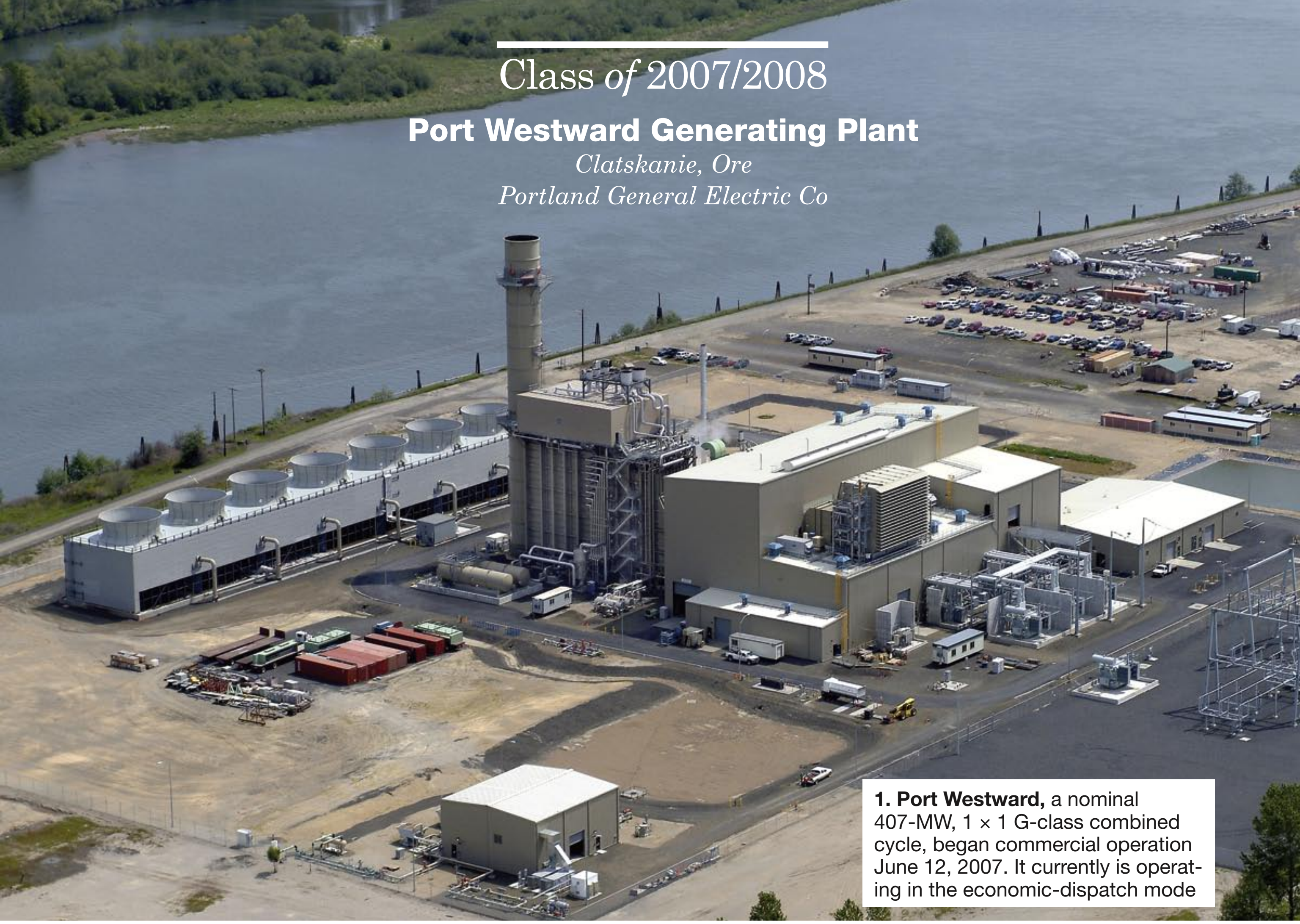
Class *of* 2007/2008

Port Westward Generating Plant

Clatskanie, Ore
Portland General Electric Co



1. Port Westward, a nominal 407-MW, 1 × 1 G-class combined cycle, began commercial operation June 12, 2007. It currently is operating in the economic-dispatch mode

