MANAGING HIGH VOLTAGE CURRENT TRANSFORMERS AND BUSHINGS USING ON-LINE INSULATION MONITORING TECHNIQUES

By

Terry Krieg, ElectraNet SA

Jeff Benach, AVO International

MANAGING HIGH VOLTAGE CURRENT TRANSFORMERS AND BUSHINGS USING ON-LINE INSULATION MONITORING TECHNIQUES

Terry Krieg, Executive Manager Asset Maintenance, ElectraNet SA

Jeff Benach, Project Manager, AVO International

Abstract

The paper describes ElectraNet SA experience leading to the introduction of on-line monitoring systems for current transformers and bushings. Changes in monitoring policies for high voltage assets have been influenced by the external environment, shareholder demands and legislative changes resulting in increased use of on-line monitoring to support traditional testing methods. A range of new monitoring systems has been introduced to improve the information available for strategic and operational decision making. The first installation was prompted by failure of a 275kV current transformer in a critical location in the ElectraNet network in 1997, a bushing and current transformer monitoring system was installed to provide early warning of imminent failure for the remaining population. On-going development by AVO International has provided alternative options for smaller installations where the cost of a larger monitoring system can not be justified. The development of Utility Communications Architecture (UCA) has enabled integration of a range of monitoring, protection, control and other functions and development of substation automation. These systems, ElectraNet operational experience and approach to integration of monitoring systems with substation communication systems are described.

Background

ElectraNet SA is a privately owned company that on 31 October 2000 acquired the South Australian transmission network through a long-term Government lease. The new owners and operators of ElectraNet Pty Ltd (trading as ElectraNet SA) are a consortium group of companies comprising Harold Street Holdings Pty Ltd (an investment company of Powerlink Queensland), YTL Power Investments Ltd (an investment company of YTL Power International Berhad), ABB Net SA Pty Ltd (an investment company of ABB Group Holdings Pty Ltd), Macquarie Specialised Asset Management Limited (on behalf of UniSuper) and National Australia Trustees Limited (on behalf of EquipSuper).

ElectraNet SA was previously the trading name for ETSA Transmission a subsidiary to ETSA Corporation a state owned authority in South Australia. The Corporation was formed from the Electricity Trust of South Australia (or ETSA) a statutory authority established in 1946 by the then Premier of the state, Thomas Playford. In 1996, ETSA celebrated its 50th anniversary.

ElectraNet SA operates the South Australian Transmission network comprising voltages to 275kV. The network consists of 5,500 km of transmission line and 69 unmanned substations.

Maintenance contractors carry out all maintenance in ElectraNet SA and no staff are directly employed for line or substation maintenance. The Corporation has retained in house contract management and the core functions of strategic planning, maintenance management and policy development.

Asset Management

In line with many other companies worldwide, ElectraNet have adopted an "Asset Management" approach for company structure and planning. This essentially involves consideration of the asset over its entire life cycle to ensure that the plant is safe, performs required service with minimum whole of life cost. This cost must include the capital cost as well as maintenance and operating costs and the whole of life cost of risk for that plant.

In ElectraNet a risk based asset management philosophy has been adopted that takes account of the nature of the network, the large geographic area covered, unmanned stations, maintenance outsourcing and cost drivers. Decision making on issues such as asset refurbishment and replacement or the implementation of an on-line monitoring system is based on a consideration of the likely risk reduction and on achieving a balance between cost and risk.

Asset Monitoring Philosophy

Driven by the business and physical environment in South Australia, ElectraNet SA has developed a strategy for the management of assets that includes the use of both traditional (discrete off-line testing) and on-line systems. The overall objective is to provide strategic level information to enable the management of the asset at the lowest whole of life cost. Monitoring is directed towards high risk plant where implementation of monitoring can be demonstrated to provide the largest risk reduction at the lowest cost. Our procurement policies for new plant do not include OEM monitoring systems. Monitoring expenditure is directed towards improving overall network reliability. Our experience is that monitoring equipment needs to be retrofittable to a range of plant types, manufacturers and ages. Asset Monitoring philosophy has also been driven by operational experience over recent years and the following examples serves to illustrate why the current asset monitoring approach has been adopted.

Failure of a Current Transformer

In February 1997 mid summer temperatures in Adelaide, South Australia reached 40C for a period of a week. In the early morning at the end of that week, a current transformer in a vital power station switchyard failed catastrophically. The current transformer was one of a population of more than 60 installed over a period from 1976. One similar failure had occurred with this

Fig 2: Failed Current Transformer

live head design at another substation some years previously.

The investigation concluded that the most likely cause of failure from the meagre evidence was quality control and design. Thermal runaway triggered by the excessive ambient heat and possible moisture ingress was considered as other likely contributing causes. The unit had been tested for dissolved gas-in-oil less than 3 months prior to the failure and the results showed no problems. Figure 2 shows the remains of the current transformer. Very little evidence was available to indicate a definite cause of failure.

