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Automation Drives Growth, Profitability

By Jim Fererro

HOUSTON–There tend to be two distinct camps in the upstream oil and gas industry: traditionalists, and those who embrace technology to lower costs and improve productivity. In an industry faced with an unstable economy, loss of experienced personnel and volatile product pricing, the latter camp is coming out ahead.

Companies that have a long-term strategy of embracing technology have the potential for even greater success if they consider design systems that incorporate the full functionality of their installed hardware into a systemwide design. Automating production equipment can produce a significant return on the capital invested, especially if legacy systems are integrated with new technology to create systems with remote monitoring and control capability.

Almost all oil and gas operators have invested in some level of automation, typically with an eye toward increased efficiency, and ultimately, a positive impact on the bottom line. However, many are not taking advantage of the fullest and best use of their technology investments.

In gas measurement, for example, electronic flow measurement devices have frequently replaced chart recorders in the field. However, many traditional field operators are still physically visiting the EFM devices and manually recording the data in notebooks. Automating the collection of data from the EFM device by installing a radio, connecting it with a network, and capturing its data remotely with a supervisory control and data acquisition system is a relatively straightforward next step that more progressive companies are taking. That step represents a significant percentage in reduction of work for the field technicians every day, which compounds to significant time saved over the course of a month or year–especially for fields with large volumes of wells.

Programmable logic controllers and remote terminal units are frequently underutilized in the field. Often, they are used merely as data aggregators to relay data to centralized SCADA systems. More progressive designs "push" intelligence farther into the field using the full programming potential of these devices to monitor and react to alarm situations.

Legacy systems often can be integrated into new and expanded applications to take advantage of new technology, or to accommodate conflicting technology in new field acquisitions. A full evaluation of existing technology should be the basis for fieldwide implementation of an integrated automation and control design for an operation.

Automation Challenges

There are several reasons why oil and gas operators stall at a relatively early level of automation in their fields. One of the most common is the lack of documentation. For example, in a field, many PLCs may all be doing the same thing, but because they were installed over several years by different people, they have different programming and do not

A "dispatch mode" of automated operations allows companies to constantly monitor compressors and other equipment in real time from a central control room. Using the data trending capabilities of a SCADA system, control room operators can dispatch field technicians as soon as a problem is detected. Leveraging remote monitoring to proactively address field problems and avoid shutdowns saves hours of production time and significant costs, while also providing HS&E benefits.

communicate with one another. A process that could be called "forensic programming" allows companies to uncover what was done previously, and can result in a structured, common, templated and documented programming approach.

Establishing a structured approach allows for documentation, including:

- Cause and effects, or diagrams show if X happens, Y is the consequence, essentially detailing what each alarm level should do (for example, does a high liquid level result in a call out, activate a shutdown, or turn on a pump?).
- Functional specifications explain how the systems operate and what functions they perform.
- Control narratives explain the programming approach for the application or the field.

These documents lead to a common programming approach across the entire field, making future work less costly and more efficient. A lack of documentation is the single biggest challenge to partially automated fields.

Configuration is another common obstacle to automation. For example, if an EFM device typically is read manually, but is upgraded to communicate with a serial communication port, the information may be available in a native protocol that is proprietary to the EFM manufacturer. If the SCADA system drivers do not read and communicate in that protocol format, they will not be able to understand and interpret the data. Finding a common format such as ModBus, installing the hardware drivers in the SCADA system, or developing an open connectivity database are common fixes. Selecting a method to link the devices in the field with the SCADA system impacts project costs and the ongoing operability and expandability of the system as a whole.

System Upgrades, Integration

Like any technology, SCADA operating systems change with version upgrades and companies must decide if they need to upgrade to respond to those changes. Version management is a work process frequently overlooked in the maintenance of a SCADA system. A significant challenge is that many software versions of SCADA are not backward-compatible, meaning that later versions do not communicate with modules of previous versions and often do not use the same programming approaches. This leads to difficulties, especially as field operations grow.

This has serious implications for oil and gas operators because it means that three fields may use three SCADA versions, none of which may be able to talk to the others or have the same protocols. To achieve profitable automation, companies have to respond by creating one master approach that communicates individually with each SCADA version and other devices, or choosing one SCADA system with which to move forward.

