Network Performance
Distribution System SCADA (DSS)
Capability Project

Project Note

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Version	**Release Date**	**Author**	**Notes**
0.1		nah	Outline.
0.2		nah	First draft (up to Section 5.2).
0.3		nah	Feedback incorporated. Sections 5.3 – end written.
1.0	24/11/2006	nah	Feedback incorporated. “Universal switch” issue added. IP enablement issue added. First release.
1.1	25/1/2007	nah	Minor corrections. Tavrida reference changed to NOJA. Requirement for remote (manual) configuration management capability added. Reference to DNP3 virtual terminal objects added.
1.2	20/2/2007	nah	Small addition to words on proposed system.
1.2(a)	28/2/2007	nah	Copyright notice and disclaimer added for IEEE release.

1. Contents

2. Disclaimer

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3. Scope

3.1 Identification

This document describes Distribution System SCADA (DSS) as envisaged by the Technology Planning Team and DSS users.

The scope of this document includes:

- Deployment (planning, design, construction and commissioning) processes, tools and resources (as impacted by DSS requirements)
- Operating processes, tools and resources (as impacted by DSS requirements)
- Architecture and specifications for equipment and systems (as impacted by DSS requirements)

Terminology note: In the past, “Distribution System Automation” (DSA) has been used as a collective term for remote monitoring and control of the distribution network. In this and related documents, the term “DSA” will be reserved for automated (as opposed to manual) operation of the distribution network.

3.2 Document Overview

The structure of this document follows the recommendations of IEEE Standard 1362 [1]. The document opens with a description of the current system. The justification for and nature of changes are discussed. Next, the proposed future system is described. Operational scenarios for the proposed future system are outlined. The document closes with a summary of impacts and an analysis of the proposed system. References to additional detail are included where appropriate.

Note: All figures appear at the end of the document.

3.3 System Overview

Figure 1 is a user-centred view of DSS. Distribution system equipment is monitored and controlled by Network Operations personnel. Status and controls are ferried from end to end via a communications network.

Figure 2 depicts concepts which underpin the user-centred view – see Project Note 2 [3] for a more detailed rendition.

4. Referenced Documents

1. IEEE Standard 1362-1998, *IEEE Guide for Information Technology – System Definition – Concept of Operations Document*
2. DSS Capability Project - Project Note 1, *Glossary*
3. DSS Capability Project - Project Note 2, *DSS Concept Space*
4. ENERGEX Network Technology Plan 2005-2025 - Project Note 35, *Executive Summary*
5. ENERGEX Network Technology Plan 2005-2025 - Project Note 4, *Network Reliability Targets 2004/05 -2019/20*
6. ENERGEX Network Technology Plan 2005-2025 - Initiatives Document 11, *Distribution System SCADA (DSS)*
7. ENERGEX, *Strategic Investment Department Guidelines*
8. ENERGEX BMS 01615, *Standard Network Building Blocks*
9. ENERGEX BMS 01611, *Operating Practices Manual*
10. ENERGEX, *DSA Analogue Communication Network Overview* (available from Network Automation Department)
11. ENERGEX, *DSA Digital Communication Network Overview* (available from Network Automation Department)
12. ENERGEX, Plan Library reference 14930-A1, *Control System Equipment, Substation and RDC, Communication Configuration, Block Diagram*
13. ENERGEX BMS 00729, *Provide Standard Products and Services*
14. DSS Capability Project – Project Note 6, *Timeliness of SCADA Data*
15. DSS Capability Project – Project Note 9, *11kV Feeder Topological Profiling*
16. ENERGEX, Minutes of 6 July 2006 Meeting, *Discuss and Review DSA Workflow* (and attachment)
17. DSS Capability Project – Project Note 13, *Application of the Manual Reclose Policy Using DSS*
18. ENERGEX Network Technology Plan 2005-2025 - Project Note 17, *Narrative*
19. DSS Capability Project – Project Note 14, *DSS Deployment Process*
20. ENERGEX Network Technology Plan 2005-2025 - *Telecommunications Strategy* (PowerPoint Presentation)
21. ENERGEX Network Technology Plan 2005-2025 – *Telecommunications* (Board Briefing Materials)
22. ENERGEX, Strategic Investment Department Guideline SP02 – *Network Planning Criteria*, 18/2/2005

5. Current System

5.1 Background, Objectives and Scope

Distribution System SCADA is SCADA for widely dispersed network facilities such as reclosers, sectionalisers, load break switches, isolators, regulators and fault indicators.

The primary objective of DSS is to improve network reliability by reducing CAIDI. CAIDI reduction is achieved through:

- Remotely controlled sectionalising and restoration.
- Remotely controlled switching as an aid to manual sectionalising and restoration.
- Remotely controlled load transfer in compliance with the requirements of [22] for the *N-1 (short loss for N-2)* and *N (short loss for N-1)* load classes (restoration required within 15 minutes).

Secondary and allied objectives include:

- To improve network reliability by reducing SAIFI (reclosers and sectionalisers).
- To improve the reliability of supply to high priority loads such as hospitals
- To improve network observability for performance monitoring, system investigations and planning purposes.

Since the late 1980s, ENERGEX has developed DSS expertise and experience, firstly through in-house development and currently through the integration of commercial products and systems based on international standards.

A rough chronology is as follows:

Late 1980s

Research and development. Initial set of products based on customised switching devices and in-house RTUs. ENERGEX's 900MHz point-to-multipoint analogue radio system used for SCADA communications.

1990

DSA Planning and Design Manual published. Products and processes standardised.

Early 1990s

Adoption of "Plug-and-Play" philosophy. Standards based on Nu-Lec switching devices communicating via MCP.

Late 1990s

DNP3 adopted as the standard protocol for IED-SACS communications in substations. Push to adopt DNP3 for DSS.

Early 2000s

GSM adopted as an alternative to radio. DNP3 with unsolicited response adopted for DSS, but restricted to GSM sites and newer 900/450MHz mountaintops. First NOJA Power OSM15 reclosers installed.

2005

Approximately 300 switching devices in service using GSM and 900/450MHz radio.

The production of the DSA Planning and Design Manual was motivated by the chaos, rework, high failure rates and risks to safety that typically accompanied early DSS projects. The initial flurry of R&D resulted in emotional "highs" and unrealistically low expectations about the cost and effort required to achieve consistent results.

A short list of the pitfalls addressed by the Manual includes:

- Failure to check radio signal strength at the preferred site of the distribution system equipment.
- Failure to check earthing conditions at the preferred site.
- Failure to account for pre-existing equipment at the preferred site.
- Failure to identify alternative sites in the event of the preferred site not being viable.
- Failure to design site earthing for both personnel safety and equipment reliability.
- Failure to allow for the substantial added costs of "remote radios" where needed.

- Failure to coordinate protection between substation circuit breakers, reclosers, sectionalisers and MDOs.
- Failure to allow for design, build and commissioning costs in the total project cost.
- Failure to obtain network operations concurrence on scheme design.