Vern Uyetake

Innovative utility, partners help industry evaluate benefits of bus technology with first implementation at Port Westward

Once upon a time, too long ago, electric utilities and their suppliers were among the most innovative companies in industrial America. In 1957, for example, they introduced the the ultrasupercritical, double-reheat steam cycle (4550 psig/1150F/1050F/1000F) to boost the efficiency of coal-fired steam plants to a then unheard of 40%. That same year, the first commercial nuclear power plant began operation with the promise of reducing the nation's dependence on fossil fuels. It was a time when technology leaders, like the legendary Philip Sporn, were likely candidates for top executive positions in utilities.

Since then—or so it seems—layer upon layer of regulation, transition to an executive corps of lawyers and financiers, industry deregulation, the proliferation of proactive public-interest groups, and other factors make it virtually impossible to hit a technology "home run." Think of the Herculean effort required just to license a new hydro, nuclear, or coal-fired plant using proven plant designs and equipment.

Progress today is measured in "singles." In the gas-turbine-based powerplant sector you win by doing the "small" things such as increasing firing temperature, decreasing emissions, reducing startup times—all enabled by advancements in materials and control systems not yet challenged in the court of public opinion.

Portland General Electric Co's Port Westward Generating Plant is a case in point (Fig 1). This relatively small utility is rich in engineering experience both at its plants and headquarters location; employees generally have a confident, easy-going nature and there is a sense of "trust" throughout the ranks. The destructive silos characteristic of many large organizations are not visible on this corporate landscape.

When it came time to add new capacity, PGE selected what it considered the largest high-performance frame with a proven track record—the 254-MW M501G1 from Orlando-based Mitsubishi Power Systems (MPS)—as the heart of a 407-MW, 1 × 1 combined cycle. Then it stepped out as an industry innovator by specifying digital bus technology from Emerson Process Management's Pittsburgh-based Power & Water Solutions division for balance-of-plant (BOP) instrumentation—this in place of conventional instrumentation and wiring systems which can be more costly and time-consuming to install and maintain.

Sometimes there's a hefty price tag associated with industry leadership and PGE knew that first-hand from its painful experience with the Trojan Nuclear Power Plant—the only nuclear plant ever built in the state of Oregon. The decision to embrace digital bus technology certainly was not made hastily. Rather, it evolved over a period of years and was based in large measure on the following:

- Long-term positive experience with digital bus in large process plants.
- Commitments by Emerson and EPC contractor Black & Veatch (B&V), Kansas City, to work collaboratively with PGE to assure project success.
- Support from top management.


Vern Uyetake

2. Black & Veatch was the EPC contractor for Port Westward, Mitsubishi Power Systems provided the power island (gas and steam turbine/generators and the heat-recovery steam generator)

Team-building begins at Beaver

A successful team achieves more than what the individual players or members could accomplish individually. This certainly was the case at Port Westward, according to Jim Gettinger, B&V's project manager who says his company, PGE, and Emerson were "all pulling the same way."

Team-building, of course, doesn't just happen; it takes leadership and time. The principals for the digital bus implementation got to know each other a few years earlier while upgrading the ageing Beaver Generating Plant a few hundred yards from the new facility (Sidebar 1). The success of that project helped unify the participants and build the confidence needed to take on the Port Westward challenge with little hesitation.

In 2002, with Beaver's controls technology three decades old and parts becoming increasingly more difficult to find, PGE decided to upgrade the GT's relay-based Mark I controls with Emerson's Ovation®. A full DCS (distributed control system) was evaluated as more cost-effective than installing individual programmable logic controllers (PLCs) on each GT. One reason for the higher cost of PLC controls was the need for redundancy on each unit.

Ovation was the most cost-effective option among the various DCS offerings—including the OEM's. Another factor in Emerson's favor was that it had previous experience in upgrading the Mark I to Ovation. The Emerson product also replaced the HRSG and BOP control systems. The NetCon®5000 (Woodward Governor Co, Ft Collins, Colo) microprocessor-based controls installed on the steam turbine (ST) in the mid 1990s were retained.

