

Designing a new IEC 61850 substation architecture

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Abstract

Manitoba Hydro, a utility headquartered in Winnipeg, Manitoba (Canada), is looking to replace their current Substation Automation System (SAS) which is a discrete RTU and PLC-based control and metering architecture with an integrated IEC 61850-based architecture. This initiative follows a trend that is observed throughout the world, as the benefits of technologically advanced IEDs and IEC 61850 get more interest from utilities.

The utility envisioned a multi-layer redundant control system following an A-B protection scheme, using protection IEDs from different vendors for each A-B pair. Station equipment is grouped into control zones as determined by reliability and availability requirements, and by the number of controlled devices. An automation processor, called a Zone Controller, serves as the standard interface to each zone and communicates with the IEDs using the IEC 61850 and where required DNP3 protocols, allowing remote control operations through the IEDs and their corresponding I/O modules. IEC 61850 GOOSE messaging is used for inter-IEDs communications. In addition to the redundant HMIs located at the station level, a smaller touch screen HMI is installed in each zone for local control operations from single-line diagrams similar to those available on the station HMIs.

Before adopting this new architecture and launching any pilot installation, a proof-of-concept project was conducted, where several IEDs from various manufacturers were successfully integrated. Additionally, user interfaces for both the zone controllers and the substation HMIs were developed and implemented. These interfaces received positive acceptance from Manitoba Hydro.

The white paper and presentation will explore in details this substation architecture, as well as the issues and challenges that were encountered and solved during the proof-of-concept project.

Introduction

The primary role of the SAS is to provide safe, secure, and reliable local/remote control and monitoring of high-voltage AC distribution and transmission stations.

Historically, the SAS at Manitoba Hydro (MH) was implemented in the substation using RTUs and redundant PLCs, with redundant computers for the local HMI and without any hardwired control backup. With a few exceptions the protection relays had limited connectivity with the control system utilizing a hardwired interface for I/O and alarms. This solution has proven itself, but it did not realize the benefits that could be provided by the advanced features offered by modern protection relays and IEDs. This was primarily due to the inability of the existing hardware to support the communication protocols necessary to integrate the new IEDs into the automation system.

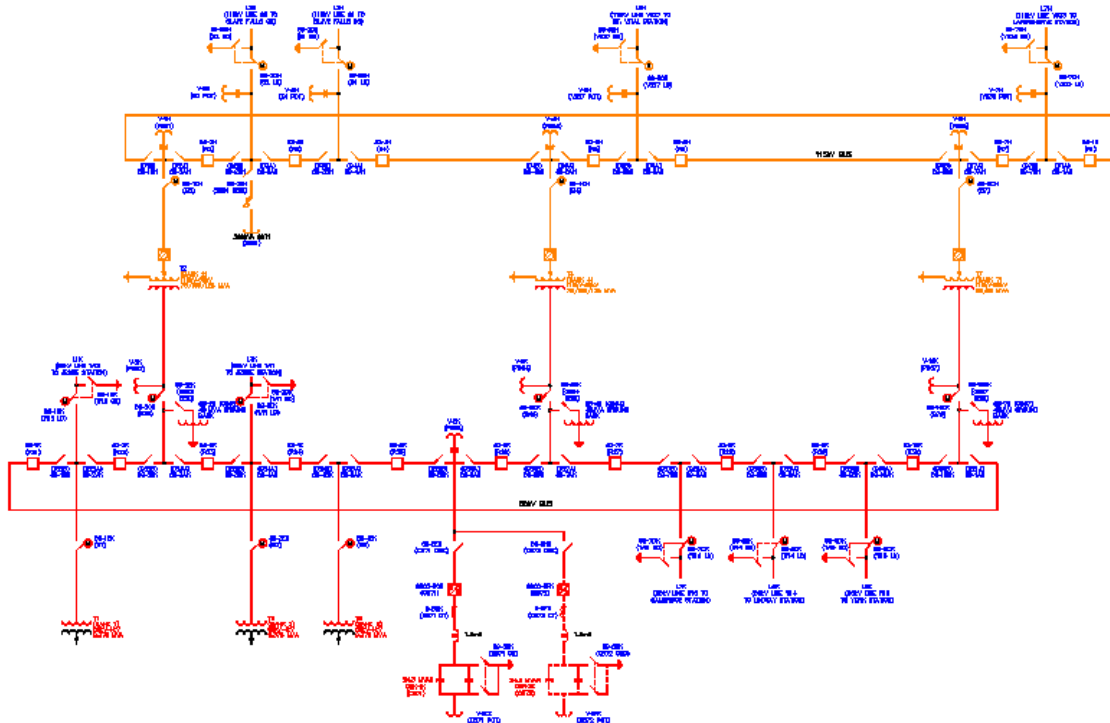
To overcome these issues and to get a flexible, sustainable, and extendible solution, MH wanted to move the current control architecture towards an IEC 61850-based solution. The IEC 61850 standard was selected for its interoperability, extendibility, enhanced performance and flexibility, and reduced wiring costs. All of these benefits will ultimately reduce engineering design costs, and improve engineering support and maintainability.

