Technical Papers

"Asset Management & ASME PTC updation"

ESSENTIAL ASSET MONITORING

Most plants in existence today were built years ago with the minimum amount of instrumentation necessary for control. Improving process unit utilization, energy efficiency, reducing maintenance costs and mitigating safety and environmental incidents requires additional measurements. The good newsis that older plant scan now easily be modernized by installing wireless instrumentation to supply the missing measurements and intelligence.

Critical assets in the plant such as expensive compressors and large pumps are already being monitored by protection systems. Due to the high cost of traditional machinery protection and equipment monitoring systems, the balance of assets may not have been previously fitted with monitoring systems. Many of these unmonitored assets are still essentialto operation. These “second tier” assets are typically spot-checked manually in the field on a periodic basis.

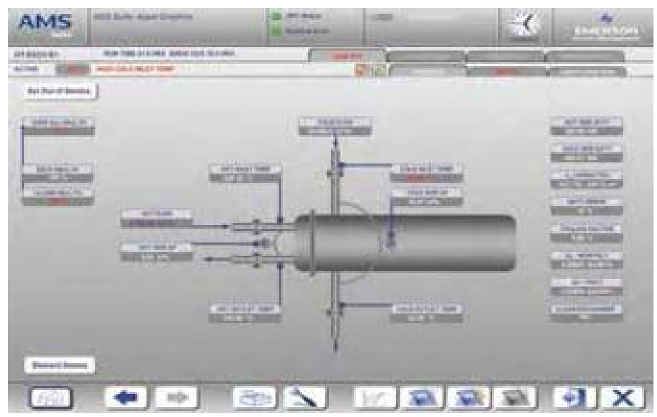
Originallytheseassetsmayhavehadstandbybackups, but subsequent debottlenecking and expansion projects may have put former standby assets into continuous service without corresponding backup. Monthly manualreadings are not frequent enough to catch developing issues, as process conditions often create equipment failures. Unexpected equipment failures in turn cause process upsets and potentially unsafe conditions. Runningto failure can result in even worse damage to the equipment.

Emerson’s Essential Asset Monitoring (EAM) solutions are specifically designed to detect common faults in various types of equipment. These applications utilize a combination of equipment sensors and transmitters (like vibration and bearing temperatures) with process data (like flows, temperatures and pressures) to provide a sophisticated analysis of impending problem situations.

Solution Value – Heat Exchanger

Emerson’s heat exchanger monitoring helps customers eliminate production inefficiencies and safety issues that result from tube fouling. The easily installed, easy-to-maintain solutions provide temperature data that is difficult or impossible to collect manually. As a result, producers will be able to make more informed decisions about when and which heat exchangers need to be cleaned – increasing efficiency, eliminating unplanned shutdowns, and decreasing risk to the environment and personnel.

Wireless temperature monitoring enables valuable information on heat exchanger condition and performance.



Solution Value -Compressor

Emerson’s integrated solution for compressor monitoring enables processing facilities to detect conditions that can lead to failure and damage, and prevent potentially dangerous situations. Our easily installed, easy-to-maintain solution can replace manualand periodic readings with online insight into compressor performance. As a result,operators will have more confidence, and maintenance staff and reliability engineers will have greater control over asset planning, increasing efficiency, mitigating unplanned shutdowns, and decreasing risk to the environment and personnel.

KAUSHAL SHRIVASTAVA

- **17 years experience in the field of Asset Reliability & Machinery Health Monitoring products and services.**

- Bachelor of Engineering (Production) from Jadavpur University, Kolkata in 1996.

- Working at Emerson Process Management since July 2006 with responsibility of Sales & Business Development of Asset Reliability and Predictive Technologies products & services.

- From July 2006 to Sept. 2012, worked as **Sales Manager for Machinery Health Products** in Asset optimization division of **Emerson Process Management (India) Pvt. Ltd.**

- From November 2003 to July 2006 worked as **Business Development Manager** in **Reliability System** division of **SKF India Limited** for Streamlined Reliability Centered Maintenance (SRCM) philosophy and Condition Monitoring Products and Services.

- From August 2000 to November 2003, worked as the Incharge of Condition Monitoring department at **Jindal Steel and Power Limited (JSPL),** Raigarh. Responsible for Reliability and efficient improvement of Critical Plant Machineries.

- From July 1996 to August 2000, worked as a Faculty at Indian Institute For Production Management (IIPM) responsible for implementation of Condition Monitoring philosophy across Indian Industries.

- Has presented paper on Asset Management at Hindustan Zinc Limited's Asset Meet happened on 25/03/11.

- Has presented various papers on Maintenance Management, Integrated Predictive Maintenance Technologies at forums like FICCI, NPC and NTPC – O&M Seminars.

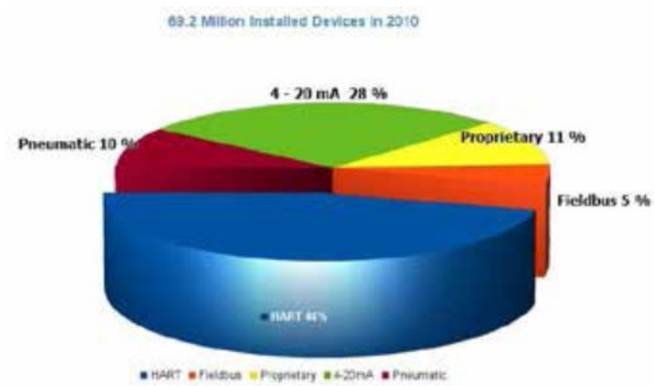
ASSET MANAGEMENT SYSTEM – INTERFACE with FIELD DEVICES

Unnikrishnan . R
Manager – Technical Support
Pepperl + Fuchs (India) Pvt. Ltd.

Asset management is the system of monitoring and maintaining things of value to an entity or group. It is a systematic process of operating, maintaining, upgrading, and disposing of assets cost-effectively. Asset Management System can help facilitate quality advice and decision-making within organizations, including the development and review of investment proposals. Transition of field devices and equipment to digital technologies has proven to provide benefits to the typical process plant operation. Digital devices offer a great deal of data about the operating environment. This data can be utilized by asset management system that prevent losses/disruptions, enhance quality & reliability, &reduce maintenance costs.

Asset Management System helps in predictive analysis and using the extracted data to predict future trends and behavior patterns. It produces interpretable information allowing oil and gas personnel to understand the implications of events, enabling them to take action based on these implications.

In the oil and gas industry, real-time data from sensors and other acquisition techniques with historical data to predict potential asset failures, and enables the move from reactive (scheduled, break-fix) to proactive (condition-based, preventive) maintenance. Traditionally detailed information about assets was used to schedule & manage work orders associated with the assets and manage the materials and equipment needed to complete the work. However, the work performed on the assets has rarely taken real-time data regarding the condition of the assets into consideration. More recently, the cost-performance of sensor and communications



Courtesy : ARC Advisory Group

technologies has enabled the widespread collection of real-time data on asset conditions such as vibration, strain, pressure, and temperature. These sensors are less labor intensive, can be placed in hazardous or inaccessible environments, and are often more accurate and timely than manual data collection techniques. Asset Management System can be used to analyze the real-time data from the sensors in the context of historical data and asset information to predict future conditions such as faults or failures and produce alarms or schedule maintenance or replacement.