It was decided that a number of suspect units of the failed type and batch be replaced but that units of other batches of that type be retained after installation of a suitable continuous monitoring system. The AVO SOS system was selected from a number of available manufacturers and the system first commissioned in May 1999. The system was justified as a lower cost alternative to replacement of the entire population of this type of current transformer.

One of the strong drivers for the decision to implement a monitoring system was the need to address safety issues for personnel working in the yard. The original failure had resulted in debris up to 50 metres from the original site.

Substation On-Line System

The AVO SOS system is designed to provide continuous on-line monitoring of insulation condition by comparative measurement of insulation capacitance and dielectric dissipation factor.

Fig 3: SOS Main Panel

Connection to Plant

Connections are made to the test tap (where fitted[1]) of each device to be monitored. A capacitor divider unit is used to develop a 40V Pk signal that is wired by twisted pair cable to the central control unit via a central marshalling box. A personal computer fitted with a high-speed data acquisition board is used to analyse signals, calculate comparative results, monitor trends, display and archive results. User configurable multi-stage alarms are wired from the computer to station alarms and SCADA system.

Fig 4: Typical Tap Connection

[1] Where test taps do not exist alternative mounting arrangements can be made to allow connection to monitoring equipment

Remote Access

The unit can be accessed remotely via a modem using standard remote control protocols and software. The computer display features a graphical representation of the monitored plant. Key conditions including warnings and alarms are shown graphically using coloured icons. This method of representing the information enables the condition of the equipment to be assessed by operating and other staff at a glance. More detailed analysis is possible using alternative views. The system enables reporting by exception as the system can be used to only report operating problems.

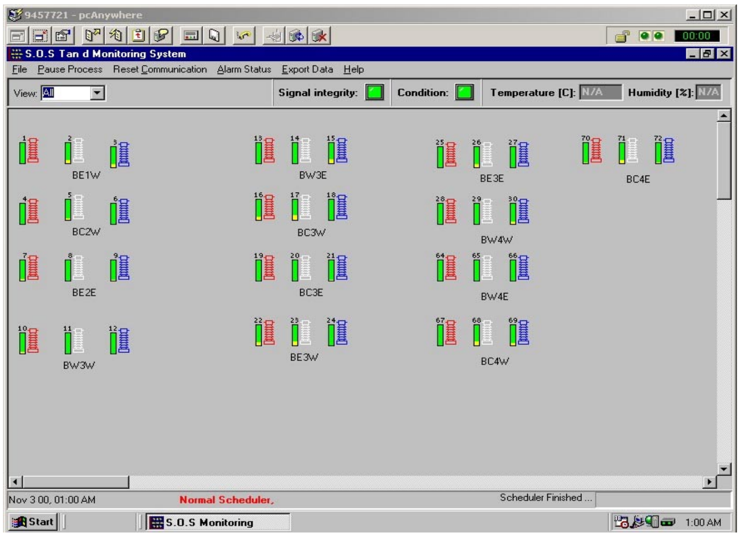


Fig 5: Remote Access Graphical Display

In addition to SCADA, alarm conditions are notified to the office by use of regular facsimiles or emails generated by the SOS system on site.

Service Experience

The Torrens Island monitoring system was commissioned in May 1999. Since that time a number of further installations have been commissioned as part of our condition monitoring implementation plan. Two potentially faulty units (first warning level) have been detected since first commissioning and those units are being monitored more closely for signs of further degradation. Of interest is the fact that warnings have been given after periods of weather similar to that evident at the time of the original failure in 1997, namely long sustained periods of high ambient temperature.

Our experience has indicated that the SOS monitoring system is sensitive to minor changes of insulation condition and as such we have developed confidence that the system can provide an early warning of potential failure. Installation and commissioning of additional systems has been completed at a number of key network locations.

Economies of Scale

ElectraNet have developed an economic evaluation tool to assist in project feasibility studies for new on-line monitoring systems. Studies have shown that implementation can provide real cost-benefit advantage with high profitability indexes and short pay-back periods. However for some time it was found that the economics for smaller substations (1-3 bays or lines) meant that the implementation of a complete SOS system could not be justified. On going discussions with ElectraNet SA and other utilities has resulted in the development and implementation of a family of modular, smaller scale devices that AVO have called their "PF Live product family". PFLive uses an identical measurement algorithm to the full scale SOS but scaled to be suitable for small substations. The first PFLive is currently being installed at a near-metropolitan substation. ElectraNet have adopted this technology due to its flexibility (can be used for a range of plant, can be hard-wired or wireless), scalability (a range of optional extra features are available) and the compatibility of the family with our existing systems and processes.

