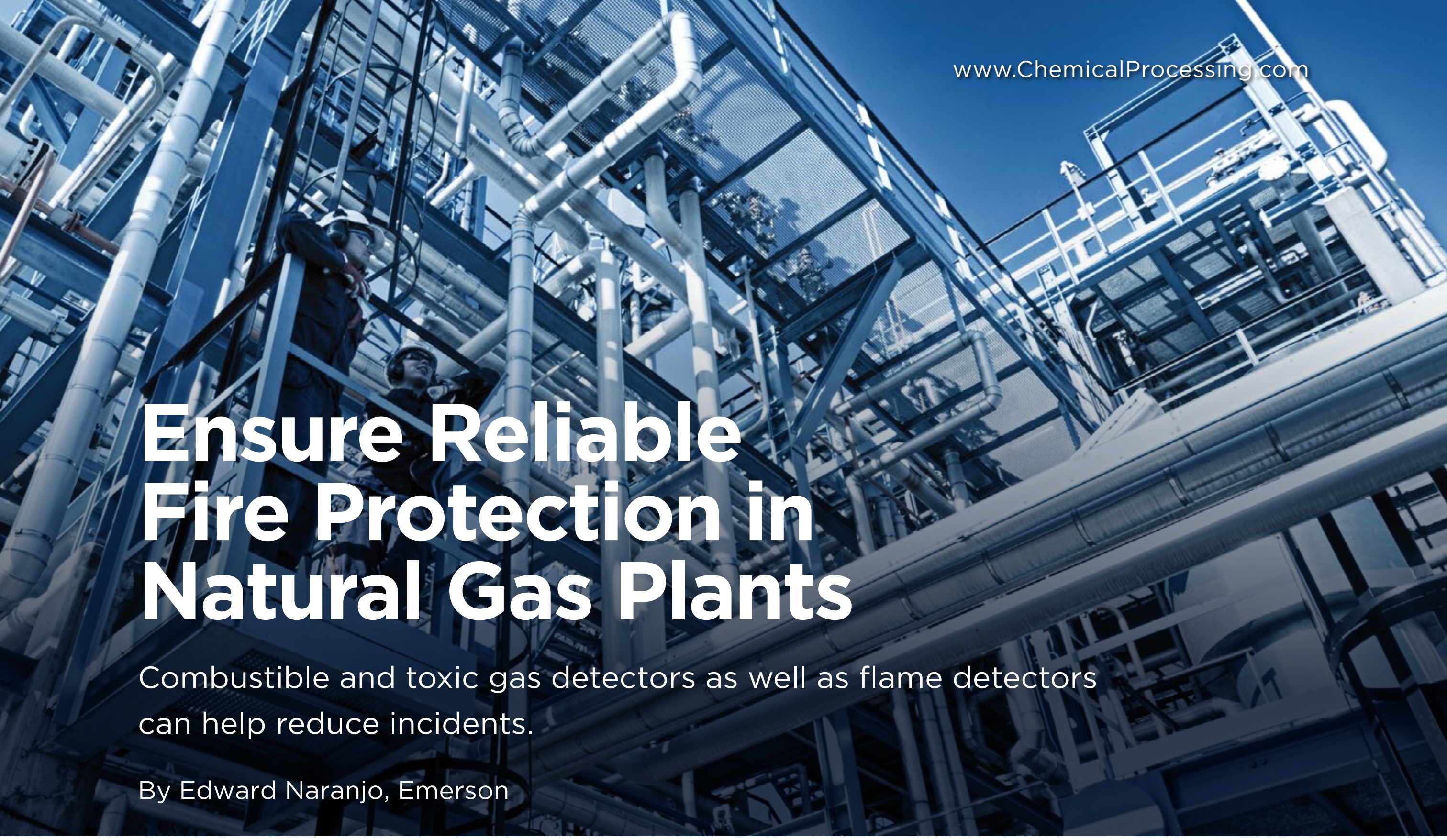


Ensure Reliable Fire Protection in Natural Gas Plants

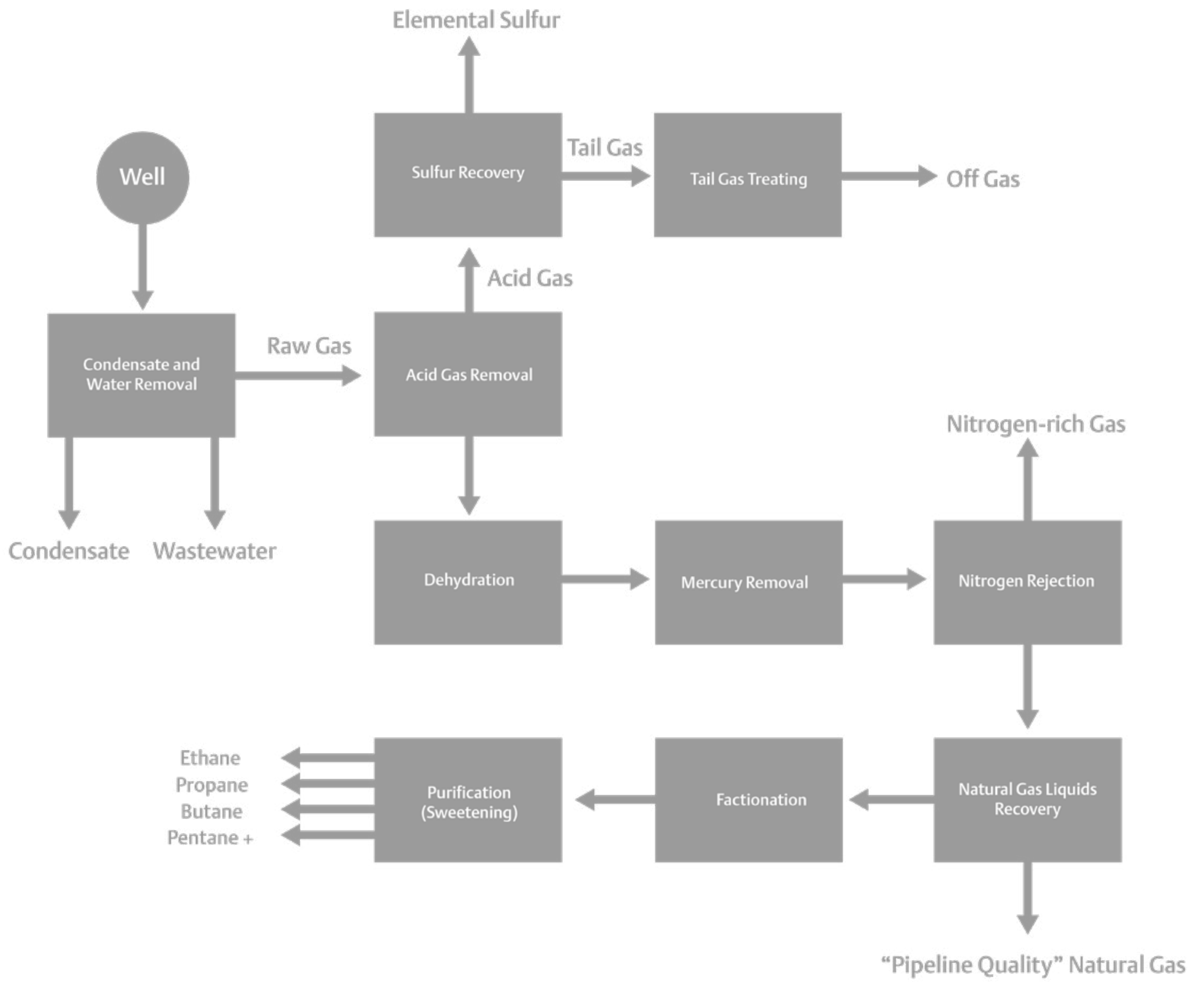
Combustible and toxic gas detectors as well as flame detectors can help reduce incidents.

By Edward Naranjo, Emerson

Natural gas processing plants are complex facilities designed to separate natural gas composed almost entirely of methane from other hydrocarbons, nitrogen, water, metals and other impurities. These plants are usually located in natural gas processing regions and connected to wellheads through a network of small-diameter, low-pressure gathering pipelines. Natural gas plants' main hazard are fires and detonations and acute exposure to toxic gases from uncontrolled releases of flammable and toxic materials. The large inventories of flammable and toxic gases and liquids managed by these plants combined with the high density of equipment and relatively large occupancy rates speak to their high hazard potential.

