Bangor Hydro-Electric Co. Shifts from RTU Links to PCs For Networkable Remote Control of Power Substations

Bangor, Maine — Bangor Hydro-Electric Company has come a long way, for a trolley company. Started early in the 1900’s to provide electrical power for the municipal trolley system, Bangor Hydro-Electric has become one of the largest public electric utilities in New England, serving about 100,000 residential, commercial and industrial customers in a service area covering almost 5,000 square miles of central Maine.

Bangor Hydro began a major system upgrade project in the early 1990’s that was intended to modernize about 3,500 miles of transmission and distribution lines that run north up the Penobscot River valley and east to the Atlantic Coast and New Brunswick. As part of this modernization program, the company’s engineering department decided to change over from traditional electro-mechanical devices (such as analog relays and telemetry equipment) to intelligent electronic devices (IED s) for its supervisory control and data acquisition (SCADA) systems. This would not only provide more efficient remote control of substation breakers and tap changers for handling routine maintenance and emergency response, it would provide better data input for management of the entire system as well as a better growth path for future networking of substations so they could be managed remotely from a single, centralized site in downtown Bangor.

Using the construction of a new power substation in East Machias as the opportunity to prove the theory, Bangor Hydro-Electric engineer Terrance O’Brien and consulting engineers from Tasnet, Inc. decided to put in equipment for computerized monitoring and control of the substation in parallel with their standard remote telemetry units (RTUs). They installed an Intel 486/66-based personal computer (PC) running Wonderware InTouch™ man-machine interface (MMI) software as the master unit for a substation integration (SI) network of intelligent electronic devices interfaced to ABB REL-301 and DPU-2000 digital relays and a GE 9030 programmable logic controller (PLC). These in turn were interfaced to substation I/O sources including circuit breakers, switches, electromechanical relays, transducers and transformers that represented the on-line equipment.

Bangor Operators have been using a large peg board as the original “one-line” diagram overview for monitoring service and repairs throughout the system.
This substation network provided four categories of functionality:

- operation of breakers and motorized switches via the digital relays and PLC;
- monitoring of all status and analog values of the substation;
- direct local and dial-up remote communications capabilities for programming and interrogation of the system;
- capability of interfacing with future IEDs as they are implemented.

East Machias is one of 75 substations in the Bangor Hydro-Electric network. About half of these sites are small, providing little more than transformer and fuse operations, but the remainder are substantial enough in size and functionality that O’Brien felt it would be good to have remote control and monitoring of them in a wide area network based in Bangor. And nowhere does the word “remote” carry more meaning than in the rugged territory known as Maine.

Manual to SCADA to PCs

“Typical of most utilities, Bangor Hydro-Electric started operations years ago using manual systems,” O’Brien explained. “The company started in business providing trolley power, and it acquired dams built for lumber production and converted them to electrical power generation. In the subsequent 90 years or so of operation, the company has added a variety of generation facilities including steam, diesel, nuclear, bio-mass and refuse-based generation systems as well as purchased electricity. The second half of the operation equation is getting that power to the customer over the distribution network.”

System Operators at the master control room on Park Street in downtown Bangor dictate each and every step that occurs throughout the system, whether it’s for routine maintenance or emergency response. Whenever faults occur and circuit breakers start opening, it is their responsibility to establish proper procedures both for maintaining safety and restoring power to customers. To accomplish this they require a “view” into the entire network.

The original operator interface was a very large pegboard that had a so-called “one-line” diagram of the system’s power generation, transmission and distribution facilities. This wall-size schematic diagram uses taped lines to replicate the transmission lines and voltage levels in the system, starting with the primary 345 kilovolt (KV) line and stepping down to 115KV, 46KV, 34.5KV and lower voltages, each represented with a different color. It also is covered with symbols representing the different types of switches or breakers used to control loads.

Crews dispatched for maintenance and repair operations used two-way radios to stay in touch with the control room, advising which switches and breakers were open or closed and what would be required to resolve problems. System Operators then tracked the job progress using pegs and colored paper tags to indicate facility status — red tag for de-energized equipment that was OK for crews to work with, green tag for energized equipment, yellow for out-of-service equipment and blue for anything that was in a test mode. They directed remote crews on what procedures to follow, and the crews handled them manually by flipping switches or breakers at the local substation to permit repairs or service on the lines.