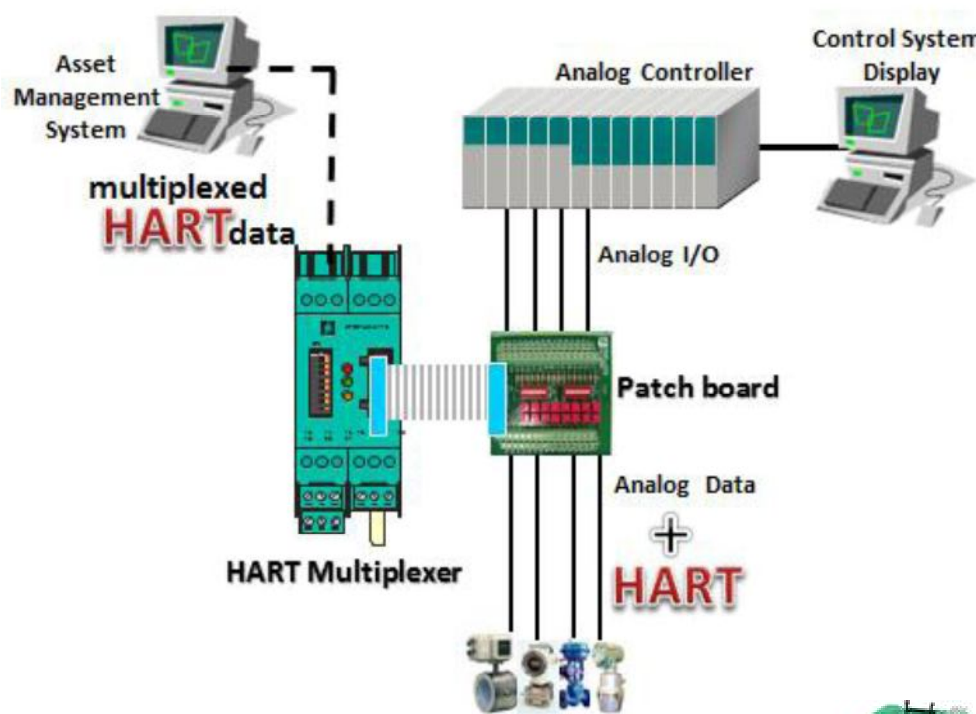
Total savings can exceed 20% of budget

Benefits of Predictive Maintenance using Asset Management System

A quick analysis of the financial statements of the majors O & G companies shows that plant, property and equipment on average accounts for **51% of total assets**. Among this group of companies, the average value of plant, property and equipment is **over $100 billion.** **-[Courtesy : IDC Energy Insight]**

In recent years, field devices & equipment supporting digital technology have the attained the growth & gained the popularity because of the acceptance of technology such as HART protocol & FOUNDATION Fieldbus protocol in Petroleum and Natural Gas Industry.

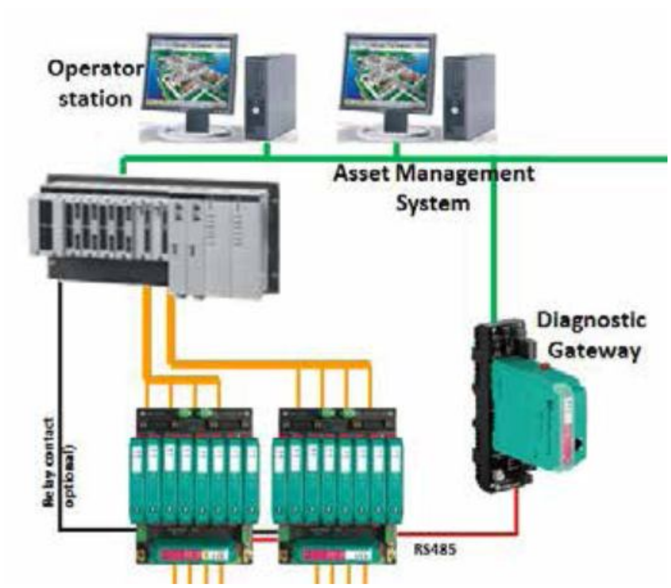
Integrating an asset management system with the DCS basically requires a means of connecting the asset management software to the HART I/O and on to the devices. In a major refinery expansion, an oil company weighed the advantages of using either a proprietary system or a HART-based system. The results indicated that the company could use HART digital instruments in 92% of their applications, compared to only 33% with the proprietary system. Choosing HART products resulted in an incremental $23,000 in savings due to commissioning efficiencies and ongoing maintenance and diagnostic capabilities. The oil company used a traditional control system with analog I/O and supplemented the control capability with an online maintenance and monitoring system. All of the HART field devices were monitored from a central location.



- ☐ Asset Health & Calibration Status Monitoring
- ☐ Planning shutdowns & predictive actions
- ☐ Reducing manual intervention
- ☐ Reducing Labor Cost
- ☐ Reducing down time
- ☐ Facilitating more continuous improvement

FOUNDATION Fieldbus is another digital technology which is dominantly growing across worldwide makes instrument data an integral part of the control and operating level. This technology is the optimum interface for your plant planning and maintenance. The basic feature of a FOUNDATION fieldbus is the distribution of intelligence to sensors and actuators of the respective plant.

Advanced Diagnostic in Fieldbus allows monitoring the health of Fieldbus networks efficiently in real-time while reducing the cost of ownership for the end user. The enhanced online diagnostic capability allows early detection of potential faults and provides users an intelligent foundation to deploy a plant-wide proactive maintenance strategy that includes the Fieldbus network.



Advanced online diagnostics integration in Asset Management System provide a richer diagnostic data set than traditional manual testing methods, enabling better decision making in operations and easier troubleshooting in maintenance. With better information about the nature and severity of detected faults, the time and frequency of both reactive and scheduled maintenance can be reduced. The system allow users to constantly monitor the health of Fieldbus networks, reduce operating and maintenance costs, and help to maintain the reliability and availability of a plant's production resources.

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ARC recommends:-

- ARC believes that users should consider adopting Advanced Diagnostic Module in new Fieldbus installations. ADM is an important asset management tool that can provide value across the entire lifecycle of a plant. Not only can it reduce the costs of installing Fieldbus networks, but it helps operations and maintenance to quickly resolve issues by pinpointing and predicting potential problems.
- Users deploying a Plant Asset Management solution to help maintain and optimize assets should not forget the Fieldbus network and consider adding ADM in legacy Fieldbus installations.

[Courtesy : ARC • 3 Allied Drive • Dedham, MA 02026 USA • 781-471-1000 • ARCweb.com**]**

Biographies

Unnikrishnan R was born in the year 1976. He holds B.Engg in Electronics and Communication Engineering from Bharathiyar University of Coimbatore, Tamil Nadu. He is having 13 years of Industrial experience in various sectors of automation field. He started carrier as Marine Instrumentation Engineer. He is an Expert in FPSO Instrumentation segment having Expertise in project executions for Offshore and Onshore installation field. At present he is working as Manager – Technical Support responsible for Indian operations of **Pepperl+Fuchs** (India) Pvt Ltd. Pepperl+Fuchs is a leading developer and manufacturer of **electronic sensors and components** for the global automation market. He involves in various Fieldbus seminars, trainings, technology promotion activities across India.

Hazardous area remote I/O with enhanced diagnostics features acc. to NAMUR NE 107

Diagnostics and the correct implementation into DCS and Asset Management systems become more and more important to run plants more effectively and to avoid unplanned shut downs. Specially in hazardous areas, maintenance work is much more difficult and costly than in safe areas so that field devices require a good local diagnostics functionality and simple to use remote diagnostics capabilities. Most modern field instruments already offer a lot of diagnostics – but maybe too much for operators to use it effectively. This is why the NAMUR (International User Association for Automation in Process Industries) has published the NE107 document: “Self-Monitoring and Diagnosis of Field Devices”. A lot of modern fieldbus devices for Foundation fieldbus H1 already have implemented this specification. But also for remote I/O systems – mainly when installed in hazardous areas - this NE107 can be a very effective tool for operators and maintenance staff. A remote I/O normally works quiet in the background but also here diagnostics and alarms are required to inform the staff in time and run the processes without problems.

