communication interfaces has become very common & the slogan "Field to Boardroom" has become the buzzword today. Can the advancements lead to a situation of true inter-operability in DCS? Let us examine in detail.

2.0. A TYPICAL DCS/PLC NETWORK IN A POWER PLANT

A typical DCS consists of Control system in which the interlock, protections & sequences (OLCS) & modulating controls (CLCS) are implemented and the HMI (Human Machine Interface) through which drive/sequence operations, plant monitoring, historical event & trend analysis etc. is carried out. An overview of the same is given in Figure 1.

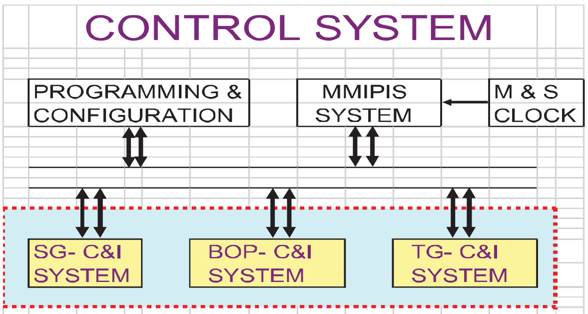


Figure - 1 Typical DCS

In present day scenario, in a DCS, the HMI & the control system are tightly coupled with proprietary interfaces, with the result that HMI of one DCS cannot usually work with the control system of another DCS, unless special interfaces are developed by both the DCS suppliers.

3.0. PACKAGING CONCEPT IN POWER PLANT:

The number of contracting packages for a power plant depends on various considerations; some of these being Cost, Engineering (which includes interfacing requirements), and Vendor base.

The control system (DCS or PLC) for the equipment being supplied under a package is either a part of the package or procured separately, either in part or whole. This has led to various packaging philosophies, for main plant as detailed below:

a) Main plant turnkey where the entire main plant equipment (SG, TG and main plant auxiliaries) is procured under a single package
b) SG-TG: where SG equipment is procured under SG package and TG equipment under TG package. In this case, one DCS is there for integral controls of SG equipment in SG package, another DCS for the integral controls of TG equipment in TG package. For the balance of plant controls of main plant, a separate Station C&I package is provided.

At present we will confine the treatment to SG-TG at b) where three different DCS are provided for main plant controls, each with its own HMI. As a result, the operator in the main plant control room has to operate the plant from three different HMIs. A typical arrangement of screens in such an arrangement is depicted in Figure 2.

SG DCS HMI BOP DCS HMI TG DCS HMI

Figure 2 - Operating screens in a SG TG packaging concept in a power plant

Another variant of b) is that within a package itself, there are two control systems, E.g. TG package where TG integral controls are implemented in the DCS of the TG OEM & balance of plants controls of TG package in another DCS. This aggravates the situation leading to as many as four different HMIs in the unit control room.

4.0. NEED FOR UNIFIED HMI:

Different HMIs in the unit control room means different set of faceplates, different look of graphics, different tools & GUI for HMI functions like trend, logs, trip analysis etc., and different views of alarms/events.

This also leads to a situation where operation of any area of the main plant cannot be done from any workstation or LVS. It has to be done from the workstation/LVS earmarked for a particular area. This eventually leads to increase in number of screens & also to a certain extent, increase in number of operators.

This is tantamount to something pointed out by an Operations personnel in some meet - “A Car with multiple steering”.

Having a single HMI increases ease of operation especially during plant disturbances, thereby providing intangible benefits.

5.0. STRATEGIES FOR HMI UNIFICATION:

A) Single DCS for the main plant:

A single DCS for the entire main plant automatically ensures that the HMI also is single. This can be achieved either through a single main plant EPC package with a single DCS for entire package, or separating out the controls of the main equipment in a separate package. The latter is not generally achieved especially in case of turbine integral controls.

B) DCS Inter-Operability:

The strategy here is to overcome the constraints of packaging philosophy by having a single HMI in multiple DCS situations through DCS inter-operability i.e. to have communication links between the two DCS through which the drives of one DCS is operated from the HMI of another DCS.

6.0. DCS INTER-OPERABILITY SCENARIOS:

Considering that one DCS (Master DCS) has to operate another DCS (Slave DCS), some scenarios are described below, & depicted pictorially in Figure-3A-3D.

Scenario A: The control system of Slave DCS is interfaced with the HMI of Master DCS, through a gateway interface, specifically developed for the purpose. Obviously, this solution is not standard, and needs to be developed for every combination of Master & Slave. Above all, it involves a great deal of effort on the part of developers of both the DCS.

Figure 3A - Scenario A

Scenario B: The HMI of Slave DCS is interfaced with the HMI of Master DCS, typically through OPC, for transfer of signals including operation command & feedbacks. The HMI of Master DCS apart from having the database of drives of Master DCS, has also the database of drives of Slave DCS.

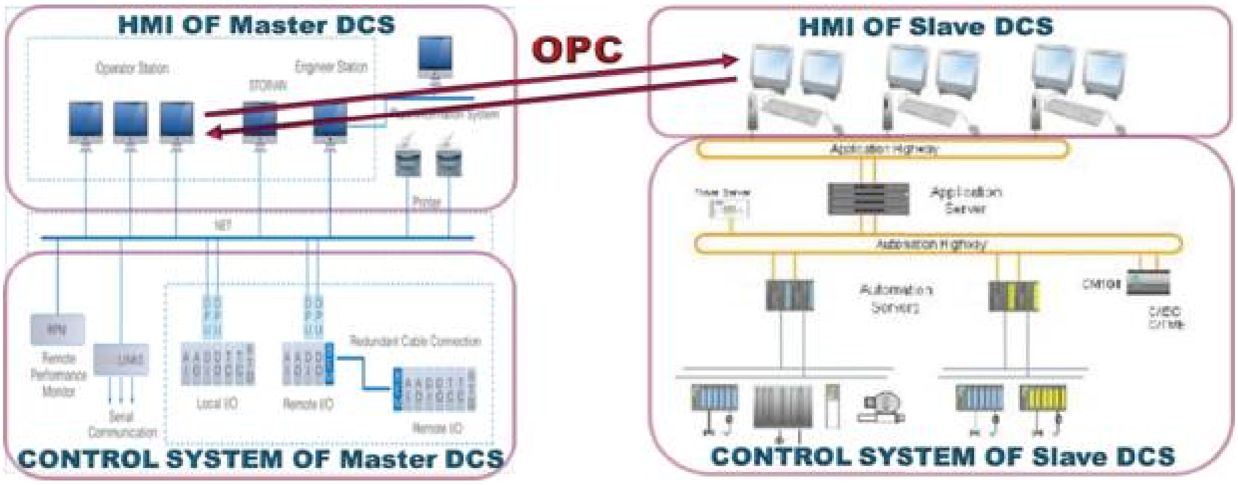


Figure 3B - Scenario B

Scenario C: The control system of Slave DCS is interfaced with the control system of Master DCS for transfer of signals including operation command & feedbacks through typically MODBUS TCP/IP protocol.

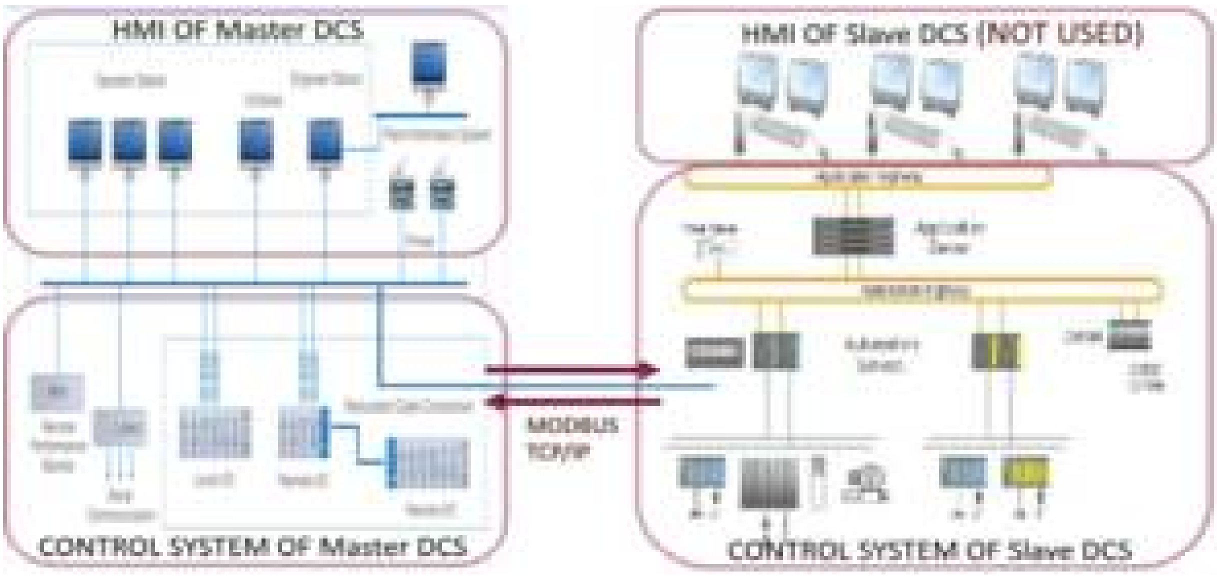


Figure 3C - Scenario C

Scenario A is always very specific for the combination of Master & Slave DCS & also involves huge efforts for development of a proprietary interface between the DCS. Hence, this option was not further explored.

Scenario B can be used if the OPC implementation can guarantee a deterministic response time or the timings are not very demanding e.g. for supervisory commands, say initiation of drive command sequences. For direct drive operation, especially for critical drives, where latency cannot be tolerated, this will not be a right solution.

Scenario C uses typically MODBUS TCP/IP protocol to transfer signals between Master DCS & Slave DCS. The entire signals (analog & binary) & the drive signals of Slave DCS are mapped in the Master DCS. The sizing of database of Master DCS takes into account this aspect. Due to its deterministic timings, real time command response times can be achieved in this scenario & hence quite suited for the power plant controls. Another advantage with this scenario is for extremely critical controls like Turbine Governing, the signal exchange for command & feedback between Master DCS & Slave DCS can be implemented using hardwiring; the 'Good Old' 4-20 mA signals used typically for sending commands from Feed water controls to TDBFP speed controls or from Combustion controls to Feeder controls.

All the above merits with Scenario C makes the realization of Unified HMI pragmatic and do-able. The implementation in intra package and inter package scenarios also use this scheme.

Another variant is the case of Scenario D where both Master & Slave DCS are operated from a separate independent HMI under a HMI package. In this case, all the drives of both DCS have to be operated from a HMI different from its native HMI. In Scenario C, at least the drives of Master DCS, the operation is from its native HMI, which is the preferred scenario. Due to this, scenario D is not further explored.

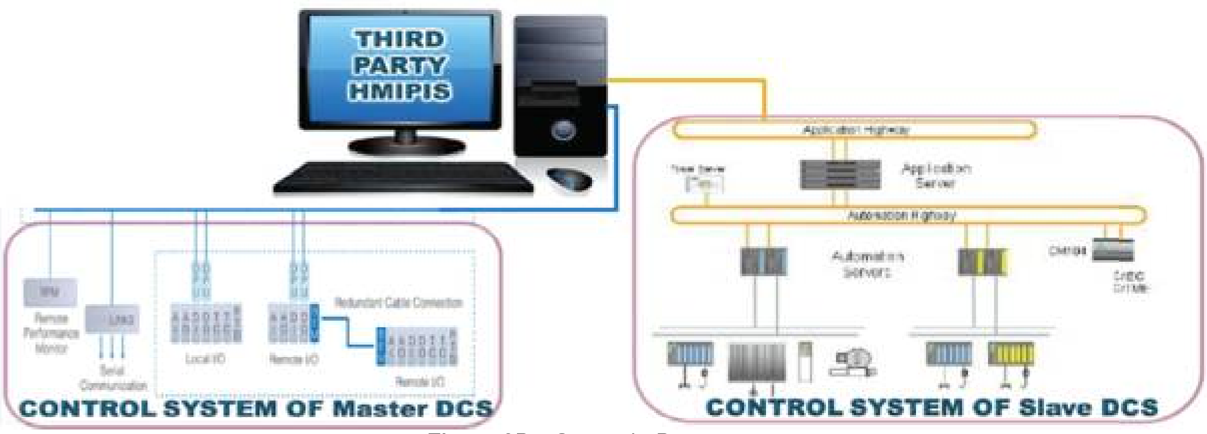


Figure 3D - Scenario D

7.0. INTRA PACKAGE UNIFIED HMI:

As pointed out at 3.0 above, sometimes, TG package within itself has two DCS, one for TG integral controls & other for balance controls, leading to a situation of two different HMI for operating the drives of TG package in the control room. While a single DCS could not be specified, requirement of a single unified HMI was specified in such situations in the tender specifications from Mauda-II TG package onwards, i.e. if two DCS are supplied by the TG package vendor, HMI shall be a single unified system. This was a triggering point for the implementation of Unified HMI in Intra Package scenario.

8.0. INTER PACKAGE UNIFIED HMI:

Having the scheme of Unified HMI within package (Intra package) leaves most of the design aspects to the package vendor, i.e. a single vendor and are finalized during the detailed engineering stage. This provides a lot of flexibility to the vendor in these aspects.

However, specifying such a concept for Inter package is quite challenging as many of the design aspects has to be specified outright in the tender stage and the coordination between the different package vendors is to be carried out by NTPC. The first & foremost criteria is who will become the Master DCS. In the packaging system as prevalent today in NTPC, there are three packages, SG EPC, TG EPC & BOP EPC (for off sites). Hence, the choice of master for main plant HMI has to be between DCS of SG EPC & TG EPC. The controls being envisaged in these packages are indicated in the following table.

Sl. No.	SG EPC Controls	TG EPC Controls
1.	SG Integral	TG Integral
2.	SG BOP	TG BOP
2.	SG Standalone (Compressor, CW/CT, ESP AC)	TG Standalone (CPU Regeneration, CPU Vessel, Main Plant AC)
3.	AHP	
4.	FOPH	
5.	AUX BOILER	

The considerations which typically go into the selection of the master DCS are:

a) Coverage of drives: One criteria can be that maximum drives in the main plant should be operated from its native HMI, in which case, the DCS which has substantially more drives becomes the master.
b) Coverage of controls: Another criteria for the selection of master is the DCS where most of the important control loops of the generating unit (such as Combustion controls, steam temperature controls, feed water controls) are implemented.

Applying the above considerations to the main plant of a coal fired thermal power plant makes SG DCS as an obvious choice for the Master. Although it is a very tough job of implementing Unified HMI in Inter Package scenario, however with the technical knowhow and experience of Mouda St II TG Package, this philosophy has been specified in EPC projects starting from Telengana onwards. This was possible only because of support from NTPC management.

9.0. SOME DESIGN ASPECTS OF THE TELANGANA IMPLEMENTATION:

In Telangana, BHEL is the SG package vendor and ABFPPL/ GE A&C is the STG package vendor. Here, there are two DCS, maxDNA of BHEL and ALSPA of ABFPPL. Due to the specification requirement of Unified HMI, a scheme for operation of ALSPA drives from the HMI of maxDNA was conceptualized & finalized with NTPC after several rounds of discussions and rigorous testing. An overview sketch of the same is given below in Figure 4.

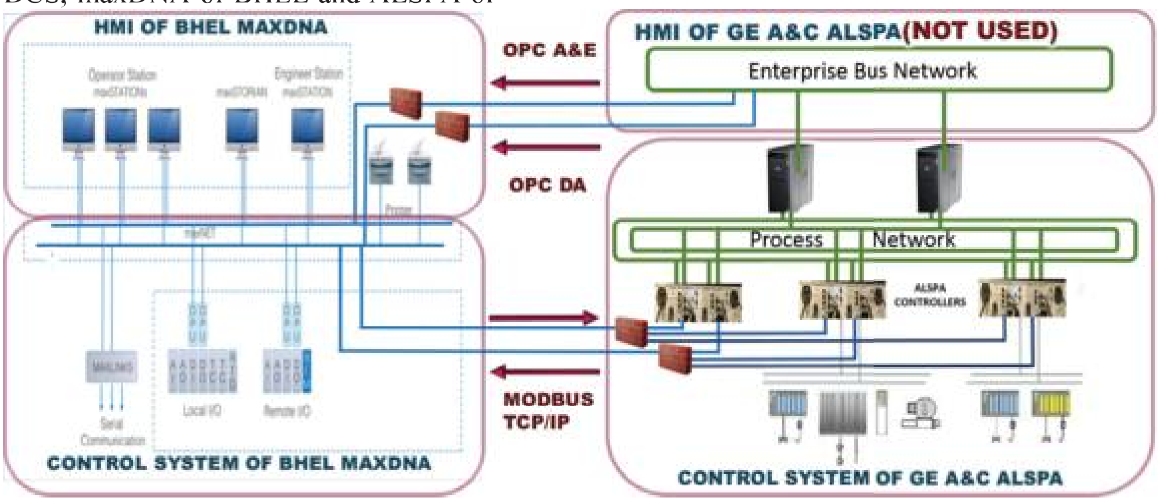


Figure 4 - Telangana implementation

The salient features of this scheme are detailed below:

a) Alspa controller pairs dedicated to individual FGs have Modbus interface. The controllers are configured as Modbus slave. Redundant Modbus slaves have one to one connectivity with redundant maxDNA Modbus masters through redundant firewalls configured in HA mode. All drive level, SGC, SLC and process signals of Alspa system dedicated to a certain FG are transferred to maxDNA using these links.

b) Thus all FG pairs are having these redundant Modbus links for transfer of these signals.

c) With the OLCS and CLCS timings fixed at Alspa end, the cycle time is set at 20 msec, 60 msec & 400 msec for time class critical, high & normal respectively for different type of signals.

d) Bump less switchover between the redundant MODBUS links is ensured.

e) All Drive macros of Alspa system are mapped to the maxDNA system maintaining the homogeneity of look and feel of the Unified HMI.

f) Analog value is being transferred as 32 bit float as ‘Hi’ & ‘Lo’ word in two consecutive 16 bit holding registers. By default maxDNA reads in reverse order i.e. ‘lo’ word in first register and ‘hi’ word in second register and there is an offset of one register at maxDNA end. Considering the above observations, Swap Register was set as 'True' & an offset of '+1' was given in Modbus start register address in maxDNA for all Analog Modbus read registers.

g) All LVS annunciation signals related to Alspa process alarms are transferred on Modbus and signals related to Alspa system alarms are transferred on OPC DA.
h) Due to the requirement of time stamping, alarms are transferred over OPC A&E from Alspa HMI to maxDNA HMI. i.e. an additional redundant HMI OPC link is provided for alarms and events.
i) Analog Setpoint signal from maxDNA to Alspa are hardwired.
j) The native HMIs are planned to be kept in Programmer room and Unified HMI in CCR.

The scheme is tested extensively at the works of GE A&C, where a prototype of maxDNA system with the required interfaces, operator stations, historians is arranged by BHEL, EDN Bangalore. The critical part of the testing was achieving command response times, which are very close to the times achieved with the native HMI. Another critical area is the changeover between the MODBUS links, since the resiliency as provided in the native HMI has to be maintained in the Unified HMI.