The steam generators also required upgrading after sitting idle for the better part of 30 years. Rusting of tube panels in the high-moisture environment without benefit of stack dampers or space heating had consumed a considerable amount of tube and fin material. New economizers were installed and evaporator bundles were retubed.

The first task to challenge the Beaver plant staff, say Plant Manager Scott Bauska and Plant Engineer Jerry Simpson, PE, was the availability of up-to-date drawings for the GTs, HRSGs, and BOP. Locating the proper drawings and revising them as necessary to reflect the plant's current configuration was time-consuming.

PGE's plan was to do all the upgrades during "the outage season" when the units were not expected to run; and to take out of service only two units at a time, keeping four ready to operate if needed. Here are the details of the plan:

- Allocate 30 days to do all work necessary on the first two units (GTs plus their dedicated HRSGs) and recommission.
- With the upgraded GTs available for service, retrofit the second two plus install new controls for the BOP equipment. Recommission within 30 days.

- Upgrade the final two GTs and HRSGs.

Unknown at the time was that the team responsible for the successful Beaver controls retrofit would come together again at Port Westward. Specifically:

- Mike Schwartz, the Beaver plant manager during the upgrade, would manage Port Westward from the start of construction through the first few months of commercial service (he now directs an engineering group at corporate headquarters).
- Quentin Frugia, PE, who would become the project manager for the digital bus implementation, was the project engineer at Beaver for the migration to Ovation.
- Gary Tingley, PE, manager of the electrical engineering department at PGE headquarters, deeply involved at Beaver from controls design through Ovation commissioning, would be the utility's leading voice for digital bus implementation.
- Black & Veatch, which would be awarded the EPC contract for Port Westward, did the design and engineering required for the Beaver upgrade.
- Emerson, of course, designed and supplied the control systems for both plants.


Frugia


Tingley

Bauska and Simpson recall a couple of challenges associated with the controls change-out. For example, where there were "third-party links" the controls interface was more difficult to accomplish. One illustration: Integrating controls for

1. Beaver proves the value of large combined cycles

If you selected at random a dozen or so attendees at a major industry trade show and asked them to write down the names of 10 power producers they associate with innovation it's doubtful that Portland General Electric Co—a company that owns less than 2000 MW of generation—would be on anyone's list. Most would likely remember it as the utility that Enron bought and possibly recall the PGE's difficult transition back to its former status as an investor-owned electric utility following Enron's collapse.

Yet PGE has a rich history of innovation enabled by its collaborative culture. Highlights include:

- Trojan Nuclear Power Plant, the first nuclear generating station in the Pacific Northwest.
- Beaver Generating Plant, the world's largest combined cycle when it began commercial operation in 1978.
- Port Westward, the first powerplant in the US to embrace digital bus technology.

Beaver's six gas/oil-capable GE Frame 7Bs began peaking and emergency-generation duty in 1974 at the Clatskanie site the plant now shares with Port Westward. Conversion to combined cycle was completed in 1978 with the addition of six unfired GE heat-recovery steam generators (HRSGs)—each capable of producing 219,000 lb/hr of 923-psig/825F steam—and a GE steam turbine/generator. The combined cycle is capable of producing 500 MW today.

In addition to Beaver's status as the world's largest combined cycle, it also was one of the most fuel-flexible, oil-fired GT-based generating plants. An uncertain petroleum market at the time the plant was designed dictated having the capability to burn heavy crudes, resid, and light distillates. Extensive onsite oil-storage and -treatment facilities were installed to enable the use of this broad spectrum of fuels.

To illustrate: Fuel delivery could be by ocean-going ship, barge, and/or truck. Nine oil storage tanks of the latest floating-roof design were installed to accommodate the fuel diversity. Emulsifiers and electrostatic desalters ensured removal of salt contamination to prevent corrosion of hot-gas-path parts. Chemical treatment protected against corrosion from vanadium.

Today, the only liquid fuel that Beaver would burn is distillate oil. Thus the facilities for treating crude and resid have been removed.

Other features of the plant, as installed, included the capability to produce a nominal 1200 gpm of demineralized water for controlling GT NO_x emissions and for boiler makeup; one of the first computer-based systems for monitoring and recording both emissions (NO_x, CO, O_2, particulates/opacity) and engine operating parameters critical for diagnosing problems and scheduling maintenance activities; automated startup—including sequential starting and loading of all GTs, steam-cycle warmup, and loading of the steam turbine.