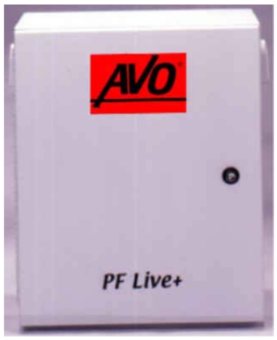


Fig 6: PF Live Plus

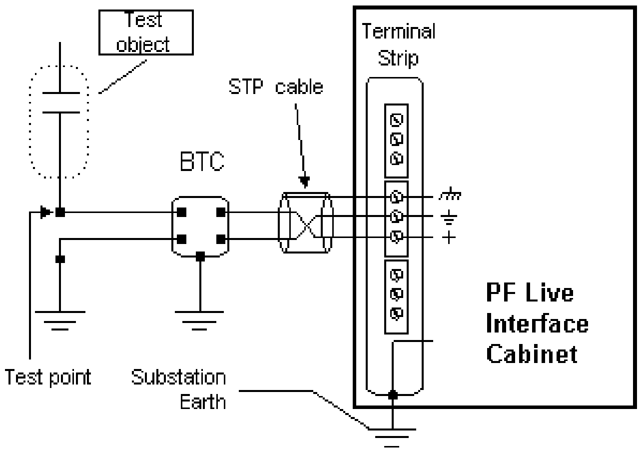


Fig 7: Main Connections of the PFLive

Key Advantages of the Systems for ElectraNet

The current transformer and bushing monitoring systems adopted have a number of advantages over discrete, traditional monitoring including:

- ***Application***. ElectraNet have adopted a risk-based approach to the selection of equipment to be fitted with continuous monitoring. It is important that the system can be used with a range of plant types and designs;

- ***Exception Reporting***. Reduced numbers of personnel and cost pressures mean that the number of staff to sift data and determine condition of plant is minimal. The system is designed so that staff are only notified when there is a problem with the plant being monitored;

- ***Expandability***. This includes the ability to add other forms of transducers and monitoring (example Transformer gas-in-oil, tap-changer and circuit breaker monitoring);

- ***Modularity.*** The ability to tailor a monitoring solution according to the size of the installation and the plant risk;

- ***Compatibility***. ElectraNet have implemented a range of on-line monitoring solutions for key plant types. It is important that all monitoring equipment is able to be integrated into existing systems and processes used for asset decision making;

- ***Early Warning***. Instrument transformer and bushing design means that failure gestation time can be short. The system provides early detection of potential failures.

Integration

ElectraNet is now entering the second phase in its implementation of a complete asset monitoring system for the entire network. Suitable on-line monitoring systems have been identified for all key plant including power and instrument transformers, circuit breakers and secondary devices. Systems and processes have been developed to ensure that the information is provided at the time required and to the people who need to make strategic or operational decisions. The growing proliferation of not only monitoring devices but also protection and control devices in substations that have communication capability has resulted in the need to examine how the information from these devices can be made available to staff from remote locations. ElectraNet have adopted the use of systems with the EPRI Utility Communications Architecture (UCA) compatibility and projects are now underway to take advantage of this protocol to integrate monitoring systems into substation local area networks (LAN) or wide area networks (WAN) at the enterprise level.

UCA interface For Substation Data Collection and Monitoring

The electric utility industry world-wide spends billions of dollars annually in providing reliable high quality service to their customers. Employing Intelligent Electronic Devices (IEDs) and integrating the monitoring, data gathering, protection, and control functions of the IED with the control centre applications via standards based technologies has the potential to improve reliability to customers and reduce costs.

UCA version 2 and Common Information Model (CIM) are now available to utilities for building an integrated enterprise that is responsive to today's business environment. UCA is a communications architecture that allows IEDs and applications from different vendors to exchange data in a client/server environment using mainstream networking technology like Ethernet, TCP/IP, and Internet compatible backbones from the substation to the control centre. The CIM is a standardized data model for exchanging data between control centre applications like EMS, SCADA, AM/FM, GIS, etc. CIM combined with UCA provides a powerful integration architecture that integrates utility's mission critical applications with the real-time data from substations. This protocol was created based on the needs of Utility managers who worked together with EPRI to define a protocol that would meet their needs. This protocol is currently being defined by an IEC Technical Committee (TC#57), Working Groups 10, 11 and 12. The standard is currently in preparation for final voting by the IEC, and will be the substation international communications standard (IEC 61850).

Advantages

The UCA protocol allows for a plug and play environment in the substation to easily integrate UCA-compatible devices together. Several equipment vendors supply their equipment with an Ethernet port to tie in to a substation network. This simplifies substation design since off-the-shelf substation hardened products are available from multiple vendors. The days of proprietary software protocols and non standard interfaces are in the past. Each substation device has been defined using Generic Object Models for Substation and Feeder Equipment or GOMSFE. GOMSFE is a descriptive string of variables for each substation device. The GOMSFE model makes it possible to easily communicate with UCA 2.0 compliant devices.