Last but not the least, it is being ensured right from the very beginning that commissioning of the TG controls takes place from the Unified HMI right from the initial commissioning stage. The habits formed during the initial commissioning remain throughout the plant cycle & hence this aspect is critical to success of the scheme. It may not be out of place to mention here that in one of the power plants, unified HMI was conceived & implemented, but both the HMIs were placed on the Unit Control desk, & due to this, operators were using only the native HMI, defeating the purpose of the Unified HMI concept.

10.0. CONCLUSION:

Technology has to be harnessed to overcome the barriers of packaging system and to create a seamless operator interface in the control room, with the underlying dynamics & jugglery being oblivious to the operation personnel. The importance of prudent & pragmatic engineering in the finalization of the Unified HMI scheme for any DCS combination cannot be undermined. The cycle times of the MODBUS links, the quantity of MODBUS links & signal distribution among these links, the redundancy & the resiliency of the MODBUS links, mapping of the signals & the mimic engineering has to be done meticulously. This leads to huge efforts on the part of the DCS vendors as well as the customer's engineers, but the efforts are worth the result.

It is to be ensured right from the very beginning that commissioning of the TG controls takes place from the Unified HMI right from the initial commissioning stage. The habits formed during the initial commissioning remain throughout the plant cycle & hence this aspect is critical to success of the scheme. With support from Erection and Commissioning, this scheme is likely to enable operation of entire controls of the TG package from HMI of SG package.

11.0. ACKNOWLEDGEMENTS:

The authors are extremely grateful to Mr. M.K. Srivastava of NTPC for his constant encouragement & support for exploring new horizons & implementing these in the C&I design. Special thanks are also due to ABFPPL, GE A&C and BHEL, EDN's HMI team for achieving the vision of NTPC through their rich technical expertise and dedicated efforts. The authors also express their gratitude to IPS 2017 for providing an opportunity to share their work & perspectives, for the benefit of the automation fraternity.

BIOGRAPHIES:

R. Sarangapani is an Additional General Manager in Project Engineering-C&I Dept. of NTPC Ltd. in its engineering office, based in Noida. He has been involved in the engineering of many thermal power plants as well as factory testing of many DCS systems/simulators.

Mr. Sarangapani has 27 years' experience in power plant C&I engineering. His exclusive focus areas are HMI engineering, Third party interfacing & OPC, display systems, control system networking, network security, closed loop control, Power Plant Performance Optimization, Simulator, and Standardization in engineering processes.

Mr. Sarangapani has been actively involved in the DCS network security architecture of NTPC and the development of network security policies & procedures. He has also been associated in the commissioning of C&I systems at site.

He has authored papers, for national & international conferences including the International Society of Automation(ISA) POWID division, for which he had coined the theme "Empowering Power with Automation" for its first conference of its Delhi Division in 2009.

He is currently involved in the preparation of the Indian manual for Cyber Security in Power Systems.

Mr. Sarangapani has done B.E in Control & Instrumentation from Thapar Institute of Engg. & Technology, Patiala & M.Tech in Computer Science from IETE.

Some Nath Kundu is Senior Manager in Project Engineering-C&I Dept. of NTPC Limited in its Engineering Office Complex, based in Noida. He has been involved in the designing and engineering of control system networking, HMI engineering, Third party interfacing & OPC, cyber security including cyber system audit. He has been involved in the engineering of many thermal power plants as well as factory testing of many DCS systems

He has also worked as a C&I Maintenance Engineer in Korba Super Thermal Power Station (KSTPS), NTPC.

He has authored papers for international O&M conference organized by NTPC Limited.

He is currently involved in the preparation of the Indian manual for Cyber Security in Power Systems.
Mr. Some Nath received the B.Sc degree in Physics Honours from University of Calcutta and Control & Instrumentation Engineering Degree (B.Tech) from University of Calcutta, Kolkata India.

Anubhav Dwivedi is Deputy Manager in Project Engineering-C&I Dept of NTPC Ltd. in its engineering office, based in Noida. He has been involved in the designing and engineering of control system networking, HMI engineering, Third party interfacing & OPC, cyber security including cyber system audit. He has been involved in the engineering of many thermal power plants as well as factory testing of many DCS systems/simulators.

He has been actively involved in implementation of DCS network security architecture of NTPC and the network security policies & procedures.

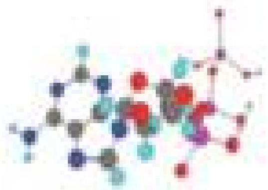
Mr. Anubhav has a B.Tech in Electronics and Communication from NIT Jalandhar and MBA from IIM Bangalore.

THE PROBLEMS WHEN MEASURING TOC/COD WITH UV LIGHT AT 254NM

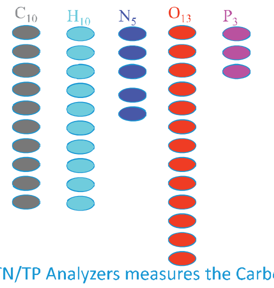
G. B. Diwakar – Application Development Manager
HACH COMPANY, INDIA
diwakar@hach.com

BioTector

Limitations of Direct UV Measurement



Molecules are like a bag of marbles



TOC/TN/TP Analyzers measures the Carbon apart from Nitrogen & Phosphate

- Direct UV will only measure compounds that contain conjugated double bonds in their chemical structure. The Ultraviolet Absorption Method is not suitable for detection of trace concentrations of individual chemicals. It can only be used as an *indication* of the aggregate concentration of UV-absorbing organic constituents.
- The following slide shows that many compounds are not measured by direct UV absorption analysis – furthermore with those which do absorb UV, the response varies greatly from compound to compound.

BioTector

What is on-line TOC/COD by direct UV Technique?

Measurement of un-oxidised sample by UV spectrometer at either a single or multi-wavelength. The result is calculated from the absorption spectra of all those components which can absorb UV light

An indication of the TOC/COD value may be determined by correlation to a laboratory analysis

Disadvantages:

1. Many organic compounds do not absorb UV light at the appropriate wavelengths, therefore these organics will not be detected and measured. In the case of a breakthrough, these organics can be completely missed.
2. Many inorganic compounds such as Carbonates do in fact absorb UV light, these inorganic compounds can lead to false high readings.
3. Direct UV system can operate as an indicator only if the sample conditions are stable. Any change in the concentration of a component may be completely missed or falsely reported as an upset.
4. This type of monitoring leads to false security for plant operators and authorities.

Benefits:

✓ Perceived as low cost where indication only is required

✓ No reagents

BioTector

WHAT IS THE UV/VIS PROBE

- **A durable submersible probe containing**
- **A multi-spectral photometer operating in the UV or UV/VIS range**

BioTector

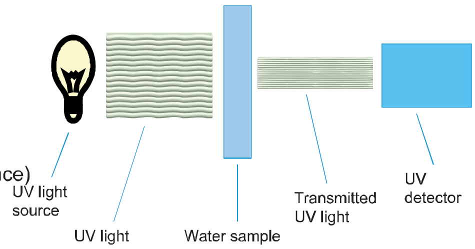
Direct UV Absorption

UV Absorption is calculated using the following equation:

$$A = -\log(\%T / 100\%)$$

Where A = Absorbance, and T = Transmittance
(Zero Absorbance = 100% Transmittance)

Low pressure mercury vapor lamps emit UV light at 254 nm wavelengths



Compounds like Beta-Carotene with many double bonds absorb UV light very well

Beta-Carotene

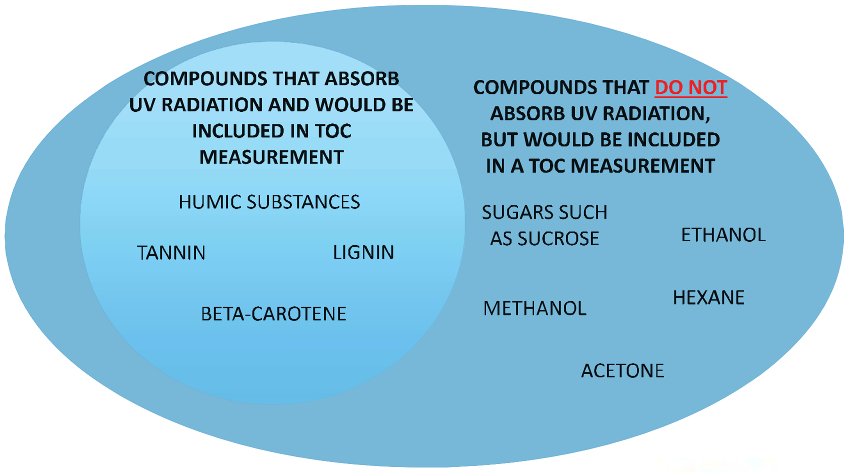
<u>Sugars such as sucrose and alcohols such as methanol and ethanol do not absorb UV light</u>

Methanol

Ethanol

BioTector

WHICH PARAMETER, TOC OR UV ABSORBANCE SHOULD YOU USE?



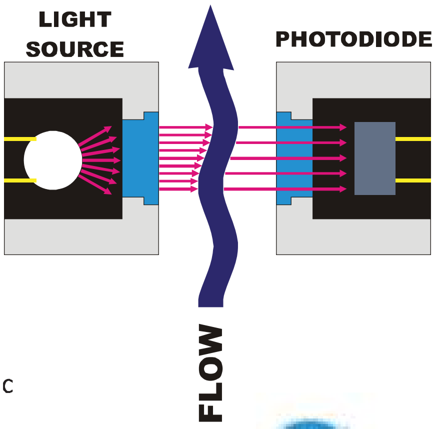
BioTector

HOW A PHOTOMETER WORKS

- Photometers transmit light through a process solution and measured the remaining light with a photodiode
- As the light travels through the process medium it is absorbed, as defined by the Lambert-Beer law
- By determining the wavelengths of the absorbed light, constituents in the process can be identified and quantified.

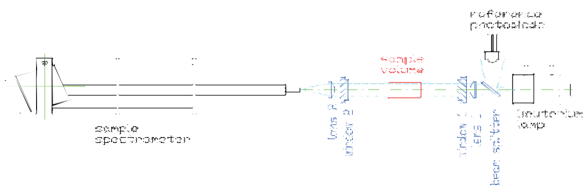
Lambert Beer law

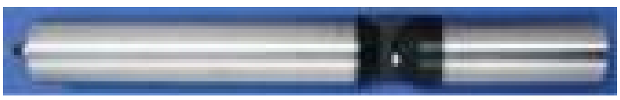
$A = -\log(T) = -\log(I / I_0) = \varepsilon\, b\, c$



HOW A PHOTOMETER WORKS

Lay-out: Photolyzer Clearwater (10 - 60 mm) / Wastewater (1 - 10 mm)





Direct UV Absorption

1. **UV absorption <u>DOES NOT</u> measure:**
   - TOC
   - COD
   - or BOD

2. Inorganic ions such as Nitrate (NO_3) and Nitrite (NO_2) also absorb UV light (false positives)

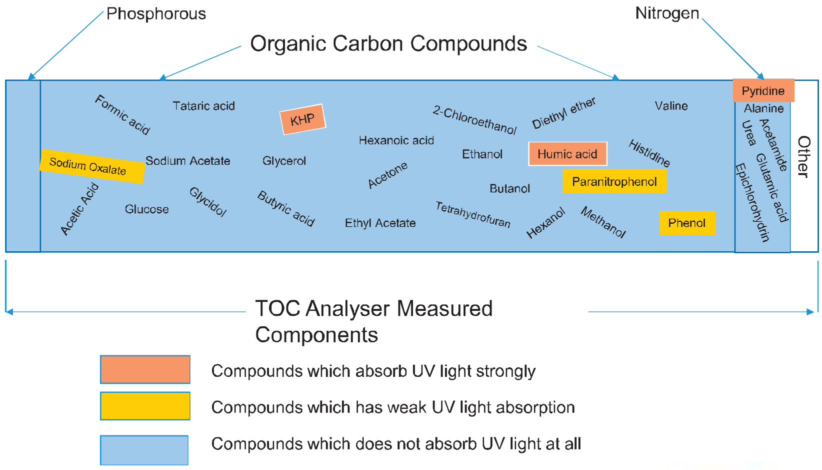
3. **<u>Many common organics are not detected</u>** (false negatives); such as e.g. Alcohols, Ether, Aldehyde, Alkane, Sugars, Glycerin, Ketone, Paraffin, Organic acids, and solvents such as Acetone and Hexane, etc.

4. All UV lamps diminish in intensity over time; which needs to be corrected for.

Direct TOC Measurement by UV Absorption

Chemical / solvent	TOC tested, mgC/l	Result at 254nm, mgC/l
Sodium Oxalate	1,000	65
Formic acid	1,000	0
Tataric acid	1,000	0
1,10 Phenanthroline	1,000	4,300
Potassium Hydrogen Phthalate	1,000	1,000
Acetic Acid	1,000	0
Glucose	1,000	0
Glycidol	1,000	0
Phenol	1,000	163
Glycerol	1,000	0
Epichlorohydrin	1,000	0
Butyric acid	1,000	0
Ethyl Acetate	1,000	0
Acetone	1,000	14
Hexanoic acid	1,000	0
Glutamic acid	1,000	0
Tetrahydrofuran	1,000	0
2-Chloroethanol	1,000	0
Ethanol	1,000	0
Butanol	1,000	0
Diethyl ether	1,000	0
Hexanol	1,000	0
Methanol	1,000	0
Pyridine	1,000	1,625
N-Methyl-2-Pyrrolidone	1,000	0
Alanine	1,000	0
Acetamide	1,000	0
Acetonitrile	1,000	0
Ethylenediamine	1,000	0
Urea	1,000	0
Sodium Acetate	1,000	0
Humic acid	1,000	2,170
Aminoantipyrene	1,000	2,600
Histidine	1,000	0
Paranitrophenol	1,000	720
Valine	1,000	0

Comparison of Components measured by TOC and Direct UV (254nm) Method



BioTector

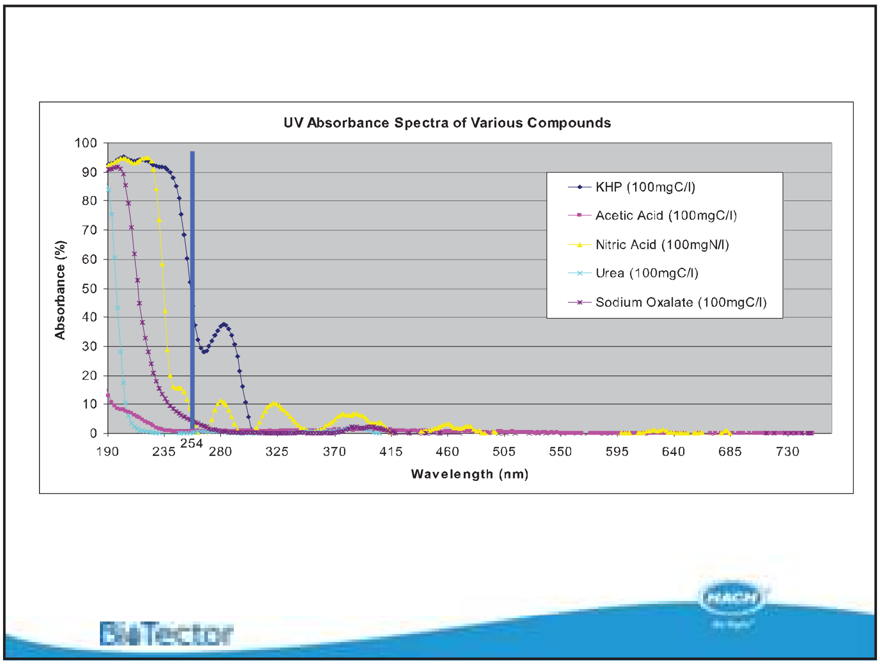
Examples of Spectra of Compounds between 190 & 300nm

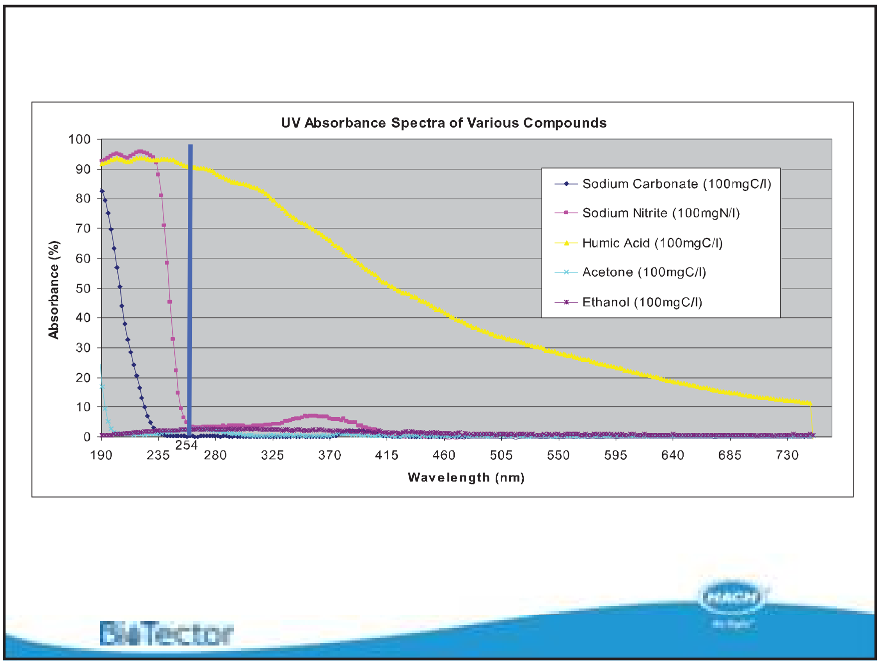
These slides show the spectral absorption of compounds in the range of 190 and 300nm.

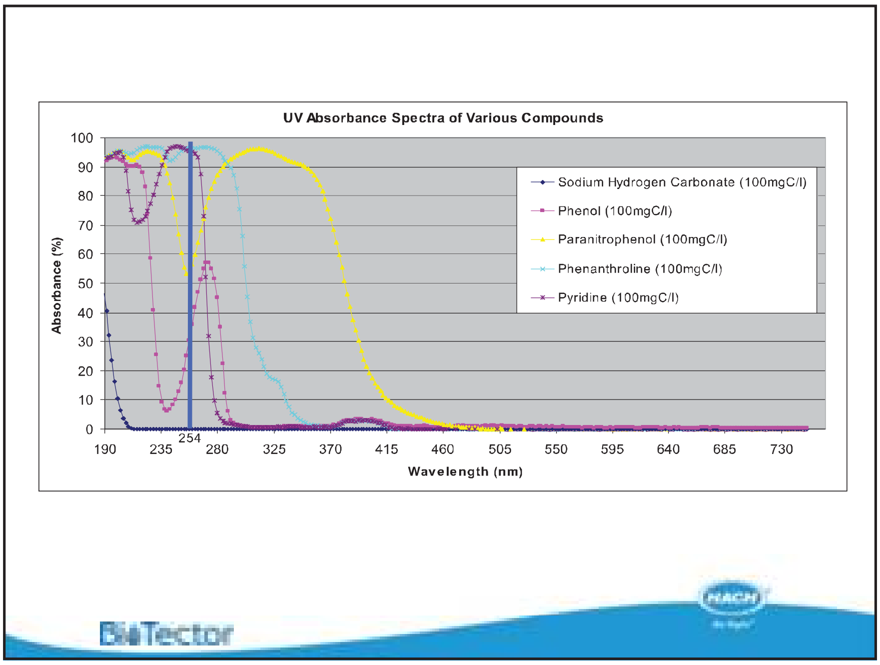
- At 254nm, a wavelength traditionally used to measure hydrocarbons, of note is the good response of Potassium Hydrogen Phthalate (KHP), a compound normally used to calibrate TOC analysers. But while other hydrocarbons, for example Glucose (sugar), Acetic acid and Ethanol will give identical results to KHP in a TOC analyser, these compounds are not measured at all by the spectrometer.
- Additionally, it is interesting to note that at 217nm, the wavelength where Total Nitrogen (TN) is measured, NO_3^- gives a strong signal, but one of the most common Nitrogen containing molecules, Urea has no signal at all.