All of these pitfalls still exist. They can be avoided only through adherence to work processes based on sound engineering principles.

The steps to successful commissioning of new equipment include:

- Scheme concept.
- Project initiation.
- Site survey and selection.
- Preliminary design and cost estimate.
- Detailed design and cost estimate.
- Design acceptance.
- SCADA system build and test.
- Scheme acceptance.
- Commissioning.
- Project closeout.
- Performance review and benefits assessment.

5.2 Operational Policies and Constraints

The *development* of DSS is controlled by the Provide Standard Products and Services macro process [13].

The *deployment* of DSS is controlled by ENERGEX policies, guidelines, standards and procedures for planning and design. These include: the Network Strategic Investment Department Guidelines [7]; and the Standard Network Building Blocks [8].

The *operation* of DSS is controlled by the Operating Practices Manual [9].

The *maintenance* of DSS-related equipment is covered by ENERGEX policies, guidelines, standards, procedures and manuals for maintenance.

5.3 Description of the Current System

The operational DSS system comprises the following major subsystems (for high-level schematic diagrams see [10], [11] and [12]):

5.3.1 Distribution System Equipment

Distribution system equipment comprises circuit breakers, reclosers, sectionalisers, load break switches, isolators, regulators and fault indicators. Controllers/RTUs are a mix of ENERGEX, third party and integrated controllers/RTUs.

5.3.2 Communications (Distribution System Equipment to RDCs)

At a high level, each communication pathway between distribution system equipment and an RDC comprises a wireless component and a backhaul component.

The wireless component is either (a) 900/450MHz analogue radio, where 900MHz is used to and from mountaintop base stations, and 450MHz is used to and from “infill” repeaters,

(b) 900MHz digital radio to and from mountaintop base stations, or (c) the Telstra GSM/GPRS network.

The backhaul component is either (a) point-to-point channels through the ENERGEX bearer network, (b) a Telstra ISDN link to the PSTN for GSM, or (c) an IP link to the Telstra data network for GPRS.

The communication protocol is either MCP or DNP3.

5.3.3 Remote Data Concentrators (RDCs)

ENERGEX RDCs are used for protocol translation and data marshalling. As a general rule, the sites covered by each 900MHz base station are aggregated into one or more mountaintop databases.

Each RDC provides a user interface for maintenance users via command line utilities.

5.3.4 Communications (RDCs to DMS)

The RDCs communicate with the DMS via point-to-point channels through the ENERGEX bearer network. The communication protocol is RDCCOM.

Over time, RDC-to-DMS communications will migrate to ENERGEX's TCP/IP WAN.

5.3.5 Distribution Management System (DMS)

SCADA points from the RDCs are mapped into the ECS database. Where DNP3 unsolicited response is used, the associated points may contain "stale" data for most of the time (this is covered in more detail in [14]).

The DMS provides the primary user interface to Network Operations users. SCADA points are displayed on "world maps" – graphical displays on which ECS, PDB and static data may be displayed in any useful combination.

5.3.6 Alarm Logging Facility (ALF)

ALF:

- Provides a backup[1] user interface to Network Operations users via IMP displays.
- Feeds a user interface for view-only users, again via IMP displays.
- Feeds the logging subsystem.

5.3.7 Design and Configuration Management

The SCADA configuration is maintained in NetCore and generated from there for each target system.

The power system configuration is maintained in NFM using Planet, Works Plans 200x and the Works Plans Data Maintenance Tool. The network model is periodically exported to the DMS using Oracle scripts.

World maps are held on disk in the DMS development environment.

The ENERGEX bearer network configuration is maintained in the CBMD system.

[1] Pending completion of the Maxi-MOPs rollout, this is the primary user interface for MOPs style commands.

RTU and RDC changes are applied by selectively stopping, reconfiguring and restarting the affected components.

ECS and PDB changes are applied to the DMS using the DBGEN utility. World map changes are applied to the DMS using the RDIST utility.

5.4 Modes of Operation for the Current System

(Not applicable)

5.5 User Classes and Other Involved Personnel

The principle users of DSS are Network Operations personnel involved in planned and unplanned network operation.

In planned operation, DSS is used to reduce the time and effort required for switching, especially to disable automatic reclosing for live-line work and to adjust regulator taps for feeder paralleling. In unplanned operation, DSS is used to reduce the time and effort required to locate and isolate faults, and restore supply.

Other users, many of whom rely on the historical data captured by (or accessible via) the SCADA system, include:

- Planners (capacity planning, reliability planning).
- Asset management and maintenance personnel (performance monitoring, system investigations, maintenance).
- SCADA installation and maintenance personnel.

5.6 Support Environment

DSS planning principles and planning guidelines are co-produced by Network Strategic Investment and Reliability & Network Performance.

The standard network building blocks are maintained by Technical Standards.

DSS deployments are initiated by Distribution & Reliability Planning.

DSS design is carried out by Network Automation (SCADA) and Network Communications (communications).

Protection design is carried out by Protection Engineering.

HV equipment installation, maintenance and support are provided by Energy Delivery.

Communications installation, maintenance and support are provided by Network Communications.

SCADA installation, maintenance and support are provided by SCADA Services.

Network data maintenance is carried out by Network Data Quality.

Maintenance policies and standards are provided by Maintenance Standards.

IT systems development and support are provided by SPARQ Solutions.

6. Justification for and Nature of Changes

6.1 Justification for Changes

6.1.1 Network Reliability

The reliability performance of the ENERGEX network is generally below the national average for comparable organisations, and far below the 20-year targets proposed by the Technology Planning Team [4], [5].

High-level investigations have shown that dramatic improvements in CAIDI and SAIDI are possible through the use of DSS.

To be effective, the population of remotely monitored and controlled equipment must be sufficient to allow the location and isolation of faults, and the restoration of supply to be effected from Control Centre. Installing four switching devices per feeder (two for backbone sectionalising and two for transferring load to adjacent feeders) would result in a population of about 3 900 devices (compared with the current population of about 300).

6.1.2 Limitations of Current System

Note: These limitations are stated without comment as to causes or possible remedies.