The GOMSFE models (called bricks) are passed through the Manufacturing Message Specification (MMS) to provide a data exchange between the device and the TCP/IP network. The structure of a UCA variable flows from GOMSFE which is the user level through MMS which provides handling and translating of the variable so it can be transferred via TCP/IP into the network. The variable then can be routed as specified by the user, within a substation network (LAN), or out through an intranet (WAN) or Internet. Using network topology allows data rates of 100MB/sec. Network speeds are available up to 10GB/sec if required. The command structure for each GOMSFE brick is used as a building block to build the commands from. A brick is required for each IED in a UCA network.

Substation Automation The OLD way

Traditionally substation automation projects required installing serial communication cables from a central data collection device out to each device individually using RS232 or fibre-optic cables with RS232 adapters. Data rates began at 300 baud, and eventually reached the limit of a serial port 115Kbaud. The protocols used varied from proprietary vendor protocols that required translators if more than one vendor device was used to common protocols like MODBUS and DNP3. The command sets varied from vendor to vendor and application to application.

Through these protocols data was transferred from device to device or device to a central data unit. Some devices were standalone and accessed via a modem to access the required information from the device. The ability to change device settings and check the status of a device could now be performed remotely over a phone line. This system although slow and sometimes expensive was reliable, and provided substation access as long as the telephone equipment and phone lines allowed.

Substation Automation The NEW way

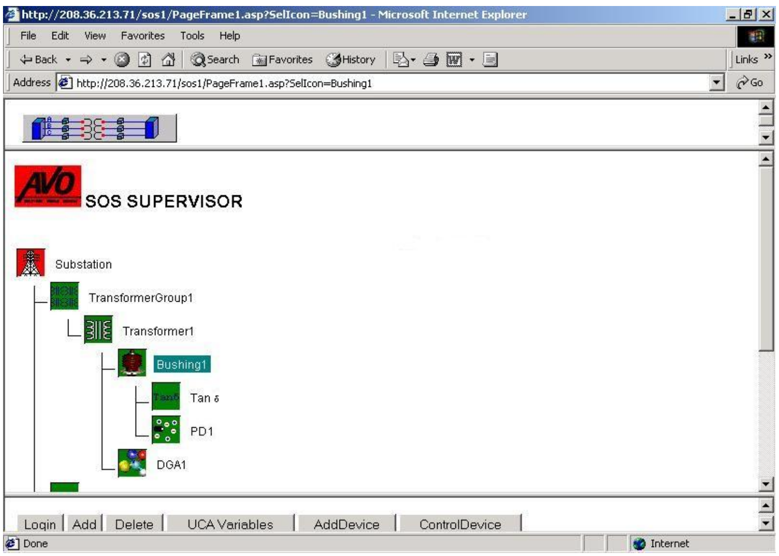
Today substation automation projects involve installing fibre optic cables for high speed virtually noiseless data transfer and communication to substation IEDs. Typical network topologies are used to tie all of the IEDs together. Routers and Hubs are required to tie the devices together into the network. Connecting from the substation network to the utility network can be performed by dial up lines, leased fibre-optic lines or utility owned fibre-optic lines. This depends on the utilities infrastructure, and using what connections are available, or can be installed.

The ability to perform protection and control communications and data transfer real time over an in house network including control functionality is now possible. It is no longer necessary to use power line carrier or pilot wire to perform control within a substation or between substations. This architecture has been installed in a few new substations by a large relay manufacturer. These relays implement a GOOSE message (Generic Object Oriented Substation Event) which is a report that sends status and control information to all IEDs on the network. The GOOSE is a powerful tool that provides reliable information that can be used in tripping/blocking schemes for breaker control, or just as an informational tool that provides a status report from an IED so that other IEDs know that new information is available to access.

Using SOS Supervisor as a UCA interface

As part of the move towards full substation automation ElectraNet SA has also adopted another AVO product, the SOS Supervisor. The SOS Supervisor provides an advanced open system architecture that is capable of monitoring data and information of equipment and related components within a substation. The system was adopted due to its user-friendly graphics and capability of communicating with various intelligent devices. The SOS Supervisor is an integration-processing tool at the substation level via a LAN, as well as, at the enterprise level by means of a WAN or Internet.

The SOS Supervisor, employing the Utility Communication Architecture (UCA) protocol, is designed to gather and exchange information, in a client – server environment, from multiple vendors' equipment and systems.



A Web Browser user interface is used to access the SOS Supervisor through various channels, such as serial line, LAN, WAN, Internet or directly from the Supervisor's PC.

Multilevel security access, in the form of username and password, is provided so that the system can be accessed, either in a viewer, supervisor or master mode, permitting the user to perform pre-defined functions at the respective levels.