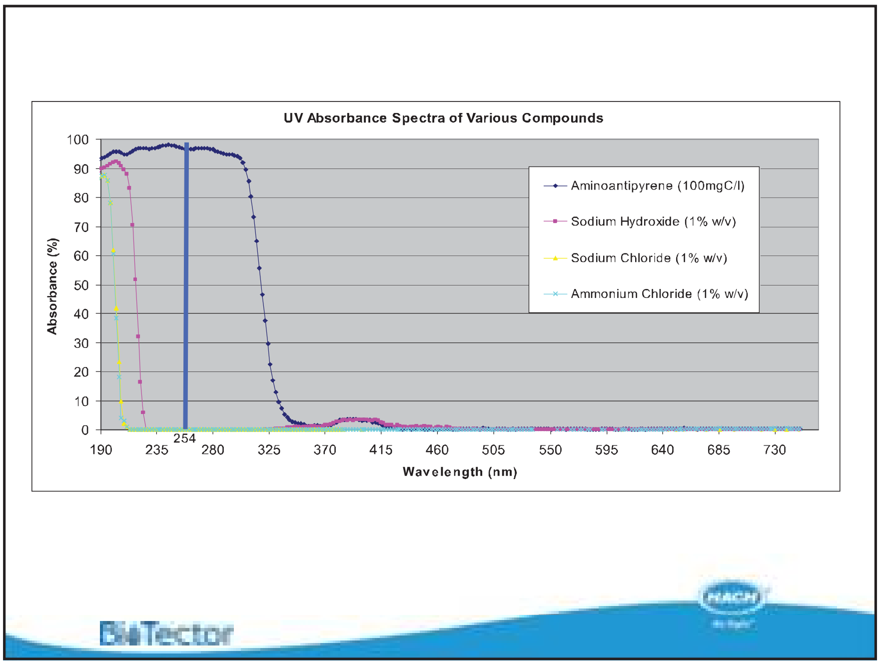
(NOTE: This presentation concentrates on the part of the spectra below 300mn, as generally there is no useful spectral data obtained above 300nm)

BioTector


UV Absorbance Spectra of Various Compounds
Absorbance (%)
Wavelength (nm)
KHP (100mgC/l)
Acetic Acid (100mgC/l)
Nitric Acid (100mgN/l)
Urea (100mgC/l)
Sodium Oxalate (100mgC/l)
BioTector
HACH


UV Absorbance Spectra of Various Compounds
Absorbance (%)
Wavelength (nm)
Sodium Carbonate (100mgC/l)
Sodium Nitrite (100mgN/l)
Humic Acid (100mgC/l)
Acetone (100mgC/l)
Ethanol (100mgC/l)
BioTector
HACH


UV Absorbance Spectra of Various Compounds
Absorbance (%)
100
90
80
70
60
50
40
30
20
10
0
190
235
254
280
325
370
415
460
505
550
595
640
685
730
Wavelength (nm)
Sodium Hydrogen Carbonate (100mgC/l)
Phenol (100mgC/l)
Paranitrophenol (100mgC/l)
Phenanthroline (100mgC/l)
Pyridine (100mgC/l)
BioTector


UV Absorbance Spectra of Various Compounds
Absorbance (%)
100
90
80
70
60
50
40
30
20
10
0
190
235
254
280
325
370
415
460
505
550
595
640
685
730
Wavelength (nm)
Aminoantipyrene (100mgC/l)
Sodium Hydroxide (1% w/v)
Sodium Chloride (1% w/v)
Ammonium Chloride (1% w/v)
BioTector

TOC/COD INDICATION BY DIRECT UV (254NM & 217NM) SPECTRA

100 mg/L KHP (Potassium Hydrogen Phthalate)

	COD (mg/L)	TOC (mg C/L)	TN (mg N/L)
	100 Calibration Compound	40	93
Actual Result	100	40	0

COD indication using an algorithm where a wide range of wavelengths of the light spectrum are scanned.

BioTector

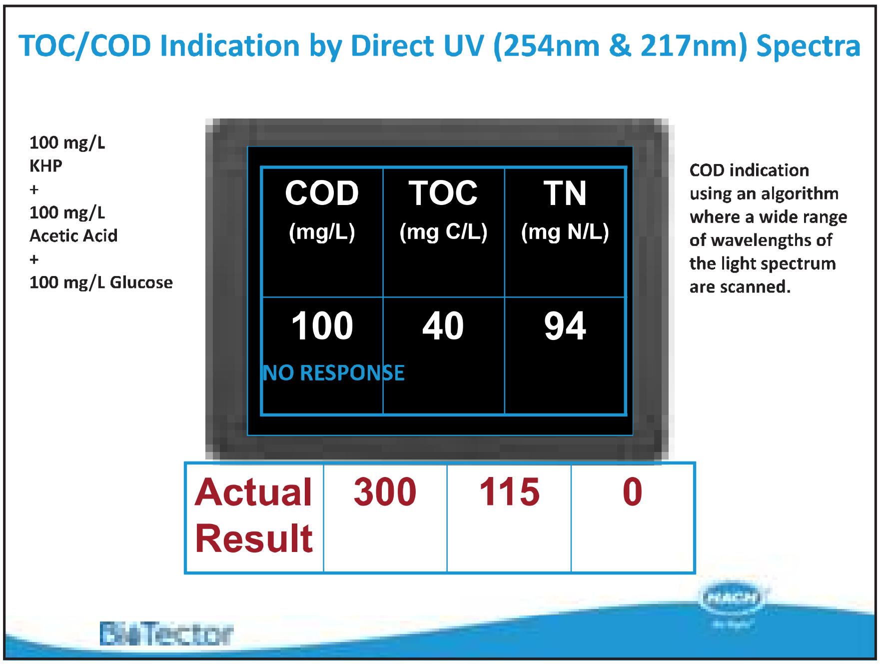
TOC/COD Indication by Direct UV (254nm & 217nm) Spectra

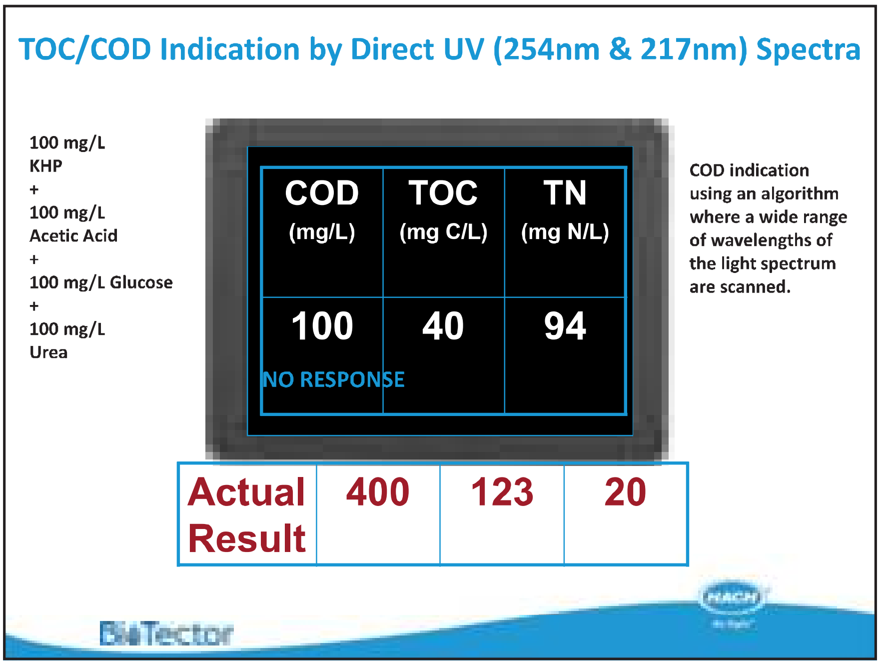
100 mg/L KHP + 100 mg/L Acetic Acid

	COD (mg/L)	TOC (mg C/L)	TN (mg N/L)
	100 NO RESPONSE	40	94
Actual Result	200	78	0

COD indication using an algorithm where a wide range of wavelengths of the light spectrum are scanned.

BioTector


TOC/COD Indication by Direct UV (254nm & 217nm) Spectra
100 mg/L
KHP
+
100 mg/L
Acetic Acid
+
100 mg/L Glucose
COD (mg/L)
TOC (mg C/L)
TN (mg N/L)
100
40
94
NO RESPONSE
COD indication using an algorithm where a wide range of wavelengths of the light spectrum are scanned.
Actual Result
300
115
0
BioTector


TOC/COD Indication by Direct UV (254nm & 217nm) Spectra
100 mg/L
KHP
+
100 mg/L
Acetic Acid
+
100 mg/L Glucose
+
100 mg/L
Urea
COD (mg/L)
TOC (mg C/L)
TN (mg N/L)
100
40
94
NO RESPONSE
COD indication using an algorithm where a wide range of wavelengths of the light spectrum are scanned.
Actual Result
400
123
20
BioTector

TOC/COD Indication by Direct UV (254nm & 217nm) Spectra

100 mg/L KHP
+
100 mg/L Acetic Acid
+
100 mg/L Glucose
+
100 mg/L Urea
+
100 mg/L Phenol

	COD (mg/L)	TOC (mg C/L)	TN (mg N/L)
	175 INACCURATE RESPONSE	70	134
Actual Result	500	155	20

COD indication using an algorithm where a wide range of wavelengths of the light spectrum are scanned.

BioTector

DON'T FORGET WHAT A RELIABLE TOC ANALYSIS CAN BRING TO AN ORGANISATION!

What are your Goals?

What is the value of Accurate & Reliable Measurement to your Plant?

- Increased Efficiencies
- Process Control
- Energy & Water Consumption/Reduction
- Information Dissemination
- Management Information
- Waste Reduction
- Lower Maintenance
- Tighter Budgets
- Incident ID & Tracking
- WWTP Capacity & Performance
- Lost Product Detection & Reduction
- Regulatory Compliance

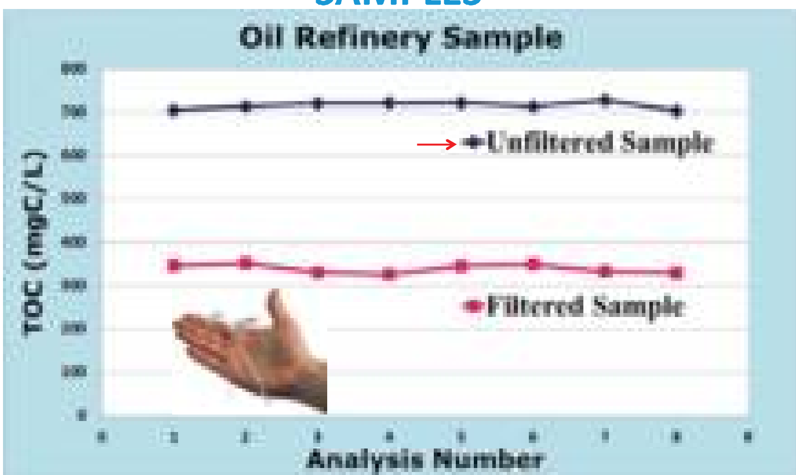
BioTector

POINTS TO CONSIDER FOR ACCURATE TOC MEASUREMENT

- Powerful oxidation for oxidizing organic compounds
- Unfiltered Sample – TRUE TOC measurement
- Good correlation for COD/BOD
- Can measure TOC/TIC/TC/VOC/TN/TP
- Large sample volume 3 to 10 mL – Representative Sample
- Low maintenance & Good Calibration Stability
- Minimal Interference with sample matrix
- Auto Cleaning for each sample measurement – No cross contamination
- Inexpensive Reagents

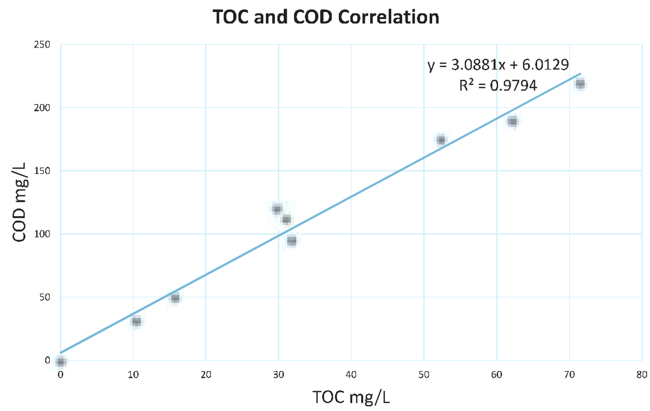
BioTector

IMPORTANCE OF ANALYZING UNFILTERED SAMPLES



BioTector

TOC & COD CORRELATION



BioTector

BE CONFIDENT IN YOUR WATER ANALYSIS:

"BE RIGHT WITH EXPERT ANSWERS, OUTSTANDING SUPPORT, AND RELIABLE, EASY-TO-USE SOLUTIONS FROM HACH".

BioTector


Questions?
THANK YOU
BioTector
HACH

FLEXIM GmbH
Wolfener Str. 36
12681 Berlin
Deutschland
Tel.: +49 30 936 676 60
Fax: +49 30 936 676 80
www.flexim.com

Technical Seminar Paper

WAVEINJECTOR® TECHNOLOGY FOR USE IN REFINERY COKING APPLICATIONS

Peter Baldwin, Dr. Mathias Panicke, Stefan Kranz, Nik Martinov, Gerhard Grabmeier

FLEXIM GmbH, Berlin, Germany

1 ABSTRACT

Flow measurement of coker feed lines is a challenging task. The flow of these hot liquids (up to 450°C/840°F) can contain solids and when cool (during start-up and shutdown phases) can be highly viscous. In many refineries around the world, conventional flow meters for the different coker feed lines have been replaced without any plant shutdown with FLEXIM's high temperature non-intrusive WaveInjector®.

This paper will introduce the technology, the physical background and theory behind the WaveInjector®. The paper will also discuss the various considerations for coker feed flow measurement including the initial problems, typical challenges, installation, measurement and long term data including diagnostics and maintenance. Real world applications will be examined along with experience gathered from other sites where this technology is installed.

The paper will be prepared by flow meter experts/users with a background of more than 20 years in flow measurement in the downstream industry.

2 INTRODUCTION

Shifts in oil supply and demand are bringing the so called “bottom of the barrel” into focus. The “bottom of the barrel” has become more of a problem for refiners because heavier crude oils are processed and the market for heavy residual fuel oils has been decreasing. Historically, heavy residual fuel oils have been burned to produce electric power and to supply the energy needs of heavy industry, but more severe environmental restrictions have caused many of these users to switch to natural gas. Thus, when more heavy residuals are in the crude oil, it is more difficult to economically dispose of them. These complementary pressures affect the supply and demand work together to make it attractive to invest in processing heavier crude oils.

Coking units convert heavy feedstocks into a solid coke and lower boiling hydrocarbon products which are suitable as feedstocks to other refinery units for conversion into higher value transportation fuels. From a chemical reaction point of view, coking can be considered as a severe thermal cracking process in which one of the end products is carbon (i.e. coke). In fact, the coke formed contains some volatile matter or high-boiling hydrocarbons. In order to eliminate essentially all volatile matter from petroleum coke it must be calcined at approximately 1100 to 1250°C (2000 to 2300°F).

The delayed coking process was developed to minimise refinery yields of residual fuel oil by severe thermal cracking of stocks such as vacuum residuals, aromatic gas oils and thermal tars. In early refineries, severe thermal cracking of such stocks resulted in unwanted deposition of coke in the furnaces. As the process gradually evolved, it was discovered that furnaces could be designed to raise residual stock temperatures above the coking point without significant coke formation in the furnaces. This required high velocities (minimum retention time) in the furnaces, but it was found that the control of the hydraulic balance of the heater furnaces depended heavily on the correct inflow conditions. Providing an insulated surge drum on the furnace effluent allowed sufficient time for coking to take place before subsequent processing, hence the term “delayed coking”.

Due to its practical advantages, external flow measurement with clamp-on ultrasonic transducers has become a standard measuring technique over the past twenty years. Experts are more than happy to resort to non-invasive technology when it comes to measuring the flow of complex media. The main challenges involved in reprocessing heavy crude oil fractions are high viscosity, solid bodies and high temperatures.

3 THE COKING PROCESS

Most coker plants in the world are based on the Foster Wheeler patented delayed coking method. The residue left over from crude oil distillation is led through a tube furnace under pressure at a high velocity and heated to temperatures of 925°F / 500°C. Due to the short length of time that the residue mixture stays in the furnace, there is no significant coke formation. This takes place in a “delayed” manner during devolatilisation in downstream coke drums.

Typically furnace outlet temperatures range from 480 to 500°C (900 to 930°F). The higher the outlet temperature, the greater the tendency to produce shot coke and the shorter the time before the furnace tubes have to be decoked. Hot fresh liquid feed is charged to the fractionator two to four trays above the bottom vapour zone. This accomplishes the following:

1. Hot vapours from the coke are quenched by the cooler feed liquid thereby preventing any significant amount of coke formation in the fractionator and simultaneously condensing a portion of the heavy ends which are recycled
2. Any remaining material lighter than the desired coke drum feed is stripped (vaporised) from the fresh liquid feed
3. The fresh feed liquid is further preheated making the process more energy efficient

3.1 Coke Formation and Removal

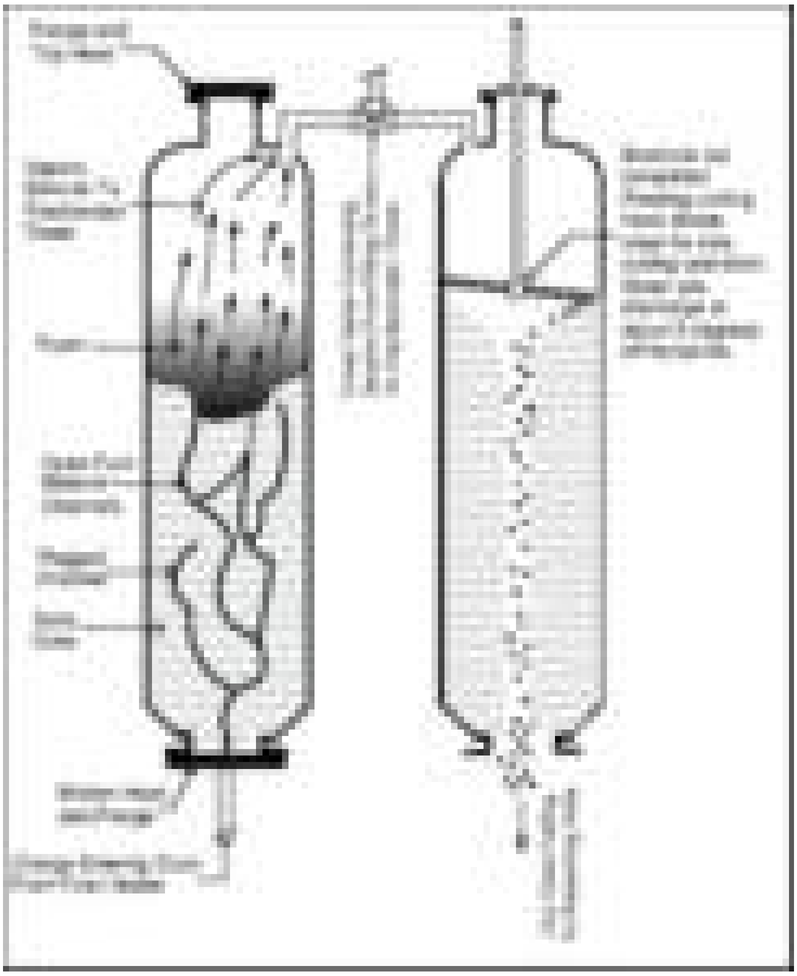


Fig. 1 : Alternating Filling and Removal from Two Coke Drums [3]

The heated residue is pumped from the furnace to the active coking drum. Due to the temperatures of around 925°F / 500°C and the pressure drop from 24 bar / 350 psi to approximately 4 to 6 bar / 60 to 90 psi, the hot feed cracks into two products, a gas vapour and a solid coke. The lighter fractions (gas, naphtha, gas oil) are separated and only solid coke remains in the drum.