The dangers of gas plants are underscored by the severity of accidents that can occur. On June 27, 2016, for example, loss of containment from a heat exchanger led to the release of methane, ethane, propane and other hydrocarbons at the Enterprise Products Pascagoula gas plant in Pascagoula, Miss. (CSB 2019). The leak led to a large-scale fire and explosion. A similar incident occurred on September 25, 1998, when a heat exchanger in the Esso gas plant in Longford, Victoria, Australia, ruptured, releasing hydrocarbon vapors and liquids (Kletz 2009). As with the Enterprise Products incident, the escape resulted in a large fire and explosion.

Natural gas plants are critical infrastructure for the modern energy supply and



NATURAL GAS PROCESSING FLOW DIAGRAM

Figure 1. Natural gas processing plants are complex facilities designed to separate natural gas composed from other hydrocarbons, nitrogen, water, metals and other impurities.

their safety is of utmost importance. In the United States, natural gas plant operators must follow process safety management regulations for general industry (29 CFR 1910) as well as several of the state plans approved by the Occupational Safety and Health Administration. Guidelines like API Bull 75L and process safety standards like IEC 61511 offer the framework for managing process safety systems through their lifecycle.

In the following sections, we will review provisions for protection of natural gas processing facilities and illustrate their use through several examples of common process modules. We will then address the interface between fire and gas detectors and the control systems that manage the plant. Fire and gas systems are in effect the independent layer of protection that drive mitigation actions to arrest the escalation of accidents. In consequence, it is important to survey how instruments and logic solvers contribute to improving the performance of the combination.

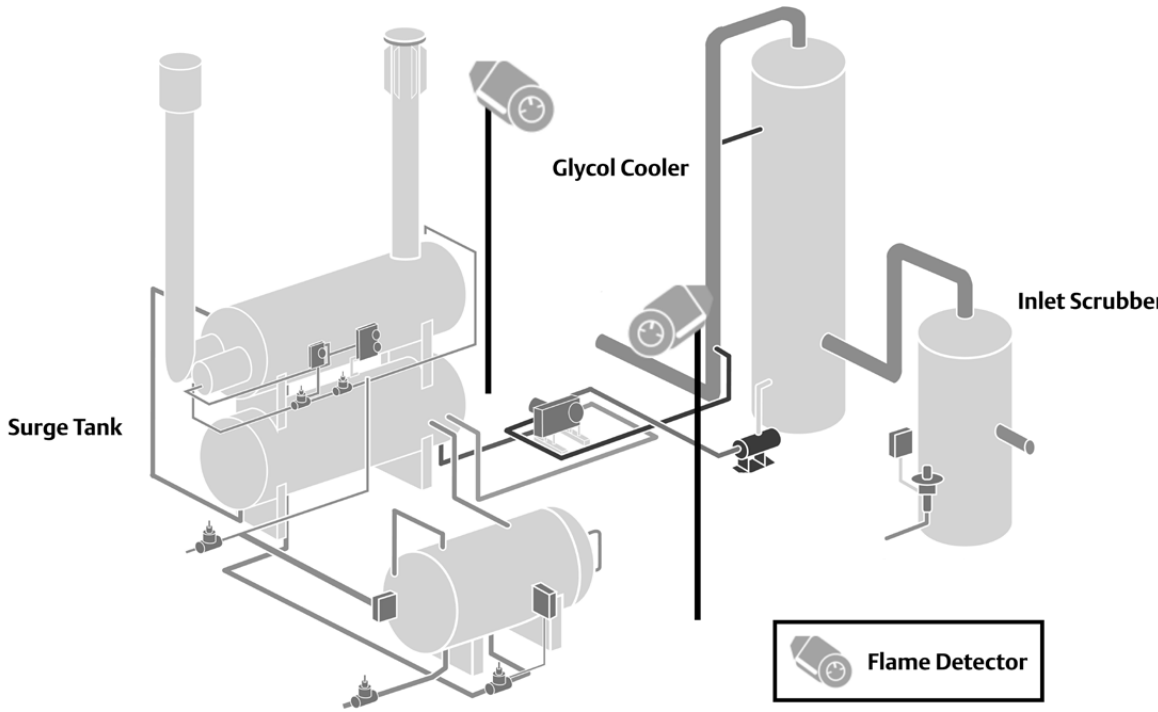
PROVISIONS OF FIRE AND GAS SYSTEMS

Natural gas processing consists of separating several hydrocarbon molecules and contaminants from pure natural gas. The process includes condensate and water removal, acid gas removal, dehydration, mercury removal, nitrogen rejection, and natural gas recovery, separation, and treatment. Many associated hydrocarbons known as natural gas liquids are valuable products of the separation of natural gas; when components are separated and fractionated, their feedstocks are sold to oil refineries, petrochemical plants and oil producers for a variety of uses. A schematic flow diagram of a natural gas processing plant is shown in Figure 1 (Riazi et al. 2013).

