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Malampaya deepwater project showcases Fieldbus technology in process automation

As a large-scale project pioneering central control and automation, Malampaya demonstrates how the technology improves access to large volumes of operating data while reducing personnel and maintenance requirements

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Offshore the Philippines, the Malampaya field development comprises subsea wells in 2,690 ft of water. They produce via a subsea manifold and two, 16-in. Inconel-clad flowlines to a shallow water platform 17.4 mi away. Condensate is removed on the platform, and dry gas is transported via a 313-mi, 24-in., export pipeline to an onshore gas plant at Tabangao (Batangas, Luzon Island) for H_2S extraction. The condensate is stored in the platform prior to export via a 1.9-mi, 24-in. pipeline and CALM buoy, Fig. 1. Malampaya is the sole gas provider for three power stations (2,700 MW), supplying 30% of electricity to the Philippines' largest island, Luzon.

A digital, process automation system (PAS) with Foundation Fieldbus devices was selected by operator Shell Philippines Exploration (SPEX) to support high availability, precise control and predictive maintenance on minimum intervention. Given Malampaya's importance, these facilities must produce gas uninterrupted. This article discusses experience gained in applying Fieldbus technology to Malampaya's development. It also provides pointers for future projects that wish to apply this technology on a similar scale.

SELECTING A SYSTEM

Four years ago, selecting Fieldbus technology for Malampaya's control communications provided significant technical challenges to SPEX engineers, designers and their contractors. Benefits to be gained, however, were deemed worthy of the challenge. The Malampaya offshore platform houses a control center that is minimally manned during the day and unattended at night. This allows platform personnel to perform combined maintenance and operations assistance roles, as necessary.

The onshore gas plant (OGP) and the platform's PAS are connected via a 512-kb/sec satellite link, forming a wide area network (WAN) to share data, Fig 2. The OGP automation system can monitor, control and operationally manage all essential functions, offshore and onshore. In addition to measurement, control, display and alarm capabilities, the PAS supports a fully functional, asset management system. This enables remote instrument calibration, diagnostics and troubleshooting of Fieldbus devices.

Major considerations during selection of a suitable PAS were:

- High system and process availability. The platform is designed for 97% availability, with an OGP target of 99%. Therefore, PAS system target was set at 99.98%. Mean time to repair was 12 hr.
- Minimal personnel. No more than 46 persons can be accommodated on the platform
- Minimal intervention, with planned, major maintenance on five-year cycles
- Remote control from the OGP
- Continuous data flow, to enable online condition monitoring and remote diagnostics, to pre-empt downtime failures
- Data access by equipment suppliers for their remote analysis.

The PAS specification called for open-system architecture with Foundation Fieldbus, the Highway Addressable Remote Transducer (HART) communications protocol, and Object Linking and Embedding for Process Control (OPC). These would be the primary data exchange standards for all field devices and control systems.