- **Limited rollout capability**: Already discussed.
- **Obsolescent SCADA protocols, controllers and radios**: The “legacy” DSS system is based on MCP, Poletop Microcontrollers and analogue radios. ENERGEX has abandoned MCP (ENERGEX proprietary) in favour of DNP3 (an international standard). Poletop Microcontrollers are no longer available, and cannot be converted from MCP to DNP3. Analogue radios are no longer available - some are being recovered for use as spares through the migration of existing DSS sites to digital radio.
- **Limited communications bandwidth**: SCADA communications in the existing system are based on cyclic polling. Given the bandwidth limitations of existing and anticipated future communications networks, a major rollout of DSS will force a change to DNP3 “unsolicited response” mode.
- **Incomplete communications coverage**: 900MHz radio is essentially a “line of sight” system. 900/450MHz repeaters are currently being used for “infill” where required.
- **Minimal security on wireless links**: The change from MCP to DNP3 means that radio communications are no longer protected by “security through obscurity”.
- **Single protocol communications**: The existing analogue and digital radio systems do not allow multiple application protocols to be carried simultaneously. Given the scarcity of spectrum space, this unnecessarily limits communications options.
- **Unmanaged radio infrastructure**: Self-monitoring and consistency checking should be fundamental requirements, especially with the move to DNP3 “unsolicited response” mode. ENERGEX should not have to wait for a command to fail or a customer to call in order to discover that something in the communications system is broken.
- **Inefficient deployment process**: Many aspects of the existing deployment process are not scaleable, or guaranteed to be effective. Example 1: Deployment has been carried out on a piecemeal basis, one or two sites at a time. Example 2: Site survey and selection has often been delegated to the person doing the communications survey work.
- **Inadequate feeder and tie capacity**: Capacity constraints and/or the absence of ties limit the ability to transfer load between feeders.
- **Limited DMS world maps**: The system of record for the state of the primary distribution network is the 11kV wallboards. World maps generally do not exist for the

primary distribution network - coverage is limited to simplified representations of DSS "schemes".
- **Limited DMS network model**: The network model in the DMS is a reduced representation of the network, maintained by periodic update from NFM. It is not as effective in supporting power system applications as a detailed, real-time model would be.
- **Limited DMS applications**: The absence of automated outage analysis, load flow and offline study tools raises the possibility of operator "information overload" as the network grows.

6.2 Description of Desired Changes

The DSS initiative [6] seeks to scale up ENERGEX's DSS capability by standardising equipment requirements and specifications, dedicating resources to the rollout, and ensuring that the equipment is reliable.

A commissioning rate of 1-2 per working day is being sought, compared with 300 commissionings over 15 years (or one per 10 working days) to date. Even at the rate of two per day, it will take nearly 10 years to achieve the target population of 3 900 switching devices.

Success is contingent on a general reduction in feeder utilisation, the establishment of transfer capacity between feeders through a targeted reconductoring programme, and the establishment of a high availability DSS communications network.

The end-to-end process can be accelerated in various ways including:

- Focusing resources.
- Increasing resources - subject to adequate training, tooling and support.
- Batching.
- Standardisation of projects.
- Standardisation of equipment.
- Automation of design, build and test steps.
- Process compaction through parallel working.
- Process compaction through multi-skilling
- Contracting out of specialist skills and equipment.
- Off-site prefabrication.
- Direct-to-site delivery, installation and commissioning.

Some of these measures can also reduce costs.

6.3 Priorities Among Changes

The most urgent changes are:

- To establish a DSS communications network with adequate coverage, capacity, and availability.
- To establish a deployment process capable of 1-2 commissionings per working day for several years.
- To establish the necessary operational capability in Network Operations.

6.4 Changes Considered but Not Included

Refer to scope exclusions under Concepts for the Proposed System - Background, Objectives and Scope.

7. Concepts for the Proposed System

7.1 Background, Objectives and Scope

The background and objectives are substantially as per the current system.

Included in the scope:

- Processes, tools and resources for deployment (planning, design, construction and commissioning) - as impacted by DSS requirements.
- Processes, tools and resources for network operations - as impacted by DSS requirements.
- Architecture and specifications for equipment and systems - as impacted by DSS requirements.
- Suitability of equipment for use in future simple DSA systems (forward compatibility).
- Decommissioning of obsolete processes, tools and equipment.

Excluded from the scope:

- Policies and guidelines for development, deployment, operation and maintenance.
- Processes, tools and resources for maintenance.
- Network architecture, including performance standards, topologies, ratings, etc. by load category. This is the subject of another initiative.
- Distribution System Automation (DSA). Commercial products and systems for DSA are beginning to appear in the market. They vary considerably in terms of architecture, maturity and demands on common infrastructure (especially communications and middleware). Functional interoperability standards are largely non-existent. Given these factors, ENERGEX's prior experience, and ENERGEX's current policy not to adopt "bleeding edge" technologies, DSA has been ruled out for the time being.

7.2 Operational Policies and Constraints

Operational policies and constraints will be substantially as per the current system.

7.3 Description of the Proposed System

7.3.1 Distribution Feeders

Characteristics

At the time of writing, 11kV Urban and Rural [2] feeders have the following gross characteristics:

	Category	
	Urban	**Rural**
Number of feeders	1203	341
Number of tie feeders[3]	293	26
Number of teed feeders	5	2
Route length per feeder overall (km)	5.2	43.2
Ratio of OH to UG route length overall	1.3	14.8

[2] See [2] for category definitions
[3] See [15] for definitions of tie feeders and teed feeders

	Category	
	Urban	**Rural**
OH-UG transitions per feeder overall	5.2	6.9
Transformers per feeder overall	13.5	72.5
Installed capacity per feeder overall (kV.A)	5266	7342
Average 2005/6 POE50 load overall (kV.A)	3241	3037
Premises per feeder overall	644.4	930.0
Topological profile[4] [5] overall	1/3/1 (absolute)	1/9/6/1 (absolute)
Average radial extent (km)	1.73	29.5
Ties per feeder overall	3.1	5.0
Average radial distance from tie to supply point overall (km)	1.5	3.9

The number of feeders in both categories will grow in line with population growth, air conditioning load growth and network reliability requirements. The proportion of underground and/or covered conductor in urban feeders will continue to grow. To improve network reliability, the number of OH-UG transitions per feeder will be reduced.

Assessment

The following broad conclusions can be drawn from the characteristics listed above:

- Ties will be useful for restoration (subject to capacity constraints) in urban areas where, on average, they are located more than half way along the feeders. Ties will not be useful for restoration in rural areas where they are clustered near the supply point.
- The use of reclosers in urban areas will be problematic due to protection grading problems (this has been confirmed in practice). Blocking schemes can be used to overcome protection grading problems, however these require fast protection signalling, which does not come cheaply unless pilot cables, optical fibres or high-speed wireless communications are readily available.
- The use of reclosers and sectionalisers will be more successful in rural areas where grading is easier.
- Accordingly, the DSS reliability improvement strategy for urban areas should be based on manual sectionalising and load transfer, while the strategy for rural areas should be based on automatic reclosing and sectionalising.
- In the absence of effective fault indicators, CAIDI will be high for feeders with “long” topological profiles. Some feeders now contain significant numbers of underground tee joints without isolation or fault indicators.
- For mixed OH/UG feeders with a high proportion of OH, it is important that fault indicators (whether located on overhead conductors or in RMUs) be effective for both phase faults and earth faults.

[4] See [15] for a definition of topological profile

[5] Rounded to the nearest integer

7.3.2 Distribution System Equipment

Distribution system equipment will comprise circuit breakers, reclosers, sectionalisers, load break switches, isolators, regulators and fault indicators.

To enable fast, high-volume deployment, the following specification principles have been developed.

