Transformation of Energy Systems: Transparent MV and LV Distribution Networks

by

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Introduction

Smart Grid or Intelligent Network has been the term used to depict the transformed energy system of the future. Around that topic the discussions have concentrated on smart metering implementation through Advanced Metering Infrastructures (AMI), and the impact of accommodating Distributed Resources (distributed storage and generation). Little time has been given to one of the fundamental aspects of the Smart Grid – the need for system-wide condition data. Future energy systems will by necessity have to become completely transparent if they are to accommodate the integration of various forms of distributed generation and storage successfully, as well as meet anticipated demand response control. Although higher voltage transmission networks have complete monitoring and control at all major points, this is not the case for the high, medium and low voltage distribution networks. Without visibility of timely loading and performance levels across the entire distribution network, it will be impossible to satisfy future network operational demands. This paper follows on from a previous publication [1] covering transformation of energy systems and the refocusing of the control room design to meet future needs. It describes the solution adopted by EnergyAustralia (EA) for the data acquisition system at the distribution level, to enable satisfactory control and management of future energy systems as the Smart Grid evolves. It concentrates on the data acquisition component of the solution rather than the IT infrastructure.

Business Objectives and "Electric Thinking"

EnergyAustralia realized that emerging global environmental pressures were real and would result in a changed regulatory regime being imposed. It would be beneficial to be proactive in determining the real technical issues in meeting the predicted changes which pointed to adopting a Smart Grid strategy. Once the vision was established, the true business costs and benefits could be assessed and a preferred evolutionary implementation established. This strategic exercise, "Electric Thinking", identified a number of major areas that would have to be addressed to meet the evolving business requirements and ensure that the distribution system was "fit for future purpose". Regulatory initiatives for the distribution business have been to encourage innovation and the development of novel solutions to facilitate the transformation from "passive" to "active" network operation. These two goals require active network management based on the collection and intelligent use of good quality asset information. As utilities are being faced with an increasingly complex operational environment, the lack of reliable network data is increasingly unacceptable to the business, its customers, and the regulator.

The business drivers supporting the “Electric Thinking” strategy include those shown in Table 1, all of which essentially fall into two categories, regulator and/or customer driven.

			Driver	Category
	Driver	Driver description	Regulator y/Gov’nt	Custome r
1	Incentive regulation	Performance recording and reporting with penalties and rewards associated with network performance	✓	
2	Outage information to customers	Provide substantive information to customers affected by outages and faults	✓	✓
3	Improve network performance	System level (average) and targeted improvement at ”worst served” customers	✓	✓
4	Demand-side solutions	Encourage demand -side solutions (embedded generation as a means to achieving carbon reductions	✓	
5	Increase network reliability	Increase network reliability and resilience without incurring increases in expenditure (CAPEX and OPEX)	✓	
6	Reducing costs	Reduce capital expenditure and operating costs on the distribution network		✓

Table 1: Business drivers common to many distribution operators across the world

As stated above and in the introduction, the need for improved monitoring at the distribution level was fundamental to achieving the goals of “Electric Thinking” and energy system transition to a Smart Grid. Consequently, a more detailed project, Distribution Monitoring and Control (DM&C) was drawn up to support the “Electrical Thinking” master strategy. This project incorporated a detailed business case identifying a justifiable per unit level of expenditure based on a specific deployment of monitors. Justification was based on the following estimated benefits listed in Table 2.

