technology is implemented at two trial sites. It is proposed that this is followed by targeted deployment to other zone substations after a detailed feasibility assessment of the proposed trials is completed.

[5] A review of the HBFRA/MBFRA boundary will be conducted as a result of recent Maximum Probable Losses analysis. This may result in an increase to existing HBFRAs and hence to an increase in the number of SCADA devices to be installed.

Table 3: GFN technology roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	N/A
Period 2 (2015 – 2020)	• Trial GFN installations at two trial sites.
Period 3 (2020 – 2025)	• Targeted deployment (dependent upon trial outcomes).

5.1.3 Back up protection in remote areas

Historically there has been reliance on one set of protection for rural feeders, often based on the use of hydraulic reclosers. In the National Electricity Rules, it is stated that:

> *"…. A Network Service Provider must provide sufficient primary protection systems and back-up protection systems (including breaker fail protection systems) to ensure that a fault (of any fault type) anywhere on its transmission system or distribution system is automatically disconnected in accordance with clause S5.1.9(e) or clause S5.1.9(f)."* [14]

Locations that are most commonly found having inadequate backup protection are the locations where HV/HV transformers are only protected by high side fuses (e.g. SWER isolating transformer).

5.1.3.1 Strategic development

It is proposed to review the majority of 11kV feeders and all 19kV SWER feeders over the next two reset periods in order to implement protection solutions as required for compliance. These feeders are prioritised based on bushfire risk category, length of the feeder, inadequacy of backup protection and feeder location related to population density.

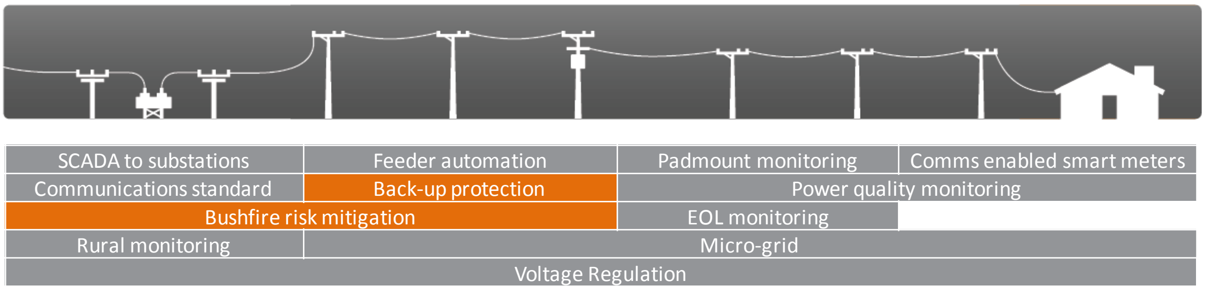
The installation of additional SCADA enabled reclosers forms a large part of this strategy as outlined in Table 4. The use of electronic SCADA connected reclosers will allow remote control on high FDL days and pro-active monitoring of the asset health and its protective functionality.

Table 4: Back up protection solutions roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	• Finalisation and approval of Protection Compliance (HV Safety) Strategy. • Install 2 33kV reclosers and SNO protection relays with SCADA. • Install 3 11kV recloser with SCADA. • Install 8 19kV SWER reclosers with SCADA as part of 2014 back-up protection project.
Period 2 (2015 – 2020)	• Install 10 33kV reclosers and SNO protection relays with SCADA. • Install 11 11kV reclosers with SCADA. • Install 98 19kV SWER reclosers with SCADA.
Period 3 (2020 – 2025)	• Install 7 33kV reclosers and SNO protection relays with SCADA. • Install 29 11kV reclosers with SCADA. • Install 124 19kV SWER reclosers with SCADA.

5.2 Optimise Asset Investment

Increased strategic monitoring to maximise asset life and optimise capacity expenditure.



Increased visibility of the network allows for improved planning and maintenance practices. Currently, there is limited network information on load and power quality, particularly in country areas. This simultaneously restricts the extension of the useful life of network infrastructure in some instances and allows life-shortening load levels and poor service quality in other instances to go undetected.

The Smarter Network Strategy sets out a roadmap to extend SCADA capabilities to all zone substations and feeder exits and a number of mid-line devices on long country feeders. It does so in coordination with other initiatives in this strategy such as the expansion of SCADA to more bushfire risk area devices.

5.2.1 SCADA to substations

The remote monitoring and control of substation plant allows for operation and proactive management of the network. In the 1990's, SCADA was rolled out to a large number of SA Power Networks' larger, primarily metropolitan zone substations to provide an acceptable level of visibility and control.

Progressively as substations have been upgraded they have also been placed on SCADA with the result that a total of 229 zone substations are now SCADA enabled with full control and monitoring capability, with a further 87 having monitoring only. This leaves approximately 91 substations with no monitoring or control capabilities.

In addition to the above, SA Power Networks currently shares 41 sites with ElectraNet, of which 18 sites have SCADA capability provided by ElectraNet owned RTUs and 21 of which SA Power Networks has its own RTU. There are 2 shared sites which currently have no SCADA capability.

All controls initiated remotely are currently undertaken by ElectraNet under SA Power Networks' NOC instructions. This is undertaken at a charge to the business for every control operation as per an existing contract.

The intent is to install SA Power Networks' owned RTUs and to migrate all services currently terminated at ElectraNet's RTUs to an SA Power Networks' SCADA RTU. This will eliminate future operational costs and will ensure SA Power Networks has full control capability of its own assets.