An environment similar to the MS Windows® Explorer allows the user to navigate through the SOS Supervisor with ease. Equipment or devices are represented by icons arranged in a hierarchy based on the user preferences and pre-defined configuration for the given device. Activating any icon will expand or collapse the hierarchy below its level, and enable appropriate graphics to perform pre-defined operations to the related device.

The icons will display a steady colour of red, yellow or green, to indicate the status of the related device and its signal condition. Should an alarm be issued due to the condition of the device, the associated icon will change from a steady state to a blinking state. The alarm signal can be broadcast by e-mail, pager and or fax. In addition to alarms, the SOS Supervisor can provide event reports.

Other functions provided by the SOS Supervisor include: Work order entry/display, Message entry/display, Data display, Graph display, and Log-on activity display.

Control Centre Architecture and Enterprise Integration

In addition to the UCA efforts, EPRI has been very active in establishing useful standards for the control centre to improve the integration of control centre applications. This work was conducted through the EPRI Control Centre Application Programming Interface (CCAPI) project. The objective of the CCAPI project was to create standards and guidelines to enable plug-compatibility (the ability to easily install, or "plug-in" applications into different control centre platforms similar to the way shrink-wrap software packages are used in the personal computer marketplace) for control centre applications like EMS, state estimation, etc. CCAPI was chartered to work with standards that are compatible with the product, data base, and middleware technology of existing suppliers to the industry. The use of CCAPI standards would help enable the creation of a broader range of solutions that users could apply to solve real-world problems in the control centre. The CCAPI project has resulted, either directly, or indirectly, in the following data modelling standards and API standards for a message bus to integrate control centre applications:

- ***Common Information Model (CIM).*** The CIM provides an object-oriented representation of electric power systems that can be adapted to describe the specific systems of electric utilities. The CIM is now being used as the basis for international standards as part of work undertaken by the IEC TC57 WG13 and WG14.

- ***Data Access Facility (DAF).*** DAF is an API by which applications can access the power system model information in other applications. Extensions are currently underway to allow applications to manipulate and change these data models as well. The DAF was an outgrowth of the CCAPI effort and was formally published by the Object Management Group (OMG). Continuing work is being undertaken by IEC TC57 WG13.

- ***Data Access for Industrial Systems (DAIS).*** DAIS is another outgrowth of the CCAPI efforts that was taken up jointly by the manufacturing and electric utility interest groups within OMG. The DAIS, as its name implies, provides a standardized interface by which applications can access data (as opposed to the model information accessed by DAF) contained in other applications. Again, continuing work is being undertaken by IEC TC57 WG13.

- ***Generic Interface Definition (GID).*** The CCAPI is currently evaluating proposals for a GID API that will be endorsed as a publish/subscribe interface for applications. The GID is the common portion of a set of interface standards for specific applications such as state estimation, SCADA, EMS, etc. The final GID could address model and data access including modification capabilities. Continuing work on the GID is expected to progress through the IEC TC57 WG13/14 groups.

Common Information Model (CIM) and Benefits

The complete CIM consists of several interrelated packages of models including Wires, SCADA, Load Modelling, Energy Scheduling, Generation, and Financial. These data models (also referred to as metadata) specify not the contents of the actual power system, but how the structure and relationships of components of a power system can be represented in a standardized manner. Each CIM package contains descriptions of *classes* of objects. Each class of object is defined by its attributes, resources, and relationships to other objects (including objects in other packages).

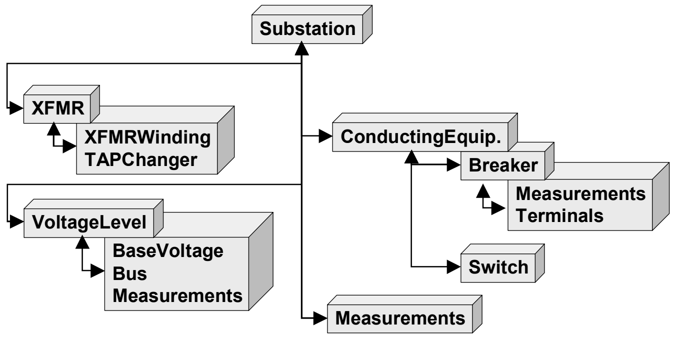


Fig 8: Simplified Example of CIM Model

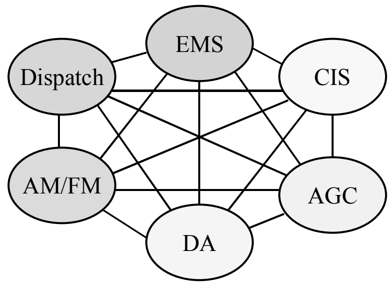
Some of the important characteristics of the CIM are:

- The CIM model is a model for data exchange. This means that the applications in the control centre do not need to be changed internally to support a new model. Instead, only the interface needs to incorporate the CIM for exchanging data with external applications.