	Benefit Type	Benefit Description	% Contribution	Benefit Category
1	Dist planning	Avoidance of conservative planning margins resulting from lack of time stamped and accurate asset loading data	4	Hard
2	Reading & reset of MDIs	Avoidance of manpower costs for twice annual substation visits to read and reset MDIs	12	Hard
3	Elimination of load surveys	Avoidance of manpower costs for substation visits to perform load surveys at substations where MDIs were not installed (25% of stations)	12	Hard
4	LV Load balancing	Maintain balanced phase loading on LV distribution feeders to avoid overloads and stressing of assets unnecessarily. Accommodate requests for three phase loads within network limits	3	Soft
5	Loss reduction	Reduce losses through optimal load balancing between substations, feeders and phases. Distribution network contributes to 60% of all annual delivery system losses with LV portion accounting for 28 % on average	Not assessed	Soft
6	Customer Power Quality	Reduce penalty payments for poor quality (low or high utilization voltage and outages) supply due to accurate information on actual network performance at the LV feeder level	1	Soft
7	Asset Maintenance	Improved continuous monitoring of time stamped asset loads over MDI generated data will lead to more informed maintenance and replacement decisions	3	Soft
8	Reporting	Improved transparency of the distribution network will strongly support any application or report to the regulator since it will be based on substantial data	Not assessed	Soft
9	Reliability	Remote identification of faults and location will reduce restoration times and outage statistics (SAIDI) not possible with manually field interrogated FPIs	65	Hard
10	Distributed Generation	Accommodation of distributed generation on the distribution network necessitates the knowledge of power flow direction and levels together with voltage	Not assessed	Soft

Table 2: Major quantified benefits used to justify the DM&C implementation

Table 2 lists and describes the major direct benefits identified that would be delivered by increased monitoring of the distribution network based on the requirements defined. Whereas some of the benefits are immediately quantifiable by calculation of avoidance costs of present activities and are thus classified as hard, other benefits are considered soft. Soft benefits can be quantified in principal but the level of benefits depends on the actual success of a course of action not presently measured. For example loss reduction may be 5% or 10%. This will only be known once action has been taken and measured as a result of the DM&C project; thus, at the justification stage a conservative estimate of the reduction or success of the action has to be made.

Justification was based on 93% of the benefits being hard and only 7% considered as soft and even within the soft category loss reduction potential was not calculated;

thus, some margin was included within the justification. It was determined that the RTU based solution would deliver the most benefit options over a smart meter approach and that the capital cost of a complete LV monitor for a four feeder substation (sensors, IED and communications) should be approximately $A 2,000, and if remote control capability was added, an additional incremental cost of $A700 could be justified. A device which included complete LV, MV, fault identification capability (EFI/LFI[1]) and remote switch control could be justified at $A 5,000 per unit.

MV/LV Distribution Network Monitoring

The EA distribution network predominantly consists of 17,361 kilometres of 11kV, covering an area of 22,275 square kilometres. The network is comprised of a mixture of underground cables in the urban districts and overhead conductors in the rural areas. The LV system is fed from approximately 30,000 11kV/415v distribution substations which are kiosk type for the cable networks and pole/platform mounted outdoor for the overhead system. EnergyAustralia's distribution network is the largest in Australia, serving 1.6 million customers with varying load density ranging from very dense in the urban areas to extremely sparse in the remote regions. The OH network contributes to the majority of permanent faults (60%).

EnergyAustralia was operating the distribution system through a Distribution Network Management System (DNMS) consisting of a combined SCADA and a limited network connectivity model for the management of the remainder of the manually switched network. This system is planned for upgrading as part of the "Electric Thinking" strategy. Remote control was limited to circuit breakers in large primary substations, no communicating devices being installed in any distribution substation. Any fault outside the primary substations was obtained by field patrols reading of fault passage indicators (EPI/LPI), where installed. In addition customer calls were also used to help in identifying fault location. Maximum Demand Indicators (MDI) installed at many distribution substations were read twice annually to provide loading data for asset planning and management. This required visiting the substations twice a year. Where MDIs were not installed, short duration load surveys were undertaken to establish peak and off peak loading levels. This level of remote interrogation and control of the distribution network would not deliver the requirements of the "Electric Thinking" strategy and consequently the Distribution Monitoring and Control (DM&C) initiative was launched to extend present remote monitoring and control levels outside primary substations. The directives were to deliver timely fault location indication, loading levels, certain power quality information and control of remote switchgear. The DM&C had two components, a solution to be based on installation of an intelligent device at many distribution substations and an IT infrastructure to manage the different data and response time requirements of the various users across the organization together with visualization applications for data analysis.