5.2.1.1 Strategic development

The Smarter Network Strategy sets out a roadmap to deploy monitoring and control to all zone substations[6] over the next 10 years in order to manage the risk of critical asset failure and optimise asset investment and operation while also improving network visibility.

Of the existing SCADA sites, 58 have outdated telephone dialling units (TDUs) which provide very limited monitoring capability. For substations without SCADA, capacity planning is conducted by deploying temporary load logging over the summer period every three years. Where the monitoring period does not include peak weather conditions (i.e. heatwaves), assumptions are made to estimate the expected loads and provide a load forecast. Each year SA Power Networks spends approximately $3 million upgrading the capacity of non-SCADA substations based on these measurements and assumptions.

Without SCADA connectivity to substations, the ability to proactively manage these important but ageing assets is reliant on customers calling in, substation inspections, and temporary logging. It is also standard practice to deploy all new electronic reclosers with SCADA, meaning in some cases, that midline reclosers but not the substation itself have SCADA connectivity.

The proposed strategy is a program to achieve connectivity to all remaining non-SCADA substations by the end of 2025. Additionally, the SCADA asset replacement program targeted at replacing TDUs with modern RTUs will continue to ensure SCADA monitoring and control is integrated at substations where feasible. The proposed roll out of SCADA is outlined in Table 5 below according to the relevant reset period.

[6] A substation is an asset with a SSD number (i.e. excludes rural pole top HV/HV transformers single customer sites and regulator stations).

Table 5: SCADA deployment roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	• Replacement of 15 out-dated TDUs.
Period 2 (2015 – 2020)	• Replacement of 43 remaining out-dated TDUs. • Deploy SCADA to approximately 45 non-SCADA sites. • Deploy full SCADA to 10 shared sites.
Period 3 (2020 – 2025)	• Deploy SCADA to remaining 45 non-SCADA sites. • Deploy SCADA to remaining 10 shared sites.

5.2.2 Substation Standards Digital Optimisation using IEC 61850

The components in SA Power Networks' substation switch rooms and yards are currently interconnected by a complex mass of copper wiring. This installation requires careful designing with physical characteristics and limitations of the cabling taken into account. This not only requires specific designs for each substation, but makes re-configuration of the design for upgrades and non like-for-like replacement time consuming and expensive.

As new technologies emerge SA Power Networks may no longer require the traditional electrical connections between components, using systems embedded into substation components to provide IT type network communications between devices. As this technology advances and becomes the industry standard, the support and features available for legacy systems will inevitably decrease.

5.2.2.1 Strategic development

Selecting a new standard is a whole of business decision as it has wide spread implications for functions such as maintenance, construction, asset management, security risk management, asset life and labour skills.

A possible solution is adopting IEC 61850, the international technical standard for smarter internal substation communication. It enables integration of all protection, control, measurement and monitoring functions within a substation.

The introduction of this standard has the potential to offer reduced CAPEX due to standardised, repeatable design as well as reduced OPEX as a result of enhanced monitoring of substation equipment. In addition, the standard supports smart network initiatives which are part of the FOM and projects such as feeder automation and the ADMS.

The proposed roll out for this project is outlined in Table 6 below, according to the relevant reset period.

Table 6: 5.2.2 Substation Standards Digital Optimisation using IEC 61850 Roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	• Document the as-is substation protection and control design. • Develop overall requirements and design methodology based on best practice. • Undertake internal and external stakeholder consultation. • Develop an IEC 61850 Strategy 2015-2020 strategy document.
Period 2 (2015 – 2020)	• Engage an industry expert to build and deliver 2 test environments. • Develop a multi-disciplinary 'IEC 61850 Taskforce'. • Specify the detailed design requirements for IEC 61850 and selection of pilot sites. • Develop detailed design and construction specifications and SDTs. • Design and build the pilot substations.
Period 3 (2020 – 2025)	• To have developed the necessary infrastructure, documentation and skilled workforce to deploy as a standard design for major projects. • Transition to business as usual (BAU).

5.2.3 Rural monitoring

Currently there is very little remote monitoring and control of the distribution network outside of urban areas. In order to quantify the loads on the network in these areas and improve overall network visibility, SA Power Networks currently has a rotational program to conduct temporary testing that meters all country non-SCADA substations, country feeders and a prioritised portion of the 19kV SWER system (90 per annum) in rural areas every three years for a few months at a time. In addition, short term testing is completed in response to customer complaints.

This approach leads to completing upgrades and remediation work based on temporary testing which as highlighted above has limitations as it is an approximation and may not be directly representative of the actual load and quality of supply at critical times throughout the year.

5.2.3.1 Strategic Development

In addition to the installation of HV regulators proposed in Section 5.4.2, it is proposed that 65 HV monitors are deployed at a number of non SCADA country substations in the next reset period. The governance, monitoring solution and implementation for rural monitoring is further detailed in the Rural Monitoring and Control Philosophy [9] document.

It is also proposed to monitor transformers on specific country feeders and 19kV SWERs. This will aid customer service and help to reduce customer voltage complaints, and is an enabler for a two way power flow network.