For this reason modern explosion protected remote I/O systemshavebeen developed that offer a powerful diagnostics solution in combination with new smarter I/O modules. These new I/O modules for hazardous area Zone 1 and Zone 2 installation feature various unique possibilities for alarming and warning messages. Operator and maintenance people expects to get exactly the level of information they need to keep the plant running. Acc. to NE107 this is a few simple status information for the operator like “out of specification” or “maintenance required” - no more details required on this level. While the maintenance people expect to get an indication “where is the failure” and detailed information about the problem and how to fix it. This is what the new remote I/O technology offers. Most flashy is the new blue LED that signals “maintenance required” acc. to NE107 – of course in combination with a diagnostics telegram to the DCS. The new I/O modules can detect external problems like e.g. a too high ambient temperature and they can even evaluate their own expected life time. This feature is extremely helpful for so called pro-active maintenance activities and very useful mainly in an hazardous area environment. Each module monitors its operating conditions like ambient temperature, load etc. and calculates the expected life time with a “maintenance required” warning 12 months before an expected failure. With this, operator and service staff will get the maintenance warning in time and do have the chance now to organize a replacement before an unexpected shut-down happens. More diagnostics for simplified maintenance are available with status LEDs for each single I/O channel to indicate wire breaks, short circuits and discrete I/O status. This makes life much easier for the maintenance team – mainly if working in a hazardous area environment where measurements and tests are much more difficult to perform. Similar to FF H1 the remote I/O now adds a status bit to each process value indicating if the value is good or bad so that the DCS easily can detect failure conditions.

With all these additional diagnostics features, of course all accessible with a DTM in any fdt-capable asset management application, remote I/O systems can be used in process automation plants in a very effective and powerful way – even in hazardous areas.

By André Fritsch, Senior Product Manager Automation - Remote I/O and Fieldbus at R. STAHL Schaltgeräte GmbH

Speaker Profile:

M.R. Kumarasamy is Technical Head – Customer support centre of R. STAHL Pvt. Ltd. After completing his bachelor's degree in ECE, he has a Post Graduate Diploma in Digital Instrumentation from Alagappa University, Tamilnadu with 24 yrs of work experience. He was with MTL / Cooper and gathered professional experience in various explosion protection methods with focus on intrinsic safety. He started working for R. STAHL since 2010 starting with the responsibility for the Automation product ranges of safety barriers and intrinsically safe galvanic isolators RIOs and FF components. He is responsible now for the product ranges of Switch gears, Automation and system solutions of R. STAHL, India.

Besides the topic of intrinsic safety, special knowledge was achieved concerning Foundation Fieldbus acc. to IEC 61158, and associated with major projects like JERP, HPCL, BPCL and IOCL for FF installations. He has attended special training on Hazardous area Display solutions, Advanced physical layer trouble shooting for FF installations and Security solutions for SCADA and Industrial Control Systems.

R. STAHL, www.stahl.de

Abstract – ASME 19.3 TW ; 2010

Thermowells are universally used, very commonly in industrial temperature measurement applications. Thermowells whilst providing suitable protection to the temperature sensors against the harsh and tough process environment, also provides an easy and convenient means of replacing faulty temperature elements / sensors, without having to shut down the process.

Thermowells comes in a variety of shapes, sizes and types.

(i) Tapered, Straight, Stepped

(ii) Bar-stock drilled, fabricated

(iii) Flanged, Welded, Threaded

(iv) Short length, Long length . . etc.

Thermowells are installed in a very wide range of applications; inert to corrosive, stagnant to Mach speed, gas, vapors, steam and liquid applications and everything that comes in between. No matter what are the characteristics of the installation or the type of application, the thermowells are expected to perform the intended function continuously and that too without failure; protects the sensor from the process, while maximizing sensitivity and responsiveness and also provides a suitable means for on-line removal of temperature sensors/ elements for replacements or checking.

The mechanical integrity of a thermowell is of paramount importance to any thermowell installation. Velocity induced vibration, stress, corrosion, erosion and proper installation technique are all factors which must be detailed out and properly considered in the assessment of the suitability of a given thermowell design for specific application.

When this objective of the thermowell is not properly achieved the results can be catastrophic. If you go through the history of thermowell failures, we will come across very many reported cases of highly critical failures of thermowells. Out of the various thermowell failures reported, the most discussed one is the failure in a Nuclear Reactor which happened in Japan in 1995. The Monju Nuclear Power Plant in Japan suffered a liquid sodium leak as a result of a vibration induced thermowell failure, forcing the shutdown of the plant. The plant could only be restarted in 2010, after a very long gap of 15 years, due to the various legalities and other statutory processes involved.

As a result of a number of major failures of thermowells, which have been reported, the industrial fraternity involved in the standard preparation came to a conclusion on the requirement of a major revamp / modification in the existing applicable standard for thermowell design namely PTC 19.3, which was in existence from the year 1975.

As for the history of the thermowell design standard used in the industry; In 1959 J.W. Murdock had published a 14 page paper titled “Power Test Code Thermometer Wells” which established calculations and methodologies for assessing the mechanical strength of thermowells in steam power station practice. In 1974 a slightly modified and condensed four page version of this paper was added to ASME PTC 19.3, Performance Test Codes, Part 3, Temperature Measurement. The simplicity of 19.3 made it easy to apply but left various ambiguities causing marked differences from engineer to engineer in terms of its application. Although the method was originally designed for steam applications of less than 300 fps velocity, its “Pass/Fail” calculation was routinely applied to every conceivable process fluid where velocity was recognized as a concern. In addition, unfortunately, the 19.3 standard only provided a rough evaluation of mechanical integrity of the thermowells.

The 19.3 standard was most recently re-approved in 2004. In 2005 the committee met to discuss substantial revision to the document to address the shortcomings and ambiguities of thermowell design in the old standard. The committee quickly determined that an entirely new standard dedicated entirely to thermowell strength calculations was required. They spent the next five years, deliberating, honing and fine tuning the manner of calculation. In July of 2010 the 19.3TW was issued with an effective date of July12, 2010.

The new ASME/ANSI standard, PTC 19.3TW-2010 (“19.3TW”) was a significantly modified one, following a highly conservative design with respect to its predecessor. The maximum allowable thermowell immersion lengths, based on the new standard can be significantly affected in comparison to the old 19.3 standard. Even though it has been widely accepted and proven that the probability of failure has been greatly reduced for thermowells designed to the new PTC 19.3 TW standard, the complexity required to assess thermowell designs has also increased immensely.

The presentation intends to highlight on the major modifications that have been incorporated into the new standard and also its impact on the design and engineering aspects of the thermowell.

The major changes includes the consideration of Von Karman vortices, the turbulent eddies created as the fluid passes by the thermowell. The PTC 19.3 standard did consider only the transverse vibration and had further simply put a limit of 0.8 on its ratio with the natural frequency of the thermowell. The new PTC 19.3 TW standard takes into account both the transverse and in-line vibrations and the ratio limit was brought down to 0.4 based on the application.

PTC 19.3TW not only changed the required ratio of wake frequency to natural frequency, it also fundamentally changed the manner of calculating natural frequency and revised the calculation of wake frequency. 19.3 attempted to calculate the natural frequency of a thermowell without consideration of the method of installation, the process fluid’s mass or the mass of the installed sensor. 19.3TW addresses each of these factors as each impacts a thermowell’s tendency to vibrate. The standard no longer stops at evaluation of the natural frequency of a well. It addresses the installed natural frequency.

The new standard also covers a condition called “lock-in” for the thermowell when the frequency of the shed vortices approaches the natural frequency. In lock-in condition, the cylinder’s frequency will increase or decrease in order to resonate with the frequency of its vortices. Once resonance is achieved the amplitude of that cylinder’s vibration increases tremendously, risking compromise to the physical integrity of the cylinder itself.

Peak stress occurs at the support plane (root) of a tapered or straight shank thermowell. For a stepped thermowell, peak stress must be evaluated both at the root and at the base of the step. Assessment of stress is another point of fundamental departure between the codes. Whereas the 19.3 simply required that the sum of static and oscillatory stress not to exceed the maximum allowable stress, 19.3TW requires that an independent assessment be performed for both steady state and dynamic (oscillating) stress for all applications where velocities exceed 2.1 fps. Under 19.3TW, steady state stress is defined as the combined effect of hydrostatic fluid pressure and non-oscillating drag on the thermowell. Further the limit of acceptable dynamic stress is temperature de-rated from the maximum fatigue stress amplitude limit at room temperature. Where information is provided an environmental factor can also be introduced to consider effects such as corrosive services using ASME B31.1

Further the new standard PTC 19.3 TW also evaluates the pressure stress separately for the shanks, tip and also requires compliance with ASME 16.5 for the pressure and temperature rating for flanged thermowells.