All required functions should be delivered with the equipment. This includes both primary and secondary functions:

- Primary system connection
- Switching
- Testing and earthing
- Power system measurements
- Protection
- Through fault and (where appropriate) internal fault indication
- Local automation
- Indication and control (local and remote)
- Configuration management (local and remote)
- Primary systems supervision and diagnostics (local and remote)
- Secondary systems supervision and diagnostics (local and remote)
- Logical communications
- Physical communications[6]
- Power supplies for secondary systems, including battery backup
- Housing
- Mounting

As far as is economically possible, all functions should accommodate both short-term operational and long-term evolutionary changes in the primary network. The means:

- The widest possible range of operating modes (recloser, sectionaliser, load break switch, isolator) compatible with equipment ratings.
- A wide range of settings, exceeding the requirements of all anticipated applications.
- Directional/bidirectional protection.
- Bidirectional voltage regulation.
- Multiple setting groups for protection, voltage regulation and local automation.
- Remote and/or automatic setting group selection.

Variations should be minimised. This can be achieved by basing specifications on a complete range of application requirements and constraints. In the past, time consuming and expensive variations have been caused by:

- Inadequate communications coverage. See Communications (Distribution System Equipment to RDCs).
- The unavailability of auxiliary power. An optional 11kV-LV auxiliary supply transformer should be a specification requirement for switching devices and regulators.
- The adaptation of legacy equipment. Legacy equipment should not be adapted.
- Custom automation requirements. Local automation should be standardised; DSA has been ruled out for the time being.[7]

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[6] Integrated physical (radio) communications capability is not a realistic goal for the next generation of equipment. As a result, the equipment will have to accommodate, interface to, and provide battery-backed power for, third party communications equipment.

[7] Put another way: The development of custom automation schemes should not divert resources from the DSS rollout.

"Plug-and-Play" installation and commissioning[8]. This means:

- International Standards should apply at all interfaces (physical and logical) to the equipment.
- Configuration management systems should be integrated and automated.
- Generic and/or self-configuring solutions should be adopted in preference to site/scheme-specific solutions.
- Physical communications equipment should be installed by the manufacturer or vendor before delivery.
- End-to-end communications should be tested before delivery.
- The range of commissioning tests required should be minimised through the use of standard configurations.

Systems integration and testing, and possibly also installation and commissioning, should be carried out by the manufacturer or vendor, not by ENERGEX.

A low total cost of ownership (not necessarily the lowest acquisition cost) should be pursued. This means:

- Costs should be assessed across the life of the equipment and associated systems, from deployment through operation and maintenance to disposal. Engineering experience indicates that this will be achieved by deploying equipment and systems which are simple, reliable and mainstream.

An associated goal is a reduction in the number of manually operated air break switches in the 11kV network. To achieve this:

- The switching devices must be suitable for use as isolation points.

7.3.3 Communications (Distribution System Equipment to RDCs)

ENERGEX will use private networks in preference to public networks for SCADA communication [20], [21]. Public networks will be used where available and there is no private network coverage.

Each communication pathway between distribution system equipment and an RDC will comprise a wireless component and a backhaul component. Options currently under evaluation for the private wireless component are:

- 900/450MHz point-to-multipoint digital radio with "infill" repeaters.
- 900MHz, spread-spectrum, mesh radio.

GSM/GPRS will be used for the public wireless component, as at present. New technologies such as W-CDMA will be adopted as available and when cost effective.

Redundant wireless links will be provided for critical equipment.

The backhaul component will be either (a) point-to-point channels through the ENERGEX bearer network, (b) a Telstra ISDN link to the PSTN for GSM, or (c) an IP link to the Telstra data network for GPRS.

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[8] Automated plug-and-play capability is not a realistic goal for the next generation of equipment. In the interim, remote (manual) configuration management and diagnostic capabilities for both DSA equipment and the communications network are considered essential.

The SCADA communication protocol will be DNP3, unsolicited response with periodic integrity scan.

The "legacy" communications network(s) will be decommissioned promptly - an upgrade programme will be implemented for sites which cannot be migrated to the new infrastructure.

7.3.4 Remote Data Concentrators (RDCs)

If mesh radio technology is used, and where redundant links are provided, the communication pathway between distribution system equipment and an RDC may change in response to secondary equipment failures. Continuity of service should be maintained though such changes. Continuity of service should also be maintained through RDC failures. Accordingly, the SCADA communication architecture should be enhanced to include:

- Abstract communications services[9] (decoupling of logical from physical pathways).
- Redundant RDCs.

7.3.5 Communications (RDCs to DMS)

RDC-to-DMS communications will be substantially as per the current system.

7.3.6 Distribution Management System (DMS)

As the DSS rollout gathers pace, the current concept of a "DSA (actually DSS) scheme" will become meaningless. Increasingly, it will be possible to sectionalise any feeder, and transfer load from that feeder to any adjacent feeder, by remote control.

At roughly the same time, under Phase 2 of the DMS upgrade programme:

- The 11kV operating panels will go "electronic".
- A detailed network model will be maintained in the DMS in real-time.
- DMS applications such as Outage Analysis and Load Flow will go live.

Subsequently, additional real-time information will become available from distribution transformer monitoring and customer supply monitoring systems.

The challenge will be to implement the changes such that:

- Communications and computing infrastructure are not subjected to uncontrollable overloads.
- Network Operations staff are not subjected to information overload.
- Best use is made of all available information.
- Data and displays can be, and are, maintained in an accurate and timely way.
- All changes can be, and are, rollout out cleanly, efficiently and completely.

Effective use of DSS will depend on Network Operations staff being able to see fault indicators and switching devices in context. The existing 11kV operating panels provide such a context by displaying substation-based views containing several feeders at a time. With the zooming, panning, dynamic de-cluttering and multi-window capabilities of the DMS, multi-feeder views should be less constrained than the existing panels; Alternatively, geographic views from the GIS could provide a canvas for SCADA data and DMS application data; Or "modular" views (one per feeder) could be created using information for each feeder and its adjacent feeders – such views could be generated "on the fly" using graphical templates and network data.

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[9] If thoughtfully implemented, abstract communications services will provide an ideal platform for future DSA.

At the time of writing, there is no strategy for developing, testing and migrating to new standards and processes for data and display maintenance.

7.3.7 Alarm Logging Facility (ALF)

The role of ALF will be substantially as per the current system.

7.3.8 Design and Configuration Management

A new PC-based tool will allow proposed sites to be assessed for communications coverage using publically available terrain data. Sites which pass this assessment will be surveyed in the field. Sites which do not pass will be rejected forthwith.

Configuration management systems will be enhanced to support "Plug-and-Play" installation and commissioning as described under Distribution System Equipment. See also Operational Scenarios.

7.4 Modes of operation for the Proposed System

(Not applicable)

7.5 User Classes and Other Involved Personnel

User classes and other involved personnel will be substantially as per the current system.

7.6 Support Environment

The support environment will be based on the current system: Scale-up and efficiency will be achieved by addressing processes, tools and resources.