Also important to recognize, in a time when owner/operators place a priority on fast starts to conserve fuel and minimize emissions, is that Beaver could meet today's objective—a 10-min start—30 years ago. Normal startup time for its GTs was eight minutes to synchronization, another 12 to base load; in an emergency, the engines could ramp from full speed/no load to full load in two minutes.

And that's not all. A cold start of the full combined cycle was possible in four hours (today it's close to three hours); warm start in two hours; hot start in one (generally possible for up to 48 hours after last shutdown).

Change is certain in the electric power industry. And it usually happens faster than anyone would like to believe. The conditions that put Beaver on a pedestal in the late 1970s had disappeared by the mid 1980s and the plant was shut down for economic reasons. But just before the end of the eighties, inevitable change made Beaver valuable once again.

The plant was converted to natural gas, which became the primary fuel. Oil capability was retained, however, and a 10-day supply of liquid fuel was maintained onsite. Beaver was reinvented as PGE's "ace in the hole" for its ability to switch fuels, respond to emergency power needs, and operate over a wide load range relatively efficiently.

Today, Beaver operates as a peaking facility and typically runs only in summer. It starts up in the morning, shuts down at night. NO_x still is controlled by injecting demineralized water right at the individual fuel nozzles. Installation of catalyst in the existing HRSGs is impractical.

Finally, the 54-person staff at Beaver may seem quite generous at first blush. Not so. This group operates and maintains the water treatment facility serving both plants and it performs combustor inspections on Beaver GTs as well as much of the generator work required—including overhauls.

the GE steamer's Siemens exciter into Ovation.

Recommissioning of the first two units was challenging as well, with tuning being difficult. But the experience gained facilitated commissioning of the remaining four GTs. Among the positives associated with the migration to Ovation: GT startups and controls troubleshooting are much easier than they were for the Mark I.

As for lessons learned, Bauska and Simpson suggest that others considering a similar upgrade form an HMI interface team prior to project implementation to decide on the number of alarm levels the plant should have and exactly what alarms operators need. Otherwise you may find that the control system, as supplied, has more alarms than your plant requires, which can be a distraction. PGE has launched a corporate alarm-management initiative to

2. Understand the basics of bus technology

Bus technology allows the connection of multiple field instruments to a single cable or network, thereby creating a digital, bidirectional communications system that enables real-time distributed control of your plant. It also provides true device interoperability and enhanced field-level control, and is less expensive to install than an analog instrumentation system—that is, one using the traditional 4-20-mA signal interface from field devices to I/O.

Blaney

Murray

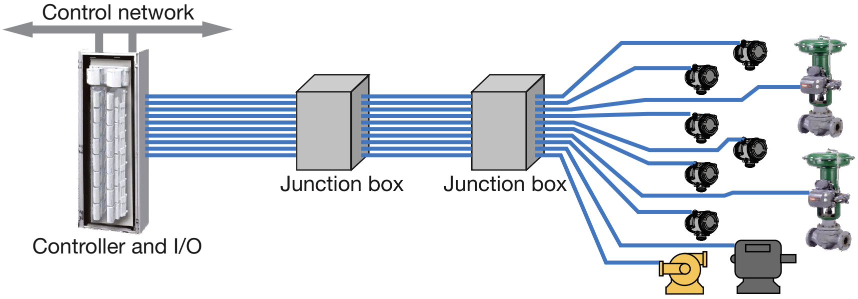
To develop this backgrounder on bus technology, the editors spoke with two experts: John Blaney and Jim Murray of Emerson Process Management's Power & Water Solutions group. Blaney (john.blaney@emerson.com), a three-decades veteran in powerplant controls, participates in determining functional requirements for the company's Ovation® products—including intelligent instrumentation, digital fieldbusses, distributed controls, and the management of these smart assets.

Murray (james.murray@emerson.com) works where "the rubber meets the road." He is a front-line senior project engineer responsible for the implementation of powerplant projects using fieldbus technologies—including coal-fired and combined-cycle generating stations.