Table 7: Monitoring solutions roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	N/A
Period 2 (2015 – 2020)	• Deploy 740 monitors at the SWER start and end of line (EOL). • Deploy 460 LV monitors for country feeders. • Deploy 65 HV monitors at small non-SCADA country substations.
Period 3 (2020 – 2025)	N/A

5.2.4 Padmount monitoring

Overloaded pad mounted transformers are expensive and time consuming to augment (either through upgrading the transformer or infill with an additional transformer). Pad mounted transformers are considered to be overloaded at greater than 100% capacity. To ensure that these transformers are not exceeding their capacity under normal operation, it is important to have an indication of the peak load on each transformer.

Given the large number of transformers on the network, it is not possible to go out and monitor each transformer individually. In order to determine which transformers are at risk of being overloaded, an "After Diversification Maximum Demand" (ADMD) approach is applied to each transformer to produce a shortlist of transformers which are considered to be at risk of being overloaded.

At present, in order to determine more accurate loading levels on these transformers, a short term load test is conducted on each transformer to estimate the actual load. SA Power Networks also currently relies on customer voltage enquiries to alert us to any voltage issues.

The proposed pad mounted transformer monitoring program will replace the short term load testing and instead permanent, remotely downloadable transformer monitors will be installed in each transformer. Not only will this enable us to monitor the load on each transformer, but it will also provide voltage monitoring.

5.2.4.1 Strategic Development

The pad mounted transformer monitoring proposal will be used to monitor specific transformers (with multiple customers connected and loads greater than 150kVA) which have been identified as being overloaded to verify and ensure compliance with statutory obligations.

635 pad mounted transformers in the metro area have been identified using ADMD as being loaded in excess of 100% of nameplate rating as well as supplying multiple customers and having a load greater than 150kVA. Over the next reset period, permanent monitoring devices are proposed to be installed in each of these padmount transformers.

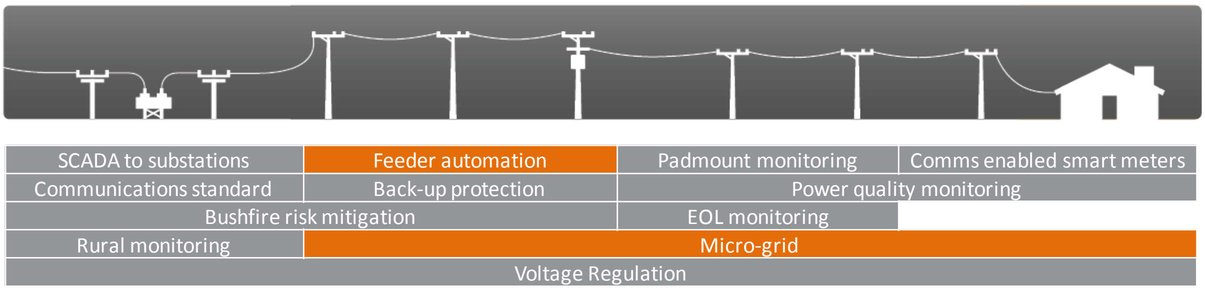
This expenditure will pro-actively assist customer service and reduce customer complaints particularly relating to high voltage at the customer's premises - often solar PV related. With the increase in distributed energy resources (DER), this additional data also will assist in the analysis of network impact of future connection of energy storage and electric vehicles. A pro-active approach will also allow prioritisation and optimisation of CAPEX resources by ensuring that each pad mounted transformer's life is maximised by only augmenting when it is actually overloaded.

Table 8: Pad mounted transformer monitoring roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	N/A
Period 2 (2015 – 2020)	• Deploy 635 targeted power quality monitors to be installed in selected pad mounted transformers.
Period 3 (2020 – 2025)	N/A

5.3 Manage Reliability

Deployment of new techniques to address poorly performing areas of the network and help mitigate the impact of extreme weather events.



Switching devices[7] such as reclosers provide the ability to switch and segment the HV network. These devices operate automatically to isolate faults on the network and have helped us to manage reliability, improve operational efficiency and provide a higher level of service to customers.

In future, technology such as battery storage, renewable generation, automation and load control has the potential to be combined to allow sections of the network regularly impacted by upstream outage to operate as a micro-grid during these events.

5.3.1 Feeder automation

It is currently difficult to achieve cost effective reliability solutions for feeders affected by heavy vegetation, lightning and ageing assets. The capability to automatically sectionalise faulted feeder sections and remotely restore supply to the un-faulted sections can be developed with the installation of advanced switching devices along these feeders.

Although reclosers have already been deployed on the network to assist with the sectionalisation of faults, a remotely controlled feeder tie can reduce the average outage duration that customers in the

[7] "HV switches" for the context of this strategy document are defined as reclosers or electronically controlled load switches (i.e. does not include circuit breakers or air disconnects).

un-faulted line sections would experience, allowing power to be restored in a more timely manner for these customers. This is particularly true during severe weather events, when our line crews are confronted with many restoration jobs and are required to place priority on community safety issues such as 'wires down' situations.

5.3.1.1 Strategic development

While there are benefits in terms of operational efficiency and risk management as a result of additional remote-controllable network switches, managing reliability on the worst performing feeders is the primary objective for the deployment of additional remote switching devices in the network.

To support this strategy, the ADMS Fault Location Isolation & Restoration (Advisory and Automated FLISR) application will be deployed to provide the intelligence to provide the automation of this process. The proposed development is outlined below, according to the relevant reset period.