Fieldbus-compliant field devices would be used wherever possible. The

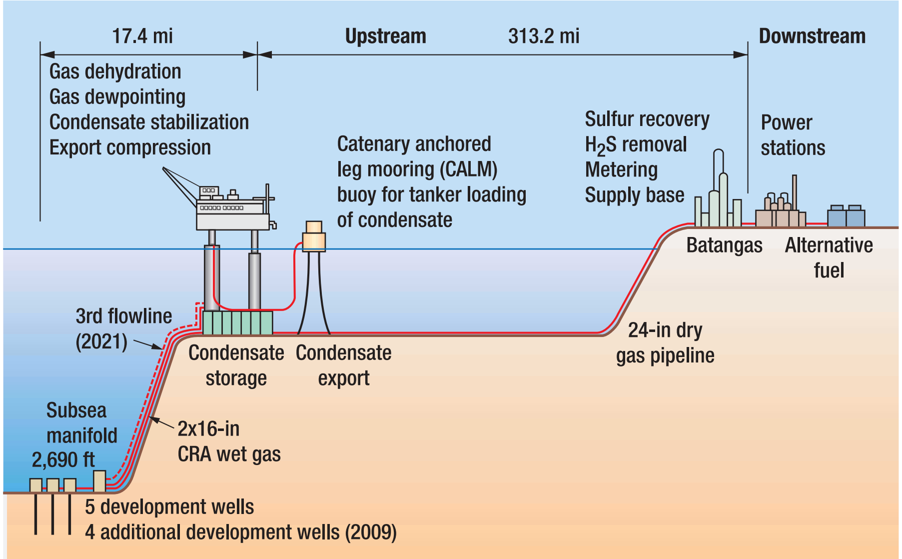

Fig. 1. Malampaya field production is routed from subsea wells to a platform, where condensate is stripped out. Dry gas output is transported to an onshore plant.

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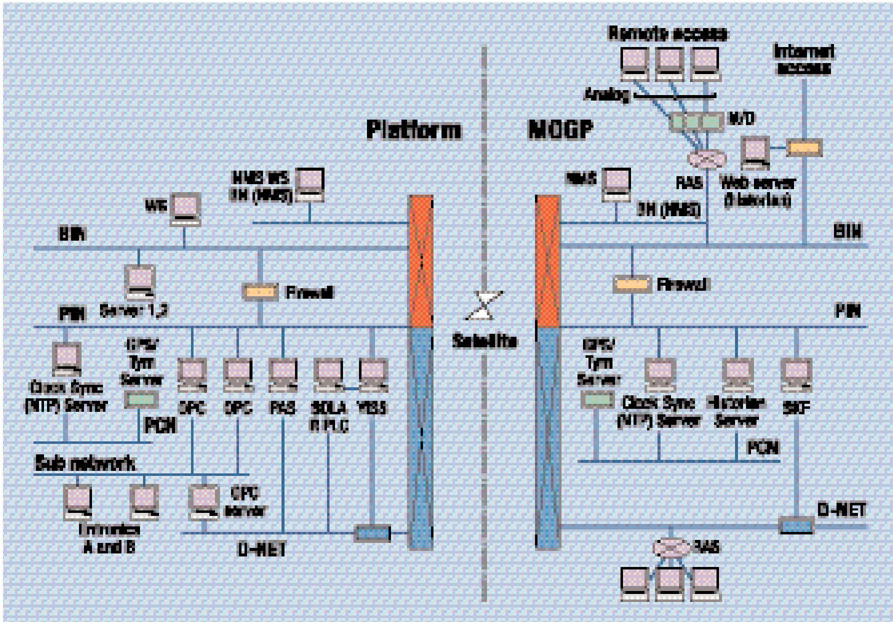

Fig. 2. Data are shared between Malampaya's platform PAS and the gas plant's automation system via a WAN formed from a satellite link.

PAS had to provide a single window into all of the package systems provided by various vendors. Stringent performance requirements required the principal supplier to develop more than 30 hardware and software items that did not exist at the time. This pushed the envelope of existing technology.

Gas is now being produced and processed at Malampaya. Output is piped onshore, where it is processed further, before transfer to three power-generating stations. First gas was produced on schedule, on Oct. 1, 2001, representing the birth of the Philippine natural gas industry. It also dramatically increased the republic's energy self-sufficiency. Production is growing, as power station commissioning progresses and gas demand increases. Scalable automation architecture has made it easier to incorporate changes needed to improve operational efficiencies at the platform and the OGP.

BUS SELECTION RATIONALE

When the automation system decision was made in 1999, this bus technology was in its infancy, with no real, large-scale experience worldwide. A large number of suppliers either had products, or were developing products, to meet the technology's requirements. However, few were considered capable of supplying the range of field devices, plus software and hardware design/development capabilities, to meet a large project's demands.

The need for high availability and minimal personnel pushed the design toward application of Fieldbus and open-system architecture, rather than existing, but proven technology. Typical with application of all-new technology, it was essential that the system's provider be proactive, committed, and capable of delivering and supporting this enabling technology.

The provider also had to take on new developments to meet specific functionality requirements. The system provider selected, indeed, satisfied these requirements and already had a track record in the emerging technology. Consequently, some of the earliest Fieldbus devices ever manufactured serve on the platform and in the OGP with great success.