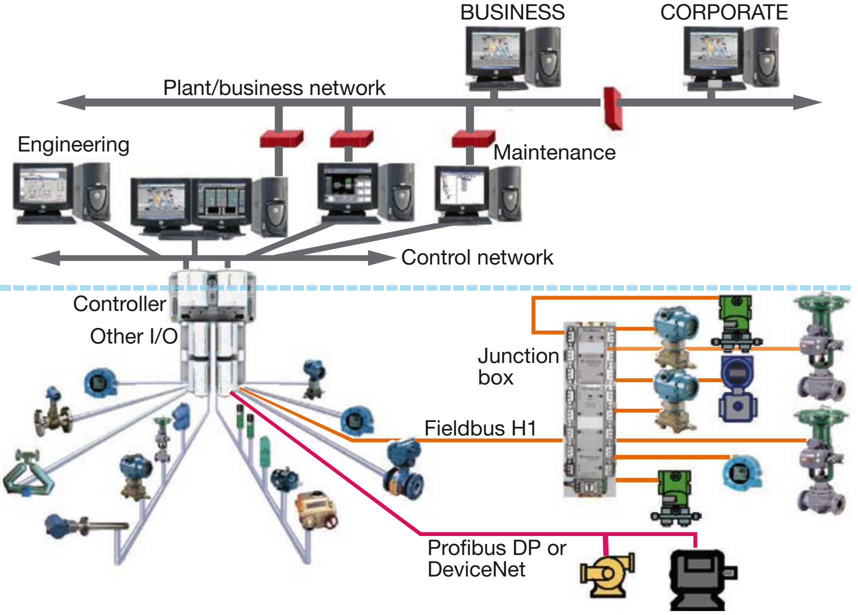
In a traditional analog instrumentation system, Murray reminds, dedicated cables are run from individual field instruments to the control room (Fig A). Over time, these cables can become difficult to identify and maintain. As the number of wires and their lengths increase, the risk of misidentification, short circuit, and data loss also increases.

Digital-bus technology trades the traditional clutter of cables for a single cable, called a segment, which is capable of supporting multiple instruments. However, each instrument connected to the segment must have an interface as well as a software program that enables the device to "talk bus." Note: According to the standards governing the various bus types, each segment can only support a certain number of devices and multiple segments usually are necessary to support the operation of a traditional powerplant.

Also important to know, says Blaney, is that there are several bus technologies to choose from, each with characteristics that supports its use in specific applications and/or under specific circumstances to assure maximum reliability. Select the bus or busses for your applications based on process and equipment requirements, he recommends, rather than by making unilateral decisions. Devices using different bus technologies cannot be mixed on a given seg-



A. In a traditional analog instrumentation system, dedicated cables are run from individual field instruments to the control room



B. Devices using different bus technologies cannot be mixed on a given segment; however, multiple segments supporting different technologies can be integrated into a single control system, along with conventional I/O decide what alarms to keep, which to disable.

Beaver's water treatment plant was upgraded to Ovation in 2004. It involves clarification and filtration (sand and carbon filters) of river water, cation and anion exchangers, and final mixed-bed polishing. This system is particularly important because it serves both Beaver and Port Westward.

Port Westward pioneers change

B&V's Gettinger radiates pride when talking about Port Westward, one of the most efficient combined cycles on the West Coast (Fig 2). It represents two technology "firsts" for the EPC contractor: G-class turbines and bus technology.

MPS was responsible for the power island, supplying the GT, HRSG, and

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ment; however, multiple segments supporting different technologies can be integrated into a single control system, along with conventional I/O (Fig B).

The bus technologies used most frequently in process control, Blaney continues, are Profibus (DP), Foundation Fieldbus (H1), HART, and DeviceNet. Others include Modbus and EtherCAT. Here are important details to know:

Foundation Fieldbus is the world's leading digital protocol for process automation (www.fieldbus.org). It is used most often for applications that typically are modulating and monitored by a distributed control system (DCS). Foundation Fieldbus is designed to provide users the freedom to choose best-in-class, interoperable control products from their suppliers of choice, as well as the power to integrate control systems, subsystems, and devices across the plant enterprise.