Process units incorporate some degree of protection in the form of fixed point and open path gas detection. Because raw natural gas contains components with higher and lower molecular density than air, detectors in several process units must be placed at both floor and ceiling level where gas may fractionate. Open path detectors may be used to protect module boundaries, particularly where heavier-than-air combustible fluids are managed, and the process is relatively close to the perimeter and dispersion modeling indicates that small, but high probability releases may cross the fence line and the sources of such releases are outside the coverage or at the limits of point detection. Point and open path hydrogen sulfide (H_2S) detection are required in acid gas removal and the sulfur recovery unit, and similarly, at the gas well during production of hydrocarbon fluids and condensates and water removal.

In general, it is impractical to provide toxic gas detectors to address every toxic release scenario in most process facilities. As a result, the use of fixed detectors is limited to target receptor monitoring and high-risk applications. Point detectors are placed on grid spacing and near points of entry and along normal travel paths of travel within the units, especially in those locations where personnel may not be able to observe the area as they approach potential release sources. Open path H_2S detectors are beneficial between equipment in toxic service and mustering points and between potential release sources and uncontrolled areas like service roads and parking lots.

The UK Health and Safety Executive (HSE) has alerted about the dangers of oil mist in offshore gas turbines (HSE 2008). When liquid sprays impinge on hot metal surfaces, they may ignite as the surface temperature exceeds the liquids' autoignition temperatures. In the same fashion, lubricating systems in gas compressors in gas plants are at risk of fires if not protected. Oil mist



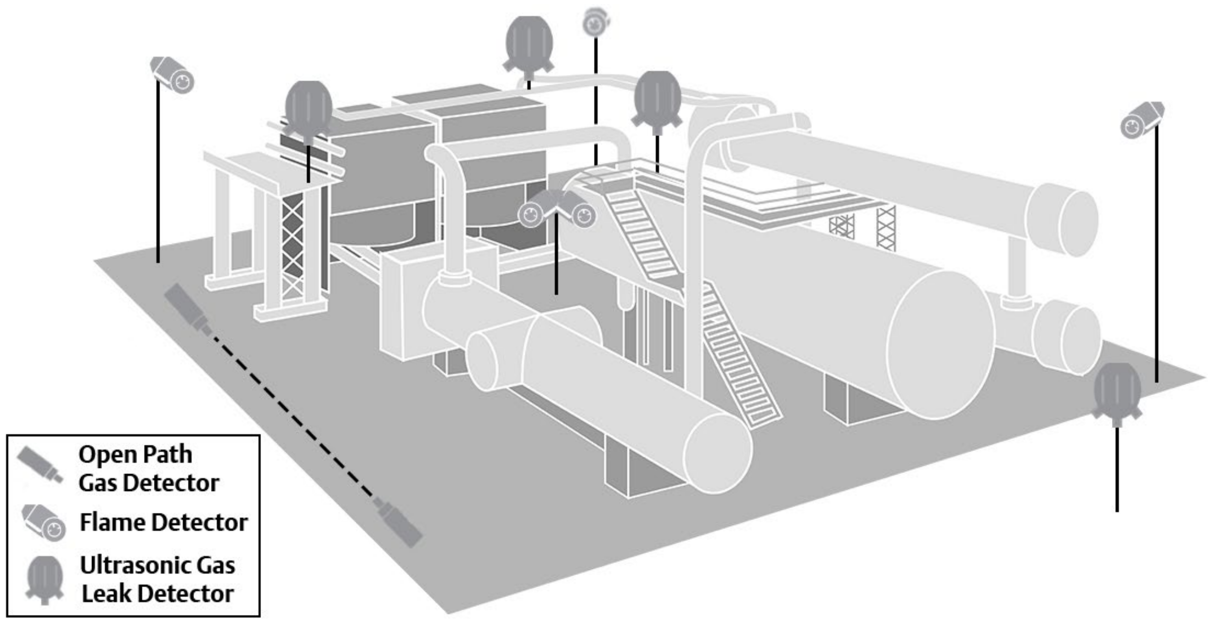
INSTALLATION IN DEHYDRATION PROCESSING UNIT
Figure 2. Two flame detectors are used to monitor the area around an absorption tower and reboiler.

detectors should be installed near compressors and lubricating and hydraulic systems. Likewise, for glycol dehydration and natural gas liquid extraction using the absorption method, best practice calls for installing oil mist detectors near high pressure sources of liquid leaks.