Fieldbus is an all-digital, serial, two-way communication system that interconnects field devices—sensors, actuators and controllers. It is a Local Area Network (LAN) for intelligent field devices, capable of distributing a control application across the network. This technology comprises three parts: 1) physical layer; 2) communications stack; and 3) user application.

The first two parts are modeled on the Open Systems Interconnect (OSI), layered communications model. A user application model was specified, so Fieldbus signals are encoded using the Manchester Biphase-L technique. The PAS incorporates all three hierarchical layers and provides plant data through wide area networks (WANs) for optimizing capacity, flexibility, environment and economics at Malampaya.

Selection of the bus technology was based largely on its capacity for open, continuous communication of large volumes of information generated by intelligent field devices. There are roughly 1,500 Fieldbus-compatible devices in the Malampaya project. It is this enabling technology that allows instruments to deliver critically important data. These data can be used variously to accomplish high system and process availability, low personnel levels, remote diagnostics, minimum intervention and online condition monitoring. The latter allows operators to pre-empt failures that cause unscheduled downtime.

APPLYING THE TECHNOLOGY

While Fieldbus technology is important, it is just one element within Malampaya's integrated PAS. Other key elements are the leading-edge, PlantWeb digital plant architecture (designed to take full advantage of Fieldbus communications capabilities) and the digital automation system. The latter presents data from field devices to operators in a single window. In addition, the Asset Management System (AMS) asset optimization software—included with the system host—sets up predictive maintenance by obtaining data from field devices.

An ability to have control resident in field devices influenced the technology selection. This has already proved to be beneficial for availability. On the few occasions where failure of a non-redundant electronic card occurred, process control (with an expected, subsequent process trip) was not lost. Control continued with direct communication between field devices. A failure of communication between host and field device was observed in the control room; a repair was immediately made without impacting production.

This field control is enabled by the back-up Link Active Scheduler (LAS), which on Malampaya, was generally configured into a valve positioner. On critical loops where field devices were split across segments, redundant electronic cards were installed. If complex algorithms required part of the control to take place in the host, redundant controllers were also used.

The digital automation system is a high-capacity, control platform. It combines the look and feel of a PC-based Windows operating system,

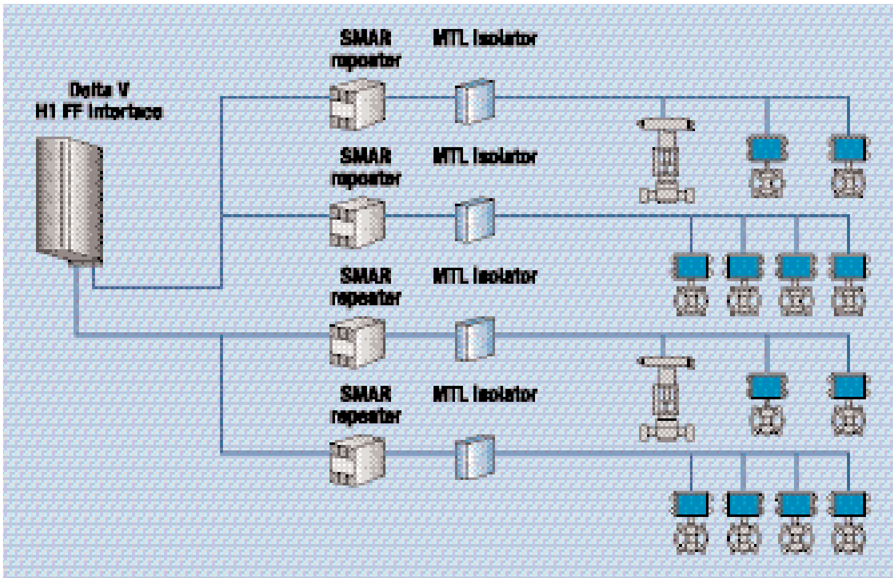

Fig. 3. To address current draw limitations, and avoid numerous additional wiring segments and electronic interface cards, a repeater was designed into the network, to allow linking of several segments.

with the security, interactive displays and information accessibility of distributed control. The familiar look and feel helped to introduce personnel to its capabilities.