Table 9: Feeder automation roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	• Kick-off multi-disciplinary project team incorporating skill sets from all affected areas of the business to progress the feeder automation project. • Trial of key equipment and concepts for use in the deployment. • Development/upgrade of mid-line switching devices. • Upgrade substation protection relays.
Period 2 (2015 – 2020)	• Introduction of automated supply restoration during 2016. • Upgrade of older telecommunications solutions. • Investigate the implementation of automation on further 33kV and 11kV lines. • Automation into BAU for network augmentation. • Development and implementation of ADMS FLISR (Advisory FLISR and Automated FLISR) module.
Period 3 (2020 – 2025)	• Develop substation outage automation capabilities.

5.3.2 Micro-grid trial

A micro-grid is an area of the network which can be configured to act independently of the grid. A key advantage of such a system is that it can either run completely independently or island itself during an outage and therefore improve the reliability to those customers connected to it. It could also provide grid support by running in parallel with the network to reduce peak load or help manage power quality in the area. Micro-grids can also be used to efficiently provide power to small, isolated communities where the cost of a grid connection can be prohibitive.

Remote areas of the network (in particular areas supplied by SWER systems) provide the ideal location to see the benefits of such a system, particularly where poor reliability is primarily as a result of upstream outages. For a SWER with poor reliability the per-customer cost to address this is often high as the customer numbers are generally small, however if a micro-grid can provide significant improvements for the customers affected it may present a viable option for some rural customers who experience reliability much worse than the state average.

In addition, SWERs are generally at the end of long lines and once exceeding their capacity, network augmentation can be very expensive. A micro-grid solution could provide an alternative augmentation option as well as providing voltage support and renewable energy integration. A micro-grid may also provide a feasible option for areas identified as bushfire safer places that may be disconnected from the main electricity grid during a bushfire event. In the future, micro-grids may also prove to be cost effective in providing electricity in new 'edge-of-grid' applications where the construction of a long grid connection may prove highly costly.

5.3.2.1 Strategic Development

During the 2015-20 regulatory control period SA Power Networks plans to conduct a micro-grid trial to investigate its use as a solution to improve the reliability to SA Power Networks' worst served customers. Secondary benefits that will be investigated as part of this trial are augmentation deferral, renewable integration and continuity of supply during bushfires.

As the focus of this trial is to improve service to a small number of worst served customers, it is unlikely to have a significant impact on the overall state reliability, but is expected to deliver improved service to the customers in the trial area.

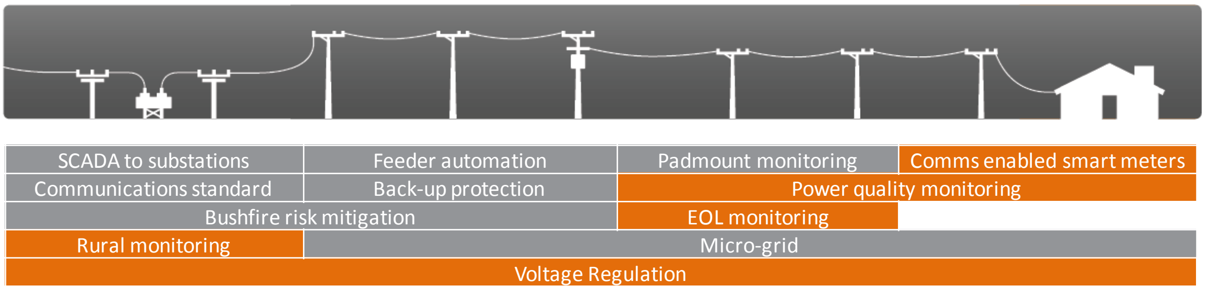
The trial will also incorporate a hot water load control trial which is outlined in the Flexible Load Strategy.

Table 10: Micro-grid trial roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	N/A
Period 2 (2015 – 2020)	• Install transformer monitoring on SWER isolating transformer in 2015. • Finalise micro-grid design based on data obtained from permanent monitoring. • Implement micro-grid trial.
Period 3 (2020 – 2025)	• Implementation of micro-grid on selected SWERs (dependent upon outcome of trial).

5.4 Enable a two-way network

Preparing the network to allow connection of additional embedded generation & new energy technologies.



Until five years ago, it was only possible to manage LV issues at the customer premises based on the topology of the network and the predictable flow of energy from centralised generation to consumers. Today, however, the network includes significant renewable generation, much of which is distributed throughout the network in small-scale residential solar PV systems. This causes variable two-way power flows in the LV network, which can cause significant localised swings in voltage.

5.4.1 Power quality monitoring

Modelling undertaken in 2014 [13] examined the impact of increasing penetration of solar PV and other DERs on the quality of supply at the customer premises. The study modelled 15 typical feeders representing a cross-section of categories of the supply area including underground, overhead and SWER. This study found that:

- On some old LV feeders in both overhead and underground networks, voltage regulation requirements limit acceptable solar PV penetration to around 25% of customers.
- Voltage unbalance, which simulations show to be in excess of the present 2% limit for one of the representative feeders, is exacerbated by the addition of credible penetration levels of DER, including DER other than solar.

Currently, the penetration of solar PV is nearly 22% of all households, and is forecast to rise further to 40% by 2020 and more than 50% by 2025. Therefore, this modelling suggests that many older feeders are already reaching saturation in terms of acceptable solar PV penetration and, without improved voltage regulation, many parts of the network may be unable to accommodate forecast increases in solar PV during the 2015-2020 regulatory period without triggering widespread customer power quality issues. These may include customer-visible fluctuations in voltage, increased failure rate of customer appliances, and customers' solar PV inverters tripping off the network due to overvoltage on mild sunny days, which reduces the benefit of their feed-in tariffs.