The main aim of the SAS was still the same: it needed to be safe, secure and reliable. But it needed to use the latest standards and technologies, such as IEC 61850 client-server communications, GOOSE messaging, fiber optic networks, and complete redundancy when required. Also, the new design needed to allow for easy system expansion due to eventual substation growth, keeping the existing part of the system in service during the installation and commissioning of new switchgear and IEDs.

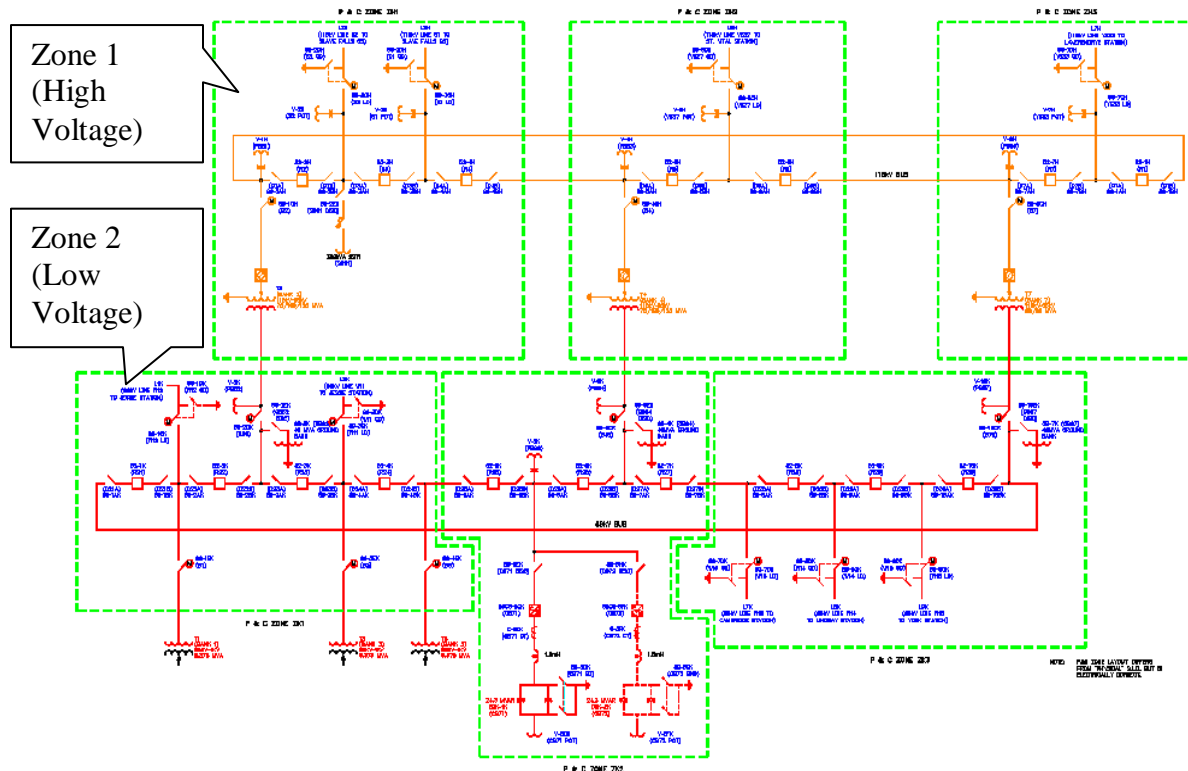
Before moving from the existing RTU/PLC-based solution to an integrated IED-based solution, a proof of concept project was conducted on a smaller scale with Virelec and Cooper Power Systems.