The AMS asset optimization software works as a node on the control network, enabling direct access of information from smart field devices beyond the control room. Data from Fieldbus devices are integrated into the digital automation system. AMS with HART-compatible devices is a standalone system, with the PAS acting as the application window. However, the project called for HART data to be seamlessly integrated with the digital automation system. Easy-to-follow screen graphics allow personnel to *look into the process* and examine instruments' conditions in ways never before possible. Based on information available, repair strategies can be planned, materials ordered and manpower scheduled to optimize efficiency. This software cuts the time required for device commissioning and startup, speeds routine instrument calibration and troubleshooting, and reduces unscheduled downtime.

DESIGN PHASE

Design intent was to create a totally integrated network of process control, safeguarding and suppliers' packages (compressors, generators, fiscal metering systems, etc.). This desire for systems integration, and a single window into the process, extended to subsea well and manifold control.

Traditionally, subsea equipment control is done by the vendor's own customized equipment. On Malampaya's platform, control of downhole, wellhead and manifold valves is carried out by the PAS, via an interface unit that has two-way communication with subsea sensors and valves.

The key to integrating these systems and using the PAS as a single window into the process was the application of OPC, enabling bi-directional transfer and sharing of information among applications.

The OPC mirror application enables data transfer between the digital automation system host and other OPC-compliant systems, integrating third-party systems into a single network. Once in the digital automation system, information is managed the same as standard process data—alarms can be set, trends created and data archived. However, some third-party vendors were not familiar with OPC requirements, and assistance had to be provided at an early stage to prevent commissioning problems. A portable host was developed to enable OPC contact with the digital automation system to be tested in third-party suppliers' factories. Commissioning problems in the system integration phase were avoided by this early intervention.

Creating a wide area control network between the platform and the OGP via satellite communications required extensive testing by the PAS vendor via a satellite simulator. Tests demonstrated that the control system would function as required.

The system was designed three years ago, when there was some concern about device compatibility. Thus, whenever possible, field devices from the same vendor were used for the digital automation system, to ensure compatibility and utilization of all diagnostic functions. This was wise, as the project was never delayed by interface problems with those devices. In one particular case, when the digital automation system vendor could not supply a particular device, another supplier was asked to develop a Fieldbus interface for an existing product. This prompted a two-year development period that had classic problems of incompatibility of the interface with the field device. Incompatibilities with the PAS host took additional time to resolve.

Use of process and valve position switches has been avoided (wherever possible) in favor of Fieldbus transmitters, to maximize remote diagnostic capabilities.

The design requirement that all platform instrumentation meet intrinsic safety (IS) requirements brought substantial changes in the field device wiring. In a traditional analogue installation, one IS barrier is used for each field device. In a Fieldbus installation, one IS barrier can be used per segment, subject to several constraints that after investigation and testing resulted in unexpected costs. The presence of IS barriers limited the number of devices to three or four per segment, due to current-draw constraints.

A close look at the barrier vendor's data sheet, confirmed by workshop trials, showed that quiescent current draw should be held to 90%. Current draw for an 80 mA barrier was established at 72 mA, limiting field devices to three or four per segment. The numerous segments created by this limitation would have required many more electronic cards. Thus, a repeater was designed into the network to link several segments, so their inputs could go to one interface card, Fig. 3. The design allowed cross-segment control. Yet, wherever possible, this was avoided by putting field devices for one control loop on a single wiring segment.

Designers had to remember that only one back-up link/active scheduler per electronic port is allowed. Care was taken to assign this to the wiring segment containing the primary control loop. The barrier and repeater are mounted in the electrical control module (ECM) in a safe area, so one cable per wiring segment must be run to the control area. This is at least three times more cabling than originally anticipated with the Fieldbus technology.

Thus, cost savings for cable compared with traditional distributed control systems (DCS) has not been as good as anticipated. Expenses for Fieldbus transmitters, plus the additional connector blocks, quick-disconnect cable connectors and two terminators per segment, further reduced projected hardware savings. These factors influenced the decision not to use IS safeguarding on the OGP.