In the past, SA Power Networks has relied on customers calling up to inform us when there are localised power quality issues, a reactive approach that has been effective and efficient given the number and nature of issues arising each year. Now, however, with modelling indicating that SA Power Networks is potentially facing widespread issues, a reactive approach would seem imprudent.

The modelling indicates that in many cases power quality issues can be mitigated by relatively simple means, for example, tap changes at transformers or refining the operation of HV substation regulation, but the key element that is missing today is any visibility of actual power quality across the vast majority of the LV network. Although SA Power Networks has the means to address power quality issues, visibility is required in order to apply these solutions. Currently SA Power Networks has limited visibility of where those issues are emerging until such time as customers call in to complain.

5.4.1.1 Strategic development

If SA Power Networks is to continue to meet customer expectations and regulated power quality standards through the 2015-2020 regulatory period and beyond, we require the capability to monitor power quality through the LV network. As noted in section 5.2, SA Power Networks intends to undertake a LV monitoring program that will install grid-side monitoring devices at a number of LV transformers in the distribution network. These grid-side monitoring initiatives will establish permanent end-of-line capacity and power quality monitoring in rural areas of the network, as well as addressing some immediate problem areas where high solar penetration is already causing increased volumes of customer complaints. However, these initiatives will focus primarily on the power quality at the extremities of the HV network and provide only limited direct visibility of the LV network itself

From 2015, all new and replacement customer meters will be ‘smart capable’, meaning that they support an optional plug-in telecommunications module to enable remote monitoring of supply at the customer premises. As the population of smart capable meters grows, SA Power Networks will have a growing fleet of end-point telemetry devices distributed across the state that can be enabled specifically for remote power quality monitoring at low cost. This opportunity will be used to install telecommunications modules in meters for power quality monitoring (at the customer’s metering point) for a targeted subset of new and replacement meters. Any customer who is having a new three-phase meter installed, and is in an area where power quality issues are predicted, will be a candidate to have a monitoring module installed in their meter.

SA Power Networks’ 17,000 largest (in terms of customer numbers) LV transformer areas account for ~87% of the total customer base. The remainder of the network is characterised by a large number of LV feeders that each serve fewer than 10 customers, where it will be more effective to deploy targeted monitoring on a case-by-case basis. Of these 17,000 transformers, 10,442 are in areas served by older overhead infrastructure[8]. These are the areas where PSC modelling indicates there will be a significant increase in power quality issues in the 2015-20 period if solar penetration continues to grow according to projections.

SA Power Networks will aim to establish power quality monitoring at three customer premises per LV feeder in these target areas (an average of six per transformer). This will give enough data points to monitor customer’s supply point performance, detect and validate power quality issues for the customer’s supply point.

Based on the current proportion of three phase meters across the customer base, it is anticipated that ~15% of the new and replacement meters installed per annum will be candidates to be enabled as power quality monitors. At projected meter replacement rates the goal of three monitoring customer supply points per LV feeder by the end of 2021 will be achieved.

[8] Excluding a small number of areas targeted by other monitoring initiatives.

Table 11: Power quality monitoring roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	• Continue monitoring power quality in response to customer complaints at the customer's supply points and at supply transformers.
Period 2 (2015 – 2020)	• Install 85 targeted power quality monitors in existing areas with PV penetration greater than 10% compared to transformer capacity in 2013/14. • Install 50,000 communication modules in targeted meters throughout the state.
Period 3 (2020 – 2025)	• Install 12,000-15,000 communication modules in targeted meters throughout the state to bring coverage up to three monitoring points per LV feeder in target areas.

5.4.2 Voltage regulation

Increased monitoring will provide the visibility required to enable quality of supply standards to be maintained in the face of increasing penetration of customer-side DERs, underpinning customers' ability to participate more actively on the demand side of the energy market.

In many cases power quality issues can be mitigated by refining the operation of HV substation regulation once more visibility of the network has been achieved. Pro-active voltage regulation options rely on centralised data collection, either substation or ADMS based, to integrate the monitoring and control points in the network and enable flexibility in a dynamic environment.

Country areas often require targeted voltage regulation solutions, even without high penetration of solar PV. Of the 131 transformers tested in country regions in 2012, over 60% had a maximum voltage greater than 253V for a sustained period and only 4% (7 transformers) had a sustained voltage level less than 216V.

There are approximately 309 voltage regulators on the entire network, of which there are currently 35 (at 19 substations) which have SCADA capability. Of these, 8 have monitoring only whilst the other 27 have full control and monitoring. There are approximately 69 HV regulators which are capable of being upgraded to SCADA, however the remainder will require most likely a controller upgrade prior to SCADA retrofitting. Small numbers of LV voltage regulators are also being trialled on single and three phase.

5.4.2.1 Strategic development

The following voltage regulation improvement projects are proposed for the next reset period:

- **HV Regulators with SCADA at country substation** – currently there is no real time control or voltage information from some non SCADA substations which have fixed voltage. The implementation of HVR (with SCADA visibility and control) will allow some ability for the substation load to follow the customer load and ensure voltage levels comply with statutory requirements.
- **Remote voltage set point at metro substations** – deployment of remote voltage control and data acquisition at selected metro substations by installing remote voltage set point control via SCADA. Remote voltage control will be implemented at substations with high solar PV

penetration, above 10% compared to transformer capacity in 2013/14, to enable voltage control on high solar PV generation days.
- **Retrofit existing HVR with SCADA enabled controllers** – provision of remote connection to a subset of existing HV line regulators to confirm they are in service, provide remote voltage control and utilise their data acquisition capabilities.