8. Operational Scenarios

8.1 Network Architecture

(Excluded from scope)

8.2 Systems Engineering and Standards

Systems engineering and the development of standards are essentially non-operational scenarios. They are mentioned here in order to record the following issues:

- Dependence on network architecture.
- The need for utilities to develop/adopt both systems-level and equipment-level Standards in order to coerce manufacturers and vendors into doing the majority of systems engineering work; achieving interoperability; and reducing equipment prices.
- The need to comply with BMS 00729 [13].
- The need to employ sound engineering principles to ensure the safety and reliability of the resulting equipment and systems.

8.3 Deployment (Planning, Design, Construction and Commissioning)

The reliability improvement planning process is depicted in Figure 3. DSS is one of many treatment options which will be considered in determining the least cost reliability improvement programme. DSS deployment will be coordinated with other treatments.

DSS deployment will be based on a process developed for accelerated recloser rollout prior to summer 2006/07 [16]. It is proposed to develop this process by batching as many tasks as possible. For example:

- Site selection, involving protection studies, communications surveys and site surveys, will be carried out for entire feeders or zone substation areas.
- Standard point sets for reclosers, sectionalisers, load break switches, etc. will pre-installed, in batch, in each RDC and in the DMS, ready to accept data when equipment is commissioned.

See Figure 4. Project Note 14 [19] contains a full-size rendition. Note that this figure is based on existing organisational boundaries – it does not take into account the formation of one or more specialist workgroups proposed under Organisational Impacts.

8.4 Operation

The key issues for remote sectionalising and restoration are discussed in [17], which concludes:

- *The inhibitions of [9] apply, in respect of severe weather, SEF protection, public safety and underground cables.*
- *Subject to satisfactory load checks, it should be possible to remotely restore the network downstream of the first non-indicating fault indicators, and spurs off the fault path, without invoking the 15 minute rule.*
- *To facilitate load checks, all relevant LGVTs and ratings should be readily accessible.*

The implications for SCADA are described in [14], which concludes:

- *Point data in unsolicited responses should be time-tagged at source, so that it can be rejected at any higher level if excessively delayed in transmission.*
- *To facilitate the above, robust, system-wide time synchronisation mechanisms should be implemented.*
- *The criteria for determining operational significance [of SCADA points, with respect to enabling for unsolicited response] should be carefully determined and applied.*
- *All relevant non-indicating devices should be integrity scanned before a final operating decision is made.*
- *Operators should be able to ascertain with little or no effort whether a point is "stale" or "fresh."*

The following constraints and limitations, also described in [17] should be addressed in order to widen the applicability and effectiveness of DSS:

- *Given the prevalence of secondary faults on the ENERGEX network, it is not reasonable to remotely restore the network upstream of the last indicating fault indicator without invoking the 15 minute rule.*
- *Non-CT-based fault indicators are, for the time being, not considered reliable enough to be used for remote sectionalising and restoration – even though products with remote indication are now appearing on the market.*
- *For OH feeders, and mixed OH/UG feeders with a high proportion of OH, it is important that fault indicators be effective for both phase faults and earth faults.*

Other issues awaiting resolution include:

- An organisational review of outage analysis and restoration (processes, tools and resources), taking into account the impact of proposed new technologies – Outage Analysis, Load Flow, Study Mode, Distribution Transformer Monitoring, Customer Supply Monitoring.
- A strategy for developing, testing and migrating to new standards and processes for data and display maintenance, as previously noted under Distribution Management System.

8.5 Maintenance

(Excluded from scope)

9. Summary of Impacts

9.1 Organisational Impacts

To guarantee resources for the DSS rollout, one or more specialist workgroups will be established using resources from the following areas:

- Network Automation (SCADA design)
- Protection Engineering (Protection design)
- Network Technical Services (SCADA configuration, testing, commissioning; Communications design, testing, commissioning)
- Network Operations Data (DMS configuration, testing)
- Distribution Services (construction)

An organisational review of outage analysis and restoration, as recommended under Operation, may result in changes to processes, tools and resources in Network Operations.

9.2 Operational Impacts

In order to achieve the desired improvement in network reliability, the "restore before repair" mantra will have to be drilled into staff at all operational levels:

- New technologies will have to be used effectively to locate faults and restore supply to customers.
- Staff will have to be appropriately trained, mentored and monitored.

Generic and/or self-configuring solutions supporting the "Plug-and-Play" philosophy will sink or swim on the quality of data in network asset management and configuration management systems. Appropriate standards for data quality will have to be developed and enforced.

9.3 Impacts During Development

Staff will be diverted from day-to-day activities for the following purposes:

- System design review.
- Review of procurement specifications.
- Development and testing of processes and tools.
- Team formation and training.

10. Analysis of the Proposed System

10.1 Summary of Improvements

The DSS initiative seeks to scale up ENERGEX's DSS capability by standardising equipment requirements and specifications, dedicating resources to the rollout, and ensuring that the equipment is reliable. Immediate improvements will be made to the deployment process and the DSS communications network. Equipment requirements and specifications will be adjusted to ensure that standard products and systems can be rolled out in the majority of instances. The necessary operational capability will be established in Network Operations.

10.2 Disadvantages and Limitations

By its very nature, DSS enables but does not execute remote sectionalising and restoration. Human assessment and decision making are required for execution. Over time, customer expectations will drive network capability and DSS capability to the point where network performance targets will not be achieved with human execution. ENERGEX should prepare for this time by investigating and evaluating DSA technologies.

10.3 Alternatives and Trade-Offs Considered

The following alternatives and tradeoffs are still under consideration:

10.3.1 "Universal" Versus Specialised Switching Devices

The argument has been made that ENERGEX should buy only one type of switching device - a "universal" device with fault making, fault breaking and isolating capability (from the power side) and configurable recloser/sectionaliser/load break switch functions (from the secondary systems side).

Arguments in favour of this approach include:

- SF6 sectionalisers and load break switches have isolating capability but no fault breaking capability and very limited fault making capability - ENERGEX should carefully consider what fault making duty will be required in both manual and automated restoration scenarios.
- The cost savings of functionally differentiated devices are insignificant compared with the total installed cost.
- Lifecycle costs will be lower overall. The distribution network is dynamic in nature. To future proof it we need devices that provide for a flexible outcome. For example, a location that's a switching point today may well need to be a sectionalising or reclosing point in the future. If the device cannot change roles, either the asset will be stranded or ENERGEX will incur relocation and/or replacement costs.
- Vacuum interrupter (VI) based devices can be supplemented with links or removable bridges for isolation purposes.

Arguments against include:

- SF6 reclosers potentially qualify, but SF6 is going out of fashion for environmental reasons, especially at distribution voltages. Also SF6 interrupters are technically complex compared with VIs.
- Problems of stranded assets and relocation/replacement costs can be overcome with proper planning.
- Devices with (significant) fault making and fault breaking capability are nowadays almost invariably based on VIs, and VI-based devices cannot be used for isolation. To

supplement a metalclad switching device with isolation links is build a weak point into the system. We want to get rid of air break switches and their ilk.