An H1 segment is a single, twisted-pair wire that carries the electricity necessary to power devices (actuators and transmitters, for example) as well as the digital signal that transmits information between the field and the control room.

Profibus is one of the most popular fieldbus technologies in discrete manufacturing and process control applications incorporating programmable logic controllers (www.profibus.com). It is a mature, proven technology designed to support modern automation systems. A Profibus segment is a single, twisted-pair wire that carries data only. Thus field devices must be powered externally.

DeviceNet, which is based on producer/consumer technology, offers robust, efficient data handling (www.odva.org). Think of it as a local area network for discrete devices. This communications model allows the user to determine what information is needed and when. A DeviceNet segment consists of four wires: two for data, two for power. Note that ODVA in the URL stands for Open DeviceNet Vendors Assn.

Blaney says that in addition to using powerful, inexpensive processors to monitor field devices and facilitate the flow of data from those devices to the control system, bus technology allows field devices to run maintenance diagnostic programs on themselves and also report this information via the bus to asset management software. Benefit: The devices require less manual oversight than those serving a traditional control system, freeing personnel for other tasks.

How bus technology works

Because bus segments allow two-way communications between field devices and the control room, the conventional "hub and spoke" arrangement of devices shown in Fig A is streamlined into the segment arrangement in Fig B. In the latter, field instruments become intelligent data servers.

Example: One temperature transmitter might communicate inputs from multiple sensors using only one pair of wires. Because information flow is two-way, a valve controller can accept a control output from a host system or other source and send back the actual valve position for more precise control.

Important to note is that the reporting of self-diagnostics, calibration, and environmental conditions of field instruments is accomplished without disturbing plant operation. Bus technology also offers the option of executing some or all control algorithms in field devices, as an alternative of doing this via the DCS.

Advantages

Blaney says digital bus technology is designed to be smarter than analog technology. It frees up space in the main control room by incorporating control procedures and logic in field devices. Plus, the field devices convert data into the correct units before sending them to the control room, thereby eliminating another task typically handled by the DCS.

Other benefits of bus devices: They can be diagnosed, repaired, installed, configured, and returned to operation faster than analog devices because of the asset-management functionality which gives a complete picture of the device and its contents to control-room operators.

In addition to being smarter than analog technology, "bus" is a superior technology, Blaney continues, because it incorporates digital communication, collects field-level diagnostics, reduces wiring, and enables a degree of redundancy.

Digital communication is more accurate than analog, adds Murray. One reason: Digital devices are more tolerant of "noise," which contributes to higher-quality communication. The improved capability for trending and retaining data offered by bus technology also favors it for the collection of field-level diagnostic information to enhance operational control.

Fieldbus offers reduced installation and material costs by replacing the traditional one-to-one wiring scheme with a networking or multi-drop configuration. Murray puts this in perspective: With a conventional analog system, if the plant has 1000 field devices it would have 1000 wire pairs. By contrast, one bus device replaces multiple analog channels; plus, you can have multiple bus devices on a single wire segment. This translates to lower hardware, labor, and maintenance costs.

Flexibility

Blaney says bus technology supports the use of multiple devices from different manufacturers, for the same bus type. Foundation Fieldbus, he notes, has established tests and guidelines for interoperability among field devices on an H1 segment. Compatibility assessment includes physical characteristics, communication, and software functionality. Profibus and DeviceNet have similar tests and guidelines.

Devices also are tested for their ability to operate correctly within multiple distributed control systems. Those passing all required tests required by Foundation Fieldbus earn "registered" status. Think of the "Good Housekeeping Seal" here.

Implementation

Murray reminds that there are practical considerations in the design of segments—including limits to the steamer. Gettinger says designing a plant with a steam-cooled M501G1 gas turbine is more challenging than one with F-class engines because the supplementary-fired HRSG is not just an exhaust-gas heat exchanger on the back end of the GT (Fig 3). Rather, parts of its steam/water circuitry are connected directly to the GT for cooling purposes, adding to the complexity of control-system design, tuning, and plant commissioning. Lots of valves to open, close, and modulate, with the GT control system controlling some valves and the DCS controlling the rest.