Once a critical mass of power quality monitoring has been reached, the set point at these additional voltage regulation points will be managed through the SCADA system in conjunction with analysis of the power quality monitoring data undertaken in the ADMS.

The proposed roll out program is shown in Table 12 below.

Table 12: Two way grid solutions roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	• Continue management of power quality in response to customer complaints.
Period 2 (2015 – 2020)	• Implement targeted additional voltage regulation in problem areas including: – Install SCADA enabled HV regulators at 10 country substations. – Install remote voltage set point control via SCADA at 20 metro substations. – Retrofit 63 existing HV regulators with SCADA enabled controllers.
Period 3 (2020 – 2025)	• Install remote voltage set point control via SCADA at an additional 10[9] metro substations. • Implement dynamic control of voltage set points through ADMS.

[9] Subject to review during 2015-20.

6 PLANNING A 'SMARTER' NETWORK

It is important to appreciate that although the Smarter Network Strategy defines the application of smart grid technology to existing and future networks, many elements of this technology are actually already implemented on the network; from SCADA connected substations to intelligent mid line reclosers. A changing distribution environment calls for the use of rapidly evolving advances in smart technology, combined with new tools available in the ADMS, to better manage the network.

For this strategy to be successful, it is critical that planning with a 'smarter' network in mind is adopted by key network stakeholders and incorporated into SA Power Networks' business as usual operations.

6.1 Safety considerations

Prior to progressing any project design, equipment specification or installation of intelligent systems or equipment, it is important to consider safety aspects of the project. Developing the design in consultation with stakeholder cross functional teams is intended to identify potential hazards, provide a mechanism to asses and agree on the risk level and implement control measures as appropriate. Depending on the complexity or size of the project the number and detail of safety reviews may vary.

Increased penetration of customer side technologies poses new risks to the network and its operation. It will be important to keep abreast of this risk by understanding the operation, equipment failure modes and the requirements of the applicable standards.

6.2 Telecommunications operations

SA Power Networks' operational telecommunications systems are managed and controlled by the dedicated Telecommunications Network Operations Centre (TNOC) at Keswick. The TNOC is responsible for active monitoring and management of telecommunications systems and front-line troubleshooting.

An expansion of resources in the TNOC will be required to support the field area network infrastructure. SA Power Networks is currently reviewing a number of industry models that could see the TNOC assume responsibility for front-line monitoring and management of all new intelligent devices associated with the LV network, with the NOC remaining focused on managing the HV network.

6.3 Network standards

In addition to the smart grid foundational elements (identified at the start of this document), it is critical that the network is constructed to allow the most efficient integration of a smarter grid in accordance with the elements of this strategy. Without standards to support the Smarter Network Strategy, the applicability of these new technologies will be greatly impaired and in some cases may not be achieved.

Converting to new standards on a network scale comes at significant cost; therefore new standards are typically only introduced for new construction, upgrades and occasionally replacement. This results in long transition periods for new standards to reach saturation of the network and therefore it is imperative to implement these standards before they are required to ensure adequate future proofing of the network.

The implementation of 'smart standards' builds on methodologies which are currently being developed by the Networks Standards group. By investing in standardised and modular equipment with a focus on reliability, robustness, functionality and whole of life cost, the following benefits can be realised:

- Future proof equipment to enable functionality in the ADMS and other elements of this strategy;
- Improve safety by providing modular segregation;
- Reduce the need for expensive retro-fit;
- Allow easy upgrade for rapidly changing smart technology;
- Warranty and quality control;
- Installation and commissioning simplification;
- Easy end of life upgrade and replacement; and
- Minimisation of business risks.

6.4 System protection

Presently in the event of a network fault, the information supplied from remote electronic protection relays includes the fault type and in some instances fault level. While this provides an insight into an event, unless the device is set up to report fault current to SCADA, it does not provide an indication that fault current has passed the device if it does not trip.

It is also essential to provide insight into the operation of protection devices in order to maintain the performance of the system. There is already a system[10] in place to allow direct remote interrogation and analysis by protection engineers, however, fault recorders on many electronic relays are still read manually, creating significant overheads and a delay in investigating system performance issues.

6.5 LV network configuration

Relatively long LV lines of high impedance make it difficult to achieve supply voltage level compliance (to AS60038) where a high penetration of customer side technologies is present. While the new standard design is capable of absorbing a greater range of load conditions, further design consideration around these issues will help to future proof the network. Distribution transformer nominal voltage, the length of mains, the service line to the customer, the loading on the transformers and distributed generation affects the ability of that LV network to supply customers with compliant power.

Often issues in the LV network can be remedied by conducting load transfer and/or balancing. The lack of sufficient suitable tie points, especially in the underground network, and the lack of customer phase records make these options difficult to achieve. It is important that these are systematically addressed to allow for the effective management of the LV network.

6.6 Future proofing equipment

As intelligent network equipment evolves and the reliance on such equipment increases, a fundamental change to the approach of equipment engineering is required; from device functionality to supply contracts. Intelligent equipment has a much shorter life span as a result of both electronics life and the rapid rate at which technology becomes obsolete, requiring a change to design philosophies.