The presentation attempts to give a very brief insight to the various intricacies of the significantly revamped and improvised design standard for the Thermowell, ASME PTC

19.3 TW 2010. The presentation also tries to capture the complex procedures and steps involved in the evaluation of the thermowell design when required to be in compliance with the new standard, ASME PTC 19.3 TW 2010.

Rejath Jacob Thomas

Has more than 23 years of experience in the field of design, engineering, erection and commissioning for instrumentation and Control Systems. He is presently heading the department of Control System and Instrumentation in TECHNIP – Delhi. He has previously worked with various international consultancies, like, Mott MacDonald, Syntech in locations like Dubai, Abu Dhabi, Bulgaria and Qatar. He started his career with FEDO, FACT Engineering and Design Organisation a public sector undertaking, where he worked for more than 13 years.

Abstract on the presentation

TOPIC : **ASME PTC 19.3 TW – 2010 – Contents of the standard and requirements for design calculation of Thermowells.**

A THERMOWELL employed in a temperature sensor assembly play a vital role in the measurement of temperature.Thermowellsprotect the temperature sensors, and at the same time facilitate the measurement of temperature, being sensed by the thermocouple or RTD housed inside it. It therefore becomes imperative that the reliability of the thermowell is given proper attention, and the ASME Performance test code 19.3 2010 guides us on this very aspect.

It is essential for the end user, or the specifying engineer, or a designer of thermowell to understand the myriad array of forces, and stresses acting on the thermowell, which are determined by the pressure, temperature, density, viscosity and host of other process conditions. The standard covers all such aspects, and helps the designer to 'construct' a thermowell which can withstand various processes and establish a criteria for thermowell reliability.

The presenter is R M Bichu, Director at Pyro Electric Instruments Goa Pvt Ltd.

An Electronics Engineer with a Post-Graduation in Business Administration, he is involved in the sales & marketing of Temperature Sensor assemblies for the last 15 years.

Technical Papers

"Pipeline protection and Fire protection"

Passive Fire Protection for Critical Systems

By Ray Browne and Andrew Bragg from Thermal Designs UK LTD

During this presentation we will be talking about what options you have when specifying passive fire protection and we will give a pictorial account of typical fires in the petrochemical industry and the findings of the Buncefield (UK) fire case study which details its cost and how the fire could be prevented in the future. We give an explanation of the different types of passive fire protection available and we review the history of passive fire protection and how modern technology has radically altered what can now be achieved. There is an explanation of the standards and test carried out so the customers can understand exactly what is being offered and finally we will explain how the end user does not get the best value for money with some types of fire protection.

Passive Fire Protection for Critical Systems:

Fire prevention is possible by following some simple rules; these rules revolve around the fire triangle, keeping the oxygen, fuel and source of ignition away from each other. EPC should design processes which are inherently fire safeby separating these parts but when you are processing fuels which havea low flash pointwith equipmentwhich has the potential to create a source of ignition then the probability isit's not if, but when you have a fire. Fire prevention should always be the first thing to planand passive fire protection should be used in addition to good plant design and equipment.

Passive fire protection limits or mitigates the losses associated with the fire, which include all of the following; loss of life, environmental catastrophes, loss of inventory, continuity of service and then possible litigation. The Buncefield (UK) fire in 2005 cost the owners £894 million, and so much of the damage could have been prevented by the use of passive fire protection, in fact in the UK government's own report(LINK) http://www.hse.gov.uk/comah/buncefield/bstgfinalreport.pdfhighlights the need to evaluate the effects of fire on emergency shut off valves and procedures for the safe shut down of processes. Following this report the UK health and safety (HSE) wrote a paper on remotely operated safety shut off valves. (ROSOV's) which can be downloaded from the following link, http://www.hse.gov.uk/pubns/priced/hsg244.pdffor more information

Fire protection has been around for thousands of years, the Romans used it in the designs of their villas, and they were one of the first to use concrete (made from volcanic ash) to act as fire barriers. Their designs took into account the same ethos we use today: separate fire from fuel, use of non-combustible materials to prevent the spread of fire and having more than one means of escape. This philosophy while still relevant today has since in the until early 1900's improved upon with the invention of Intumescent epoxies, which have only been used for protection of critical equipment for the last 25years.

Prior to this point we had to use insulative products like blankets and fire boxes which use the same technology as the Romans used;non-combustible materials and add air gaps to prevent the transfer of heat. These products have major limitations which should make them the last choice when selecting passive fire protection namely:

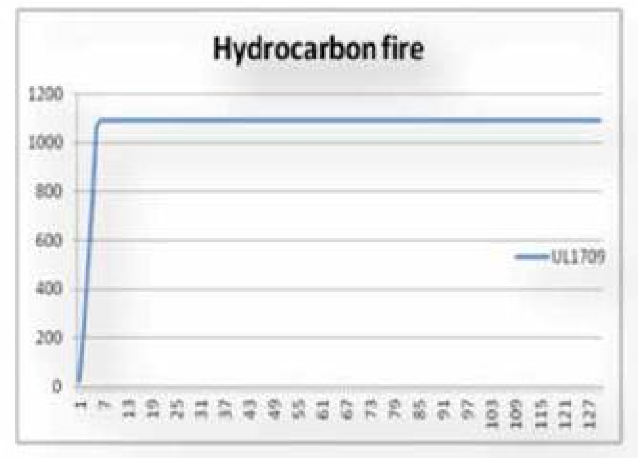
- They are difficult to fit correctly.
- They can store gases or liquids between the cover and the pieces of equipment creating zone 0/1 areas during maintenance.
- They cover vital flame paths on explosion proof equipment rendering the certification invalid (BS EN60079-14:2008) and can create a source of ignition (not ideal with the point made above).
- They cover equipment hiding possible corrosion, which is made worse by not allowing proper ventilation to help spills evaporate.
- And they are not people proof, the fire protection can be left off and doors can remain open all of which defeat the point of the fire protection.

Directly bonded intumescent passive fire protection is completely different as it has none of these drawbacks! Not one.

Directly bondedIntumescents only became available 25 years ago with the introduction of Thermal Design's K-Mass®, and this was only possible because of thework done by NASA for the protection of the Apollo space missions. However now we have two distinct sources (industries) for Intumescent materials:

1. Steel work protection. e.g.Chartex, which was designed to protect steel work structures from failure during a fire. The reactive temperature window is normally the max ambient temperature until the failure point of the steel and this typically is 65°C to 400°C the chemical reaction has to be fast enough in 30 mins to prevent a temperature rise of 335°C.
2. Space industry (NASA) e.g.K-Mass® was designed with the help of AMES research centre to operate in outer space BBT of 3 Kelvin or -270°C to re-entry temperatures which was in excess of 2700°C and still protect the astronauts inside the capsule at less than 30°C.

These intumescents are very different in their fire protection properties, and should not be confused. As the failure point of most critical systems is no more than 110°C and the hottest ambient temperature is 80°C it gives an operating window of 80°C to 110°C. For intumescents like K-Mass® which is derived from the NASA product this is no problem as it's higher specification easily copes with this requirement. However intumescents which are derived from steel work protection need to be adapted (not very successfully in some cases)to cope with the tougherrequirements.The only perfectly suitable product is the technically advanced products with its pedigree from the space industry.