10.3.2 Integrated Versus Third Party Controller/RTUs

As noted in [18]:

> *The driver for improvements in computing "bang for buck", Moore's Law, shows no sign of abatement. The component count per device continues to double approximately every 18 months, leading to phenomena such as the 3GHz desktop personal computer with 1Gb of memory, 100Gb of hard disk storage and a flat panel display for under $2 000 (astronomical figures just a few years ago, soon to be ordinary).*
>
> *The same advances have led to small, low power, multi-functional personal computing and communications platforms - laptop and palmtop PCs, PDAs, mobile phones, music players and the like. Also to embedded systems – computer systems which are integrated into the fabric of the host device.*
>
> *Embedding will be a mixed blessing for the electricity industry. On the one hand, it will deliver "smart" components capable of monitoring and controlling the network at unprecedented levels of precision. On the other hand, the mismatch between the average life expectancies (to failure or obsolescence) of electronic components and power system apparatus will lead to difficulties with equipment maintainability and interoperability.*

Approaches to the "embedding problem" include:

- Scrapping the equipment when embedded component spares became obsolete or uneconomic. A case would have to be made to the Regulator to substantially reduce the "regulated" equipment life.
- Purchasing estimated quantities of embedded component spares with the equipment. This would lock up capital and fill warehouses with (possibly surplus) spares.
- Requiring the manufacturer/vendor to maintain a stock of embedded component spares (or their backward compatible equivalents) for the life of the power system apparatus. This would be difficult to enforce and could inflate the purchase price.
- Specifying a standard wiring interface to the equipment as well as standard physical and logical communications interfaces. When embedded component spares became obsolete or uneconomic, a third party controller/RTU could be substituted. This would limit the manufacturer's scope for design innovation and cost reduction.
- Requiring the manufacturer to document product line architecture and policy on cross- and backward-compatibility of switchgear and controller/RTUs.
- Requiring the manufacturer to divulge all details of the equipment's physical interfaces so that third party retrofit components could be designed or purchased when embedded component spares became obsolete or uneconomic.

None of these approaches is especially appealing. In recent years, ENERGEX has purchased pole-mounted equipment with embedded controller/RTUs, viz. Nu-Lec reclosers. Nu-Lec is a reputable manufacturer with a track record of manufacturing backwards compatible spares. Even so, the oldest such equipment is only about 15 years old, well short of its "regulated" life.

10.3.3 Vendor Installation and Commissioning of Distribution System Equipment

For greatest efficiency, the installation and commissioning team(s) should have the following (somewhat unusual) mix of skills and equipment:

- OH construction
- Live line working
- Heavy lift
- Application and verification of settings
- Communications and SCADA troubleshooting
- Testing and commissioning

Requiring the vendor to install and commission distribution system equipment would minimise demands on ENERGEX resources at a time when resources are in short supply. It would also put the onus for successful commissioning of both primary and secondary equipment on the vendor. On the down side, the vendor or his contractor could be competing for resources in the same market as ENERGEX.

10.3.4 IP Enablement of SCADA Communications

Given the global phenomenon of IP convergence, the question is not “whether” but “when and how” IP will become the underlying transport for SCADA communications services. One example should suffice to illustrate the benefits:

Options for remotely applying protection settings to switching devices include SCADA setpoint control; DNP3 file download; Console access via a DNP3 virtual terminal objects; Console access via a public wireless network (where available); and IP enablement allowing independent logical SCADA communications and management channels.

The last of these options is the most elegant; it is also standards-compliant, given the existence of a specification for transporting DNP3 over local and wide area networks; and it is well within the capability of integrated controller/RTUs.

10.3.5 Radio Technology

Technologies being considered for the DSS communications network are:

- 900/450MHz point-to-multipoint digital radio with “infill” repeaters.
- 900MHz, spread-spectrum, mesh radio.

Point-to-multipoint radio is a “conventional,” well understood technology. Propagation at VHF is essentially “line of sight”, so it is very difficult to achieve perfect coverage from a small number of mountaintop base stations. “Infill” repeaters can be used to augment coverage, subject to compliance with licence conditions. Because the technology uses licensed frequencies, interference from other services is rare.

Mesh radio is in regular use in the USA but hitherto unknown in Australia. Data packets traverse the network in short hops (routes are discovered automatically by the equipment). Because the technology uses unlicensed frequencies, interference from other services is possible and must be tolerated.

Both technologies are capable of supporting multiple application protocols, and both have inbuilt network supervision.

At the time of writing, ENERGEX is acquiring “UtiliNet” mesh radio equipment for evaluation and comparison with point-to-multipoint radio.

10.3.6 Migration of Operating Panels to DMS before Phase 2 of the DMS Upgrade Programme

This option is based on the following premises:

- Effective use of DSS will depend on Network Operations staff being able to see fault indicators and switching devices in context.
- SCADA-only displays of the 11kV network would be useful in their own right as an aid to fault location and restoration, before DMS Phase 2 applications became available.
- Such displays would be a useful interim step toward “electronic” operating panels.
- The existing operating panels would remain the primary record of system state pending a final decision to go “electronic.”
- Experience with SCADA-only displays would help to solve the technical challenges of full migration, and might lead to full migration being completed before Phase 2 of the DMS upgrade programme.

11. Notes

(Not applicable)

12. Glossary

For a glossary of related terms, see Project Note 1 [2].