[10] RATPAC – Remote Access to Protection and Control

The existing SCADA deployment strategy aims at ensuring that the installation, or upgrade of new reclosers and SCADA assets inside substations improves future functionality of the grid while aligning with industry standards and best practice to ensure ongoing adaptability and modernisation of the network.

6.7 Future proofing assets

In a move to 'future-proof' the network, SA Power Networks' standard HV switching cubicle is now supplied with the capability to retro-fit a RTU to provide remote monitoring and control of the cubicle. In a similar strategy, it is proposed to provide all future padmount transformers with facilities to easily retro-fit transformer monitoring equipment. With the current cost and lifespan of monitoring equipment, the installation of monitoring equipment will be based on retro-fitting older transformers. Currently, retrofitting transformer monitoring, specifically voltage reference connection in pad mounted transformers is difficult, labour intensive and occasionally requires interruption of customer supply. Providing a method to easily retrofit transformers for future application will improve the speed, neatness and safety of these installations.

Similarly the cost to retrofit dissolved gas analysis monitoring to substation transformers is prohibitive. Providing the facility for easy install and replacement of online DGA monitoring units in transformers and tap changers will allow for cost effective online monitoring of these assets.

6.8 Focusing on reliability

Current planning criteria only have a secondary focus on customer numbers and potential STPIS impact; hence while a load transfer may defer capital, a fault event on that feeder could incur significant penalties. Additionally, any reconfiguration of the network as the result of these load transfers can result in the obsolescence of the position of fault sectionalising switches. Similarly, a reliability project could be implemented in an area planned for upgrade or reconfiguration within a short period and not achieve the desired benefit, requiring anything from settings reconfiguration to moving and recommissioning the device.

In order to maximise the benefits of remote sectionalisation and supply restoration, it is essential that feeder topology and capacity is designed to allow for the transfer of load between feeders to aid the restoration of customers on faulted feeders.

6.9 Asset Management

As an increasing number of intelligent network devices, meters and sensors are deployed much more information will be available on the network's assets and equipment supporting the move toward strategic asset management which is built on three key ideas;

- Alignment with levels-of-service;
- Expenditure as an investment; and
- Empowerment of the field.

Operationally more data and analysis about SA Power Networks' assets will potentially increase customer value by the use of more efficient maintenance practices with initiatives such as automated maintenance triggers and gathering inferred intelligence on downstream 'non-smart' equipment.

The asset management strategy sets out the roadmap for the integration of 'smart' devices and the systems and processes required to deliver the next step in asset management.

6.10 Planning criteria

With the increase in intelligent remote monitoring and control in the network, not only will more systems and information be available to assist the efficient planning of the network, but the planning of the network will have to adapt to new standards and skill set requirements.

Currently the planning of the network is not optimised due to the lack of available data on SA Power Networks' assets and planning criteria based around the current operational model. With the increasing penetration of remote monitoring and control, advances in the visibility and operational flexibility of the network will provide an avenue for more efficient and potentially less conservative planning of the network. As the integration of remote switches in the network increases, planning criteria will need to be reassessed accordingly.

6.11 Management

Communications, inter-operability, ease of integration, adaptability, upgradability and range of functionality play an important role in modern device engineering and as a result, the physical properties of equipment are no longer the sole focus of specification and assessment. With the integration of IT into network infrastructure, consideration must be placed on the skill sets required of engineering, installation and maintenance personnel.

This requires SA Power Networks' management to adapt accordingly and as a result additional roles in the planning area have already been established to take responsibility for the planning and on-going management of feeder automation and deployment of 'smart' devices. This will ensure focus on intelligent solutions, providing better specification coordination and leveraging a greater number of benefits.

6.11.1 Implementation plan

- Whenever construction work involving a feeder is undertaken, a review is placed not only on capacity requirements, but the ability to improve the smart functionality on that feeder including the position of tie points and line capacity.
- Place feeder ties as close to the end of the feeder as practical - an assessment of any additional cost implications should be compared with the level of benefit achieved from such configurations.
- Wherever a reliability solution is implemented with mid-line switches, ensure all devices on that feeder and any selected tie points are configured for fault passage indication unless it is uneconomical to do so.
- Continue to upgrade to electronic relays wherever mid-line protection devices are added or upgraded.
- For all new and upgraded relay installations, protection only lock-out indication for future automation implementation.
- Conduct a review of current network switches and create an action plan for the solution of current issues and development of the required functionality.
- Trial any new equipment or configurations for review by mid-2014.
- Develop a system to provide remote fault diagnostics, and conduct automated performance analysis of the system.
- Develop and implement an adaptive, centralised control methodology to allow feeder automation on sites with export distributed generation is greater than 1MW (i.e. rotating plant).
- Conduct a review of LV network design to ensure future compatibility including transformer size, transformer nominal tapping, loading, mains, customer service line, switching points.

- Conduct a review of the Service and Installation Rules to include:
  - Allowable volt drop and rise per house;
  - Customer funded service line upgrade requirements for DER customers.
- All new and reconditioned padmount transformers (250 per year) to be supplied with facilities to easily retrofit monitoring equipment including unit mounting, current and voltage connections.
- All maintenance jobs involving the outage of a padmount transformer to include the installation of accessories to allow the easy retrofit of monitoring units at a later date.
- Strategic substation transformers specification (i.e. 20MVA and above) to be updated to include DGA monitoring as standard using generic fittings for easy future replacement at end of equipment life.
- Conduct a review of current planning criteria, to coordinate the requirements of the smart grid and provide a united and future proof approach to network design.
- Investigate the application of remote monitoring and control whenever specifying applicable projects.
- Network planners, as experts on their area, should provide the central management and coordination of all projects works conducted in their areas including reliability projects.
- Develop a smart equipment purchasing contract with a combination of equipment and IT elements to reflect the requirements of new equipment.
- Conduct a review of organisational structures to investigate the optimum solution to managing a smart network.