- The CIM model allows each functional group to have their own view of the power system. For instance, the operational folks can view substations from the perspective of buses, feeders, transformers and breakers. The protection people can view the system as an interconnection of relays and breakers. The power engineers can view a transformer as a collection of windings, tap changers, CTs, and PTs.

- The CIM is expressed in a standardized form of the widely used eXtensible Markup Language (XML). XML is an Internet standard method of expressing and exchanging data that is widely used in commercial web sites. This allows the CIM to be used in many different computing environments independent of the specific suppliers of the computing systems.

- The CIM is widely supported by many of the leading application providers to the electric utility industry. The CIM is already in use in over 40 utilities world-wide with new systems being deployed constantly.



Integration Without CIM

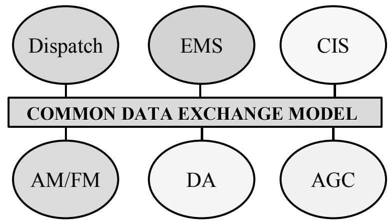


Fig 9: Integration Using CIM

The key benefit of the CIM is its ability to lower the cost to do complex integration of applications in the control centre by providing a common information model for data exchange between these applications. Can integration be done without the CIM? Of course. In very simple systems involving only one or two applications and minimal data exchange the real benefits of a common exchange model may not be as significant. However, in more complex systems, such as the typical electric utility control centre, the burden of model translations can quickly become overwhelming. This makes the system overly complex and difficult (if not impossible) to implement cost effectively. Using a common exchange model like the CIM greatly simplifies the integration task, lowering cost, and reducing technical risk.

Using the CIM for integration results in the implementation of a common view that is then available to all utility operations and applications. This very high-level of integration can enable the development of new business applications that are not practical without common a data model for all operations. Complete enterprise wide integration of both IT and real-time operational systems becomes feasible.

Message Bus

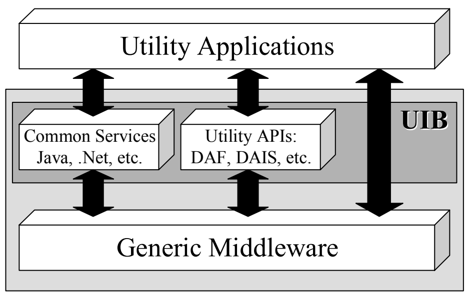


Fig 10: UIB Architecture

The CCAPI interfaces are designed to support operation over a message over which the various applications are integrated. In the same manner that the CIM simplifies integration by minimizing the point-to-point model transformations required, the integration bus simplifies application integration by minimizing the number of integration points. Without a message bus, each application must be independently integrated with each other application for complete integration. With a message, bus each application must integrate only with the message bus—greatly reducing the amount of work required for complete integration. Products that address utility specific integration, or a Utility Integration Bus (UIB), are examples of these message buses.

Applications access the UIB via a set of APIs. Standards based APIs such as DAF, DAIS, and the forthcoming GID are typical. The UIB layers these utility specific APIs over industry generic middleware products for the actual message transport. The UIB provides a set of services, via the APIs, that are required for applications commonly used in the utility control centre while leveraging the fast developing mainstream information technology (IT) and e-commerce products for the underlying message transport and enterprise application integration (EAI).

In a typical system, the complete power system model is implemented in many different systems. Customer information is in the customer information system (CIS). Geographic information is stored in the geographic information system. Current power system information is stored in the energy management system (EMS). And so on. Each application in the system contains a subset of the overall power system model. For a given complex business object, such as a work order requiring installation of a new power system component, the necessary model and status information is contained in several different systems. The UIB can proxy this information from several systems and provided a single, CIM-based, view of the entire system. Instead of each application using the APIs to access each separate application they access the globalised data of the UIB. This further simplifies the integration and development of applications by isolating the system architecture of external applications from affecting the local application. Changes can then be made in one application of the entire system without significantly impacting all the other applications in that system.

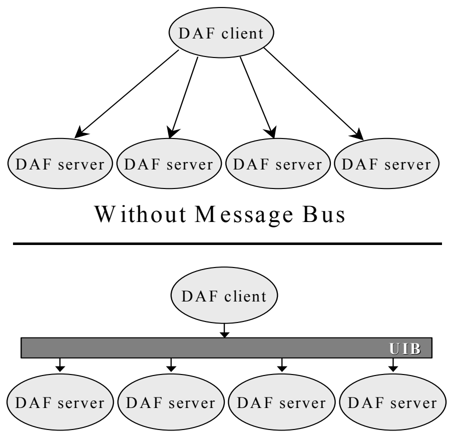


Fig 11: With Message Bus

Legacy Control Centre to Substation Integration

Information on the status of the power system must be made available to applications in the control centre. This is typically achieved in the legacy systems in use today via phone lines or other relatively low-speed links to a remote terminal unit (RTU) in the substation. For power system information outside of a substation these same kinds of links are used again to communicate with an RTU that acts as a *front-end* to the power system. The RTU collects the data. The applications in the control centre, typically EMS or