When the coke drum in service is filled to a safe margin from the top, the furnace effluent is switched to the empty coke drum and the full drum is isolated, steamed to remove hydrocarbon vapours, cooled by filling with water, opened, drained and the coke removed.

Decoking is accomplished by a hydraulic system consisting of a number of high pressure (350 bar / 5000 psi) water jets.

As the coke drums are filled and emptied on a time cycle, the fractionation facilities are operated continuously and at least two coke drums are necessary for continuous batch processing. A typical processing time of one operation cycle is 20 hrs.

4 FLOW METERING REQUIREMENTS

From an engineering measurement perspective, this is the ability to measure the quantities of actual processes and physical components. As such, flow measuring instruments are used to measure the quantity of a flowing fluid at a certain point in a process. The fluid can be in an open or closed conduit and can be measured as an observed volumetric flow or a corrected mass flow.

For the coking process, which is not only extremely hot but can also contain toxic substances, the most important factor is safety. This safety is not only important for the operational and maintenance staff but also for the environment. Also, good process control and heater tube balance is essential in the running of the furnaces. To achieve this, the profile of an ideal flow meter should be built.

An ideal flow meter should have the following characteristics: -

1. Accurate and long term stability, even under changing process conditions

    - Suitable for the process conditions of high temperature, changing product in start-up and shut-down phases, changing viscosities and densities and solids and gasses in the liquid phase
    - High turndown
    - Fast response

2. Safe & Reliable

    - Self diagnostics to prove that not only is the reading valid, but also to warn of possible failures
    - Intrinsically safe not only in ATEX terms but also in operational and failure modes

modes

- There should be no possibility to vent or leak hazardous materials to the atmosphere during operation or maintenance
- Long term reliability suitable for plant lifecycle
- Resistive against wear, tear, scaling, chemical attack

3. Maintaining plant availability

   - Maintainable without plant shutdown
   - Pigable, have the ability to remain on the pipe during decoking, regardless of the method used

4. Reaction-free measurement

   - There should not be any reaction to the process caused by the flow meter

5. Economic - LTCO (Low Total Cost of Ownership)

   - Purchase price
   - Maintenance free
   - Energy usage / pressure drop

Currently, the typical differential pressure systems used do not fulfil many of the above requirements, but the closest ideal fit meter on the market is an ultrasonic meter. Ultrasonic meters by their very nature fulfil most of the above requirements and are proving to be a real benefit to many refineries around the world today.

For safety, these same flow metering instruments are independent of the process control system and are used to maintain a safe state as part of a Safety Instrumented System (SIS). The importance of these systems cannot be underestimated or brushed aside lightly. Process control allows for fully automated systems in which a small workforce can operate a complex process from a central control room.

For a SIS to operate, equipment must function correctly and quickly. These systems must be capable of detecting abnormal operating conditions. A logic solver system, which normally forms part of the SIS, receives input signals from all of the various sensors and makes appropriate decisions based on pre-defined limits. International standards IEC 61511 and IEC 61508 provide guidance to end-users on the application of Safety Instrumented Systems in the process industries.

We can therefore conclude that flow metering is a vital link in a very large process. The metering must be robust, accurate and reliable, for without these traits, it would not be possible to control and safely maintain a complex oil refining system.

5 CURRENT METERING TECHNOLOGIES

There are so many types of metering on the market today and they fall into various categories. These can be seen as mechanical (turbine, variable area, positive displacement, paddle etc), pressure based (orifice, venturi, pitot etc), electromagnetic / acoustic (magnetic, ultrasonic clamp-on, ultrasonic wetted etc), coriolis force based and other fringe systems such as optical and thermal mass systems.

With so many systems on offer, how does an end user decide which one is best fit for their process? [2] One thing is for sure, no one meter offers a panacea, but they each have their advantages and disadvantages. We will now explore for the more common systems seen in the modern refinery, these advantages and disadvantages.

5.1 Differential Pressure Meters

5.1.1 Orifice Plate

An orifice plate measures the flow of a liquid or gas by the difference in pressure from upstream to the downstream of the plate. This plate creates a restriction in a pipe that causes a difference in pressure between the two sides. A differential pressure transmitter then measures the difference in pressure across the orifice plate and converts this into a flow signal.

Fig. 2 : Typical Orifice Plate Hook-Up

Advantages:

- Can be used for liquids, gases, and steam
- Good for extreme process conditions (up to 400bar / 5800psi and 1000°C / 1800°F)
- Basic element is robust and entirely mechanical with no moving parts
- DP-transmitter isolatable for calibration
- Cheap installation cost

Disadvantages:

- Risk of clogging
- Pipe shut down for exchange of primary element
- Chance of leak (pressure tubing, valves)
- Limited turndown range
- Only 60 to 65 % of pressure drop is recovered
- Effected by changes in density, pressure and viscosity
- Pressure tubing needs trace heating
- slow response time due to cold liquid viscosity increase

5.1.2 Wedge

A wedge meter measures the flow of a liquid or gas in a similar manner to that of an orifice plate by the difference in pressure from upstream to the downstream of the wedge. This wedge creates a restriction in a pipe that causes a difference in pressure between the two sides. A differential pressure transmitter then measures the difference in pressure across the wedge and converts this into a flow signal.

Fig. 3 : Wedge Flow Meter on Coker Feed Using Three DP Transmitters with Diaphragms

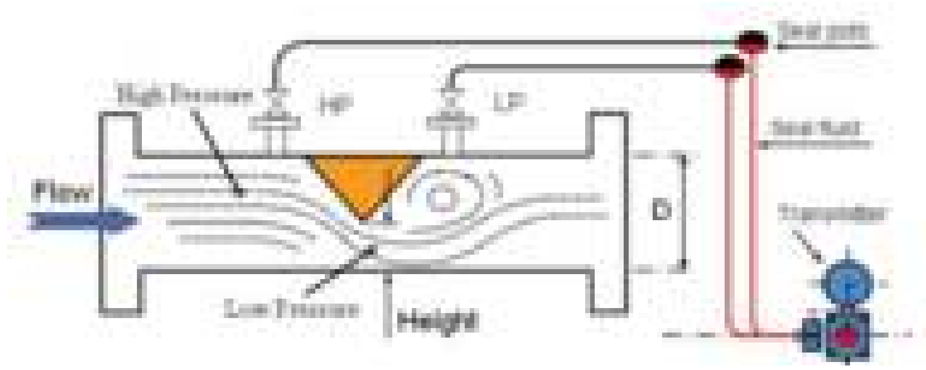


Fig. 4 : Wedge Flow Meter Cross Section Showing Pressure Restriction Wedge

Advantages:

- Small pressure drop
- Can be used for liquids, gases, and steam
- Basic element is part of the assembly and is robust and entirely mechanical

Disadvantages:

- Risk of clogging
- Limited turndown range
- Nominal sizes in the range of 150 to 600mm / 6 to 24inch
- Sensitive to variations in the velocity profile and turbulence
- Effected by changes in density, pressure and viscosity
- Pipe shut down for exchange of primary element
- Chance of leak (pressure tubing, valves)
- Pressure tubing needs trace heating
- Slow response time due to cold liquid viscosity increase

5.1.3 Common Differential Pressure Meter Problems

Purging

Impulse Lines - A common problem which occurs on orifice plate and wedge meters using impulse lines is blockages. To overcome this, when temperatures are lower than 315^{o}C / 600^{o}F it is common to purge the lines with glycol. When temperatures are over 315^{o}C / 600^{o}F, substances such as Krytox are used, which is not only expensive but when significantly above 300^{o}C, the fumes are about as toxic as cyanide. This is a serious plant and personnel safety issue where a plant can no longer continue to run safely and the cleaning or purging procedures can be extremely dangerous to personnel.

Fig. 5 : DP Assembly Removed (Left) and Impulse Lines Blocked (Right)

The control of the hydraulic balance of the heater furnace depends heavily on the correct inflow. Therefore, as shown in Fig. 5, if impulse lines become blocked, the result is a meter which exhibits erratic readings as shown in Fig. 6. This is both an operational and a safety issue.

Fig. 6 : A Typical Eight Heater Feed Flows with One DP Blocked

Diaphragms

Chemical Seals - When using diaphragms seals, manufacturers have to employ special capillary liquids to cope with the extreme temperatures. They also tend to employ large area diaphragms to overcome blockages of the mounting nozzles. Overall measurement accuracy can drop if the chemical seal is small, its diaphragm is stiff, or if the capillary system is not temperature-compensated or not shielded from direct sunlight or other heat exposure.

Fig. 7 : Typical Diaphragm Seal DP Transmitter

Diaphragm seals always carry a concern over their fragility when exposed to such a hot and harsh service with clogging, build-up and often large particles and potentially lumps of coke running down the pipe.

Advantages:

- No blockage of pressure tubing
- Pressure transmitting fluid maintains low viscosity even at low temperatures

Disadvantages:

- Unequal heating of the filled capillaries leads to errors
- More complicated
- More costly maintenance
- No isolation and thus calibration of the DP transmitter is possible without process interruption

5.2 Clamp-on Ultrasonic

A detailed clamp-on ultrasonic explanation will be covered in section 7.1. To be consistent, the following are the advantages and disadvantages of a clamp-on ultrasonic flow meter.

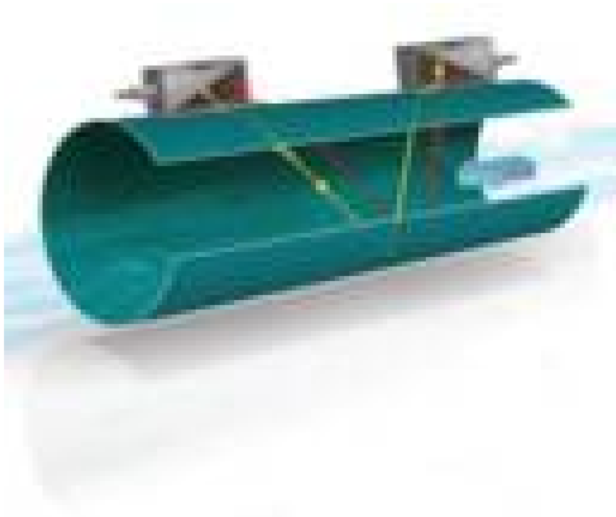


Fig. 9 : Clamp-On Ultrasonic Flow Meter

Advantages:
- Safe - No chance of leaks
- Safe - Self monitoring measuring principle with diagnostics
- Retrospective installation on running plant (full plant availability at all times)
- Non intrusive, no pressure drop, no risk of clogging and pigable
- Not in contact with fluid
- High turndown > 100:1
- Fast response time
- Can be used for liquids, slurries, solids, or gases

Disadvantages:
- High content of solids or gas in liquids can cause meter to fail
- Standard couplants will degrade over time
- Limited temperature range for transducers directly coupled to the pipe

6 FLOW METERING PARAMETERS

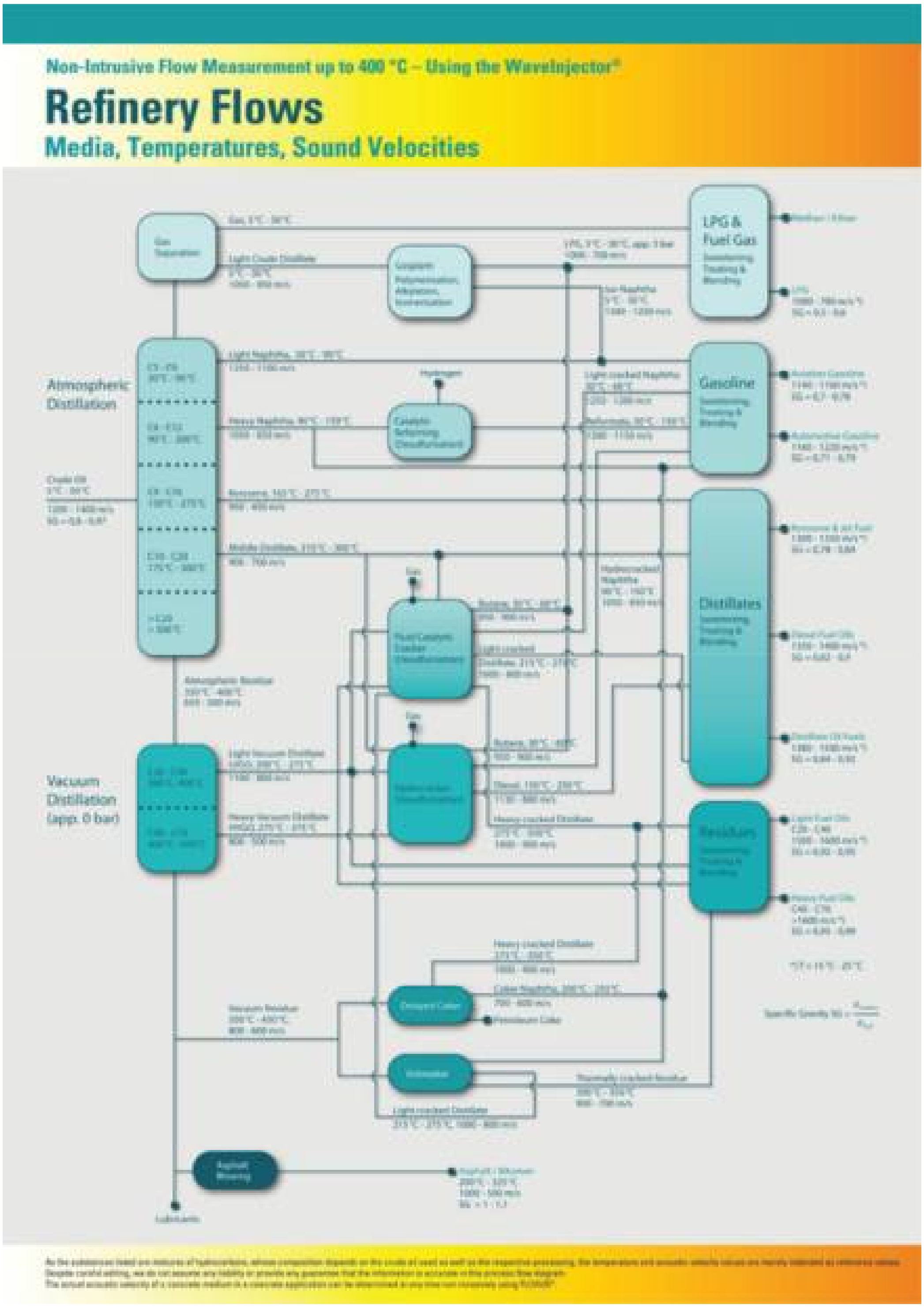


Fig. 10 : Refinery Flows Showing Typical Temperatures

7 THE WAVEINJECTOR®

Ultrasonic flow measurement at high temperatures was until now a troublesome business. Temperatures above the Curie Point [5] cause spontaneous polarization of the piezo crystal and the transducer ceases to 'sing'. Furthermore, high temperatures accelerate the aging of the ultrasonic transducer's piezo elements and thus limit their useful operating life. The gels or pads used for acoustic coupling between the transducers and the pipe have a limited temperature tolerance.

To solve these issues, FLEXIM's unique WaveInjector® as shown in Fig. 11 has been specially engineered for high-temperature applications. Using patented technology, the WaveInjector® thermally separates the ultrasonic transducer from the hot pipe, allowing operation at process temperatures up to 450°C / 840°F.

Fig. 11 : FLEXIM's Unique WaveInjector®

The patented transducer mounting fixture realises a long-term stable clamp-on ultrasonic flow measurement with standard temperature transducers at temperatures as high as 450°C / 840°F. It offers all the well known advantages of the clamp-on ultrasonic technology, a non-intrusive measurement with a wide dynamic range and a high flexibility.

Since the WaveInjector® is a purely mechanical device, it can be used in explosion hazard areas without any further certifications.

7.1 PRINCIPLE OF MEASUREMENT

7.1.1 Meter Formula

The transit time ultrasonic flow meter measures the transit times t_{up} and t_{down} of an ultrasonic signal travelling upstream and downstream respectively. The difference T between the transit times is directly proportional to the mean flow velocity v_L on the sound path.

$$v_L = K_\alpha \frac{T}{2T_{FL}} \quad (1)$$

K_α is the acoustical calibration factor and T_{FL} is the transit time within the fluid. The volume flow Q is the product of the average flow velocity V_A over the cross section of the pipe multiplied by the area A of the cross section.

$$Q = v_A \cdot A \tag{2}$$

Fig. 12 : Ultrasonic Clamp-On Measurement

If the flow profile V is known, the area average V_A of the flow velocity can be calculated from the path velocity V_L measured by the flow meter. The meter calculates the fluid dynamical calibration factor K_{RE} .

$$K_{RE} = \frac{V_A}{V_L} \tag{3}$$

Thus the meter formula is

$$Q = K_{\mathrm{Re}} \cdot A \cdot K_\alpha \frac{T}{2T_{FL}} \tag{4}$$

In order to calculate the volume flow, a fully developed flow profile has to be presumed. This requires a sufficiently long distance of the measurement location from disturbances like bends and Tees. In that case the fluid dynamical calibration factor K_{RE} depends on the kinematic viscosity of the fluid and the roughness of the pipe wall only.

If the flow profile can not be assumed to be fully developed, a deviation of the fluid mechanical calibration factor K_{RE} has to be expected. Usually, this deviation is nearly independent of the flow velocity, as long as the Reynolds number is well above 10000. This permits accounting for such conditions by means of a constant correction factor if the magnitude of the influence is known. In some cases, empirical data can be used as many investigations have been carried out on 90° elbows for instance. The most reliable way of determining the necessary correction factor is to measure it on site by a calibration against a reference if such a reference is available. If neither method is available, a numerical simulation of the flow profile can help. This approach is described i.e. in [1].

7.1.2 Path Configurations

The fact that the flow profile is not always ideal is often addressed by using multiple sound paths. Fig. 13 shows a reflecting configuration in two planes. The advantage of a reflecting path is that non-axial flow components are compensated for. This is because the effect of the non-axial component (cross flow) on the two components of the reflecting path is the same in magnitude but opposite in sign. The use of sound paths in two planes reduces the impact of non-symmetry in the flow profiles caused by disturbances like bends or t-branches.