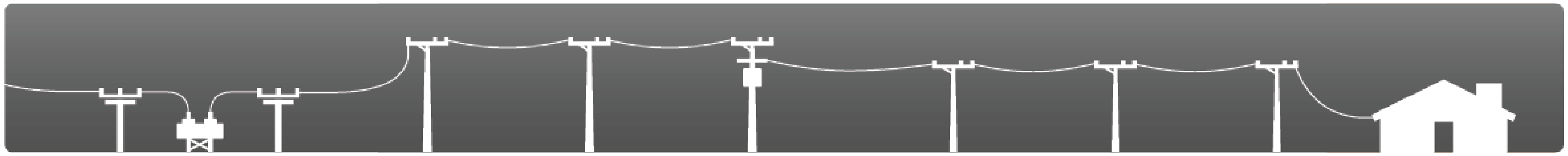
7 IMPACT ON KEY ROLES

The effects of a smarter HV network on the roles of key personnel are displayed in the table below:

Table 13: Effect on roles - a smarter HV network

Role	Effects
Network Planners	Have the required tools and visibility to efficiently model and plan the network with more accuracy and fewer assumptions.
Asset Managers	Are able to determine a reliable assessment of current asset health and plan for the pro-active replacement of assets prior to their catastrophic failure and emergency replacement.
Network Standards	Technical Standards and Equipment Engineers will need to consider: • minimum whole of life cost; • standardization/rationalization; • technical standards; • emerging technologies; and • standard design templates.
Network Controllers	Are aware of the state of the network and can provide real-time remote control of the network. Can quickly respond to, isolate and restore the network remotely, with a minimum of control input. Are able to provide fast and accurate advice to field crews in response to changing conditions. Are aware of the operational condition of assets and are able to provide management of impending failures and load management in peak load conditions. Have increased visibility during emergency conditions and are able to make firmer decisions. Are able to remotely change protection settings on all reclosers located within bushfire regions to prevent reclosing onto network faults. Can assist the crew to restore the network after a fault repair.
Field Crew	Are dispatched directly to where they are required with the intelligence of fault type and location. Can concentrate on finding the exact cause and location of the fault and repairing it. Spend less time manually switching. Are freed to respond to other network faults. Do not have to travel to or enter the substation and reclosers for switching.
Substation Designers	Are able to design substations more efficiently resulting from a simplified and standardised design. This is facilitated by both the standardised design efforts currently being undertaken by Network Standards and Performance.

8 CONSOLIDATED ROADMAP



	Substations		HV network		LV network		Customers	
	# of smart device/number of points							
2015	SCADA substations[1]	229	SCADA switches[2]	466	TF monitoring	200	Comms-enabled meters	2,000
2020		274		821		2,120		50,000
2025		319		1,066		2,120		63,000
	Foundations							
Systems	SCADA/ADMS		SCADA/ADMS		ADMS		MMS	
Tel	Fibre/NBN		4G/Private		4G/Mesh radio		4G/Mesh radio	
Data	Historian		Historian		Historian		MMS	
	Initiatives							
	SCADA to substations		Feeder automation		Padmount monitoring		Comms-enabled meters	
	Communications standard		Back-up protection		Power quality monitoring			
	Bushfire risk mitigation				EOL monitoring			
	Rural monitoring		Micro-grid					
	Voltage Regulation							

[1] Number of SCADA substations with monitoring and control (i.e. excludes substations with monitoring only).

[2] Number of SCADA HV switches (includes load switches and reclosers - excludes circuit breakers and air disconnects) with monitoring and control (i.e. excludes switches with monitoring only).

Figure 6: Consolidated monitoring and control roadmap

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GLOSSARY

Abbreviation	Definition
ADMD	After Diversity Maximum Demand
ADMS	Advanced Distribution Management System
AER	Australian Energy Regulator
CAPEX	Capital Expenditure
CDM	Common Data Model
CIM	Common Information Model
DER	Distributed Energy Resources
DSP	Demand-Side Participation
EOL	End of Line
EV	Electric Vehicle
FDL	Fire Danger Level
FLISR	Fault Location Isolation and Supply Restoration
FOM	Future Operating Model
GFN	Ground Fault Neutraliser
HBFRA	High Bush Fire Risk Area
HV	High Voltage
HVR	High Voltage Regulators
ITSP	Integrated Technology & Systems Plan
IP	Internet Protocol
KPI	Key Performance Indicator
KRA	Key Results Area
LV	Low Voltage
MBFRA	Medium Bushfire Risk Area
MPLS	Multi Protocol Label Switching
NBN	National Broadband Network
NOC	Network Operation Centre
NOM	Network Operational Model
OGC	Open Geospatial Consortium
OMS	Outage Management System
OPEX	Operational Expenditure
PD	Partial Discharge
PV	Photovoltaic (solar energy generation)
QS	Quality of Supply
RF	Radio Frequency
RIT-D	Regulatory Investment Test - Distribution

RTU	Remote terminal unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TDU	Telephone Dialling Units
VBRC	Victorian Bushfire Royal Commission
WH&S	Work Health and Safety