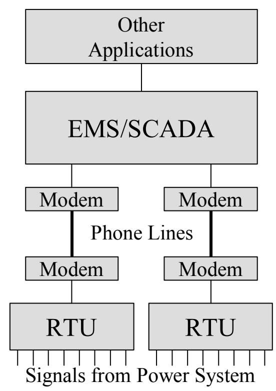


Fig 12: Legacy Architecture

SCADA, communicate with these RTUs in a point-to-point fashion. This presents several barriers to effectively getting the real-time information from the power system into the applications existing in the rest of the utility enterprise:

- ***Minimal Function Protocols***. Most RTU protocols are simplistic register access protocols that represent data as an unstructured collection of data points. Each data point is represented as the integer value that the RTU sees on the analogue-to-digital converters connected to the PTs and CTs in the substation. Scaling factors must be programmed into the control centre applications in order to convert the signals into a useful piece of data such as a voltage. Furthermore, applications must typically have detailed knowledge of low-level addressing within the substation in order to access the data.

- ***No External Integration Points.*** These legacy systems typically utilize low-speed phone lines and radio links for communications with substations that do not provide independent access to applications. The EMS or SCADA application that communicates with the substation controls and consumes the entire link to the substation. Any other applications must access the data via the EMS or SCADA. Therefore, if a new application requires a new piece of data from a new piece of equipment in the substation ALL the intervening applications in both the control centre and the substation must be reconfigured.

UCA Approach to Control Centre to Substation Integration

With UCA, a more modern approach is taken that allows the utility to effectively leverage the mainstream commercial solutions for communications that are rapidly developing to address a broad increase in demand for Internet access, e-commerce, and mobile communications. The UCA approach uses standardised networking technologies for the substation and control centre based upon TCP/IP and Ethernet. Interconnection of the networks is accomplished using generic network switches and routers to enable a single virtual network to be implemented. In the control centre, a telemetry server (or possibly an EMS or SCADA) publishes the real-time information from the substations to the UIB. Applications on the UIB need only subscribe to the information they desire without having to concern themselves with how the information is obtained.

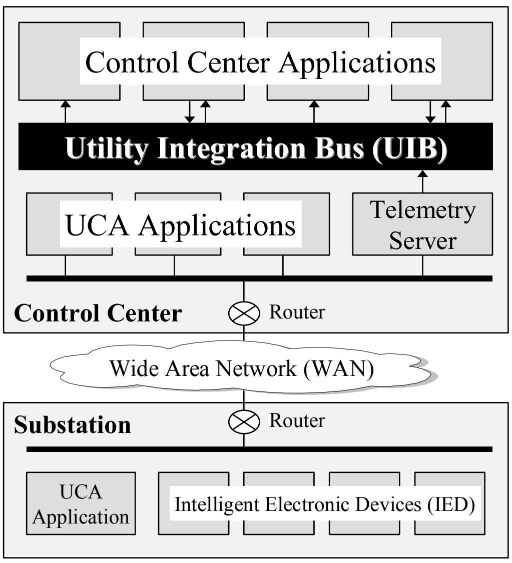


Fig 13: UCA Based CC-Substation Integration

There are numerous benefits to the UCA approach for control centre to substation integration:

- ***Lower Configuration Costs.*** UCA has several unique features that enable it to significantly lower configuration costs: self-describing devices and standardised naming conventions. UCA clients can obtain a complete description of all the points defined in a UCA device by simply asking for the data. This means that UCA clients do not have to be manually configured with pre-determined and arcane point/tag names as most legacy systems require. Additionally, UCA devices conform to standardised naming conventions for all points that illustrate both the meaning and hierarchy of the data. A voltage in one device is named exactly the same as it is any other device. And, the function of point names and what kind of device that they are located in can be easily discerned from the name of the point.

- ***No Barriers to Information Access.*** A UCA approach leverages mainstream networking technology to create a single virtual network which can access all the data. UCA clients that need data need only know the network address of a device in order to access the device. The device does not generally need to be pre-configured to allow access. Any application that needs data can access the data without having to reconfigure all the intervening equipment. As existing equipment is changed or new equipment added this barrier-less approach can save significantly on maintenance costs.

- ***Maximize Capabilities.*** Because the UCA approach uses mainstream networking technology utilities can leverage the vastly expanding choices of wide area networking technologies for integrating their enterprise. The old legacy approaches simply can't make use of these new capabilities. The UCA approach results in a network and system architecture that is flexible to accommodate changing needs incrementally using the latest most cost effective technologies. The new capabilities that these architectures offer allow utilities to build business applications that were simply not possible with the legacy architecture.