[1] EFI- Earth Fault Indicator, LFI-Load Fault Indication (all are FPIs-Fault Passage Indicators)

Remote Electronic Intelligent Device

The functional requirements for an intelligent device to be fitted at a typical substation shown in Figure 1 were developed and comprised of the following:

- MV Fault identification with optional load current measurement with alarming.
- Measurement of all LV phase current and voltages for all feeders in a substation (typically 4-18 feeders).
- Measurement of real and reactive power.
- Control capability and SCADA interface for up to two switches per substation (all substations were assumed automation prepared)[2]
- Power quality thresholds to monitor and alarm for normal level currents and voltages outside set limits.
- Integrated common communications interface for remote control and interrogation of the above functions.

The device must be able to be retrofitted in existing substations noninvasively or supplied to manufactures of new substation equipment for factory installation, all at distribution cost levels.

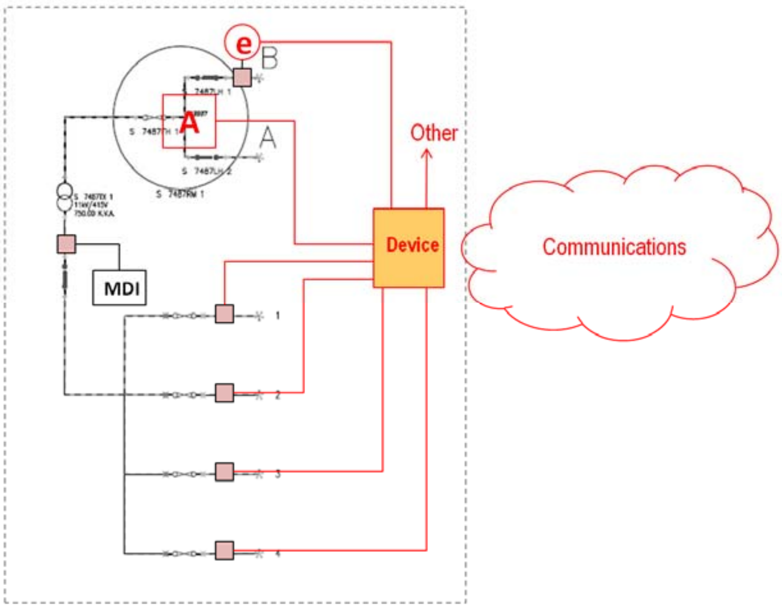

Figure 1: Single Line Schematic of a Typical Distribution Substation showing primary/secondary data paths

These secondary functions could be met by a number of solutions using traditional FPI technology, smart meters and RTUs coupled to a selected sensor technology that could be noninvasively attached to the MV and LV cables or conductors. In locations where remote switch control (automation) in addition to monitoring could be justified, the solution would require RTU functionality.

[2] Automation prepared primary device has provision for an actuator to be easily installed

Following an extensive procurement exercise, a “third generation” distribution monitoring system was selected since it provided all the mandatory requirements, yet its modularity allowed for expansion, accommodation of all optional items and adaptation to future Smart Grid operational practices such as bi-directional power flow. The selected intelligent device used advanced optical sensors that could be strapped noninvasively to MV cables for current measurement on each phase. The optical sensor measurement range was 5-20,000A without saturation, allowing both normal current measurements and fault identification to be performed by the same device. Standard split core CTs were employed on each LV feeder phase integrated into the internal device data bus by an LV I/O module for normal load current measurements. This approach kept costs down to justifiable levels. In addition sufficient DI/DOs[3] were embedded in the modules for switch control purposes as standard. All sensor modules were connected to the smart communications front end configurable to accommodate many different communications protocols. It also included a data management facility that allowed alarm data to be streamed to a different destination than measurement data witc require a slower transaction rate. Extensive health checking (battery supply, light quality of optical LEDs for the sensors and electronics etc.) and power quality limits on voltage and current were configured as alarms. Figure 2 shows a block schematic of the selected device.