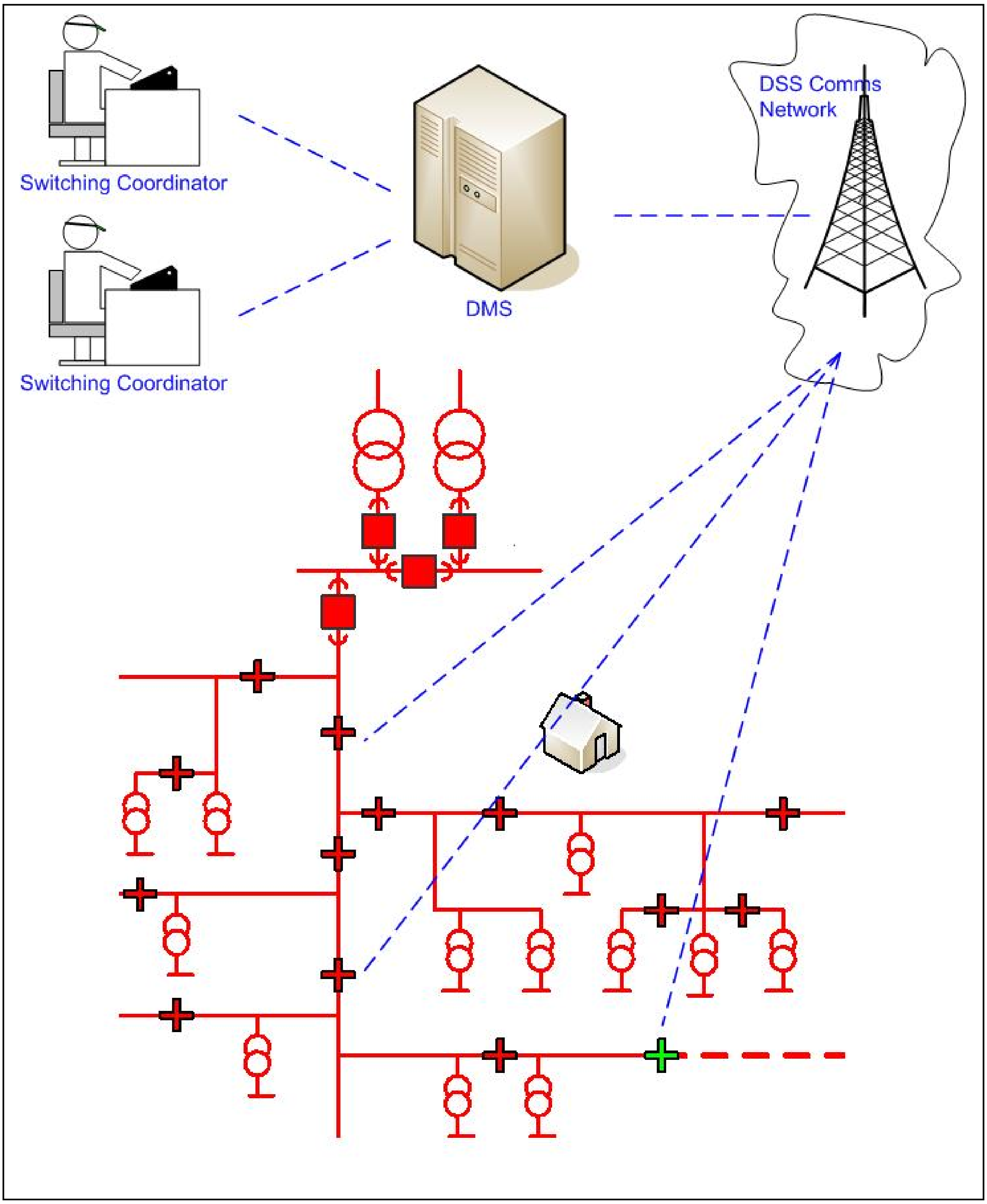

Figure 1 - DSS Overview

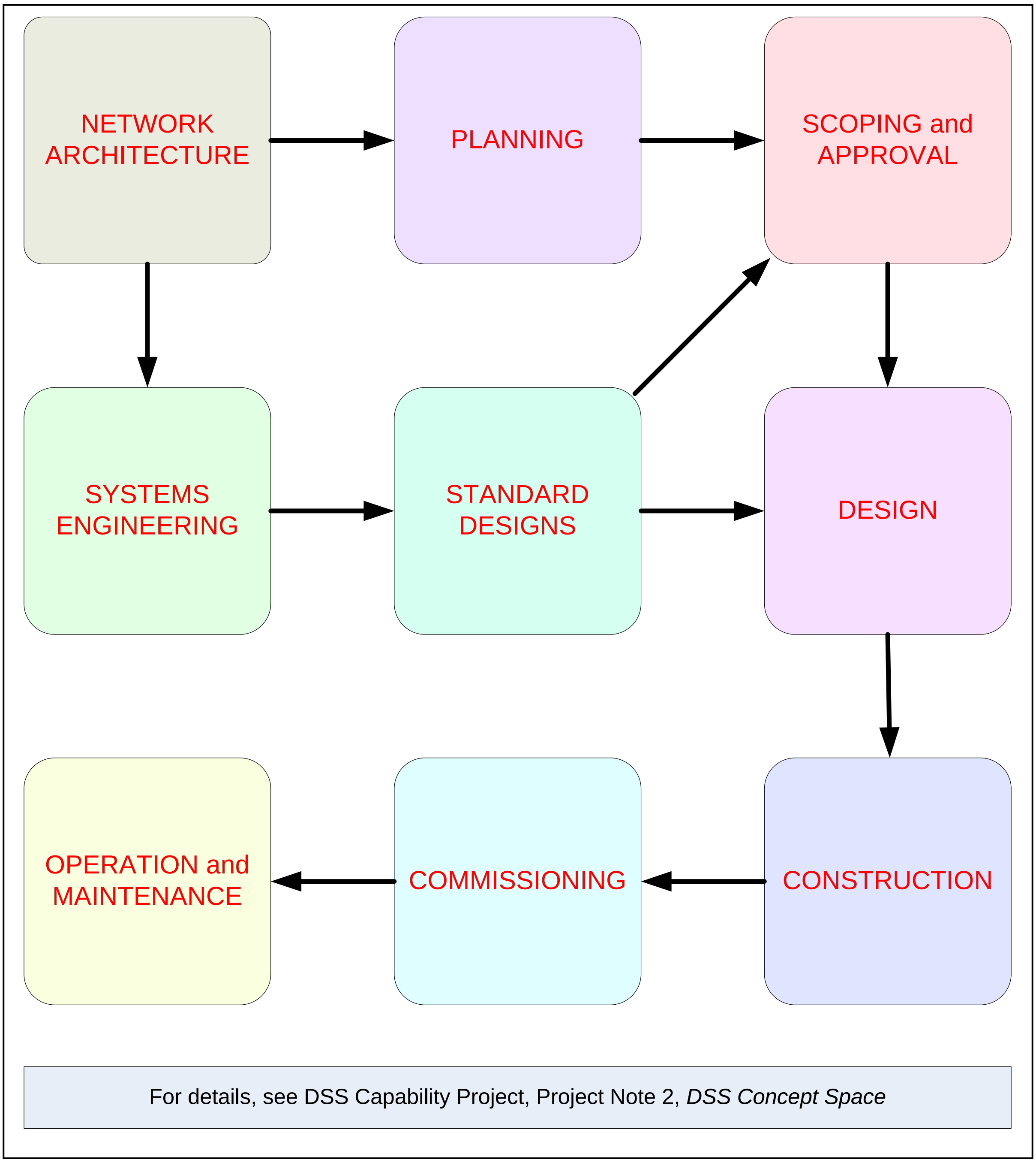

Figure 2 - DSS Concept Space

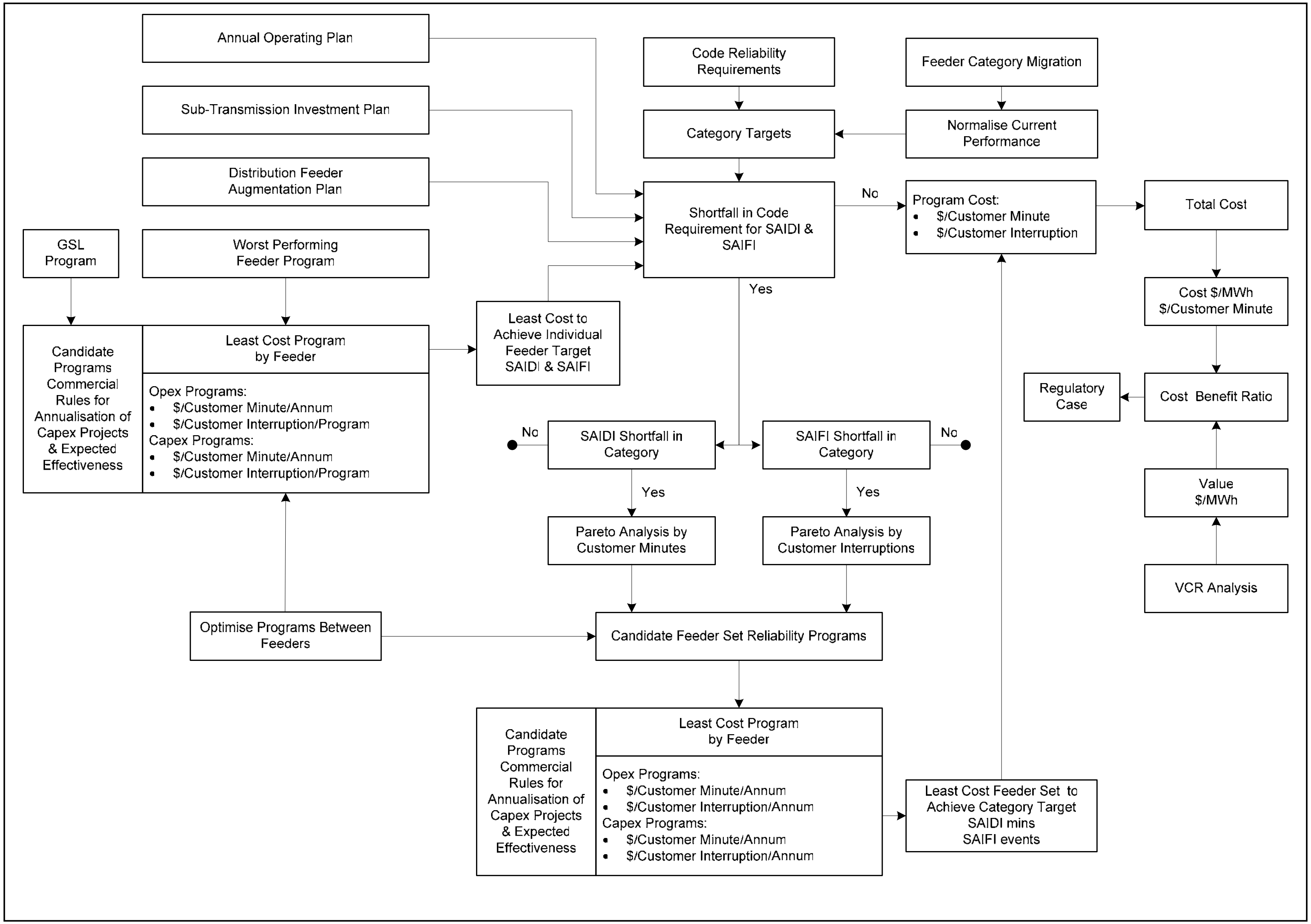