Control system design was a shared responsibility between MPS and B&V. Both turbine/generators and their associated equipment are controlled by the OEM's Diasys Netmation®, BOP equipment and the HRSG by the Ovation DCS.

Mitsubishi's Project Manager Schwartz Thangiah offers perspective on the extent to which the GT and HRSG interact at Port Westward. He says the M501F and G are similar in many respects; however, the latter requires steam cooling of the combustor. The impact of this is that a G startup must proceed deliberately to ensure proper warmup of the cooling circuit, which can take around an hour in the Northeast during winter. Confirmation that all steam passages are drained before the unit operates is part of this. Once the warmup step is complete, Thangiah adds, the G operates essentially the same way an F does.

Steam for combustor cooling typically comes from the IP superheater. However, a pressure reducing station permits use of HP steam if necessary. During startup, a packaged gas-fired boiler usually provides warmup steam for the GT, gland-sealing steam for the ST, etc. Alternatively, steam can come from another source—such as another operating unit onsite.

IP feedwater heats the fuel gas.

MPS uses compressor discharge air for rotor cooling after removing some of its heat of compression in a vertical shell-and-tube heat exchanger that the OEM calls a TCA (turbine cooling air) cooler. At Port Westward, the cooling medium is water from the HP feedwater circuit. After flowing through the TCA cooler it is returned to the HRSG downstream of the HP economizer. The benefit of this arrangement is a slight reduction in heat rate.

The tandem compound ST is generously sized to maximize performance. The standard Mitsubishi unit is arranged with HP and IP sections in one casing, the double-flow LP section in another. Discharge to the condenser is in the downward direction.

Digital bus implementation

Change doesn't just happen, it has to be driven. The driver of digital bus implementation at Port Westward was PGE's Tingley. Most who meet Tingley for the first time probably would not visualize him as a "driver." Tingley reflects a confident, easy-going persona—anything but the drum-beating, horn-tooting personality one

number of devices that can be supported on a given segment. Also, some devices are not amenable to connection by bus to the control system—at least at the current stage of technology development. Hardwiring the device directly to the DCS is recommended when fast response is vital to plant operations. High-speed data transmission typically is recommended for such devices as steam bypass valves and attemperator control valves.

Before researching devices, decide which instruments and applications you want to implement with bus technologies. Expect to have a mix of conventional local and remote devices that use Foundation Fieldbus as well as one or more of the other bus technologies. Next, figure how many segments are needed to handle your I/O. Murray says good segment design maximizes the capital, installation, and maintenance cost savings possible with bus technology.

The following guidelines can help you determine the optimum segmentation scheme:

- Group common processes together. This is especially important when grouping your devices.
- Avoid mixing critically important loops and devices on the same segment. You can mix a critical device with less critical loops and devices.
- Avoid mixing loops with different response times on the same segment. Keep fast-function blocks with other fast-function blocks, slow with slow.

Once these criteria are met, try to incorporate into the same segment devices and loops that are in close proximity to each other—this to minimize the cost of wiring.

Installation hints

Minimize the cost of wire and its installation by connecting the segment to field junction boxes located near the field devices. Then link devices to the junction box by (1) extending individual wire pairs (using conduit) from the trunk to the individual devices using terminal blocks, or (2) running quick-connect, premolded cables from the junction box to the individual devices.

When connecting your devices, take time to investigate the features of the terminal blocks and make them part of the installation plan. They alleviate such concerns as identifying trunk cabling, having extra spurs for future devices, providing segment terminators, and having built-in short circuit protection.

Select time-saving devices. Quick-connect wire connectors are fast and easy to install and can reduce wiring errors. The premolded cables cost more than twisted pair, but the added cost usually can be justified.

Check device polarity. Many bus devices are polarity-sensitive and inverting the positive and negative anywhere on a segment can cause individual devices or parts of the segment to malfunction.

Anticipate device and segment changes. Define standard methods for attaching and removing individual devices that do not initiate a segment short and communicate this information to your technicians. When using terminal blocks, select them to have spare spur connector ports for adding devices later.