Fire protection standardsfor Hydrocarbon processing

The American Petroleum institute (API) 2218 standard which details good practice for fire protection of Hydrocarbon processing plants, looks at fire zones, structural integrity of the fabric of the plant and lays out very nicely protection time scales and how to calculate them. However API 2218 does notsay much about relatively new concepts like ROSOV's and actuation which now requires some more attention. As API 2218 already makes reference to the UL1709 (rapid rise hydrocarbon fire test) the industry adopted it as a catch all standard.

The UL1709 standard was adopted because it has the fastest temperature rise coupled with one of the highest heat fluxes (outside Jet fire) but more importantly it stated that the item must remain operable. "Must remain operable" means that any equipment which is tested using this specification has to be operated during the test, which makes this a real world functional test. As a minimum all K-Mass® protected equipment is tested to 30minutes and in some cases considerably more.

One of the big problems with the hydrocarbon industry is the long purchase andspecification chain; things get diluted or even changed from the end-users initial decisions. These changes are normally instigated not by the end users but by companies in the chain to better suit them (not the end-user)and are to reduce the cost to get lesser types of fire protection approved. This will end up costing the end-user more money and reducing the effectiveness of the fire protection. We have shown that apparent cost reductions of $755 will end up costing $5,685 over the life of the expected life of the actuator. These extra costs are associated with additional maintenance (refitted),replacement due to life expectancy, shipping and fitting, cost which are notnecessary with directly bonded intumescent coatings.

In summary:

When choosing passive fire protection it's not about does it meet the required standard anymore. Making sure the fire protection is inherently safe and robust becomes a factor that can directly affect cost function and serviceability onsite.Intumescent coating of critical equipment, like ESD's ROSOV's and instrumentation has the technical edge my some margin. Which is why most end-users specify it for new installations, yet because of long convoluted purchasing chains they rarely get what they asked for.

Passive Fire Protection of Critical Safety Equipment and Instrumentation

Robert Pitman, Darchem Engineering

Synopsis

Passive Fire Protection (PFP) solutions are designed and installed for protection of critical process equipment and instrumentation from fire scenarios on offshore and onshore oil & gas installations. In line with the Operator's own fire protection philosophy, installed PFP systems must confirm to international standards for testing and certification; take into account the potential plant fire scenarios; the limiting temperatures of critical equipment; and the considerations of day-to-day plant operations.

'Passive Fire Protection' defined

Passive Fire Protection (commonly abbreviated to the acronym PFP) is defined as a coating, jacketing, or other enclosure typesystem that, in the event of a fire, will provide thermal protection to restrict the rate at which heat is transmitted to the object or area being protected. PFP systems are used to:

- Prevent fire escalation due to continuing release of hydrocarbon inventory.
- Protect critical safety systems such as separators, risers and topside emergency shut down valves (ESDVs), actuators, pipe work, and vessels where failure in a fire cannot be tolerated.
- Minimize damage to structural elements, especially those that support refuge or escape of personnel; or surround critical production equipment.
- Allow safe evacuation of personnel

PFP specifications require that "Equipment shall be protected against a 'fire type' for a period of 'x' minutes". This means that the PFP system will provide fire resistance to ensure the protected equipment remains below its limiting temperature during the specified period, taking into account the type and size of fire. PFP must also be designed and installed to withstand deformation caused by any initial explosion.In contrast to Active Fire Protection (such as fire detection, water deluge and gas suppression), PFP systems require no human, mechanical or electrical interaction to perform their task. PFP is often employed where active systems are impractical, unreliable, or have a delayed response.

Firetypes

There are two main fire scenarios referred to in the oil and gas sector. Hydrocarbon Pool Fire, the common reference standards being UL1709, or BS476; and Hydrocarbon Jet Fire, the main standard for which is ISO 22899-1 and OTI95-634. Typically a failure or leak that may lead to a fire is associated with pipework, flanges, and small-bore fittings. Full bore failure may result from a failed bolted joint engulfed by fire or damaged from an initial explosion; or a pipe burst due to pressure increases and structural weakening from the fire.

Hydrocarbon Pool fires typically occur from an ignited spill of flammable liquids. Following a major leak, engulfment of pipework, vessels, and storage tanks will potentially lead to a quick spread to neighbouring plant equipment via heat radiation or flame impingement. A Pool Fire however is generally limited to the duration of release of inventory. Hence a protection period is important for the period of time necessary to enact a controlled shutdown of the associated plant preventing further hydrocarbon release. PFP systems are most commonly designed for fire protection periods from 15 (H15) to 60 minutes (H60) and temperatures up to 1,100°C.

Jet fires, mainly a consideration for offshore operations, occur upon ignition of pressurised inventory; and characteristics are determined by release rate and mass of the inventory. Jet fires are highly directional, and hence flame impingement depends on geometry of release and the nature of obstructions by equipment, pipework and structures in an often very crowded platform or FPSO environment. Jet fires can also lead to Pool fires as flame spread and heat radiation affects the surrounding plant. Due to the remote and isolated nature of offshore structures, and the need to allow time for evacuation of personnel, Jet fire specifications can demand fire protection from 30 (J30) to up to 120 minutes (J120). Jet fire PFP solutions must also be able to withstand the strong eroding force of the Jet fire as well as resist the higher temperatures within the region of 1,200°C.

During a new-build project FEED or detailed engineering stage; it is the job of Project Engineers or specialist fire consultant to model and determine the fire zones that may be affected by direct flame impingement or flame splash, when considering the specifications and extent of installation of PFP systems.

Defining PFP scope and specifications

The level of protection required must be determined by a 'needs analysis' examining the factors relating to the potential severity and duration of exposure of equipment in a fire scenario. Factors not only include the probability of an incident, availability of active fire protection, the intrinsic and production value of equipment, but also social, environment and personnel impacts. The results of the analysis (often with the assistance of sophisticated computer fire effects modelling) will outline a fire specification (type and period) as well a scope of equipment to be protected.

Equipment	UL1709 Pool fire considerations
Emergency valves and actuators	• 30 minutes – to allow time for valve motor operator to fully open and close. • Actuators will lose functionality within minutes of fire engulfment – limiting temps determined by internal cabling & instrumentation • Actuator limiting temps range from 70 to 150°C. • Valve limiting temps range from 200 to 400°C
Pipework, flanges and bolted connections	• Loss of tightness of unprotected bolted connections leading to potential leaks. • 30 to 60 minutes protection against limiting temps of 200 to 400°C
Critical Control systems, Electrical Power, and Instrument cables	• 15 to 30 minutes protection – especially for systems used to control emergency systems (shut-down, isolation, depressurisation, etc.) • Operating limits around 150°C.
LPG vessels	• 90 minutes protection.

Types of Passive Fire Protection enclosures

There are many types of PFP materials available in the market, as well as many local and international suppliers. However there are only a few suppliers with genuine appropriate certification from international agencies such as Lloyds Register, DNV or ABS. Options available for critical safety equipment and instrumentation can be categorisedinto the following groups shown in Table 2:

Table 2 – Types of PFP solutions for process equipment and instrumentation

PFP type	Description	Advantages	Disadvantages
Flexible jacket / blanket / wrap around systems	Endothermic fibre materials encased in weatherproof vinyl cloths. Jacket panels fastened together by either SS316 lacing, Belts and Buckles, or Velcro.	• Flexibility to protect all equipment types • From H15 to J180 fire periods • Withstand high process temperatures • Good accessibility or removal for inspection and maintenance • Low maintenance • Low cost • Durable and weather resistant	• Susceptible to water or moisture ingress - which can open up gaps in panels if not properly fastened • Rely on plant operator diligence for removal and refitting to ensure integrity is retained
Composite enclosures and casings	Enclosures made out of epoxy intumescent, phenolic or ceramic insulation layers, with protective outer gelcoat and ablative coating.	• Can be designed to protect most types of equipment, subject to space constraints at site • H15 to J60 protection • No maintenance • Good accessibility • Durable and weather resistant	• Expensive for one-off designs • Limitations for use with high process temperatures or steam environments • Potentially large space envelope • Difficult to modify/repair at site • Limitations to J30; and not properly tested for low limiting temperatures under such conditions
Stainless steel fireboxes	Endothermic fibre materials encased in SS316 outer skins.	• Can be designed to protect most types of equipment, subject to space constraints at site • H15 to J120 protection • No maintenance • Good accessibility • Durable and weather resistant	• Weight considerations • Large space envelopes • Cost of materials
Coating materials	Epoxy intumescent coating applied directly to the equipment, i.e. actuator or valve.	• Aesthetic appeal of 'integral solution' • Accessibility • Durable and weather resistant	• Solution better designed for structural elements with large flat surface areas • Limitations for use with high process temperatures or steam environments • Difficult to modify or repair at site • Limitations to H30 or J30; and not properly tested for low limiting temperatures under such conditions • Long lead times for coating of equipment at suppliers location