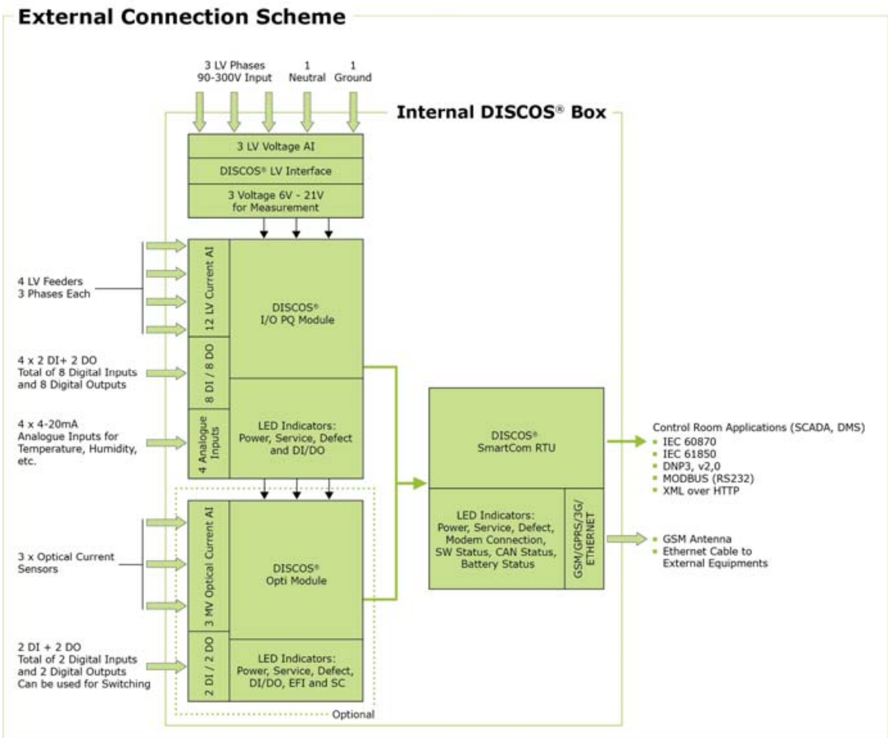

Figure 2: Intelligent Electronic Device block schematic showing sensor inputs, functions and local LED alarm/status displays

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[3] Digital Input and Digital Output provision for switch control

Field deployment of monitors

The business case justified monitoring 12,000 of the 30,000 distribution substations. Although this number only represented 40% of the total substation population, it covered 70% of all customers and high load density sectors of the service area. The goal set was to complete installation at all the 12,000 designated substations by midyear 2013, which equated to completing a levelized average approximating 15 substations per day over the period. In order to achieve this installation rate, a series of trial installations were conducted in advance to optimize the procedure and make any small adjustments to the IED, securing fittings and interfaces. This proved invaluable in reducing the elapsed average installation time from 6 hours to 5 hours per station (travel time included) with an ultimate goal of 4 hours considered achievable for the simpler stations. The installation was able to be carried out entirely live for fitting both the LV and MV sensors for all modern substations. At older style stations it was necessary to take an outage to access the termination box to make the power supply connection. The optical sensor being non invasive was able to be attached safely to the incoming cables in kiosk substations, and the outdoor sensor was designed to be attached to bare conductors with a live working hook stick. Examples of both indoor cable and outdoor bare conductor sensor installations are shown in Figure 3.

Figure 3: IED cabinet mounted in a kiosk substation, MV cable and overhead optical sensors

All sensors were connected by fibre to the IED cabinet which contained the communication front end installed with a modem suitable for the Telstra's NextG (3G) network used by EnergyAustralia across its service territory. Provision for use of WIMAX in the future has been made in the design.