Ultrasonic gas leak detectors are applied in all outdoor locations with pressurized pipework. Locations include compressor areas, filter stations, separators, gas metering skids and receiver areas.

Flame detectors should view all modules and all major items of the plant. A common arrangement is to locate detectors at the corners of an area or module such that the detectors' field of view covers areas where fires may occur. Computer aided design tools should be used to optimize area coverage at the design stage. To increase detection effectiveness, no area should be completely dependent on a single device. Figure 2 illustrates flame detectors on an absorption tower and reboiler.

Because of their long-range capability and wide field of view, multispectral infrared flame detectors offer optimum performance for these applications. Flame detectors should be used with combustible gas detectors to safeguard plants against fires and explosions. As the HSE has shown in the UK



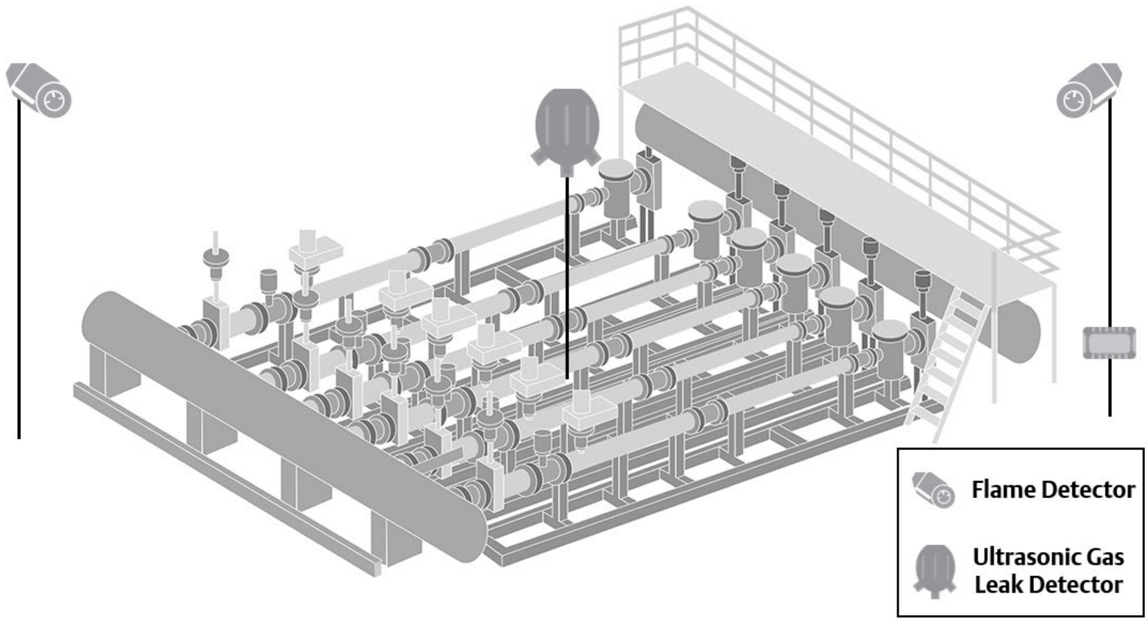
FLAME AND GAS DETECTORS AND CONTROL SYSTEM IN SEPARATOR AREA
Figure 3. A distributed I/O block can be placed near the process module to help reduce wiring and the control system's footprint.

offshore sector, combustible gas detection equipment is not 100% effective in open installations (McGillivray and Hare 2008). The likelihood of credible gas releases escalating into incidents that could cause large-scale damage is much diminished when flame and combustible gas detectors work in tandem. In the next section, we'll examine some common arrangements of these devices in process modules.