When the design team began planning the OGP's PAS network, a lower maintenance intervention was expected, due to remote diagnostic capabilities and the expected, high mean time between Fieldbus device failures. Thus, it was decided that IS functionality, as specified for the offshore platform, would not be required in the gas plant. Instead, the final design called for Exd flame-proof equipment.

With elimination of the barriers, up to 16 field devices could be connected to each segment. In practice, the average per segment was six to eight. Where practical, each segment was related to a particular process. Occasionally, the wide geographic distribution of devices made it simpler to provide additional segments rather than extend existing lines to distant field devices. Substantial reductions in home run cables, terminations, cable trays, junction boxes and labor should bring significant cost savings.

Segment design guidelines include:

- Set segment and electronic card total current draw
- Assign control devices for a "loop" to a segment
- Group devices by location
- Assign non-critical devices
- Assign the back-up Link Active Scheduler (LAS)
- Assign segments requiring segment-to-segment communications to the same electronic port
- Check segments for compliance with design constraints—cable length limitations, cable parameters (resistance, inductance and capacitance), current draw and macro-cycle time.

Within a tropical, offshore environment, subject to earthquakes and typhoons, Malampaya's facility has to maintain production in all but the worst conditions. In addition to the OGP and platform structural considerations, the PAS was built to withstand seismic events. Thus, equipment cabinets are reinforced with welded seams and additional cross-bracing. All elements within the control unit cabinets are secured with fasteners. Workstation monitors within the central control panels are fixed in place. Cables are secured in their cable trays and, wherever possible, field devices are close-coupled to the process, so that everything can move in unison.

Fig. 4. On the Malampaya platform's IS installations, the additional expense of quick-disconnect cables was offset by speedier installation and shorter transmitter replacement times.

INSTALLATION AND COMMISSIONING

Correct cable types must be used with appropriate electrical parameters, and they should be installed correctly to prevent distorted signals. Digital signals are susceptible to noise caused by poor cable installation. Precautions had to be taken to ensure good installation practices—the shield is earthed only at one end, with the other end cut back and correctly insulated.

To confirm that wiring problems were successfully resolved, a Fieldbus cable tester was used to determine acceptable cable parameters. On a few occasions after rectification of initial wiring problems, when the tester indicated unacceptable field cabling, an oscilloscope provided more detailed information on digital signal quality. Where necessary, the PAS supplier's personnel provided guidance.

On the platform IS installations, quick-disconnect cables with molded plugs were used to speed installation. While more expensive than other connection methods, they hastened installation and reduced mean time to repair transmitters. This significantly lowered transmitter replacement time, Fig. 4.

Commissioning Fieldbus devices was uneventful, with fewer problems than anticipated. Even so, time required for instrument commissioning was not much less than might have been experienced with a traditional DCS. This judgment is rather subjective—lack of significant time-saving while commissioning field devices is partially a result of device and cable installation quality.

The commissioning team learned to think about "segments" rather than "loops." The sight of a box of IS barriers with blown fuses required quick re-evaluation of commissioning methods. In conventional analog loops (one field device, one cable), once process piping or machinery is in place, the instrument is mechanically/electrically installed and commissioned.

Multiple field devices on a LAN can be geographically distributed to different process equipment that may not all be installed concurrently. Extending incomplete segments that were powered up and partly commissioned resulted in blown IS barriers more times than was acceptable. With additional planning, engineers tried to complete installation of all field devices on a segment before commissioning it.

However, once a device is field-installed, it shows up on the workstation—commissioning is only a matter of "drag and drop." Where there were commissioning problems, diagnostic facilities provided quick identification, compared to time-consuming fault-finding on traditional analog loops.

Anyone contemplating installation of a Fieldbus-based system should recognize that instruments are configured and checked differently than with traditional, distributed control systems. After Fieldbus instruments are installed, they can be checked out and configured from a central workstation, rather than having personnel go out onto the platform to find the instruments and use handheld devices.

Individuals doing this work should be trained in Fieldbus network nuances and how to commission instruments. Time is saved when these personnel understand how to use the host to check out each device and control loop, particularly if there is a fault.