The finalized procedures were used to prepare training for the installation crews. The crews were then assigned to the different operating districts in accordance with the substation monitoring strategy for each district as shown in Figure 4.

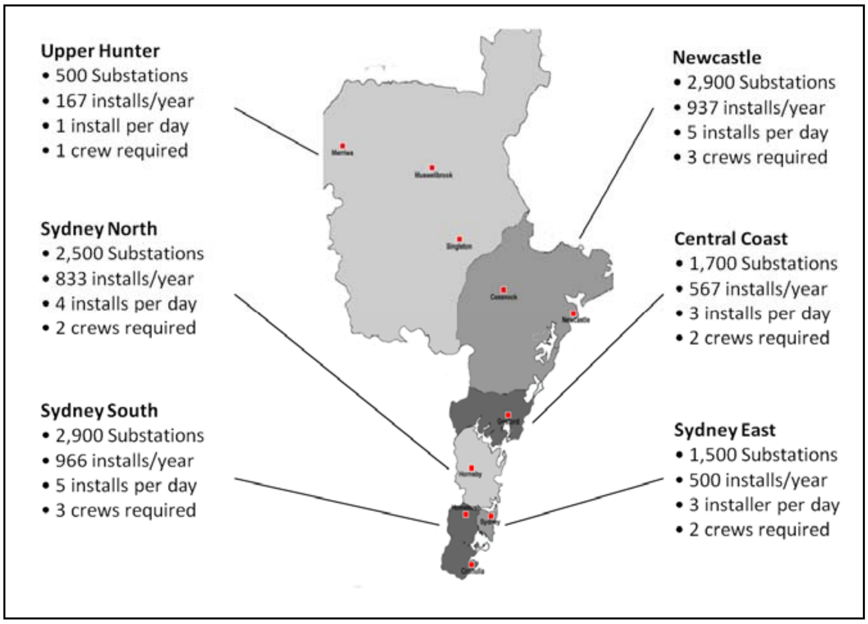


Figure 4: Proposed deployment of Monitors for Distribution Substations by district together with installation crew resource assignment

In addition to monitoring, the control option will be implemented at certain distribution substations, to provide remote control of the switchgear. These substations have been selected by the planning department to improve reliability (SAIDI reduction). Typically, these were located at feeder mid and normally open points or in areas of high customer volume. Remote control was to be established at approximately 15% of the 12,000 substations.

Enterprise IT Infrastructure

The enterprise IT infrastructure will integrate many existing applications within the power company and set up a real-time information bus that will accommodate and distribute the data relayed from the remote distribution monitors. The architecture[4] of the infrastructure is summarized in Figure 5. The IT application will receive asset measurement data (currents, voltages and real and reactive power) "pushed" from the monitors every ten minutes and archive the information in preparation for data mining and further network visualization provided by the ION project. The ION project is also another application being developed as a result of "Electric Thinking" strategy. Alarms resulting from fault identification, out of limit normal values or health checks will be immediately communicated by the monitor to the IT application for transmission to the appropriate responsible line function.

[4] Details of this part of "Electrical Thinking" will form the subject of a future paper