SEPARATOR AREA

Separator process modules include the separator, heat exchanger, and gas cooler. Figure 3 shows an ideal arrangement. Point gas detectors are placed between the separator and heat exchanger, under the coolers, where gas may accumulate. Two open path detectors are placed on opposite sides of the process module to provide area monitoring consistent with the prevalent wind direction. For fast response to pressurized gas releases, ultrasonic gas leak detectors are positioned to cover potential leak sources like flanges and valves on the separator and coolers. To avoid shadowing and reflections, gas leak detectors are placed on either side of the cooler, while flame detectors are installed at the corners and between the separator and heat exchanges to view most of the module.

A cluster of devices as shown may be interfaced with a logic solver installed in a control room. To reduce wiring and the control system's footprint, a distributed



FLAME AND GAS DETECTORS IN NATURAL GAS METERING SKID
Figure 4. An ultrasonic gas leak detector covers the footprint of the metering skid.

I/O block can be placed near the process module also shown in Figure 3.

METERING SKID

Measurement of process fluids being transferred to other plants takes place in metering skids. The primary variable to be measured is mass flowrate. Main components include the structure frame and supports, pipework, process equipment like flowmeters and process gas chromatographs, and local control system. For illustration, we'll assume the process fluid is pipeline quality dry natural gas. As shown in Figure 4, an ultrasonic gas leak detector covers the footprint of the metering skid. Depending on size and degree of obstruction, one or several flame detectors may be necessary to supply adequate area coverage for the skid. In this example, two detectors are placed on opposite corners.

A distributed system offers an elegant approach for managing field devices in a metering skid installation. A distributed I/O block, for example, can interface with flame and gas detectors for one or several metering skids in proximity, an arrangement that offers the benefits described in the previous section.

PACKAGED FIRE AND GAS SYSTEM

Fire and gas systems in gas plants are no ordinary equipment. Because gas plants are located near exploration and production facilities, logic solvers may be exposed to adverse conditions like high humidity, brine, high vibration, and voltage variations.

Not surprisingly, printed circuit boards are weatherized by application of conformal coating and wires and other electronic components are designed to allow for few common failures. Compared to other controllers, a fire and gas system logic solver incorporates redundant power and communication paths for input and output devices and must easily integrate with safety instrumented and emergency shutdown systems to which they may pass certain demands.

Certifications also play a critical role for fire and gas systems in gas plants, because these address minimum requirements for product performance, reliability and survivability. In the United States, fire and gas systems are installed according to NFPA 72 and certified to performance standards like FM 3010 and UL 864. Similarly, the system level standard for Europe is EN 54-2.

One of the most important differences between personal computers and industrial logic solvers is the design of the latter as complete packages. In logic solvers, software, hardware, and documentation are designed and tested to work together. Similarly, fire and gas systems are designed to meet performance standards that link the size and nature of the hazards to the characteristics of the system and ensure requirements are met for operation and availability. Such packaged solutions offer several benefits to natural gas plants. To begin, the performance of the complete system, from a selected group of initiating devices to notification appliances and other fire outputs is defined and limits and exceptions are known. Surprises during installation commissioning, and operation are kept to a minimum. In addition, packaged solutions are equipped with configuration libraries that facilitate the automatic commissioning and documentation of several devices at a time. As mentioned above, gas plants can have several hundred or thousand flame and gas detectors and other peripherals associated with fire and gas monitoring, resulting in numerous weeks of installation and commissioning for manual or sequential set up, an approach that is also prone to error. In one instance, smart commissioning with pre-loaded field device settings resulted in a significant reduction of commissioning cycle time.

The profit to be gained from packaged systems extends well beyond commissioning. It is well known that real-time HART integration into system architecture enables users to get access to diagnostics and configuration information. Continuous communication between field devices and control system allows problems with the device to be detected within seconds, enabling action to avoid process disruptions and unplanned process shutdowns. Regrettably, many end users have no access to such information. Unlike field devices for process control, flame and gas detectors make use of analog output values below 4 mA to report faults. Values of 1, 2 and 2.5