Scope of the proof of concept project

A portion of a new proposed substation was selected for the proof of concept project. The selected part included typical equipment configurations used at MH. It was also one of the first substations that would be built utilizing the new architecture in the near future.



MH typically organizes its substations into control zones and switchyard equipment bays, which contain one or more breakers, one or more switches at a single voltage level but may also include transformers. The MH zone layout could not be directly translated to the standard definition of an IEC 61850 bay because of the conflicting definitions of a “bay”. MH wanted to keep the zone and bay notation and layout. However, the interface to each zone is based upon IEC 61850 standards. Below is the same substation, but with zone delimitations indicated.



For the proof of concept project, the new architecture solution was implemented based on control zones 1 and 2 of the substation.

Solution architecture

The architecture of the new solution is strongly based on the IEC 61850 standard, notably at the inter-equipment communication level, although it also supports other industry-standard and proprietary protocols. Redundancy is also a core characteristic of the solution.

At the communication level, the solution implements the IEC 61850 protocol as much as possible. GOOSE messaging is used for breaker and switch status, and other high speed signals; it is also used between IEDs, as well as from the IEDs up to the zone controllers, which are supplying the interface between the zone

and the substation SCADA gateways. IEC 61850 client-server communication is used to retrieve the rest of the data from the IEDs up to the zone controllers and SCADA gateways. Other protocols also need to be supported by the zone controllers, for non-IEC 61850 capable devices. For the proof of concept project, a wide selection of protection IEDs from industry-leading manufacturers were selected and successfully integrated.

At the equipment level, the solution architecture was designed to meet reliability and availability requirements, by implementing various redundancy schemes:

- For protection, an A-B scheme was implemented, using different relays for the A and B breaker protection to enhance tripping reliability.
- Redundant zone controllers for a given zone are fully running in parallel, in a hot/hot configuration. Both controllers are active.
- Both SCADA gateways are configured to run in a “hot standby” redundant mode to optimize failover timing; therefore, only one gateway is active at the time, and the other is always ready to take over the active role as fast as possible.
- Local substation HMIs are running in parallel and obtain their real-time data from the active SCADA gateway.
- All devices are connected through Ethernet-based networks that are set up in ring configurations, using fiber optic as much as possible.

The following figure presents the resulting solution architecture diagram.