It is not always possible to use reflecting paths. In such cases the compensation for cross flow can be achieved by using two direct paths as shown in Fig. 14.

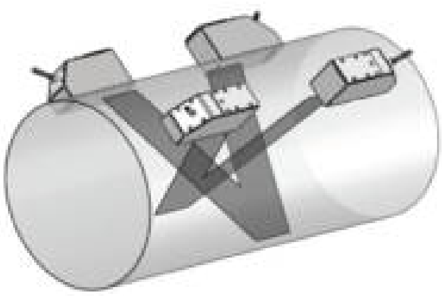


Fig. 13 : Reflecting Paths in Two Planes

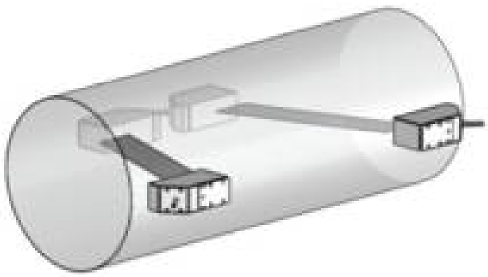


Fig. 14 : Two Direct Paths

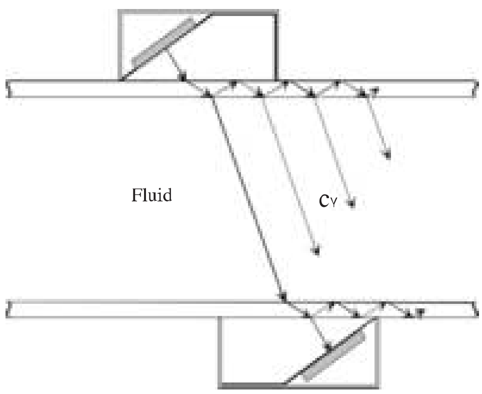


Fig. 15 : Shear Wave Transducers

7.1.3 Sound Transmission

The clamp on technology requires that a sufficient amount of the sound energy can be transmitted from the transducer on the outside via the pipe wall into the flowing fluid. The angles under which the sound waves propagate through the pipe wall and the fluid are given by Snell's law as expressed by formula (5).

$$\frac{\sin\alpha}{c_\alpha} = \frac{\sin\beta}{c_\beta} = \frac{\sin\gamma}{c_\gamma} \tag{5}$$

The propagation method used with clamp-on WaveInjector® measurements is the shear or transverse mode. Shear waves travel under an angle of approximately 45° through the pipe wall as shown in Fig. 15. The advantage of the shear waves is that the sound absorption within the pipe wall is negligible and nearly independent of the transducer frequency. So there is practically no upper limit in pipe wall thickness and the choice of the transducer frequency is not restricted by the pipe wall

8 WAVEINJECTOR® APPLICTIONS IN THE FIELD

FLEXIM's WaveInjector® was launched in 2004 and trials started instantly with many customers interested in the potential that this solution offered them. Amongst these customers were refinery engineers, who were amongst those looking for solutions to their high temperature flow metering problems.

The following two studies will look at instances where flow meteringproblems were faced by refinery engineers in the field, the parameters involved and the solutions provided. In each case the diagnostics will also be examined.

8.1 North American Refinery

A North American refinery expressed an interest in applying the Flexim Ultrasonic Flow Meters on high temperature fractionator tower bottoms in the delayed coker unit on the heater inlet. The Flexim ultrasonic flow meter was installed as follows: -

Pipe OD	-	101.6 mm / 4 inch (schedule XS - 4.5 inch / 114.3 mm OD)
Wall Thickness	-	8.1 mm / 0.319 inch (as measured by FLEXIM meter)
Pipe Material	-	9 Chrome 1 Molly Steel
Medium	-	Coker feed (short resid)
Operating Temperature	-	390^{o}C / 730^{o}F

Following pipe preparation, the 'WaveInjector® Plates' (see Fig. 16) were installed using silver coupling foils and a signal was immediately acquired.

A short data logging sequence was gathered to confirm the functionality of the meter (see Fig. 17)

BLUE	-	Volumetric flow (standard bbl/h)
RED	-	Signal amplitude (%)
GREEN	-	SCNR (dB)
BLACK	-	Sound speed as measured by flow meter (m/s)

The average flow rate recoded over this short period of time was 411 standard bbl/h. This was in line with the existing orifice plate meter. At this point it is important to point out that the standardisation of operation flow was carried out using the flow meters inbuilt specific gravity equation.

In order to standardize the volumetric flow down to base conditions a calibration factor, equal to the ratio of S.G. at flow conditions over S.G. at base conditions, was entered into the meter: -

S.G. at flow	=	0.76
S.G. at base	=	1.0
Calibration Factor	=	0.76

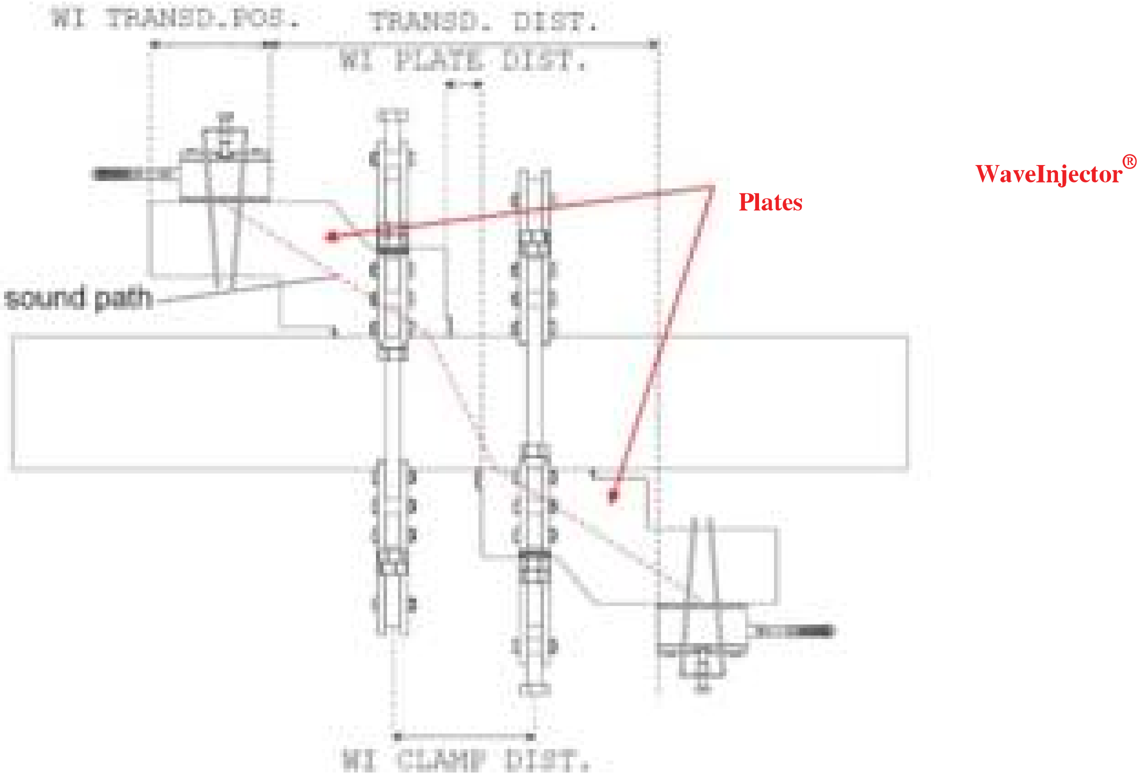


Fig. 16 : Typical WaveInjector® Installation Showing WaveInjector® Plates

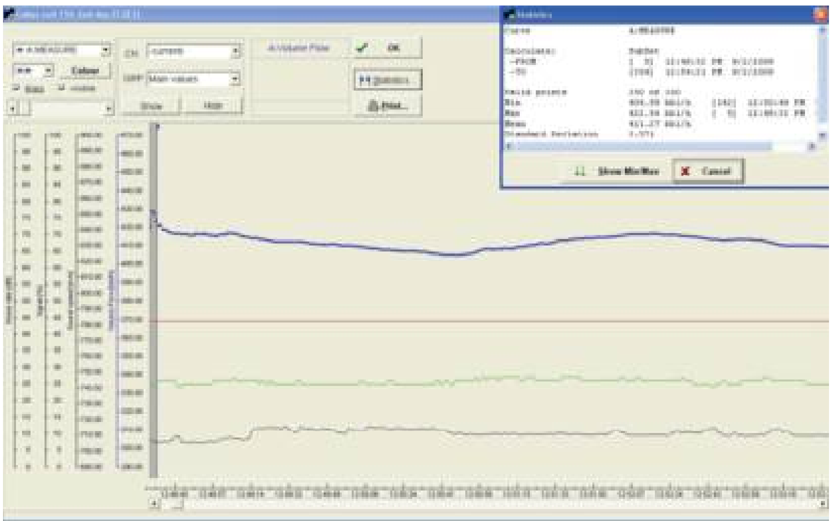


Fig. 17 : Data Logging Sequence

The Signal amplitude is well within specifications and held very steady throughout the test. The SCNR or signal to correlated noise ratio (see Section 12), which is considered to be the most important diagnostic tool is also within specifications at about 26dB and held very steady. Variations in any of the diagnostics would point to a marginal installation. The trend also shows the sound speed of the medium as measured by the meter in real-time. This is quite consistent at an average of 711 m/s (this being a typical sound speed for coker feed short resid).The final installation is lagged, leaving just the transducers in free air for cooling purposes (see Fig. 18). The result was a flow meter working on a coker short resid feed line at 390^{o}C / 730^{o}F, which compares with the troublesome in-line orifice plate. The whole procedure was carried out without shutting the line down or stopping production in any way.

Fig. 18 : Final Installation Prior to Lagging

9 DECOKING [6]

An established fact is that the most critical measuring point in the coking process is the flow meters for the different heater passes (coils). Due to the high asphaltene containing feed in North American refineries, the different heater coils tend to scale up with coke due to the unbalanced flow in the different pipes. Low flow leads to higher temperatures, which leads to faster coke build-up. This problem becomes self perpetuating creating more and more build-up as time progresses. The best way to slow down this build-up is to have good metering and hence good balancing of the heater coils, but coke build-up is still going to occur. To overcome this issue, various methods of decoking are employed.

There are three methods of decoking a heater; steam air, mechanical (pigging) and online spalling. Steam air decoking is the oldest of these three methods and is currently being replaced by the other two methods. Steam air decoking can be rough on the heater tubes, labour intensive and requires a heater and unit shutdown. Some facilities have moved away from this method because the environmental problems caused when burning the coke out of the tubes.

Online spalling has become the best method of decoking, but is not always possible depending on the heater mechanical arrangement and the size of the coker. A small delayed coker with few tubes passes will find this method more difficult than a large coker with multiple drums and heaters. This process is very attractive as the unit does not require a shutdown and loss of throughput and reliability problems are kept at a minimum.

Finally, mechanical decoking or pigging has become a popular practice for delayed coking. The mechanical decoking does require a heater shut down, but some facilities have developed isolation procedures where individual heater boxes can be isolated and the heater passes decoked without a complete shutdown. The time required to mechanically decoke a heater is approximately the same as online spalling of a heater. Since pigging is relatively easy, many facilities have elected to only mechanically clean their coker heaters. This method of decoking can remove difficult inorganic solid foulant from solids in the coker feed. Inorganic solids generally foul in the upper radiant section or even the convection section of the heater. Spalling coke in the upper section of the heater is very difficult if not impossible, which is why a method of pigging the delayed coker heater was developed.

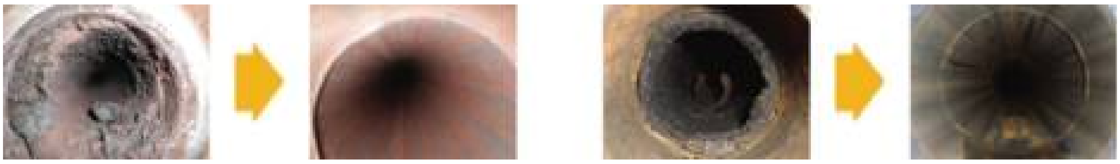


Fig. 25 : Before and After Decoking by Pigging [7]

Fig. 26 : APRO-PIG® Decoking Pigs [7]

The WaveInjector® is ideally suited to any kind of decoking process as it is non intrusive, has no pockets for coke to build up in, does not restrict the line, is not damaged by any of the processes above and can be left in-situ during the whole process.

10 THE FUTURE - OVER 10 YEARS AND COUNTING

Currently, the FLEXIM WaveInjector® has an installed base of over 1000 systems across the globe. These systems range from high to low temperature, from refineries to liquid LNG. Other common flow measurements for the WaveInjector® include heat transfer oils, bitumen, pitch/tar, crude oils/synthetic crude, gas oils, refined petroleum products and other hot and toxic substances.

The limits are still being explored by our customers with recent work in thermosolar applications where molten salts can reach temperatures in excess of 600^{o}C / 1100^{o}F.

The WaveInjector® continues to be popular and further developments are underway within the FLEXIM Research & Development group to push the boundaries even further.

11 CONCLUSIONS

Flow measurement in the coker section of a refinery is a challenging task with high process temperatures, coke formation, changes in feedstock qualities and fluid properties.

Critical for the reliable and efficient operation of the furnace is a balanced feed of the different heater passes for the coker feed. There is no ideal flow meter for this application and measurements were made by classical orifice plates. The replacement of these orifice plates by wedge flow meters in combination with diaphragms improved the situation but brought their own new problems with them. A question which is always asked is do the meter readings really represent the flow rate inside the pipe? Ultrasonic flow meters seem to be the best solution currently available, since they bring with them diagnostic capabilities. With the invention of the WaveInjector®, a non intrusive solution is now available with additional safety in operation and flow measurement.

This WaveInjector® offers a reliable and non-intrusive solution for Coker/Heavy Oil applications with reliable measurement to 450°C / 840°F. The metering systems offer easy set-up with no process interruption or upset during installation.

Some of the major benefits offered with this flow measurement technique are no pressure drops, no potential leaky connections, no more plugging of the meter or capillary lines, cost effective with low cost of ownership and virtually maintenance free. In addition, the meter can be installed with no intervention or loss of production and once completed can immediately be called into service.

Should any maintenance be required, the meter can be worked on safely and without the maintenance personnel being exposed to any part of the process.

FLEXIM's transit-time technology has a response time of <1 second, resulting in a SIS system in which the alarm will be activated as soon as flow reaches a preset limit. Differential pressure systems include mechanical damping that introduces a longer response time, which is not what a SIS system should be relying upon.

Finally, we should return to our ideal flow meter and consider each of the requirements and ask if the WaveInjector® system fulfils some or all of the requirements.

An ideal flow meter should have the following characteristics: -

1. Accurate and long term stability, even under changing process conditions
2. Safe & Reliable
3. Maintaining plant availability
4. Reaction-free measurement
5. Economic - LTCO (Low Total Cost of Ownership)

Now we should consider how the WaveInjector® system compares to the questions asked: -

1. The WaveInjector® system is currently suitable for process temperatures of up to 450°C, full line pressure, can work with varying temperatures, viscosities and densities. The meter is largely unaffected by solids and gasses in the liquid phase but does have an upper limit where the meter will stop working

   The meter has a turndown of greater than 100:1 and has a response time of <1 second

2. The system contains full internal diagnostics where a live sonic velocity shows that the reading is valid and other diagnostics parameters show the health of the system. All of this is available on a HART link and can directly link into an AMS system

   These systems are available as ATEX certified, but of more importance, if the meter is not working it is not because an impulse line is blocked or conditions have changed significantly but that something more significant has occurred and the diagnostics will tell you why

The system is non-intrusive so no leak paths are possible even during installation, commissioning and maintenance. The pipe always remains at full integrity, therefore the meter is fully resistive against any wear, tear, scaling or chemical attack

3. Regardless of the decoking techniques employed (steam air, mechanical (pigging) and online spalling) the meter stays on the pipe. The meter will suffer no ill effects from any of these methods and can remain on the pipe almost indefinitely throughout the entire flow cycle of the coking process including start-up, shut-down, cleaning, maintenance and normal running

4. The system is non-intrusive, therefore not only does the meter have no possible leak paths, but has no pockets or interaction with the process and therefore does not react with the process in any way

5. The WaveInjector® system has been installed and working for a number of years now and with over 1000 systems installed globally has shown its long term viability and reliability

Due to it's fully non-contact clamp-on nature, the meter is installable and maintainable during normal process operations, develops no pressure drop, has no crevices or lines to block. This results in a meter which is easily installed, is virtually maintenance free and presents no pressure restriction to the fluid

So, we can see that although the WaveInjector® flow meter does not fulfil all of the requirements of an ideal meter, it is the best fit on the market today.

12 GLOSSARY

12.1 Gain (dB)

The gain is the amount of amplification required by the raw signal and is measured in decibels. The amplifier can run up to 108 dB.

12.2 SNR (dB) - Signal to Noise Ratio

The noise in this context is random with respect to the signal. It can be filtered and further reduced by signal processing (as long as the remaining noise is not so strong that the signal cannot be detected) and does not affect the long term average of the measurement result. The only effect is an increased standard deviation. Potential random noise sources are electrical sources like variable frequency drives and acoustical sources like regulating valves.

12.3 SCNR (dB) - Signal to Correlated Noise Ratio

This is a FLEXIM specific term and the noise here (the pipe signal) is correlated to the signal because both signal and noise are generated by the same source. This noise cannot be filtered and can only be reduced by acoustical means. The use of damping materials and transducer design are used to reduce this noise including matching the transducers to the pipe (selecting the right transducers).

12.4 USFM - Ultra Sonic Flow Meter

The term USFM is applied to any ultrasonic flow meter, regardless of its technology, physical arrangements or flow analysis technique. The term can be applied to clamp-on time of flight, correlated signal as well as Doppler. The term also applies to in-line ultrasonic meters from the basic right up to the fully fiscal multi-chord systems.

13 LITERATURE

[1] Dr. B. Funck. Ultraschall Clamp-on-Gasdurchflussmessung in der Nähe der Einsatzgrenzen. 5. KÖTTER Workshop Gasmengenmessung, Rheine, Germany, März 2010
[2] Dr. R. A. Furness. Flow Measurement in Refineries. JDF and Associates UK, January 2007
[3] http://www.oilcoalgas.com/osha-delayed-coker-standards.html
[4] http://www.cape-sports.co.za/conversions/pressuredisplacement.htm
[5] http://www.pc-control.co.uk/piezoelectric_effect.htm
[6] Sim Romero. Delayed Coker Fired Heater Design and Operations. Brazilian Petroleum, Gas and Biofuels Institute - IBP, Rio Oil & Gas Expo and Conference 2010
[7] http://www.asiaprotech.com/emainset.htm?id=pro03&xcode=03

Ultrasonic Flow Measurement with Clamp-On Transducers

Keitmann-Curdes, O.