Figure 1 – Examples of PFP type installations

The importance of PFP systems Testing and Certification

Notable international certification agencies such as Lloyds Register, DNV and ABS will conduct Fire Resistance Tests of PFP systems to recognised standards such as the UL1709 fire curve for Pool fires and ISO 22899-1 for Jet fires. However, these standards refer to the testing of structural steel, and not specifically for process equipment or instrumentation. Fire tests have a pass/fail criterion of maximum temperature that any thermocouple attached to steel plate (whether a planar or tubular test specimen) must not exceed 400°C for the defined period of the fire test.

Thereforeit should not be acceptable for a PFP supplier to simply say that their proposed solution meets with the requirements of UL1709, ISO 22899-1 etc. For example, the failure temperature (or maximum permitted temperature) for actuators (which can range from 70 to 150°C when considering PFP for electrical or pneumatic actuators) is much lower than the fire test criteria for steel plate specimens at 400°C – see figure 2.

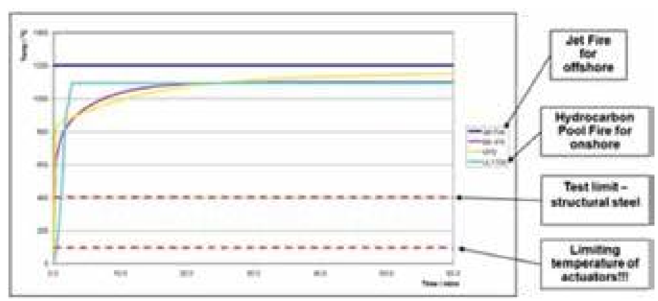


Figure 2 – International fire curves

When sourcing Passive Fire Protection, it is essential that end-users demand that PFP suppliers demonstrate that:

- A Type Approval certificate from a recognised agency is available for the proposed PFP solution.
- The correct thickness of the PFP system is calculated for each and every item to be protected – i.e. how are process and ambient temperatures, equipment mass and heated surface areas, taken into account when calculating PFP thickness? Such PFP designs and calculations should also becertified by Lloyds etc.

Before allowing commissioning and start-up of a new plant, a Fire or Safety Officer should be able to inspect and approve documentation not only showing a legitimate fire certificate from a recognised international agency, but also showing that the PFP installed is genuinely 'fit-for-purpose'.

Speaker profile

Robert Pitman is the Business Development Manager within the Oil & Gas sector for Darchem Engineering, a UK engineering and manufacturing company solving customer insulation, fire protection, and heat shielding requirements in the Aerospace, Automotive, Marine, Nuclear, Oil & Gas and Power sectors.

Robert is a graduate in Engineering & Management from Durham University in the UK, and as well as 4 years' experience with Darchem in fire protection, he has worked with other companies supplying to the Oil & Gas sector, including in India, since 1997.

References

1. API RP 2218 – Fireproofing Practises in Petroleum and Petrochemical Processing Plants
2. FABIG UK Technical Note 8 – Protection of Piping Systems subject to Fires and Explosions
3. ISO 13702:1999 – Control and mitigation of fires and explosions on offshore production installations

Modeling Corrosion Integrity of Natural Gas Pipelines using NACE Standards

Amitabh Chaturvedi
Manager - Corrosion Solutions, Honeywell APAC and Middle East
Honeywell Process Solutions
56 & 57, Hadapsar Industrial Estate, Pune – 411013

Internal Corrosion Direct Assessment (ICDA) is a process used to evaluate pipeline integrity by identifying locations along the pipeline where internal corrosion damage is most likely to occur. Liquid Petroleum Internal Corrosion Direct Assessment (LP-ICDA) is designed to address pipelines that are fully packed with a liquid phase whereas Wet Gas Internal Corrosion Direct Assessment (WG-ICDA) is being targeted towards wet gas pipelines much like Dry Gas ICDA (DG-ICDA) has been developed to address normally dry gas transmission pipelines. The four step ICDA process requires integration of pre-assessment, indirect inspection data and detailed examination data to determine overall pipeline integrity. The prioritization of critical locations along a pipeline forms a major part of this process and includes modeling of flow, predictions of flow-regime, characterization of environment and development of pipeline profile that identifies critical locations that are most susceptible to internal corrosion.

DG-ICDA focuses on identifying critical segments which have great likelihood of water accumulation and thereby possibility of corrosion. It is applicable to natural gas pipelines that normally carry dry gas, but may suffer from infrequent, short-term upsets of liquid water (or other electrolyte). DG-ICDA standards are released as NACE (National Association of Corrosion Engineers) DG-ICDA SP0206 – 2006.

On the other hand, WG-ICDA is mainly related to selection of final assessment sites from preselected sites as a function of subregion, liquid holdup and wall loss percentage. Due to varied geospatial routing of wet gas pipelines–especially of pipelines that are routed underground and where pigging or other hydrostatic tests are not possible–operators face significant challenges in characterizing corrosion integrity. WG-ICDA standards are released as NACE WG-ICDA SP0110 – 2010.

Honeywell recently developed a software model that uses both DG-ICDA and WG-ICDA guidelines provided by NACE and assists pipeline operators in understanding corrosion integrity of their pipelines in better way.

Keywords:

Internal corrosion direct assessment, dry gas, wet gas, ICDA, critical segments, critical angle, water accumulation, flow regimes, sub-regions, liquid holdup, wall loss, water accumulation, pre-assessment, indirect inspection, NACE SP0110, NACE SP0206 – 2006, corrosion, WG-ICDA, DG-ICDA, pipeline integrity.

Speaker Profile:

Mr. Amitabh Chaturvedi currently serves as Manager – APAC, ME at Honeywell for its Corrosion Solutions business and works out of Pune. In his current role, Mr Chaturvedi oversees the development of various corrosion prediction software models and related software solutions, and is also responsible for Business Development in Asia Pacific and Middle-East markets for Honeywell's Corrosion Solutions portfolio of products, solutions and services that include corrosion monitoring, corrosion prediction & material selection software, corrosion research and consulting services, and comprehensive Asset Integrity Solutions.

Mr. Chaturvedi's key responsibilities at Honeywell include development and enhancement of various industry-leading corrosion prediction software tools by working with Honeywell's global corrosion research team and by understanding the voice of customers, and creating value for customers by conceptualizing and proposing holistic Corrosion and Asset Integrity Solutions to solve their problems - latter activity includes opportunity analyses and development of customized corrosion management strategy as per customer's requirements by integrating various models and corrosion monitoring with other advanced applications.

Mr. Chaturvedi has also represented Honeywell's leadership in corrosion business by participating and presenting papers at national and international conferences and has provided solutions to various global customers.

During his career spanning over 13 years, Mr. Chaturvedi has assumed various roles of increasing responsibility right from working as a Project Engineer for Chemical Engineering consultancy to design & development of number of software applications for various O&G verticals before moving to the current business role.

Presentation on Leak Detection & Location Systems

If your business involves the transportation, storage,processing or consumption of hazardous fluids, thepossibility of a leak must be considered. Whether your concern is gasoline, jet fuel, diesel,crude oil, acids, bases, contaminated water or anyother hazardous liquid, aleak detection system tailored to your needs is now available.