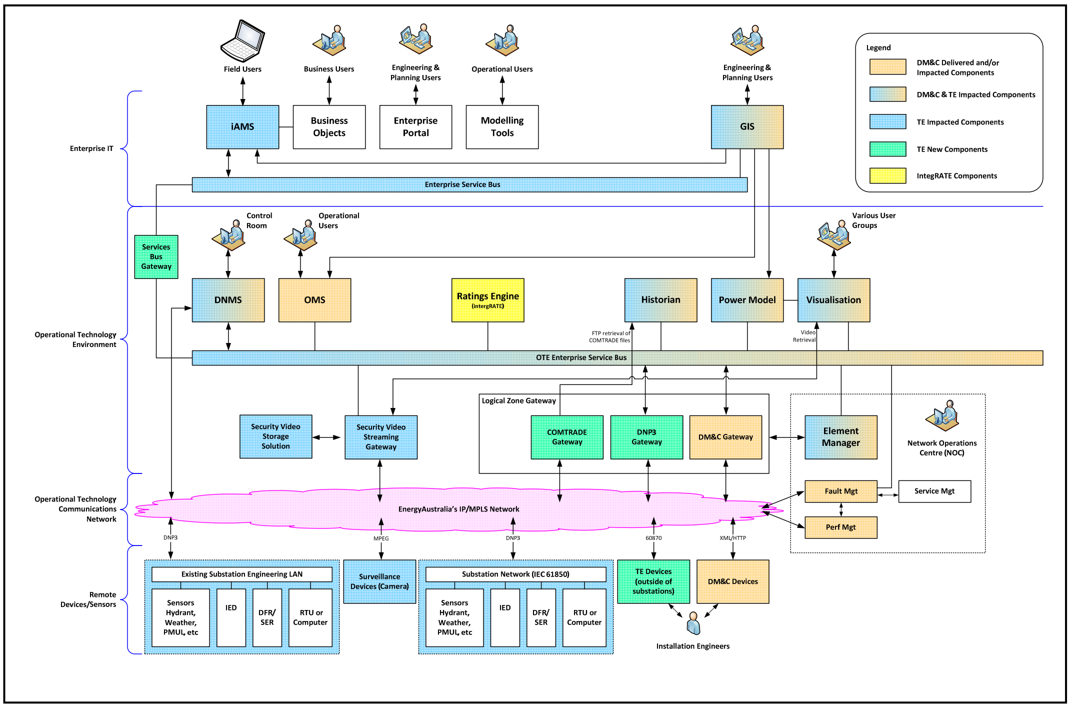
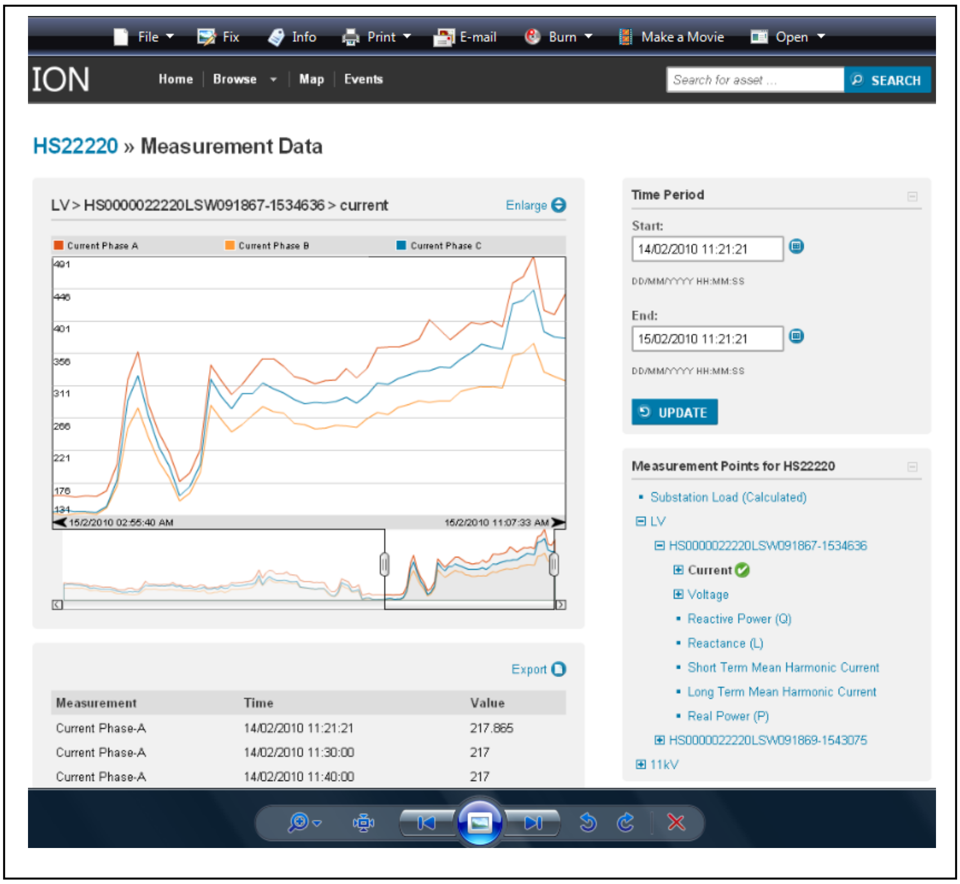