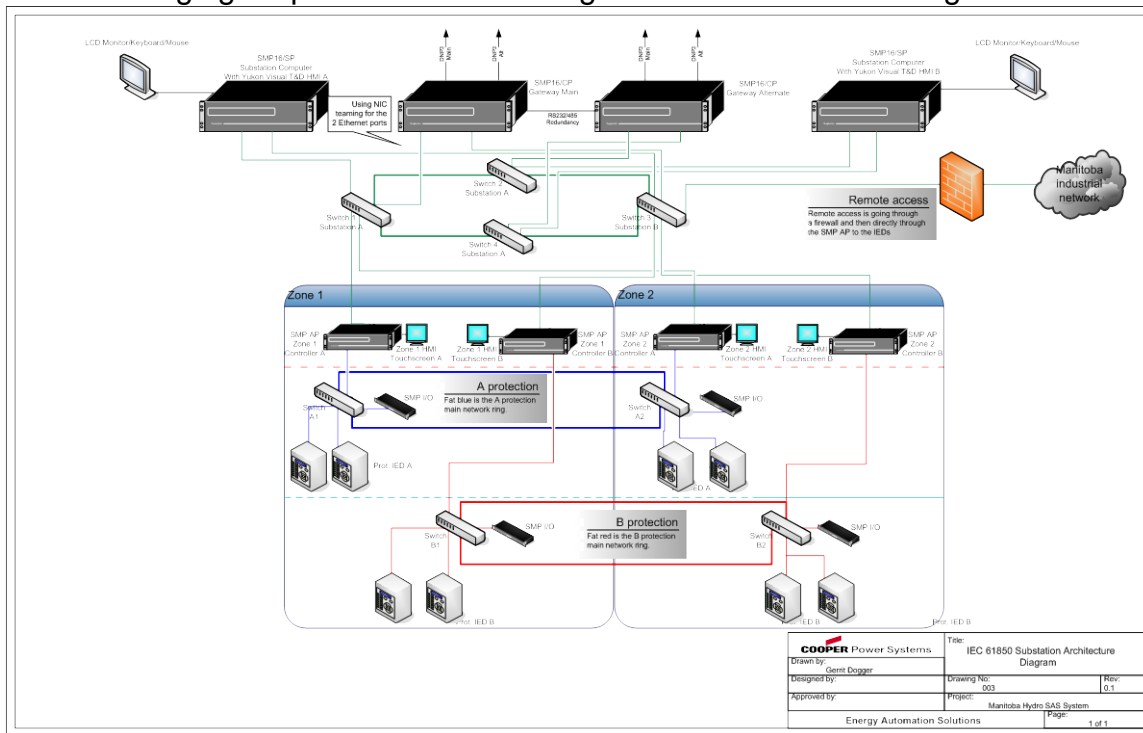


Figure 1: Solution architecture

The zone controllers are redundant with a dedicated controller in each of the “A” & “B” subsystems for a given zone similar to the redundant protection IED strategy to ensure reliability and availability of the protection and control system. With zone controllers running in parallel, the logic required on the controllers is simplified, since there is no need for any special interlocking schemes between the “redundant “ controllers in regards to GOOSE messaging or controls. This redundant-parallel approach also allows each zone controller to be used separately, when one of the subsystems in the zone is under maintenance or commissioning. The interface between the zone controllers and the SCADA gateways is implemented following the IEC 61850 client-server model.

The SCADA gateways are configured in a hot standby redundant mode and have dual links to the substation network ring. The substation network ring comprises 4 Ethernet switches that are required to facilitate splitting the network in 2 parts (A and B) for system expansion and maintenance. A communication link between this network ring and the Manitoba Hydro Industrial Data Network (IDN) will be available for remote access and support; this link was not part of the proof of concept project, but will be implemented in the field. The HMI design includes KVM appliances which will utilize this IDN connection.

Internal logic

The control logic for local and remote breaker control and for alarming is distributed over the SCADA gateways and the zone controllers, and implemented using built-in IEC 61131-3 SoftPLC.

In normal operation the gateways are in hot/standby configuration and the A and B redundant subsystems run in parallel. There are several control modes:

- Master operation from the remote control centre
- Local operation mode from the substation HMI
- A “test” mode for scheduled or unscheduled maintenance and system expansion with the ability to split the redundant system into two standalone systems, one system is out for maintenance, and one system remains in normal operation mode.
- Local operation mode from the zone controller, for each separate zone.

At the zone controllers, control commands that operate high voltage apparatus are validated against any “do not operate” tag, substation interlocking, and substation control authorization (remote or local). Circuit breakers that require a synchronizing and/or synchrocheck close have a specific sequence necessary for a breaker close operation. Both A and B subsystems have dedicated synchronizer IEDs. To operate breakers with a synchronization check the synchronizer IED must connect to potentials on both sides of the open breaker. This is done using electromechanical potential select relays driven by the breaker point select logic. Once confirmation that the proper potentials are selected for the breaker close operation, a start signal is sent to the synchronizer IED. When

both incoming and running potentials and phase difference are within the acceptable parameters, the synchronizer IED issues a permissive close to the zone controller which issues the breaker close command. When the breaker status indicates that the close operation was successful, the zone controller deselects the synchronizer potential select relays and resets the point selection.

Besides the high voltage apparatus control operation logic, the SCADA gateway also handles all special alarming logic. Manitoba Hydro requires the ability to dynamically associate alarm points to alarm groups, inhibit alarms from the substation HMI, as well as dynamically change alarm timing for each group. The indication that an alarm has been inhibited from the substation HMI must be displayed on the HMI and reported to the remote SCADA control center to alert operators.

Visualization and control

The architecture solution provides visualization and control features at three levels:

1. From the remote control centre (SCADA)
2. In the substation
3. In a zone

For the proof of concept project, the remote SCADA system was simulated in the factory using an HMI that provided the required SCADA features for thorough testing. In addition a full-featured DNP3 protocol test unit was used to monitor the communications data stream. Successful control and data communications were achieved.

In the substation, an HMI that provides dedicated access to the internal database of the SCADA gateways was selected for the proof of concept project, as well as for the final solution. Manitoba Hydro standard objects were implemented based on the existing HMI standards of the utility in order to reduce the learning curve of the new system by its operators. Because the new software did not have the exact same features as the former system, careful planning and design work performed closely with Manitoba Hydro was necessary to reach compromise solutions that met the requirements of the utility.