FLEXIM GmbH, Berlin, Germany

Keywords: Ultrasonic Flowmetering Clamp-On Transducer

Correspondence: Oliver Keitmann-Curdes,
FLEXIM GmbH, Wolfener Strasse 36, 12681 Berlin,
Tel.: +49-30-93667660, Fax: +49-30-93667680, ~~E-Mail: o.keitmann@ieee.org~~

Abstract—The paper provides an overview of the technique, the advantages and limitations of ultrasonic flow measurement with clamp-on transducers. Ultrasonic clamp-on flow measurement has the big advantage of being a contact-free, non-disturbing and non-intrusive method of flow sensing. Thus, it can be attached almost anywhere to a pipe without production interruption. Aggressive liquids as well as gases can be measured. Today, most manufacturers use the transit time method for flow measurement, where the difference in the time of flight of two signals is evaluated – one signal travelling upstream, the other downstream. For different media types (fluid, gas), there are also different transducer types available. A wide range of pipe dimensions is covered by providing a selection of transducers with frequencies in the range of 200 kHz to 8 MHz. For fluids, high frequency transducers which generate shear waves in the pipe walls are most common. For gases, low frequency shear wave or Lamb wave transducers are available. Current applications range from small hydraulic oil pipes in aircraft with low flow rates, to pipelines for crude oil or natural gas and sewage pipes of several meters in diameter. Contemporary devices often include a microprocessor for digital signal processing and for increased functionality. Thus, digital flow meters can take on the functions of a flow computer. This is useful for example in gas flow measurement and for applications in the hydrocarbon industry, where standard volume compensation is often required. This paper presents the technology and its theoretical background, as well as showing the range of applications and current limitations.

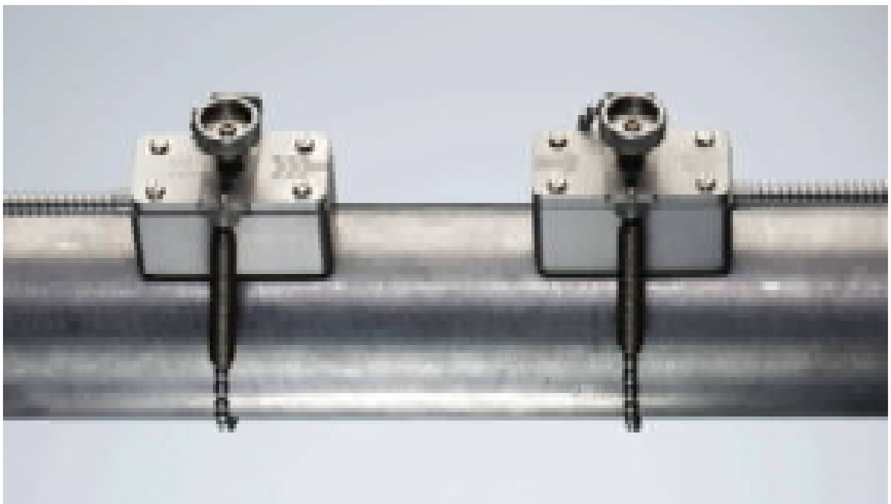


Fig. 1: Two clamp-on transducers on a steel pipe

I. Ultrasonic Clamp-On Flow Measurement

Ultrasonic flow measurement is done by inline systems as well as by Clamp-on type meters. While inline systems comprise a spool piece like all other flow meters, clamp-on systems consist of at least one pair of portable sensors together with the flowmeter hardware. Thus, the meter's most important advantage over all other flow meter concepts is its portability and universality. As the sensors are attached to ("clamped on", see fig. 1) the outside of an existing pipe, the measurement and all components are independent of the measured media and the medium pressure. The installation of clamp-on sensors is easy and can be performed without damaging the pipe, without any leaks and without interruption of the process. The installation position can easily be be adjusted and all these advantages are also true for any subsequent maintenance or servicing. The meter's cost-of-ownership is thus quite low.

Further advantages of clamp-on technology are bi-directional measurement and independence from static pressure drift, wear, humidity and thermal conductivity. Additionally, changes in the composition of the medium (fluid or gas) do not affect the measurement.

Especially for gas measurements there is no high pressure limitation and no special materials are needed for aggressive or harmful gases. On the other hand, gas measurements are more challenging than fluid measurements. As gases normally show a very low density, lower sound speeds and higher flow velocities, less acoustic energy can be transferred into the gas for the measurement and the soundpath is subject to beam blowing (see fig. 4).

Principles of Measurement

Most ultrasonic flow meters use the transit time method. Nevertheless, some devices use the Doppler principle which will be briefly mentioned first.

The Doppler principle is commonly experienced when hearing an ambulance driving past for example. The tone of the siren changes as the siren approaches and passes by. The same principle can be used for flow estimation and is widely used for medical applications. For industrial flow, the Doppler principle, which can only be applied where bubbles or particles are present in the flow, shows lower accuracy and lower robustness compared to the transit

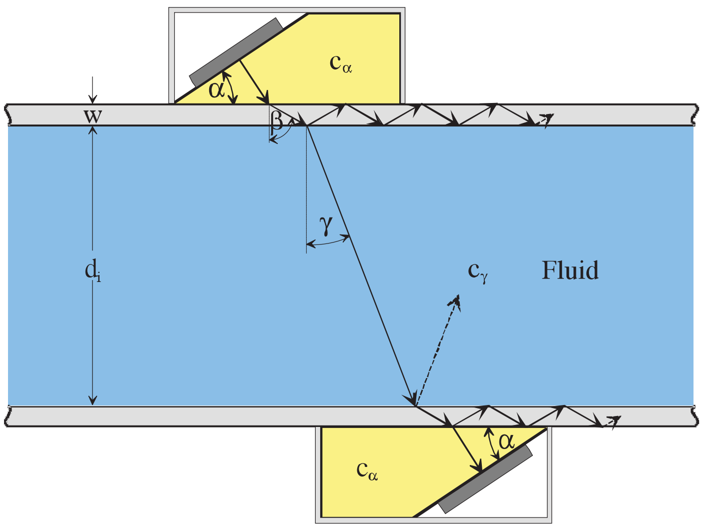


Fig. 2: Definition of angles and sound speeds for ultrasonic clamp-on flow measurements

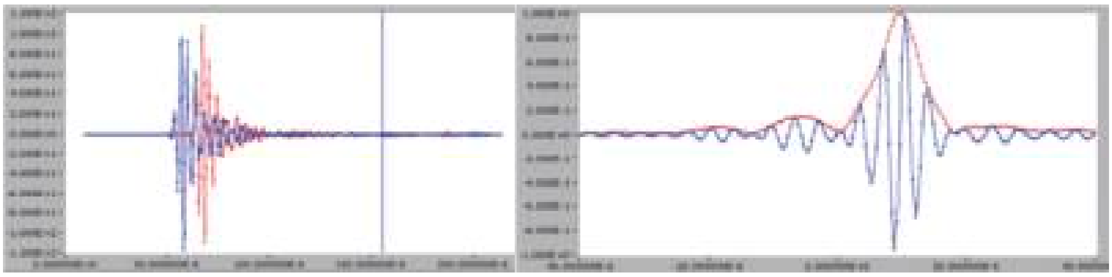


Fig. 3: Upstream and downstream signals with the presence of flow (left) and cross-correlation with envelope (right)

time method. Some flow meters can toggle between transit time and Doppler mode.
With the transit time method, which is the quasi-standard of the industrial ultrasonic flow measurement, ultrasonic pulses travel from one transducer to the other and vice versa. With the presence of flow, the pulse traveling upstream is slower than the pulse traveling downstream. The time difference Δt, the average time of flight $\bar{t}_{\text{fluid}}$ for both pulses and a sensor constant K_α determine the measured flow:

$$v_{\text{meas}} = K_\alpha \frac{\Delta t}{2\bar{t}_{\text{fluid}}} \tag{1}$$

The angle γ (see fig. 2) of the sound path in the fluid can be calculated from Snell's law and depends on the sound speed in the pipe wall and in the medium. Thus, it may be necessary to adjust the transducer positions during a measurement, according to the medium properties.
Modern flow meters incorporate a digital signal processor (DSP) for signal evaluation. Good noise suppression can be obtained by using the cross correlation (see fig. 3) of the upstream and the downstream signal for calculating the time difference.

Flow profiles and effects

The flow profile in a pipe depends on the Reynolds number which is given from the inner diameter di of the pipe, the flow velocity V and the viscosity of the liquid as

$$\text{Re} = \frac{d_i v}{\eta} . \tag{2}$$

Based on the Reynolds number and a flow profile model the meter calculates the fluid mechanical calibration factor which relates the average flow velocity on the sound path to the average over the cross section of the pipe and thus enables it to calculate the volume flow.
The Reynolds number is typically well above 10000 which means that the flow is in a turbulent state. Then, the fluid mechanical calibration factor is nearly independent of the Reynolds number. With Reynolds numbers below 2300 the flow usually is in a laminar state.

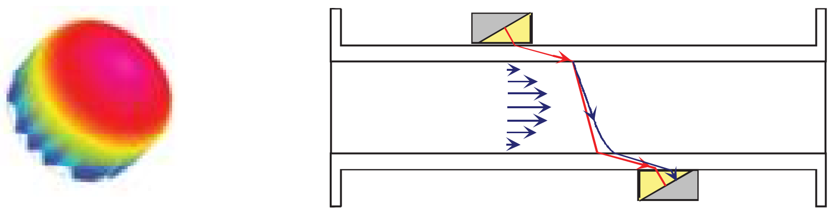


Fig. 4: Simulated fully developed turbulent flow profile (left) and beam-blowing effect (right)

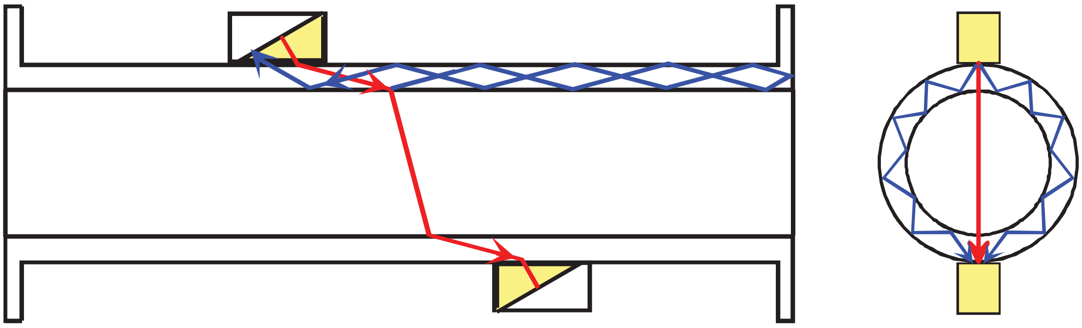


Fig. 5: Sound path of pipe noise generated by a flange and circumferencial pipe noise (blue) and original sound path (red)

In the transition range between laminar and turbulent flow the profile cannot be calculated. If the Reynolds number of an application is in the transition range a calibration at the site is required.

High flow velocity

As shown in fig. 4, the sound path can be “blown” by the flowing medium. With an increase in the ratio of flow velocity to sound speed of the medium, this effect also increases. Especially for gas measurements, as mentioned before, the beam blowing effect can require adjustment of the transducer positions to ensure proper flow measurement.

Different wave modes

In acoustics, different wave modes are used. In fluids only longitudinal waves can occur which are characterized by compression and decompression of particles in the sound propagation direction.
In solid media, additionally transversal waves, also called shear waves, occur. These waves, which show an oscillation of particles perpendicular to the sound propagation direction, can be found in the pipe walls.
The third wave mode of importance for ultrasonic flow measurement is the Rayleigh or Lamb wave. This wave mode exists only in plates (here: pipe walls) with a resonant size in relation to the frequency of the propagating wave. These waves can also only be found in the pipe walls. More explanations regarding when to use which wave mode in the pipe walls are given below.
Not all of the acoustic energy reaches the receiver in the direct way through the fluid. A portion of it travels through the pipe wall (see fig. 5) and some of this energy reaches the receiver at the same time as the fluid signal. This so called pipe signal is stronger when the acoustic impedance match of the fluid to the pipe wall is poor. This effect is negligible with

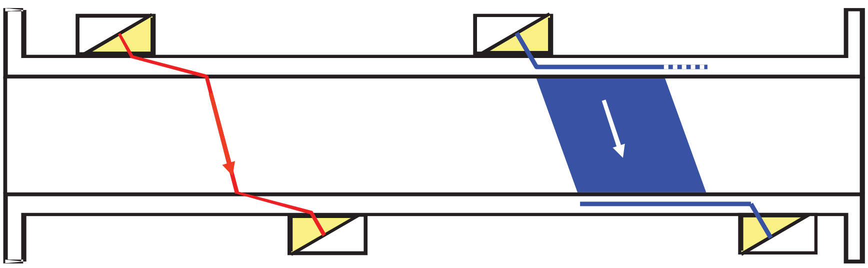


Fig. 6: Sound path of shear wave transducers (left) and Lamb wave transducers (right)

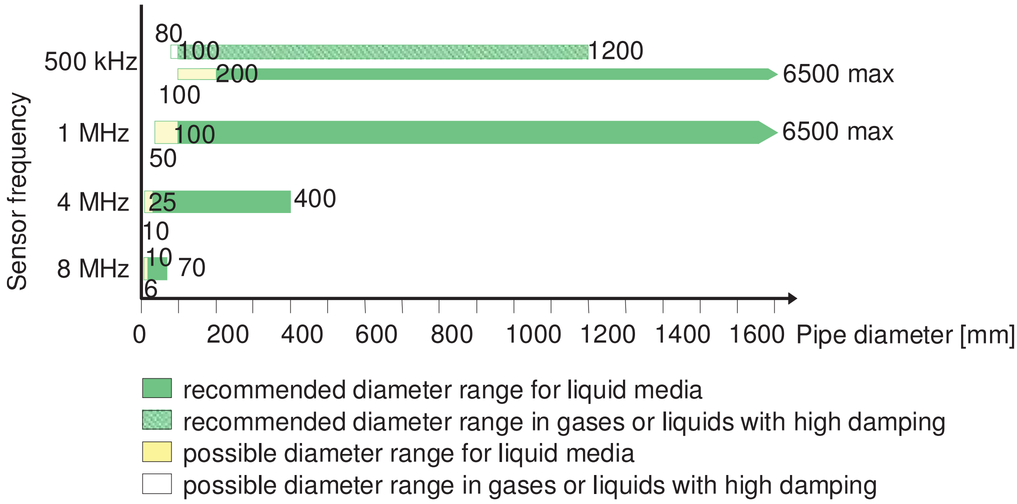


Fig. 7: Application range of shear wave transducers with frequencies between 0.5 and 8 MHz

liquids but it is an issue with gas. Sonic damping materials can be applied on the outer pipe wall to reduce such pipe signals.

Transducers

Most manufacturers provide shear wave transducers, which means that in the pipe walls of typical applications shear waves propagate (see fig. 6). For some applications, some manufacturers provide Lamb wave transducers, which generate Lamb waves in the pipe walls (see fig. 6).

Shear wave transducers can be used universally. They match nearly every pipe material and nearly every medium. The transducer and its angle α determine the sound path and thus the propagation in the medium. There is no upper limit to the wall thickness (see fig. 7).

Lamb wave transducers need to be matched in frequency to the thickness of the pipe wall. The transducer generates a Lamb wave in the pipe wall. This wave travels along the pipe

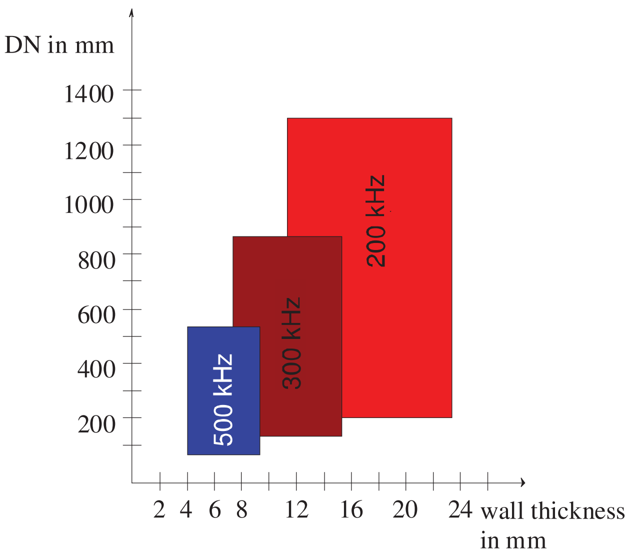
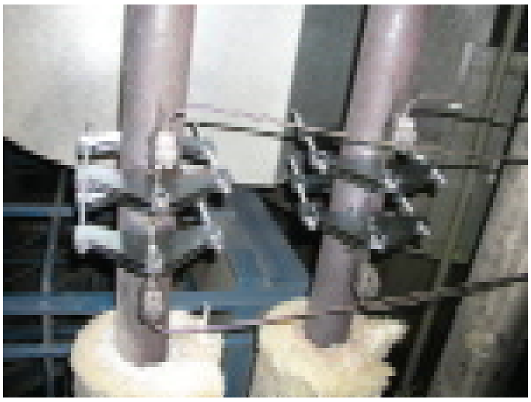


Fig. 8: Application range of Lamb wave transducers with frequencies between 200 and 500 kHz



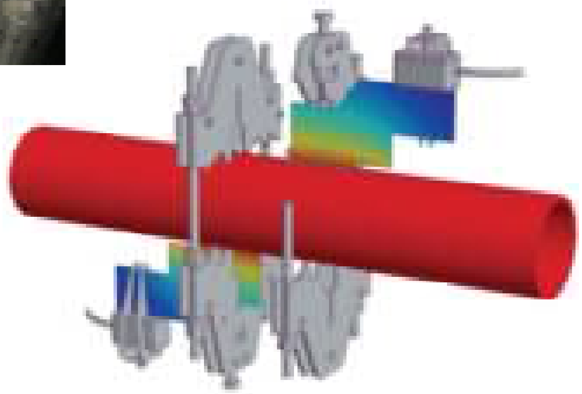


Fig. 9: Picture of a WaveInjector® installation (left) and simulation of the temperature distribution in the plates (right)

wall and by that transmits the waves into the fluid. One can say that “the wall becomes the transducer”. The advantage of Lamb wave transducers are a broad sound beam and more tolerance in transducer position. When tuned perfectly to a pipe wall, Lamb wave transducers are less affected by high flow velocities with respect to beam blowing (see fig. 8).

Shear wave transducers are commonly used for fluid applications. Lamb wave transducers are mostly used for gas applications with higher flow velocities.

High temperature applications

High temperatures decrease the lifetime of transducers and especially the piezo-elements within. For applications on hot pipes either special transducers made of special plastics or temperature insulators have to be used to make flow measurement possible.

One example for temperature insulation is the WaveInjector® from FLEXIM (see fig. 9). With the WaveInjector®, special plates assure that the temperature at the transducers do not increase above 120°C. By using the WaveInjector® the flow measurement is possible with pipe temperatures as high as 400°C. Typical high temperature applications can be found in refineries.

II. Oil & Gas Flowcomputer

Due to the rather strong temperature dependence on hydrocarbons’ density, their flow measurement is normalized to base conditions in terms of temperature and pressure. The normalization procedure is described in various standards as ASTM D1250, ASTM D4311 and TP25. This so-called standard volume compensation requires that the meter know the properties of all liquids flowing in the pipeline. The measured sound speed enables the meter to detect which of the liquids is present at a particular time.