Figure 3 - Reliability Programme Planning Flowchart (Uncontrolled)

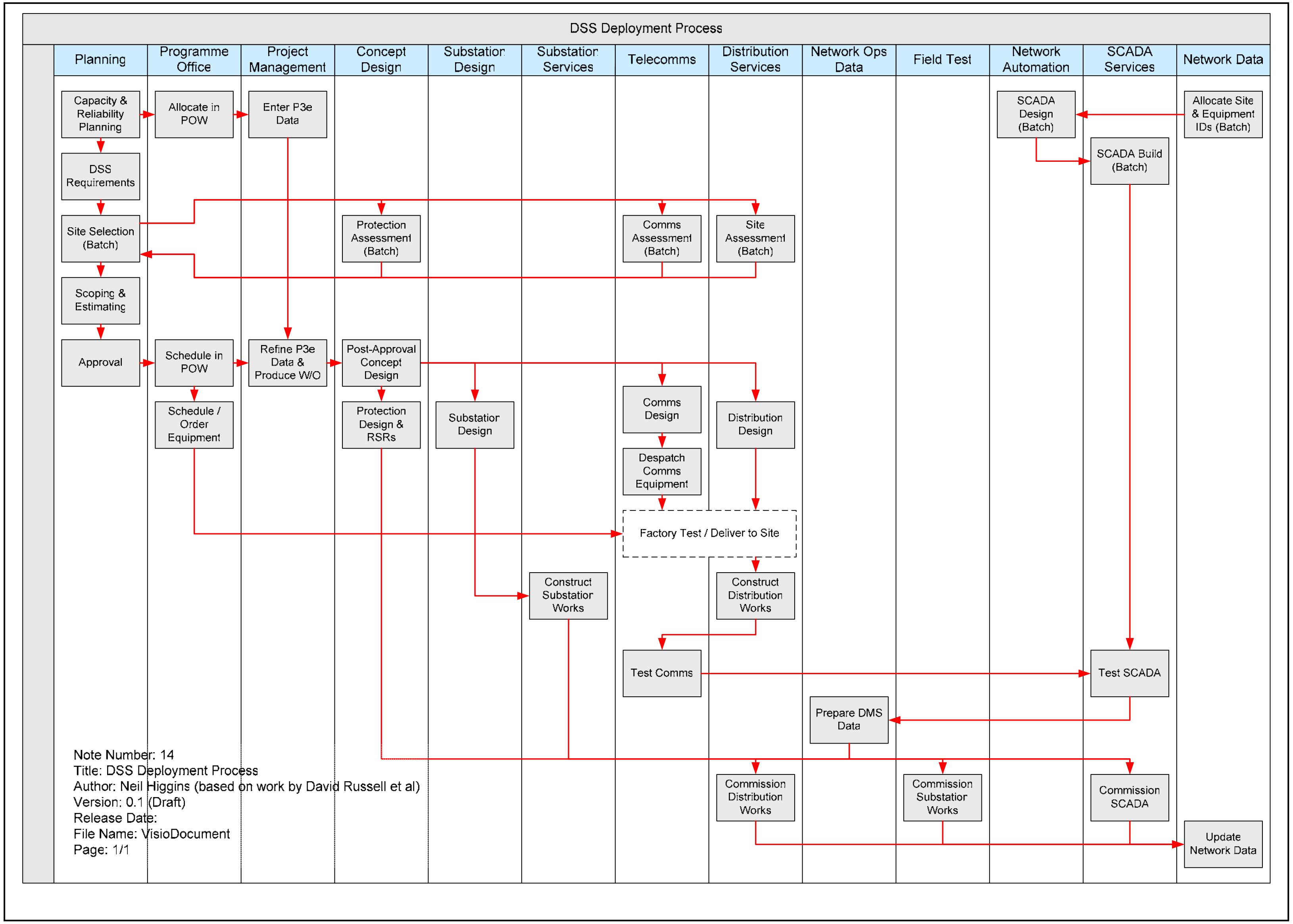

Figure 4- Proposed DSS Deployment Process