OPERATIONAL EXPERIENCE

Shortly after gas production and processing began on the platform, it became apparent that installing digital valve positioners on shutdown and blowdown valves, rather than limit switches, offers significant operational benefits. Operators can monitor actual valve positions during opening and closing, and determine each valve's stroking time. Deviation alarms ensure that operating times are not exceeded.

Early in the commissioning process, all valve signatures were taken, providing a useful baseline for identifying degradation. In some cases, automatic recording of a safeguarding valve correctly functioning during normal operations eliminates the need for further, unnecessary valve testing.

It was also apparent that the smart field devices produced massive amounts of process and device data. Large numbers of process condition alarms and device alerts occurred daily, swamping personnel. This made it difficult to identify the alarms that really posed a threat to process availability.

A review of alarm values was carried out, resulting in limited reduction of alarms. A successful exercise of static and dynamic alarm masking was undertaken on the OGP and platform. This exercise required considerable effort, to ensure that a true alarm was not masked inadvertently.

The PAS event historian gathers essential, event-driven data from throughout the process, using the OPC alarms and events reporting standard. However, a better way to manage and present these vast data as useful information to operations personnel is needed—a task being addressed by the system provider's engineers.

As the design developed, it was apparent that more use could be made of remote diagnostics of third-party equipment. An addition made to the PAS network, called D-Net (or diagnostic network), gives suppliers remote access to platform and/or OGP equipment conditions from anywhere in the world. They can also obtain associated process or safeguarding information.

For example, engineers are frequently on-line, checking gas turbine generators' operation. Gas turbine-driven compressors are continuously monitored, 24 hr per day. This remote diagnostic power has enabled the awarding of maintenance contracts that place responsibility for equipment health on the vendors, even though their representatives are not present.

Equipment suppliers in their offices use D-net to remotely diagnose problems and plan corrective actions. This facility has been used effectively by the PAS vendor to interrogate the system, analyze results and engineer an appropriate solution. To extend remote data access and diagnostics, two workstation terminals are being installed in the SPEX office in Alabang (Manila).

LESSONS LEARNED

While implementing Fieldbus technology, numerous lessons were learned. For instance, package suppliers had varying competency levels for implementing OPC. A portable PAS was developed for use by package vendors to confirm communication integrity.

Furthermore, Fieldbus signals can be sensitive to noise, due to poor cable installation. Selection of correct cable is important—good installation practices with correct grounding are a must.

Individual devices' macro-cycle time is important. Maximum execution speed was limited to 250 milliseconds for device-resident, Fieldbus, closed-loop PID control. New software releases progressively reduce macro-cycle time.

Close-coupled instruments with integral manifolds can significantly reduce leak paths, where appropriately applied. Bus devices greatly reduce the probability of process leaks, because less physical access by maintenance personnel is needed.

Maximum technical integrity of field control is achieved when instruments associated with a particular control loop are on the same segment. Personnel engaged in installing and commissioning Fieldbus-based systems should receive prior training to maximize productivity.

FUTURE DEVELOPMENTS

Moving forward, there are a few development suggestions, some of which are already in the Malampaya program. One is to add software to analyze and evaluate large data volumes received from smart field instrumentation. Additionally, methods for handling large numbers of alarms and events must be developed.

A convenient way to auto-tune Fieldbus devices would also be a great time-saver. AMS time-stamping would benefit maintenance personnel trying to troubleshoot suspected problems. Another suggestion is to fully integrate AMS for HART devices with the asset management system.

Yes, not all anticipated cost savings materialized from employing Fieldbus technology at the platform and OGP. However, its use is justified by the progress made toward high availability, remote control and diagnostics ability, and minimum staffing. WO

ACKNOWLEDGMENT

The author thanks Emerson Process Management and Lawrence Thorpe of L. R. Thorpe Public Relations for their assistance. This article was prepared with permission from copyrighted OTC Paper 14044, presented at the 2002 Offshore Technology Conference in Houston, May 6–9, 2002.

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Part# D350893X012 / 00802-0100-2132 / 2,500 / 12/02 2.5M/01-2003