The figures below present the main single-line diagram, a close up view of a breaker icon with any safety tags (cards) applied to the breaker, and the details of a typical Caution safety card, as they appear in the HMI at the substation level.

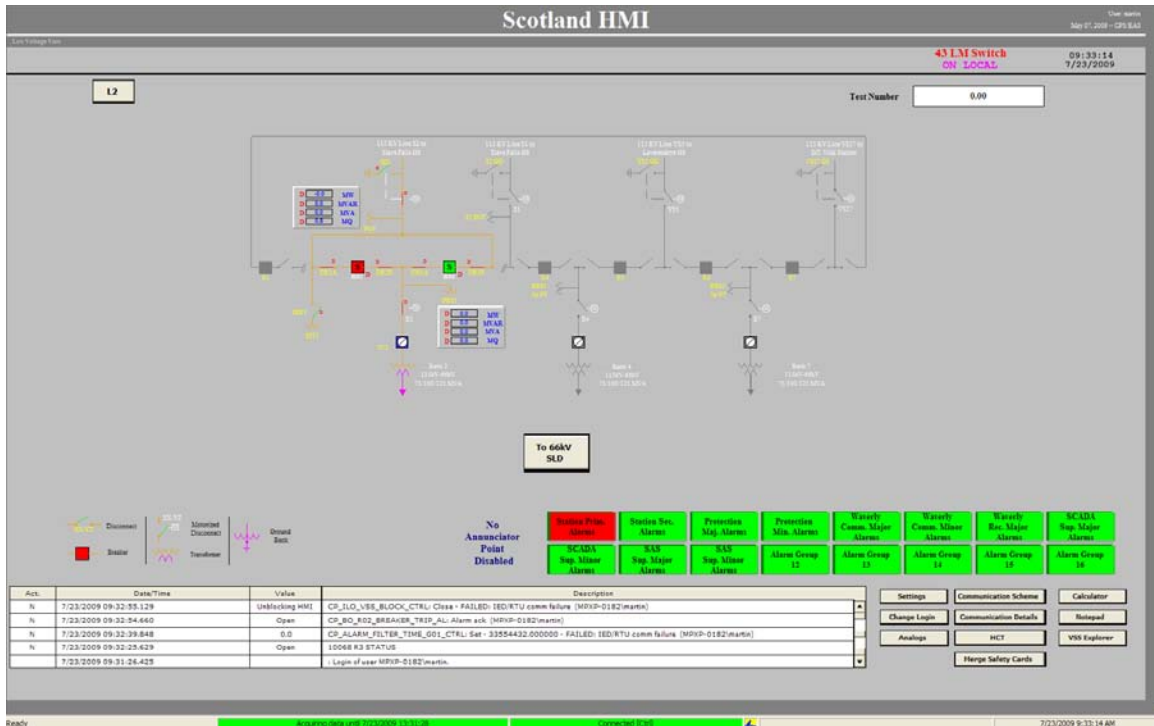


Figure 2: HMI main 115kV single-line diagram



Figure 3: HMI breaker close up, caution & hold cards applied

Safety Card ✖

Operation Order No: Device:

Placed By: For:

Permit Number: Date & Time: 5/7/2009 10:40:23 AM

CAUTION1 **DO NOT CLOSE**

Comment:

The line is under maintenance.

Figure 4: HMI Caution safety card interface

In each zone, there are no physical control switches installed, as all control switches are emulated in software in the new substation architecture. The zone controller provides a simplified interface for the operators compared to the station HMIs, using the built-in annunciator feature of the controllers and associated flat panel touch screen monitors. The only options at this level are the following:

- Real-time values visualization
- Basic alarm indications
- Control operations
- Display of safety cards (cards cannot be edited at this level)

System expansion mode

Like most utilities, Manitoba Hydro knows that substations will be upgraded in the future to accommodate constantly evolving needs. To minimize planned or inadvertent substation and equipment outages as much as possible during upgrades, Manitoba Hydro envisioned a system operation mode built upon the redundant A/B characteristics of the control system. In this mode:

- The normal parallel redundant operation of the system is split into independent A and B systems
- One subsystem (A or B) is used for normal operations.
- The other subsystem is used to perform expansion work and related testing of the upgraded software and hardware components.
- Both A & B protection IED trip outputs remain unaffected (unless the protection IED is out for maintenance)