SAMPLE FAULT ANALOG CURRENT LEVELS

Fault Condition	Product Model(s)	Analog Output (mA)
Input voltage less than 8 VDC	Gas Transmitter	2.5
Input voltage more than 33 VDC	Gas Transmitter	2.5
Critical memory fault	Gas Transmitter	2.5
Onboard power supply fault	Gas Transmitter	2.5
Sensor zero drift	Toxic Gas Sensor	2.5
Memory fault	Toxic Gas Sensor	2.5
Calibrate sensor	Toxic Gas Sensor	2.5
Span calibration failure	Combustible Gas Sensor	2.5
Zero calibration failure	Combustible Gas Sensor	2.5
Sensor over-range	Combustible Gas Sensor	2.5
Low temperature	Combustible Gas Sensor	2.5
High temperature	Combustible Gas Sensor	2.5
Replace sensor	Combustible Gas Sensor	Momentary 2.5 mA
Memory fault	Combustible Gas Sensor	2.5
Power supply fault	Combustible Gas Sensor	2.5
Sensor nearing end of life	Combustible Gas Sensor	Momentary 2.5 mA
Sensor weak signal	Combustible Gas Sensor	Momentary 2.5 mA
Fault	Flame Detector	1.0
Dirty window	Flame Detector	2.0
Sensor test fault	Ultrasonic Gas Leak Detector	2.0
Internal process fault	Ultrasonic Gas Leak Detector	1.0
Major fault	Ultrasonic Gas Leak Detector	0

Table 1. This list includes several Rosemount flame and gas detectors, as well as their common diagnostics and corresponding analog output levels.

mA to denote informational or critical faults are not uncommon. Table 1 illustrates some common diagnostics available in a few commercial models and their corresponding analog output levels.

For field devices equipped with HART, the FieldComm Group specifies a minimum analog current signal of 3.5 mA. As a result, end users wishing to take advantage of diagnostics, process variable, and configuration information available through HART must program logic solvers to read values below the HART limit. The process is time consuming because every model's specific range of analog output levels and configurations must be considered. Even if some controllers allow access to HART commands with analog output values below 3.5 mA, device specific commands may be suppressed. Invariably, ensuring the device meets the design safety intent requires additional programming and testing, often after installation. Compare such an approach to one of a packaged pre-engineered system. By design, with a packaged solution pertinent commands are tested for every HART field device within the scope of the certification. The need for custom programming is reduced, which helps keep system implementation on schedule.

Finally, pre-engineered systems enable more efficient alarm management. When an assortment of field devices and control systems which have not been tested together are first integrated, the diversity of alarms and alerts that must be managed can be overwhelming. Which action should be undertaken if a device reports a low line voltage fault? Can it continue to operate under low voltage for several weeks or is it unable to perform its protective function? Although standards for alarm management like ANSI/ISA-18.2 specify rankings for diagnostics, the terminology, what constitutes an alarm, and what is critical for a device's safe operation varies considerably by vendor. Making sense of the diversity falls on the end user, which must rationalize alarms through trial and error. At one extreme, all diagnostics are suppressed, putting an end to improved asset utilization, while at the other alarm flooding is likely to occur. With pre-engineered systems, much of the trial and error related to alarm rationalization is minimized. Rank ordering of diagnostics and level of criticality is consistent across field devices. In consequence, implementations are not only faster but the plant also benefits from fewer abnormal situations and decrease of capital equipment for repairs.

CONCLUSION

Natural gas plants are critical infrastructure for natural gas supply. Although some separation of water, metals, and other impurities from raw natural gas takes place at wells, natural gas processing facilities carry out most of the steps to separate natural gas liquids into feedstock for oil refineries and chemical plants and produce pipeline grade natural gas. Due to the potential for accidental release of hazardous chemicals, natural gas plants face severe risks. Fires and explosions and acute exposure to toxic gases and asphyxiants can disrupt operations and cause harm to the workforce and any surrounding population. Fire and gas systems protect these plants by reducing the consequences of incidents. Minimum provisions for fire and gas systems include the installation of combustible and toxic gas detectors and flame detectors. As shown in the two examples above, the ideal arrangement of these devices varies across process modules based on the nature, location and severity of the potential hazard.

Fire and gas systems for natural gas plants must be reliable. Due in no small part to the risk of business disruption, process facilities have instituted tougher safety practices including more safety instrumentation and layers of protection. System hardware and software are designed for adverse environments and

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the systems themselves are certified under performance standards for adequate availability and survivability. Distributed I/O configurations contribute to reducing the footprint of these systems, enabling operators to integrate devices over long distances at reduced costs compared to conventional peer-to-peer networks.

For operators seeking to deploy or modify a fire and gas system, packaged safety solutions offer significant benefits. Smart commissioning, ready access to configuration and diagnostic information through HART and rank ordering of alarms out of the box reduce the need for custom programming and testing, which in turn leads to faster implementations and reduced maintenance costs.

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