Figure 5 Electric Thinking IT Infrastructure

The evolution to the Smart Grid, particularly at the distribution level, brings significant exposure to new security threats, and as part of the coherent transformation of the IT and communications infrastructure the following precautions have been implemented. The protocol between the data acquisition devices and the EIT applications has been implemented as a HTTP wrapped XML with the option to implement a secure protocol HTTPS in the future. This implementation has been delayed since the 3G communications network being used has a full encryption layer available, which has been used instead. This provides full security outside the EA Enterprise IT (EIT) infrastructure but does not provide internal security for initiating control commands from the EIT applications to the data acquisition device for opening and closing switches or changing parameter set points. An internal encryption facility has been implemented for authorized personnel to initiate commands, with the limitation that each command is uniquely encrypted for single operational commands. This brings the EIT security facility in line with accepted control room authority practices.

Initial results

By year end 2010, the number of substations fully commissioned with monitors will be in excess of 1500. Since the first installations have been scattered across the network, it is not possible to report detailed analysis on a feeder by feeder and substation by substation basis and thus be able to draw significant conclusions on asset loading, effects of real diversity values and time of day loading. This will form the basis of a future paper which will track actual benefits compared with those estimated and also discuss strategic planning and operating policy changes that should be implemented as a result of this network visibility. Initial results, though, have been satisfactory with some faults being recognized before customer calls were received of the outage. Currently work is progressing at implementing symbols in the DMNS, so that a fault will be visible in both the control room and on the ION network visualization application. The results also endorse the effectiveness of remote monitoring in delivering economically, timely and richer load data compared with that from MDIs and load surveys. It can also be deployed tactically as was done recently at Wallsend Admin substation to provide real-time information at sites where the engineers felt it was too risky to have someone measuring the load on site as the substation was energized. Current measurements are being accumulated and are showing LV phase unbalance as well as incidents of normal operating values straying outside the required thresholds. Figure 6 shows typical current measurements for phase A of a feeder as displayed by the ION network visualization application.



6: Sample Current measurement output from the 3G monitor polled at ten minute intervals as displayed by the IT visualization application

Conclusions

The undertaking of the “Electric Thinking” strategic exercise allowed an unconstrained examination of the power company’s strategy for the future and the role of the Intelligent/Smart Grid. It prepared the network business for the potential radical changes that would be required in operation. The need for a massive increase in distribution network transparency resulted in the initiation of the DM&C project. This project has been successfully progressed to the deployment phase where the installation of a third generation distribution monitoring system is proving practical and cost effective. The non-invasive nature of the device has allowed rapid installation giving confidence that the target of 12,000 monitored substations can be achieved in the planned 18 month schedule. Results from the first two hundred substations fitted with the monitor have delivered the expected information on fault occurrences, threshold violations and measurements for asset management. The integration with the back office IT infrastructure is supporting the other Electric Thinking projects such as network asset visualization (ION) and will support the replacement Distribution Management System. Clearly, the decision to make the distribution network monitoring the foundation of the Smart Grid has been substantiated through the greatly enhanced visibility of actual network operation and any power company should give this strategy serious consideration in their energy system transformation plan.

References

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[3] James Northcote-Green, Robert Wilson, ”Control and Automation of Electric Power Distribution Networks, publisher CRC Taylor and Francis, Florida 2007, ISBN 0-8247-2631-6