In this mode the normal hot/standby configuration of the SCADA gateways becomes a hot/hot configuration, each gateway active and dedicated to either the A or B subsystem, with the ability to supply data to the SCADA and the associated substation HMI from the respective control subsystem. Various mechanisms were implemented to support this mode:

- The serial communication link between the SCADA and either one of the SCADA gateway is routed depending on which control subsystem (A or B) is used for expansion and testing.
- Physical switches in conjunction with logic in the gateways allows toggling of the connection from SCADA to either of the active gateways and toggling control of the substation between SCADA and local control HMIs.
- Mechanisms in the substation network switch between the normal and system expansion operation modes, and between master (SCADA) and local control modes, using ethernet switches to break the fiber optic loop.

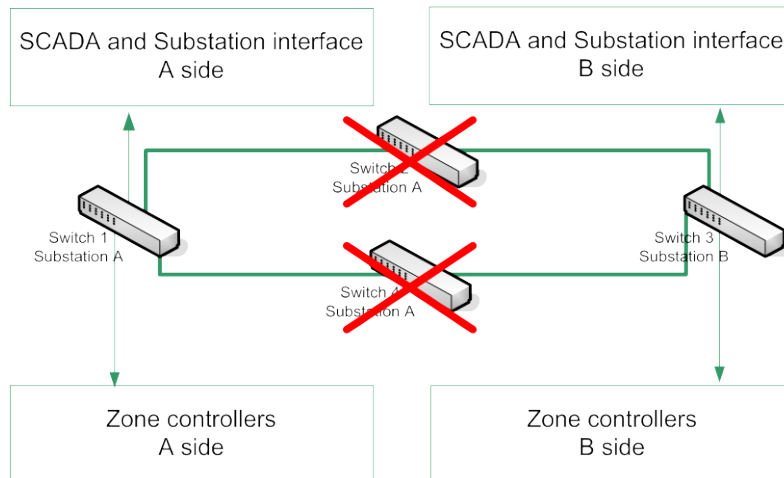


Figure 5: Substation network when in split mode

The selection of the operation mode, as well as the selection of which side will be communicating with the remote SCADA, is done through a combination of physical Local-Master (43LM) and Hot-Standby (43HSBY) switches and logic implemented in the gateways. Based on the status of these switches, the gateway will turn off Ethernet switches as required (number 2 and 4) and route SCADA communications to the selected SCADA gateway.

At the zone interface level, no switching mechanism is required, as the redundant zone controllers run in parallel. However, for security reasons, the physical outputs of the subsystem (A or B) selected for maintenance, expansion or testing, are electrically isolated from the switchgear by an electromechanical relay that removes the control wetting voltage from the final 125VDC control outputs. Correct control subsystem operation can be verified to this point. Alternatively, logic in the protection IED can inhibit the physical outputs while in the test mode if a visual tag is displayed or event generated for logging to verify that the output will operate correctly.

Conclusion

The aim of the proof of concept project was to implement a multilayer redundant IED-based control architecture based on the IEC 61850 standard and complete interoperability of different vendors' IEDs. This aim was successfully achieved.

Moreover, integration of non-IEC 61850 devices is possible without any issue in the new architecture. These devices that lack GOOSE messaging support can report their status data to zone controllers, which in turn propagate this data through GOOSE messaging, with some limitations to their processing time.

Limited application of the IEC 61850 interface was done at the zone controller level. Additional functionality should be integrated in future projects along with

further enhancements to the IEC 61850 model, as it is getting increasingly more important to ensure interoperability with other vendors' IEC 61850 tools and interfaces. The current SoftPLC logic must also be reviewed and optimized to be more modular and scalable.

Engineering tools, still under development, must be improved to enhance the complete process ease-of-use and efficiency.

Next steps

For Manitoba Hydro, the next step is to put in place a substation based on this newly developed architecture, in 2010. During this next development phase, IEC 61850 zone models and the PLC logic of the zone controllers must be finalized, tested and put into service.

As engineers at Manitoba Hydro and elsewhere gain experience with this architecture, the additional feedback received will help to refine the models and logic. This will facilitate the development of the IEC 61850 integration tools that will be required to update other MH substations.

To ensure efficient and complete system support during and after installation, the OEM and integrator will have remote access to Manitoba Hydro substation SAS systems to assist with any issues the utility cannot resolve on its own. Additionally, Manitoba Hydro will purchase a complete test system for ongoing maintenance and support.