Integration with External Systems

Utilities are increasingly concerned with data exchange with other parties such as regional transmission organizations (RTO), security coordinators, neighbouring utilities, and power plants. The days of utilities owning and controlling all the components of a power system are disappearing as more and more utilities move control of power plants and transmission assets to other organizations.

For data exchange in this deregulated environment UCA defines the Intercontrol Centre Communications Protocol (ICCP per IEC60870-6 TASE.2). ICCP allows each side of a communications link to carefully control the data that is exchanged. Confidential data that should only be accessible to internal applications are prevented from being included in the ICCP data exchanges needed by third party power plants, security coordinators, and transmission operators.

Just as the need to exchange model information has become critical internally within a utility, so has the need to exchange model information with external entities increase. As utilities add substations, plants, switches, breakers, feeders, etc. to their power system, they must increasingly find effective means of communicating these power system model changes to the external companies that must coordinate their activity with that of the utility. The CIM plays a crucial role here. These large scale regional, and national, power system models are much too complex to be exchanged effectively without standards.

Conclusion

Technologies that were seeded from EPRI projects such as UCA, the CIM, the UIB, and ICCP all play an important role in creating a modern computing and networking infrastructure that is capable of supporting the requirements of the modern utility. Although each of these standards addresses a specific application area within a utility they can be used together effectively to provide a broad range of solutions for many systems within the modern electric power utility.

Changes to the Corporate environment and increased competition as part of participation in the National Electricity market has increased awareness of the benefits of on-line and continuous forms of monitoring for asset management in ElectraNet SA. Where previously systems were implemented as part of research and development projects, decreased personnel, out-sourcing of maintenance and increased awareness of the need to reduce whole of life costs with minimised risk, have resulted in an asset management strategy that includes implementation of comprehensive and detailed monitoring systems. There has been significant expenditure in developing necessary infrastructure and in ensuring that the information collected is at sufficient level and quality to enable strategic decision making for operations, plant refurbishment and replacement decisions. The installation and commissioning of bushing and current transformer monitoring systems has provided ElectraNet with a low cost alternative to replacement of a population of ageing instrument transformers. Integration of monitoring systems with other information sources and with substation local area networks is now underway using the UCA protocol compatibility of installed monitoring equipment.

References

[1] R. Linn, *"ETSA - The Story of Electricity"*, ETSA Corporation, September 1996

[2] T W Krieg, *Monitoring And Asset Management Of High Voltage Equipment In South Australia",* Proceedings of TechCon'99, New Orleans

[3] T W Krieg, M Napolitano, *Implementation of On-Line Transformer Monitoring and Fault Diagnosis in ElectraNet SA*, proceedings of ICMEP 2000, Wuhan, PR China, 25-26 September, 2000.

[4] T W Krieg, *On-Line Condition Assessment Of High Voltage Current Transformers In South Australia*" GE Energy Management, 18th Conference On-Line Monitoring Conference, Bethesda, Maryland USA November 13-15, 2000

[5] T W Krieg, M Napolitano, *Techniques and Experience in On-Line Transformer Condition Monitoring and Fault Diagnosis in ElectraNet SA,* Proceedings of PowerCon 2000, Perth, WA, December, 2000

[6] J. Benach AVO International and R. Mackiewicz SISCO Inc., *UCA Interface For Substation Data Collection and Monitoring*, EPRI Substation Conference, New Orleans, LA February 2001

[7] T W Krieg, *On-Line Condition Monitoring Of Transformers And Bushings,* AVO New Zealand, 2nd International Technical Conference, Methven, New Zealand, April, 2001.

Biographies

Terry Krieg is currently acting in the role of Executive Manager Asset Maintenance for ElectraNet SA in Adelaide, South Australia. The Asset Maintenance group is responsible for the whole-of life management of substation, line and telecommunication transmission assets throughout South Australia. This includes contract management, policy development, performance monitoring and fault investigations. In addition the group carries out diagnostic, high voltage and oil testing services for ElectraNet SA and a range of customers in Australasia.

Prior to his current position Terry Krieg was employed in a range of asset and risk management and Condition Monitoring engineering roles within the South Australian electricity industry.

Terry graduated from the University of South Australia in 1993 in Electrical Engineering (BEE-Hons) and has carried out research projects in the development of monitoring systems for surge diverters and has experience in the implementation of major new maintenance information systems.

Previous employers include the Snowy Mountains Hydro-Electric Authority, Hydro-Electric Commission, Tasmania and the Department of Defence.

Jeff Benach, is the Project Manager of Substation On-Line Monitoring Systems with AVO International. Jeff's responsibilities include acquisition of new technologies, and development of new transformer monitoring technologies.

Jeff graduated of the Ohio Institute of Technology in 1982 with a Bachelors Degree in Electronics Engineering Technology, and is currently working on an MBA in Technology Management from the University of Phoenix.

Before joining AVO, Jeff spent 10 years with General Electric Power Management, and was project manager responsible for developing Digital Transmission Line Relays.