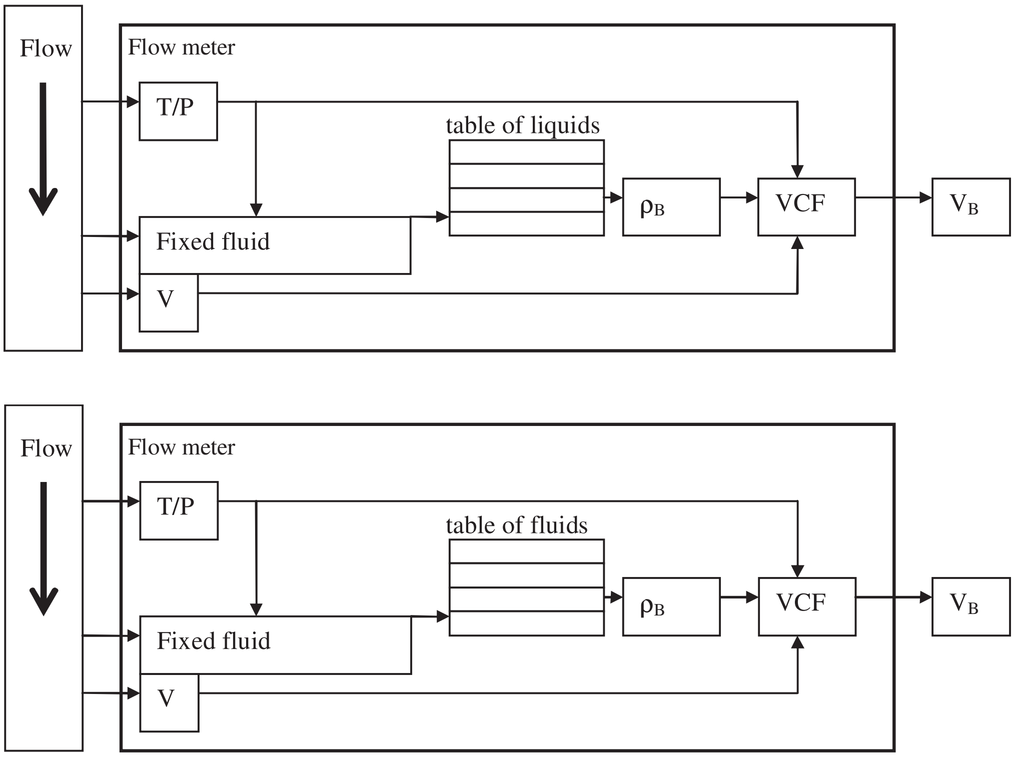


Fig. 10: Realization of fixed fluid flow meter for Standard volume compensation (above) and flow computer method with atomatic medium detection (below)

If the liquid is not an accurately defined mixture the measured sound speed can be used to estimate the density and provide an estimated mass flow. The arrival of a new liquid batch at a given point in the pipe line produces a rapid change of parameters as density and sound velocity. So, the liquid detection is also referred to as interface detection.

Interface detection and mass flow measurement with mixtures and undefined liquids

This is relevant to applications where either mixtures of liquids are flowing or different pure liquids are flowing successively. A liquid or a mixture of different liquids can be characterized by sound velocity measurement. The sound velocity normalized to base temperature can be calculated by assuming that all the application's liquids have the same temperature dependency $C_{subst}(T)$. The normalized density can then be calculated by further assuming a linear relationship between normalized sound velocity and normalized density.

The sound speed at base conditions is calculated from the measured sound speed at the measured temperature $c_{meas}(T_{meas})$ as

$$c_{meas}(T_{base}) = c_{subst}(T_{base}) + c_{meas}(T_{meas}) - c_{subst}(T_{meas}). \tag{3}$$

The estimated base density is then calculated from the relationship $\rho_{base}(c)$ between density and sound speed at base conditions as

$$\rho_{meas}(T_{base}) = \rho_{base}(c_{meas}(T_{base})). \tag{4}$$

This measured base density can be fed into a flow computer to carry out the interface detection and standard volume compensation. Also useful is the output of the API number and the derivative in time of the estimated density and the API number.

The meter can give an estimated mass flow using the relationship $\rho(c,T,p)$ between density and sound speed, temperature and pressure at flowing conditions to calculate the "flowing density":

$$\rho_{meas}(c,T,p) = \rho(c_{meas},T,p) \tag{5}$$

Fluid identification and standard volume compensation

To enable the flow meter to identify the liquid from a limited number of possible liquids, all these liquids have to be pre-defined. The standard volume compensation requires the following data as well as the usual fluid properties:

- The definition of the base temperature
- Density at base conditions
- Which method of normalization applies (ASTM 1250, ASTM 4311 or TP25)

The condition for unambiguous identification is that the difference in sound speed between the liquids within the whole range of temperatures is greater than the measurement error. It is not required that all liquids have the same temperature dependence. The fluid identification can be done by comparing the measured sound speed at a measured temperature $c_{meas}(T_{meas})$ with the sound speeds of all pre-defined fluids at the same temperature T_{meas}. After the fluid is identified, the standard volume compensation can be calculated.

III. Outlook

In the future, gas measurement will become more and more standard with ultrasound. For fluids and gases, measurement of media at very low temperatures (e.g. liquid gases) will become possible. Prospects for future developments also include flow measurement of steam lines as well as low pressure gases in steel pipes.

IV. Acknowledgements

We would like to thank all colleagues at FLEXIM for support during the preparation of this paper and for supplying information and images. Moreover, we would like to thank flotek.g for the invitation to give a key note lecture.

V. Bibliography

[1] ASTM D 1250-80: Petroleum measurement tables. Volume X-Background, development and Program documentation. American Society for Testing and Materials. 1980 (Reapproved 1997). ISBN 0-89364-033-6. (Page X-73)

[2] ASTM D 4311-04: Standard Practice for Determining Asphalt Volume Correction to a Base Temperature.

[3] TP-25. Temperature Correction for the Volume of Light Hydrocarbons Tables 24E and 23E. ASTM, API, GPA. 1998

[4] Manual of Petroleum Measurement Standards, Chapter 11.2.

VI. Authors

Oliver Keitmann-Curdes (Senior Member IEEE), born 1974, studied Electrical Engineering (Dipl.-Ing., comparable to M.Sc.) at Ruhr-University Bochum, Germany. In 2000, he started his scientific work at the Institute of High Frequency Engineering in Bochum (Prof. Helmut Ermert). His ultrasonic research dealt with an ultrasonic transmission camera and ultrasonic non destructive evaluation. Oliver Keitmann-Curdes worked on the simulation of ultrasonic wave fields, the optimization of beamforming parameters, experiments with ultrasound contrast agents in transmission mode, the design and development of single element ultrasonic transducers for the application in NDE and 3D contour detection. He has authored and co-authored more than 20 scientific papers (four of them in peer-reviewed journals, one book chapter and one patent application). Since May 2006, Oliver Keitmann-Curdes has been employed by Flexim GmbH, Berlin, Germany, where he works in the R&D group for ultrasonic flow meters. His expertise in the field of flowmetry includes sensor design, signal processing and application support.

Presenters:

Lalit Mohan   Flexim Instruments Asia Pte Ltd

Lalit Mohan is a Graduate in Chemical Engineering from **Dr. S. S. Bhatnagar University Institute of Chemical Engineering**, Panjab University, Chandigarh, India. He has over 19 years of experience in Sales & Marketing of process instrumentation and automation in India and overseas with various MNC's. Currently working as Country Manager – India with Flexim Instruments Asia Pte Ltd.

Predictive emission monitoring system (PEMS) , an inferential way of emission monitoring as a viable complementary emission monitoring technique for Indian Industry

By:-Sourav Mukherjee(Sr. Engineer(Inst.) Engineers India Limited), R. Priyamvada (GM E&I, Engineers India Limited), NarendraKakar (AGM (inst.) Engineers India Limited)

Introduction:

Modern day oil and gas industry constitute of major process and rotary equipment like heaters, turbines etc. working 24X7 to maintain plant uptime. However, such equipment contributes to emission of gasses like SOx, NOx, CO2, SO2 hydrocarbon etc. to the atmosphere. The environmental guidelines have become more and more stringent in terms of total allowable hydrocarbon discharged to atmosphere through such emission installations. All oil & gas installations shall meet emission norms as outlined by the regulatory authorities.The environmental guidelines mandate continuous monitoring of such emission. Typical Indian oil and gas industries use continuous emission monitoring systems(CEMS) to monitor such emissions via analyser systems with live data being transferred to the regulatory agencies(Central Pollution Control Board) directly from the analyser data monitoring servers. Industries ensure that the emission levels lie within the mandates of central pollution control board. (For example, the Central pollution control board limits the NOx content for furnaces to be less than 250mg/Nm3). However, such systems require installation and maintenance of a number of analysers monitoring the emission of gasses (Hydrocarbon, SOx,NOx,CO2, SO2 etc.) near the major emission causing sourcesall the time.The environment regulations also stipulate uptime of analyser data. Over the time, analysers become complex and leads to high CAPEX. For example, it becomes necessary to use shelters with HVAC systems , where the combined installation cost of the analysers with shelters. Few examples of major emission causing sources are Heaters, reformers,reboilers, GTGs etc.

This calls for a need of a more cost effective and practicable solution for monitoring emission.***In the global oil and gas industry of today, evolution of advanced inferential methods for emission monitoring i.e. PEMS(predictive emission monitoring system) has been a game changer in the field of emission monitoring.***First introduced in USA , this is a software tool which "predicts" the possible pollution levels from the plant performance rather than actually measuring the emissions. Under the US environmental guideline EPA 40 CFR Part 60 regulations, PEMS are acceptable for monitoring emission as an alternative to continuous emission monitoring systems, subject to quarterly validations. Already the PEMS method has gained ground in the middle east as well .

2.0 Overview ofContinuous emission monitoring (CEMS)

Continous emission monitoring or CEMS has been the traditional method of emission monitoring. The overall system concerns use of analysers for emission monitoring and subsequent online reporting to the regulatory authorities. The following system for emission monitoring and reporting is currently implemented over typical refineries and petrochemical complexes.

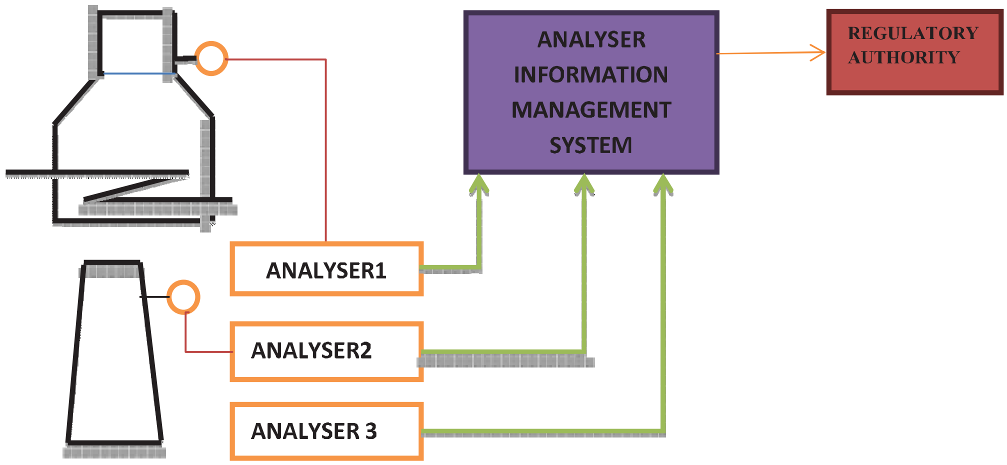
i. The emission from the pollution emitting sources like stacks, flare system is monitored by Online analysers.
ii. The emission values from the analysers are fetched by the analyser information management system(AIMS).
iii. The emission data is transferred from the AIMS to the CPCB server via a firewall at regular intervals.

iv. The maximum emission rates are defined as per **STANDARDS FOR EMISSION OR DISCHARGE OF ENVIRONMENTAL POLLUTANTS by CPCB.**

v. For testing the accuracy of the analysers, samples are collected from sample points in sample bombs , time stamped and sent to CPCB accredited laboratories for testing.

vi. Test results are matched with the analyser readings recorded at the time the sample was collected.

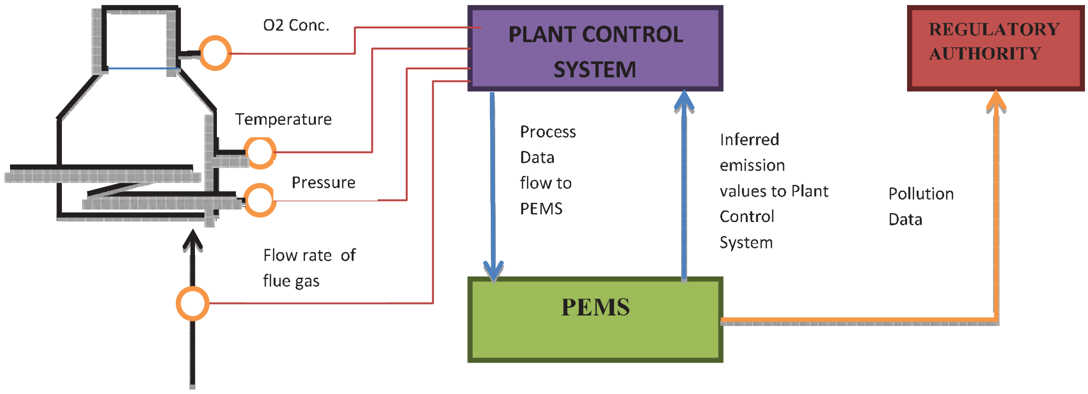
vii. In case the analyser readings match the lab test results, then the analyser is certified as OK.



3.0 Overview of Predictive emission monitoring system (PEMS):

Considering the fact that the equipment/machinery which are the major emission causing sources can be easily identified, hence emission from these sources can be calculated using mathematical modelling tools which takes necessary process variables as inputs and evaluate the emission levels for those process conditions. The predictive emission monitoring system (PEMS) is such a mathematical model based system which efficiently evaluates emission data using inferential methods.

This system comprise of a standalone server based system which takes in necessary process parameters which influence emission from the plant control system (DCS system), applies mathematical functions to evaluate the emission values(SOx, NOx, SPM etc.) from those process parameters. These inferred emission values arethen transferred back to the plant control system.As per the mandates of environmental agencies, this emission data is then transferred to the database of environmental agencies.



Effective implementation of PEMS system involves various stages.

The first stage and foremost stage is proper modelling of the plant with identification of equipment/machinery/systems which are major sources of emission. Usually heaters, incinerators, burners etc. are few such equipment which cause major amount of emission.

Once the equipment are identified, the available process parameters which are required for calculating the emission from that system are identified and boundary conditions for that equipment is defined. In defining the boundary condition, it is specified the range of operation for the equipment for which the PEMS data is accurate within permissible limits of deviation and can be used by the environmental agencies to monitor emission.

Once the models are developed, the system in installed in the control room and necessary data exchange with the plant control system is established. Process related information and final output can be exchanged with the control system over MODBUS RS 485 or TCP/IP .

This is followed by validation process. The validation process involves a real time test audit(RATA) employing a third party agency. The typical method of validation is employing an accredited third party agency which measures the emission from the targeted equipment using mobile analyser systems during equipment operation within the defined boundary limits. The model is first calibrated using these results, and later, the emission figures predicted by the model is compared with the figures measured online by the analyser systems of the third party agency. Once the PEMS predicted values are found to be above 99% accurate in predicting emission levels, the system is certified for operation. This process of validation has to be conducted once in three months as per of the EPA standard(EPA 40 CFR 60 Guideline 2).

4.0 PEMS implementation rule set

The following section discusses an approach to implement the PEMS. The rule set is reproduced from US EPA guidelines for PEMS.

4.1 APPLICABILITY

1. ***Plant, its location, and emission causing unit shall be identified first***
2. ***Type of industry shall be identified next.*** This is important because the environment regulations are usually defined based on the type of industry under consideration.(Refinery, petrochemical complexes etc.).
3. ***Equipment of interest shall be identified.***
4. ***Regulations applicable to the industry and locations shall be enlisted*** (National as well as state environmental regulations for the concerned category of industry with clear indication on the maximum possible emission boundary limits of the pollutants).
5. ***Pollutants subject to monitoring shall be identified*** (SOx, NOx , CO, SMP etc).

4.2 SOURCE DESCRIPTION

1. ***Equipment operations and conditions that are known to significantly affect emissions or monitoring procedures along with the frequency of occurrence of such events in case shall be identified*** (product changes etc.).

4.3 MONITORING SYSTEM DESIGN

1. ***System related description of the system used for the monitoring the emission shall be studied*** This step is extremely important because the equations and algorithms used for the PEMS may require systems with advanced control equations capability. Hence, choice of control system shall be made keeping in mind the equations and functions the system has to execute. Besides, the system shall meet additional requirements like communication with the plant control system over serial bus or OPC.

2. ***All components/process variables etc. which are available forcalculation/evaluation shall be enlisted.***

3. ***The necessary equations and transfer functions involved in the deduction of the various pollutants from the other process parameters shall be identified.*** The equations which shall be used for evaluating the constituent pollutants has to be formulated. This is the most critical step involved in proper functioning of the overall system. While deriving the equation, the available parameters i.e. the variables which are actually measured during normal process operation shall be kept in mind.

4. ***Boundary conditions for which these equations are valid shall be identified.*** The derived equations may work in a given set of boundary conditions.

4.4TESTING

The developed model shall be thoroughly tested initially simulating the necessary real time conditions. However, the practical model simulation EPA 60 guidelines mandates the RATA for system in the following procedure.

a. The most significant independently modifiable parameter(SIMP) for the transfer function used to evaluate pollutant concentration shall be identified. For example, for heaters, Oxygen concentration is the most significant parameter affecting the NOx concentration and firing rate is the SIMP for CO concentration (EPA 40 CCFR 60).

b. An industrial sample van equipped with analyser systems shall be located to the equipment and the data is collected by varying the concentration of the SIMP after a fixed duration. (for example, for furnace heaters , initially the firing rate will be varied from maximum to normal and then to min. for a period of 23 minutes each and CO values are measured by the calibrating vans as well as the PEMS. Similarly, the firing is kept constant and the Oxygen concentration is varied and the NOx concentration is measured refer EPA 40 CCFR 60).
c. The deviation between the PEMS data and the analyser data shall be less than 2%.
d. In case a particular sensor fails to give reading, in that case, the PEMS software shall be able to detect that failure and give an alarm indicating that the output of the PEMS may be erroneous due to non-availability of a critical parameter in the equation.

From the above it is clear that the PEMS is a globally accepted methodology with well defined implementation guidelines.

5.0 Methods of determination of PEMS transfer functions and equations

5.1 Parametric method or method of 1st principle

In this method, the transfer function of emission is expressed as a simple transfer function of a few number of input parameters.

For example, $P(CO) = K * C(O2)^{R} * T^{s}$

Where, K is a coefficient(O2) is oxygen concentration in the heater furnace

R,S is constant

T is furnace temperature

The major advantage of this model based technique is that it is a simple method of determination and it is easy to implement. Also, no historical data required

The major disadvantage is that this method works well for the normal operation however it does not cover the entire range of operation well.

5.2Statistical hybrid model

The statistical hybrid model actually uses the benefit of large capability of data processing in modern day computers. This technology is also dependent on data analysis method. This method works on following steps.

i. The statistical data of the pollutant concentration and the other available parameters are stored.
ii. The concentration of pollutants are expressed as concentration of all N parameters through a statistical function.
iii. Similarly, a number of equations are derived gradually removing one parameter for each equations.
iv. Finally, during operation, the parameters are checked and using these models, the concentration is evaluated. Depending upon the availability of parameters, the necessary equation is chosen for which all parameters are available.