“This manual system worked very well for a lot of years but, by the 1980’s, we were forced to enhance it because we were simply becoming too labor intensive,” explained Bill Leeman, system operator and SCADA programmer. “In 1984 we installed a SCADA system at Park Street and RTUs in our larger substations so that we could reduce labor requirements and control remote equipment to facilitate repair work. Dispatchers now had computer terminals on which they could call up one-line wiring diagrams of each substation and turn devices on and off.”

This SCADA system continues to run today on a Hewlett Packard A-600 minicomputer, with a second one on hot standby. By today’s PC standards the system is outdated — its CPU speed is only 1 MHz, it...
has only 2 M bytes of main memory, a pair of 150 M Byte disk drives and three operator monitors. It also uses HP Real Time Executive (RTE) operating software and custom SCADA application software. But it works. It provides Leeman and the other system operators with a view into the 28 most critical remote substations and uses 900 M Hz radio systems, leased phone lines and microwave communications to interact with RTUs at each site for equipment control. It also provides a database repository for operating information, although the unique organization of the database files limits the usability of the data for anything other than historical data analysis.

When we first got the system, it answered most of our needs,” Leeman said. “However, despite a major upgrade in 1989, we still face problems because every time we add a substation to this SCADA network it reduces the performance of the master HP computer. Plus the graphics capabilities are primitive by today’s standards and not easy to work with. The enhancement proposed by the original system integrator was to upgrade to new UNIX-based HP computers, but we didn’t feel that would be a cost-effective way to provide the growth path projected.”

“We figured that if we could implement local substation control using commonly available, inexpensive personal computers and powerful Windows-based software that provided a common communications protocol for diverse types of equipment, we could give ourselves a lot of potential for future expansion at very low incremental cost — so that’s what we did and East Machias has become our test installation,” O’Brien said.

Convenience of MMI

The Bangor Hydro-Electric engineering staff had been making a transition from electromechanical, analog equipment to intelligent electronic devices at substations for several years. “There are great advantages to replacing switches, indicator lights and relays with digital devices because not only do they provide the functionality you need, they have a comm port that lets you collect all the operating data,” O’Brien said.

“A significant problem, however, is that the utility industry hasn’t caught up with the manufacturing industry in the sense that there’s no standard communication protocol. Every IED manufacturer has his own protocol. We had to use co-processor cards and write translators in C code to serve as the bridge between PCs and the intelligent meters, relays or other equipment.”

The addition of the InTouch HMI software has provided a convenient way to bridge the different environments so that we can monitor and supervise an entire substation within one system.”

The PC-based InTouch HMI system and all communications at the Scotts Hill Road substation are powered via a DC inverter on an isolated 125 volt DC battery bank, so that power is available even during a system outage. The PC runs 24 hours a day but it and the touchscreen is powered down in a “sleep” mode to reduce battery draw when the system is not in use. The batteries will provide seven amps of power for a minimum of eight hours — more than enough time to outlast the most common outages. In normal operation, when an operator needs to use the system, he simply has to touch the top of the screen and it brings up the InTouch program.
“The difference is that the RTU system has no local keyboard or CRT so there’s no way to interact with it on-site,” O’Brien said. “It cost $20,000 for the RTU, its wiring and the associated transducers and it’ll only do that one function — provide remote control. If we change to PC-based systems in every substation, the initial cost would be comparable but we’d gain much more with the PC system. The initial investment at each site would be usable for a lot of future activities that are only in the planning stage, with very little incremental cost.

In the future we’ll have the ability to network substations back to the Park Street facility so that we can control activities from a single central site,” he said. “In addition, we would be able to maintain a centralized data base so that we could implement programs to view historical data to spot trends that could further streamline operations. Having the ability to do historical trending would let us track every state change and analog value over time, using an Excel spreadsheet to manipulate the data and even chart it to do things like load profile analysis.

“We could even record voltages over time to show how good our regulation was,” he said. “For example, we deliver power at 120 volts plus or minus five percent. This would let us know if we’re running the system voltage too high or too low, and we could adjust the upper and lower limits on the computer. That could save us a lot of money just by having a tighter tolerance on it. It’d be like having quality control in a power plant. And with better quality power, we have a significant marketing advantage.”

Cost-Effective Future Growth

Because this was a new system that had to be proven in field use, Bangor Hydro still installed a redundant, parallel RTU system for monitor and control of the substation. On a practical basis the East Machias MMI has replaced the traditional control panel and RTU system for most activities. For example, rather than using transducers, the PC-based system digitally interrogates the IED’s to monitor the watts and VARs passing through the system. When comparing conventional SCADA/RTU technology with the PC-based computerized substation, some distinct differences are notable.