The leak detection systems can detect andpinpoint the source of a leak to help you takedecisive action long before the spill can ruinyour reputation.

Leak Detection offers a unique solution to leak detection & location systems. There are different types of cable technologies available.

1. Thick Wall / Cable Technology

Fuel sensing cable is designed to react to liquid hydrocarbon fuels.The entire length of the cable is sensitive to the presence of hydrocarbons. Figure 1 illustrates thebasic construction of the cable. The core of the cable is composed of a bundle of wires formed

into a spiral construction. Two of the wires are electrodes. The two electrodes have a metalconductor core and a jacket of conductive polymer. The electrodes wires are on opposite sides ofthe spiral bundle of wires and do not touch each other. They are somewhat smaller than the otherwires in the core bundle.

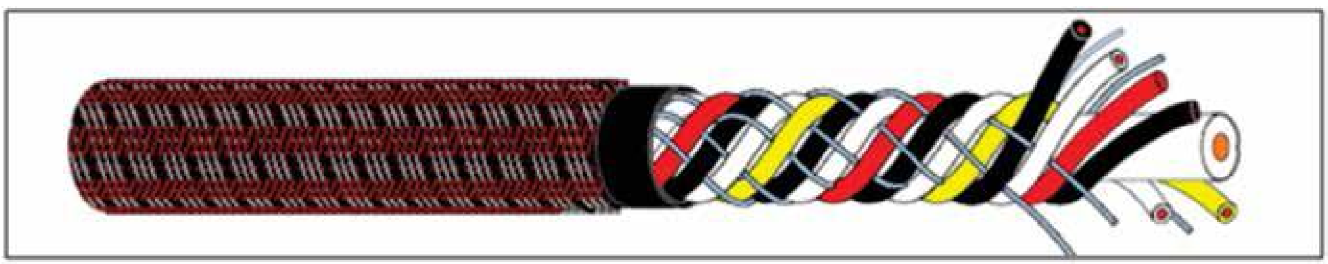


Fig 1.

A tubular jacket of conductive, rubbery polymer is extruded over the top of the wire bundle.Since, the electrode wires are slightly smaller than their neighbors in the core bundle, undernormal conditions (no leak) the electrodes do not touch each other nor do they touch the innerwall of the rubbery tube. Figure 2 illustrates this principle. In this condition there is no electricalpath from one electrode wire to the other. The monitoring instrument is constantly checking forany conductivity between the two electrodes. An "open circuit between the two electrodes is anindication that the cable has not been exposed to hydrocarbons.

Should a liquid hydrocarbon come into contact with the cable, a very small amount of the

spilled liquid will be absorbed into the rubbery tube,

Figure 2: TT5000 sensor cable cross section

causing it to swell. After sufficient fuel (lessthan a milliliter) has been absorbed into the rubbery tube, it will have thickened enough to comeinto contact with the two electrode wires in the core of the cable. Figure 3 illustrates the conditionof the sensor cable

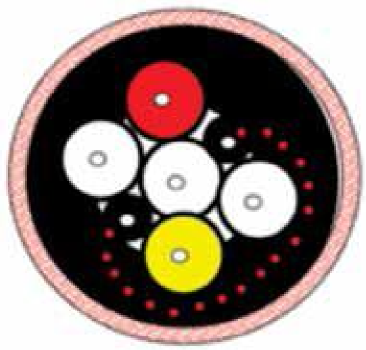


Figure 3: TT5000 cross section after detecting fuel

after a fuel leak has been absorbed into the rubbery tube. At the momentwhen contact between the jackets with the two electrodes occurs, an electrical pathway exists fromone electrode wire, through the conductive material in the rubbery tube, to the other electrodewire. The monitoring instrument detects the sudden drop in resistance between the two electrodes and reports that a leak has been detected. (This whole process is very similar toclosing a switch that has been connected across the two electrodes.) Once a leak has beendetected, the circuitry in the monitoring instrument has been designed to measure the distancealong the sensor cable to the point of leak detection.

Typical application for a buried pipeline

2. Thin Film Carbon/Polymer Technology

In this technologythe fuel probe is designed to react to liquid hydrocarbon fuels. The entire

height of the probe is sensitive to the presence of hydrocarbons. Figure 4 illustrates the basic

construction of the probe. The core of the probe is composed of a circuit board. A conductive

polymer has been sprayed on each side of this circuit board. The two conductive sides are

connected at the bottom of the circuit board.

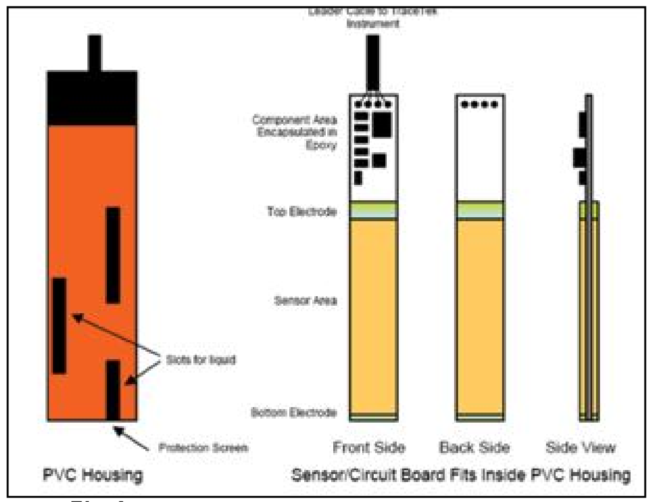


Fig 4.

Under normal conditions (no leak) the resistance path through sensor material is low. The monitoring instrument is constantly checking the resistance of the polymer. No resistance variation is an indication that the cable has not been exposed to hydrocarbons. Figure 5 illustrates this principle.

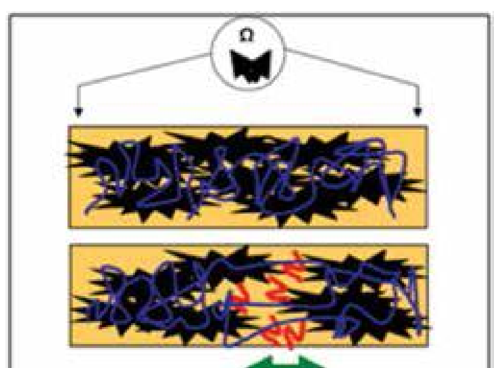


Figure 5: TT-FFS sensor section before and after detection

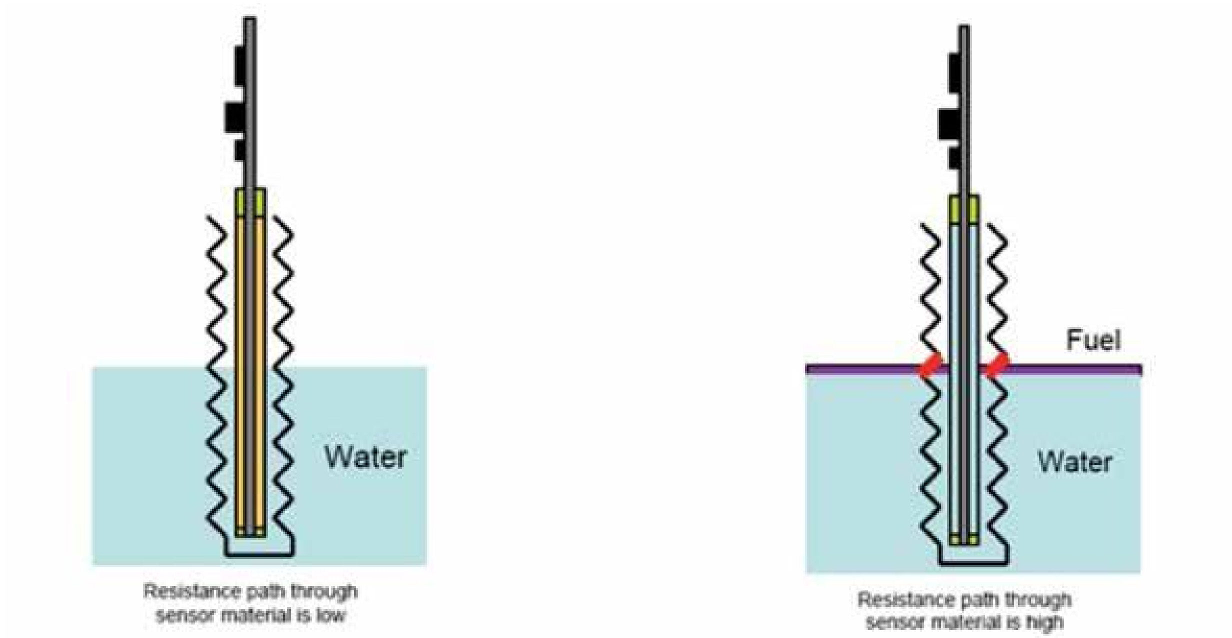
Should a liquid hydrocarbon come into contact with the probe, a very small amount of the

spilled liquid will be absorbed into the carbon enriched polymer, causing it to swell.