One situation in which the compatibility of legacy automation systems can be a major issue is in asset acquisition, where as part of the purchase of a property or even an organization, a company may inherit automation hardware and software that is not configured to work with its own internal system components. An example occurred in 2007, when an oil and gas company acquired a crude oil pipeline that runs from Artesia, N.M. to Cushing, Ok. The control panels and PLCs were different from the company's standard systems, and the pipeline was run on a different version of SCADA.

The company turned to a third-party services provider to provide solutions to integrate the disparate systems, build new PLC panels, and create a documented programming approach. PLCs were created to be expandable for additional monitoring points or capability. The project included river crossing programs, custody transfer points, valve stations, and pump stations (each location along the pipeline was different and needed new programming).

At the completion of the project, the operator will receive a system that uses a common language and will communicate with other devices. With concise and strict documentation, and continuity throughout the system, future system expansion will be easier and less costly.

The initial cost of new technology can be significant, especially coupled with the efforts to integrate legacy systems into fully automated production operations. However, that cost and effort is quickly mitigated by the decreased downtime, increased efficiency, safer operations and reduced operating expenses that result from automated operations.

Proactive Problem Solving

Many oil and gas fields traditionally are operated in what can be likened to a "milk run" mode. Under this model, a field technician visits the sites in his field based on a daily schedule, or daily milk run. The operator begins his day at the field office and then heads out to visit his sites in rotation. If a compressor shuts down after his site visit because of high gas discharge temperature, for example, there is the potential for it to go unnoticed until the next scheduled visit. This can mean up to 24 hours of downtime, resulting in lost production and revenue. The alternative to the milk run is a dispatch mode of operation.

Under a dispatch mode, this same compressor would be monitored constantly and in real time from a central control room. The control room operator assigned to monitor that area would be well aware of the increasing discharge temperature because of the trending capabilities of the SCADA system, and could dispatch a field technician as soon as he noticed the trend. The technician would arrive at the scene with full knowledge of the trend before the unit went down on a high-temperature shutdown. Most likely, he already would have surmised that the cause was a failing compressor valve, and he would have a replacement valve with him to quickly remedy the situation.

Leveraging remote monitoring to proactively address field problems and avoid shutdowns saves hours of production time and significant expenses. It also has safety implications. For operators working in environmentally sensitive areas, dispatching field operators based on need, rather than following a set schedule, means that operations will be run with fewer employees driving fewer miles. From a health, safety and environmental perspective, it also reduces chances for injury because drive time is reduced.

Preventive Maintenance

Each hour of downtime costs oil and gas operators thousands of dollars in lost production. If a field compressor produces 5 million cubic feet of gas a day and that gas is worth $3.50 an Mcf, each hour of downtime is worth $730. If a site averages 20 hours of downtime in a month, it would equate to $14,600 in lost production. Reducing that downtime by only 10 percent (two hours) would bring increased revenue of almost $1,500 each month. Achieving a 20 percent reduction would result in $3,000 a month.

Operators can achieve these reductions in downtime and increases in production and revenue by adopting a dispatch-based field operation model. Automation enables a proactive approach, which also allows operators to implement condition-based maintenance and root cause failure analysis to increase equipment efficiencies and lower costs.

Condition-based maintenance is a scheduled maintenance program based on reviewing trends in certain operating conditions, such as vibration readings, discharge temperatures and the results of regular oil analysis. Maintenance is scheduled and planned based on the indicated need, rather than based on the calendar or run hours. The result is a proactive and truly preventive maintenance program that lowers costs and increases the mechanical availability of the compression equipment. Preventative maintenance can result in reductions in downtime of as much as 25 percent.

As compelling as they are, arguing these benefits is quite unnecessary after considering the issue of personnel. The average age of a field technician in the United States is more than 50 years. A shortage of qualified personnel is expected to become a growing problem in the years ahead. As the normal attrition rate climbs and as the industry's expertise begins to retire, there simply will not be enough people to cover the wells under the old model. Operators will be forced to find a new solution, and remote monitoring is a clear fit for reduced manpower if a dispatch mode of operation is applied.

Increased automation in the field holds clear operational benefits and significant potential for cost savings. Fortunately, creating a full-functionality automated production system does not mandate a full investment in new technology. Many companies are integrating component equipment and disparate legacy systems to achieve full remote monitoring and control capability. ❒

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