Check voltage requirements. Bus devices require between 9 and 32 Vdc for operation. Heavily loaded segments with long runs can result in low voltage at some devices. Make sure the voltage at the farthest point of a given segment is at least 2 V higher than required to accommodate a possible temporary voltage drop when a new device or handheld is added.

Document everything. Ensure consistent installation and streamline future maintenance by immediately updating standards and project records to reflect any changes made during engineering and installation.

Instrumentation data sheets enhanced with bus requirements should be retained. Each segment should have a single drawing. Avoid adding information to the P&ID except as necessary for logic or control purposes.

often associates with change today. He never once mentioned the word "I" when speaking to the editors.

Tingley had been studying the application of digital bus technology for years through participation in industry meetings, such as Emerson Exchange. At those events, he benefited from the experiences shared by "bus users" in many industries. His assessment was that the technology had matured to where even the conservative electric power industry would view a transition to fieldbus as a step rather than a leap.

Tingley was right, of course. But virtually nothing in the power business is a "slam dunk." He had done his homework thoroughly—including obtaining a personal commitment from Bob Yeager, president of Emerson Process Management's Water & Power Solutions division, "to do whatever it took" to ensure project success. He got a similar commitment from B&V.

That backing in place, Tingley went "up the line" to get management support. PGE's executive corps includes many experienced engineers who are proponents of change and advancing technology when and where appropriate. And they liked what he told them.

Tingley was on his way, but there was a long road ahead. Saying "digital bus" is easy, but successful project implementation requires in-depth knowledge of a technology with many idiosyncrasies.

Frugia was looking forward to his assignment as PGE's project manager for bus implementation. He went to school to get a good foundation in fieldbus basics (Sidebar 2). One week-long course was presented by Foundation Fieldbus, another by Emerson. Frugia says they were invaluable.

Black & Veatch also had some bus experience in its organization. The company already was involved in the design of a coal-fired plant specified with fieldbus applications. Gettinger says use of bus technology adds another decision level to the design process—that is, what instrumentation is suitable for fieldbus application and what's not.

In his view, fieldbus works well for data-gathering and for most power-plant control applications. However, fieldbus technology has limitations in high-speed analog loops—such as those serving turbine bypass valves. For these applications at Port Westward, 4-20-mA control loops were hardwired directly to the DCS.

Patrick Hogan, B&V's lead control engineer on the Port Westward project, echoed Gettinger's thoughts, adding that fieldbus changes the design process because you have to have a good idea early in design where instruments are located. In the old paradigm, the location of devices could be determined later in the design process and mechanical design could be done separately from I&C design. No longer, because fieldbus pushes the mechanical design to determine equipment location earlier. This is necessary to support design of the fieldbus segments.

At Port Westward, all BOP control logic resides in the DCS controllers. The digital bus technology is used exclusively to transmit data between field devices and the DCS; it does not include any control programming at the field-device level. The idea was to gain fieldbus experience in small, deliberate steps.


Vern Uyetake

3. Balance-of-plant critical loops are controlled via the digital bus—including the HRSG's drum-level signal and feedwater flow. From left in front of boiler are Jaisen Mody, engineering/construction/startup manager; Mike Schwartz, plant manager; and Bill Monroe, plant engineer

Consensus among Port Westward participants was that they were proactive partners in a collaborative learning experience. One of the most important lessons learned was to pay greater attention to the details in the field-device specifications. They have to be more exacting, based on experience.

All agreed that device manufacturers had more to learn about fieldbus applications and that the preferred supplier list for the next project would likely be shorter than the one for Port Westward. Also important to note is that while Foundation Fieldbus may approve a particular field device, some testing also may be required to confirm that the device is fully compatible with the DCS fieldbus hardware and software.

Fieldbus is a new paradigm, one that requires a change in traditional thinking to assure successful design, installation, troubleshooting, and maintenance. For example, a multimeter is not your primary troubleshooting tool during commissioning. Special fieldbus hardare and software tools are required for fieldbus commissioning.

In sum, Port Westward represents a solid first step in the application of digital bus in the electric power industry. Cost and schedule were about the same as for traditional I/O wiring—the additional engineering and startup time required to implement the new technology being offset by reductions in conduit and wire. In nearly a year of operation, no specific plant issues could be attributed to fieldbus. CCJ