After sufficient fuel (less than a milliliter) has been absorbed into the polymer, liquid hydrocarbonscause micro swelling in polymer film at point of contact. Resistance through carbon particlesincreases dramatically.

Figure 5 illustrates the condition of the sensor cable after a fuel leak has been absorbed into

the polymer. The monitoring instrument detects the sudden increase in polymer resistance andreports that a leak has been detected. In most cases, the probe will reset when removed fromcontact of the spill and the fuel is allowed to evaporate. Reaction time is typically less than a fewseconds for light or middle weight fuels such as gasoline, jet fuel, and diesel. It is also responsiveto crude oil and some heavier weight fuels and heating oil, but becomes progressively slower asthe fuel viscosity increases and the volatility decreases.



Images show typical application in bunds around large above ground storage tanks

A Leak Detection System consists of Sensor Cable, Sensor Interface Modules and Alarm Panels. Additional sensor options include: float switches, point probes, pressure switches or any other sensor device that can provide a contact closure.

Instrumentation options includelow voltage / relay contact devices, instruments for hazardous locations, battery powered flashing light indicators, and other options tailored to the application.

Certifications, Approvals and Listings

Leak Detection products and systems have been tested, reviewed and approved by a variety of organizationsand agencies. Our sensors have been tested by Carnegie Mellon University, Wilcox Associates and othersin addition to our own testing. Some of the resulting approvals are described below.

National Workgroup for Leak Detection Evaluation (NWGLDE)

In 1995 sensor was tested in accordance with the NWGLDE standards and subsequentlyobtained an NWGLDE listing. The NWGLDE is an organization principally made up of state and nationalenvironmental regulators in the US. Many state and local authorities within the US use the listing as ameans of ensuring that leak detection systems are qualified for their intended use.

Florida State Department of Environmental Protection

The external fuel leak detection system for single wall pipes was evaluated by theFlorida State Department of Environmental Protection (DEP) as an alternative to double contained pipingfor fuel pipelines. A series of tests were performed by an independent third party laboratory todemonstrate the performance of the system under a variety of soil conditions. The DEP found that theleak detection system for single-walled underground bulk product piping will provideenvironmental protection substantially equivalent to that provided by compliance with therequirements…" The DEP approval and the third party test report are included in the appendices.

UL, CSA, TUV and VDE

Leak Detection modules and systems are listed with one or more of these agencies (agency listings vary byproduct). Systems are approved for use in hazardous areas, and some of the systems areapproved for use in plenums.

Baseefa Approval

Discrete Fuel sensors has been approved by Baseefa for equipment or protection system for use in potentially explosive atmospheres directive 94/9/EC the EC certificate is Baseefa11ATEX0221X

PESO/CCoE Approval

Discrete Fuel sensors has been approved by Indian organizations CCoE/PESO for use in Zone 1, gas group IIA/IIB/IIC hazardous areas.

Speaker Profile:

Name	**Mohit Agarwal**
Designation	TraceTek Regional Sales Manager – India & Middle East
Organisation	PENTAIR THERMAL MANAGEMENT
Telephone	+91-120-4649500/4129444
Mobile	+91-9971797253
email	mohit.agarwal@pentair.com
Qualification	BE (Electronics) & MBA

Mohit Agarwal has spent over 5 years in the leak detection business in the Middle East & Indian market.

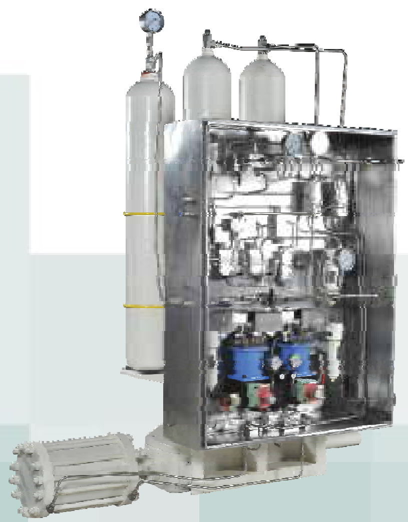
Started his career withTyco Fire & Security where he worked for 2 years dealing with various Fire & Security products. He also worked for over 5 Years in Bosch Security Systems

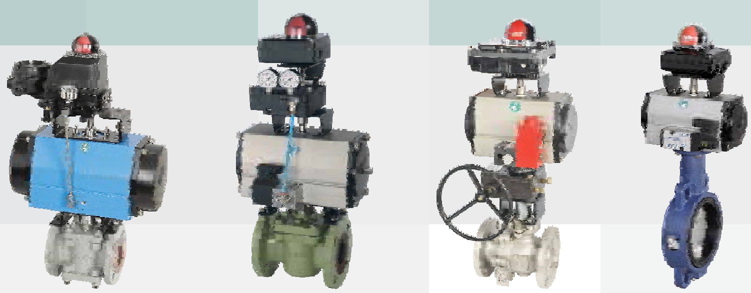
He travels extensively in Middle East to understand customer needs & provide technical solutions for leak detection. In his present role he is responsible for sustainable growth of TraceTek leak detection systems in the region. Last 5 years he has been leading the TraceTek business in the role ofRegional Sales Manager for India/Middle East Region and was successfulin building and growing the leak detection system business in Middle East.He and Team were involved with the following projects:

- EMAL SMELTER – UAE
- ADCOP UAE (10 Tanks)
- TAKREER REFINERY – MUSSAFA TANK FARM
- TAKREER REFINERY – RUWAIS TANK FARM
- ABUDHABI AIRPORT
- UAE MILLITARY TANK STORAGE AND PIPELINE PROJECTS (10 sites)
- NEW DOHA INTERNATIONAL AIRPORT
- NAVAL BASE FUJERIAH – UAE
- HELIPAD – QURNYAN ISLAND
- SIPCHEM – SAUDI ARABIA
- JET REFUEL OIL PROJECT - Al-Medinah Al-Munawarah City - SAUDI
- ONSITE ENEGRY DIESEL LEAK DETECTION – MUSCAT OMAN

Valve Automation Systems

- ECF / EECV / SSF Double Rack & Pinion Actuators
- DRS High Performance Scotch yoke Actuators
- DRV heavy duty Rack & Pinion Actuators
- HYV Hydraulic Actuator range
- Actuators with Fire Box/ Fire blanketing
- Gas operated Actuators, Control panels etc. for Pipeline valves
- ON OFF & Control valves including Ball valve, Butterfly valves & Plug valves





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For more information about

ISA-Delhi & PNID

ISA Delhi Section, B-45, Sector-8, Noida-201301, Tele-FAX: +91-11-41759416

Please visit: **www.isadelhi.in**, Email: **isadelhi.org@gmail.com**

RAJIV GUPTA (Program Convener) Cell: +91-9818341262

Help Desk – **Ashish Manchanda** (+91-9350043430), **Radheyshyam Tiwari** (+91-9313384543)