P(N) is the concentration of pollutant.
F1, F2, F3, …Fn are the other process parameters which are measured.

Method 1;- P(N) = f1(F1,F2,F3…Fn) when all parameters are available.
Method 2:- P(N) = f2(F1,f2,F3,…F(n-1))when Fncan not be measured
Method R:- P(N) = fR(F1,F2,F3…FR), when Fn, Fn-1, Fn-2, Fn-3 .. FR-1 parameters are not available.

The major advantage of this technique are that this model can predict the outcome at the start-up and shutdown more accurately. Also, Very accurate in predicting the outcome for normal operation also, since the equation itself used during the normal operation and during start-ups and shutdown conditions change. As a result, the accuracy levels meet the US EPA CCFR 75 requirements.

However, the major disadvantage is that the model is not self learning. Hence, the statistical equations developed during testing remains as it is later on.

Accuracy depends upon the data provided during the simulation. In case the simulation data is insufficient in terms of the later equipment running cycle, then the entire model will fail , as this is not self learning.

5.3 Data driven model using artificial neural network

These model employ artificial neural network delta method to determine the concentration of the pollutants. They do not work on a specific set of values. Instead, initially the output is expressed as a combination of variables with a number of weight factors or nodes.

i. An artificial neural function with various weight factors or nodes is written for the pollutant concentration.
ii. The test data for the equipment operation is fed and the system processes the data and keeps on updating the weight functions to fit the final output concentration.
iii. The more the data , the better the weight functions get tuned to predict the outcome accurately.

P(pollutant) = w1* F1 + w2*F2 + w3* F3 + w4*F4 ……+ wn* Fn

Where w1, w2,w3… wn are the nodes
F1, F2, F3, …Fn are the other process parameters which are measured.

For example, for determining the emission of CO in a heater where the following paramaters are available to us, Feed type(FT), Firing rate(FR), Fuel gas density(FGD),preheat temperature(T),Percentage oxygen(O), Stack temperature(Ts), Inlet air humidity(H)- Inlet air temperature(Ti)

P(CO). the concentration of CO released to atmosphere is expressed as

P(CO) = W1* FT +W2* FR +W3 * FGD + W4*T + W5 * O + W6 * Ts + W7 * H + W8 * Ti

Here, the weight function W1 to W8 are the nodes. Learning data or test data is entered into the system and the system evaluates these nodes. As more data is fed, the model keeps refining these nodes.

Major advantages for this method is

a. Actual mathematical modelling of the equipment from 1st principle is not required.

b. If modelling is properly done keeping in mind only those parameters to which the output is sensitive, high accurate outputs are achieved which meets the US EPA 40 CCFR. 75 requirements.

However, there is a disadvantage that this model is not evolved enough during initial start-up and shutdowns as the model is not evolved sufficiently for such conditions. However, gradually the model starts predicting the emission levels accurately even for the start-up and shut down conditions as it self learns and evolves with time.

7.0 From CEMS to PEMS (Roadmap for Indian industry)

For Indian industry, the challenges for implementation of PEMS are quite different, since this technique is novel to the Indian industry.

Following steps broadly clarify the necessary steps:-

APPROACHING THE CENTRAL POLLUTION BOARD FOR ACCEPTING THE PEMS AS A ALTERNATIVE METHOD FOR EMISSION MONITORING FOLLOWING THE US EPA MODEL.

SELECTION OF THE MOST APPROPRIATE & SUITABLE METHOD OF MEASUREMENT

INTEGRATION OF PEMS SYSTEM WITH PLANT EMISSION MONITORING SYSTEM

CHECKING FOR THE FEASIBILITY OF VARIOUS SUPPORT SERVICES REQUIRED FOR PEMS W.R.T. INDIA

MARKET RESEARCH ON THE ACCEPTANCE OF PEMS FROM THE END USER

A. APPROACHING THE CENTRAL POLLUTION BOARD FOR ACCEPTING THE PEMS AS A ALTERNATIVE METHOD FOR EMISSION MONITORING FOLLOWING THE US EPA MODEL.

The US EPA standards (followed worldwide) does allow PEMS as a viable method for emission monitoring. 1st of all, a necessary initiative has to be taken to get the PEMS approved as an alternate way of emission measurement to the Indian regulatory authorities citing references from the US EPA as well as various countries along the world which have accepted the use of PEMS (For example, UAE) .

B. SELECTION OF THE MOST APPROPRIATE & SUITABLE METHOD OF MEASUREMENT

As discussed before in this write-up, there are three methods by which the PEMS model can be developed. V.i.z.

i. The first principle method
ii. The Neural Network based model
iii. The statistical regression model.

A number of vendors offer different solutions from all of the three methods.

C. INTEGRATION OF PEMS SYSTEM WITH THE PLANT EMISSION MONITORING SYSTEM:-

In case the refinery / petroleum complex has an existing CEMS based emission monitoring system , then the data from PEMS system can be sent to the pollution board server by connecting to the existing system using TCP/IP.

PEMS can be used as a standalone system communicating with the pollution board server directly also.

D. CHECKING FOR THE FEASIBILITY OF VARIOUS SUPPORT SERVICES REQUIRED FOR PEMS W.R.T. INDIA

The most important support service required for the success of the PEMS is the availability of the agencies to carry out RATA tests. Since the concept is novel to the Indian markets, no such agencies exist. Capability of agencies which integrate analyser systems and provide support service in India can tapped in provide necessary services required for RATA. Specially analyser accessory suppliers and calibration gas manufacturing companies can also cater to this requirement efficiently adding the "***make in India***" flavour to this initiative as well.

E. **MARKET RESEARCH ON THE ACCEPTANCE OF PEMS FROM THE END USER**

Although the PEMS is a success story in the middle east, in order to make inroads in India, it is important to understand how the Indian industry will respond to it. For projects where new emission monitoring requirements exist, PEMS can be a viable option. For the existing systems where CEMS based systems are already functional , a PEMS based system can work as a back-up.

Benefits of PEMS in Indian Oil and gas Industry

Benefits:-

1. **Model Based approach saves the cost of expensive stack monitoring analyser systems:-**
   The initial installation cost of this system is much lesser than the installation cost of online analyser systems.

2. **Reduction in maintenance cost of the analyser systems:-**
   The maintenance of analyser systems, necessary inventory management of spares, procurement of calibration gas cylinders etc. are no longer required with the PEMS system. PEMS system is an easy to maintain system with no requirement of such hardware.

3. **Fail safe system:-**
   The PEMS system is a redundant server based system which has much lesser probability of failure when compared to the online analyser systems. This gives added benefit to the end user.

8.0 Conclusion

There are major economic benefits in implementing the PEMS system over traditional Continuous emission monitoring systems using analysers. Cost of installation of a number of analysers for emission monitoring is huge, whereas, in comparison a single server based system shall be much more economical in terms of initial investment. As far as maintenance cost is concerned, an analyser maintenance involves inventory costs for maintaining necessary spares, zero and span gas cylinder costs and their re-procurement as per the expiry dates and validity. There are major expenses as man power cost in terms of skilled man-power to handle the analysers. These days most of the production companies are keeping vendor personnel stationed as a part of comprehensive maintenance contract. In contrast, the PEMS calls for cost involved in validation once in every three months. Since the process data is fetched by the server from the plant control system, hence no hardware whatsoever is needed in the field.The PEMS based systems are successfully implemented by refineries in middle east as well. In India also, a number of production companies have started adopting the PEMS system as a back-up to the existing CEMS system. The time is ripe for this new technology to make a major breakthrough in the landscape of industrial emission monitoring in India.

9.0 TABLE INDICATING THE FEASIBILITY OF PEMS AND CEMS FOR FEW MAJOR EMISSION CAUSING EQUIPMENT IN A TYPICAL REFINERY COMPLEX

S. NO.	Unit	Equipment	Emission monitoring
1.	Sulphur recovery Unit(SRU)	Tail Gas incinerator stack	CEMS for SO2 & O2 PEMS for balance
2.	CDU/VDU	Crude Heater& vacuum heater stack	PEMS
3.	NHT-CCR	Reformer Heater stack	PEMS
4.	Offsite	Boiler	PEMS
5.	Gas oil HDT	Charge heater stack	PEMS
6.	Offsite	HC Flare	PEMS
7.	Hydrocracker	Fractionator feed heater	PEMS
		GO stripper reboiler	PEMS
		Debutaniser reboiler	PEMS
8.	U&O	GTG	PEMS

Industry 4.0 : A Futuristic Automation

Introduction

Industrial revolution started with the discovery of Steam engine by James Watt. Before industrial revolution it was purely agriculture based economy; land and manpower were considered as the most precious possession for any country or kingdom. Industrial revolution lead to a paradigm shift where countries or regions with more advanced technologies started playing a dominant role. It leads to the concept of Capital Economy or Capitalism and Banking system which were hitherto unknown to the people. In a way it completely changed the society or business used to function and even kingdoms and their rulers; first in Europe and then in the rest of the world. It gave rise to industries driven by big machines and a new working class of people known as the Middle Class. Since then human society has undergone through many ups and downs including two World Wars where technology played a decisive role giving birth to a new Military-Industrial complex. Since then most technologies are first used in defense and space industry before they are launched for commercial applications.

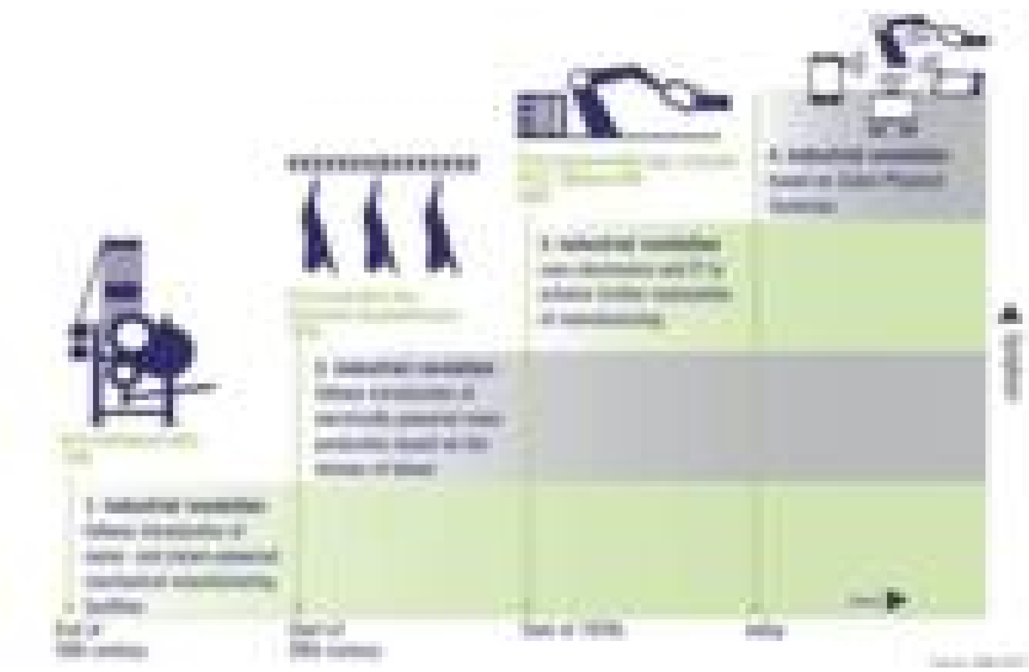
Let us have a look at the Industrial revolutions till date

First: The introduction of steam turbine and mechanical production

Second: The age of automobile and aircraft, mass production with the introduction of assembly line by Ford company.

Third: The era of Electronics and IT industry

Fourth: Embedded computing, usage of cyber physical system, IIoT. Industry 4 represents the evolution from embedded system to cyber physical system



The term Industry 4 was coined in Germany as part of their strategy for futuristic automation. The concept of High Tech Strategy was introduced in August 2006 with the objective of bringing all stakeholders of innovation and technology on a common platform to develop a roadmap for futuristic automation. The vision of High Tech Strategy 2020 was approved by the German Cabinet in July 2010. High Tech Strategy 2020 was developed aiming to provide cutting age technology and solutions in the field of

- Climate/ Energy
- Health/ Nutrition
- Mobility
- Security
- Communication

One important aspect of Industry 4 is analysis of Big Data. Real time data of a manufacturing unit or process plant can be used to avoid unplanned shutdowns and loss of production through implementation of predictive maintenance. Embedded sensors can help us understand the exact condition of the trays of a distillation column or the tubes of furnace in a running unit. It will facilitate in developing better metallurgical solutions for handling very difficult processes and fluids. This can help extend the turnaround cycle and contribute significantly in enhancing productivity. Those days are not very far when Refinery Units and other units which forms an integral part of the Oil & Gas industry will go for turnaround once in 10 years instead of 5 years or lesser time period followed presently. That way we will have 2 -3 turnaround in the entire lifetime of a Plant. The feed rate of an unit can be optimized based on the conditions of its major equipment. Also material planning for a turnaround can be done more efficiently as knowledge about the exact condition of the equipment would be available.

Industry 4.0 objectives:

The main objective of Industry 4.0 is to achieve manufacturing of tailor made smart products with the help of low cost production facilities, which in line with the intelligent products and smart production process. Machines and equipment in the future are going to be intelligent machine and equipment with using the fundamental technologies like cyber- physical system(CPS) and internet of things (IoT).

Intelligent products: Smart products will play a vital role in the product life cycle by their unique ability of knowing their own history, current status and reacting or responding to it proactively. Sensor technologies like acoustic wireless transmitter will let us know the condition of control valves and steam traps which then can be easily monitored and corrective action taken.

Smart production process: From concept to design to manufacturing the entire process is integrated through intelligent network and machines/ equipment spread over a wide geographical area often across continents. This will involve extensive use of machines and equipment with embedded sensors and Artificial Intelligence that will analyze the real time data from different equipment / machines and convert it to useful information impacting the decision making process and strategies of companies.

Some of these have already started to happen in manufacturing products with very specialized design. Once the 3-D Model of the desired products are finalized a process called Direct Metal Laser Sintering (DMLS) process is used to manufacture those specialized products or machine parts. The DMLS process involves the use of metal powder layers melted by laser rays to create the desired object. Products of any geometrical shape or design can be manufactured which are beyond the limits of traditional manufacturing process. The amount of metal or material loss involved in traditional casting process will be reduced to negligible levels in the DMLS process.

Smart factory units will communicate with each other over wireless network enabling optimized production. Product Assembly lines will no longer be fixed or standard but flexible and can be manipulated depending on the design of end product. A number of intelligent machines will interact with each other in an asynchronous manufacturing process. Extensive use of robotics and even bio-robots will be a key feature of this manufacturing process. In this system components are automatically identified and information is passed on to each machine and operator to enable the manufacturing of customized end product. Small batch of products can be manufactured even up to the e level of a single unique item.

Smart Manufacturing Leadership Coalition (SMLC) founded in the US has similar objectives as Industry 4 although it is not exactly the same as Industry 4. This involves cloud based open architecture manufacturing through collaboration of innovative ideas and thoughts across the industry.

Key Challenges:

There are several barriers for adoption of Industry 4.0 which need to be overcome. The most important challenges include the standardization of IIoT, work force competencies for new skill sets, cyber security, research, training and new business model.

Industrial Standards for IIoT are required, that will allow the smart and embedded devices to interact with other smart machines and devices in a transparent fashion and with an option of interoperability.

Data integrity and security is also another great challenge, which demands a good IT infrastructure, services, protocol and security measures. All the cyber components shall be highly secured and certified by cyber security experts for any cyber threat and attack.

For industry 4.0 highly skill-set work force required to run industry on an IIoT-based system. A significant amount of industry4.0 concepts, courses and trainings will be conducted for familiarization with the new industrial concept and new skill-sets.

Most of the automation devices comes with the diagnostic feature but in addition to diagnostic feature the devices will be designed in a way that can easily identify the problem cause. This will ensure that a malfunctioning or inoperable system can be restored quickly.

The challenges can be overcome by industry 4.0 concept newsletters awareness, sharing experiences, working committee reports circulars, industry 4.0 concept courses and trainings.

Futuristic Impact

Industry 4.0 will have great impact on the manufacturing companies by making more efficient and productive components. Since the response times will drastically shorten due to smart and embedded products, it will completely change the business model to an out-come based approach.

Combination of Embedded sensors and artificial intelligence are going to revolutionize the Process and Manufacturing industry and the way business is done today. It will also require a close collaboration between research institutes, industry and universities. Automation professionals will be instrumental in bringing about this revolution and they will be the flag bearers of the change and disruption that we are going to experience in the coming days.

- Atanu Ghoshal
- Vidhya Ratna Pal

DESIGNING THERMOWELLS IN ACCORDANCE WITH ASME PTC 19.3 TW-2016

Vikas Lodhi (Senior Engineer), Prateek S. Virdi (Engineer)
Bechtel, India

Abstract

Temperature is the most often measured process variable in Oil and Gas Industry. Its accurate measurement is critical to ensure the product quality, process efficiency and safe operation. There are many ways to measure temperature depending on criticality and application.

The assembly of temperature sensor (RTD or thermocouple) and thermowell is the most common method of measuring the process temperature. By using a thermowell, the sensor is immersed in the process fluid for direct and accurate measurement of temperature, but it also creates many complex design issues with risks of creating a potential leak point. Several thermowells designed in accordance with relevant industry standards have failedleading to catastrophic consequences. In Monju, Japan (1995), a failure occurred with a thermowell mounted in a pipe carrying liquid sodium coolant resulting in loss of containment of liquid sodium. When investigated, it was found that the thermowell failed due to intense vibration and exposed several weaknesses in its design methodology.

Prior to the incident mentioned above, the thermowells were being designed in accordance with ASME PTC 19.3 TW-1974. After this incident, there was a need to revise this standard, which lead to release of its 2010 version in which various parameters such as Scruton number, drag/inline frequency, cyclic stress, pipe thickness, etc.are stated and are to be considered during wake frequency calculations of thermowells.

As of today,ASME PTC 19.3 TW-2016 is the latest industry wide accepted standardto perform complex thermowell wake frequency calculations.

Wake frequency calculations should be done at different process scenarios like start up, operating (maximum/normal/minimum) and upset conditions. If not done, then it could lead to failure of thermowells.

The four quantitative criteria emphasized in ASME PTC 19.3 TW-2010 for a thermowell are:
1. Frequency limit
2. Dynamic stress limit
3. Static stress limit
4. Hydrostatic pressure limit

By following the intent of these standards, failure of thermowellsand the total installed cost can be minimized.

This paper comprises of major changes which have evolved in ASME PTC 19.3 TW from 1974 to 2016 and other industry standards which should be referred while designing thermowells to avoid irreversible damages.

Comparison between 1974 and 2010 version

ASME PTC 19.3-1974 requires process data and the thermowell material information for

1. Calculating the natural and Strouhal frequency and meeting frequency ratio (f_s/f_n) less than 0.8.
2. Calculating the bending stress or steady state stress to check the maximum unsupported length.
3. Comparing maximum design pressure with process pressure.

1974 version ignored the effects of different stem profiles such as straight, taper and stepped which are covered in 2010 version. Thermowell of different bore dimensions shared the same constant in equations of 1974 version. 1974 version used a fixed Strouhal number of 0.22 whereas in 2010 version Strouhal number was made a function of Reynolds number. As a conservative case 0.22 can be taken if the designer cannot establish dynamic or kinematic fluid viscosity to determine Reynolds number.

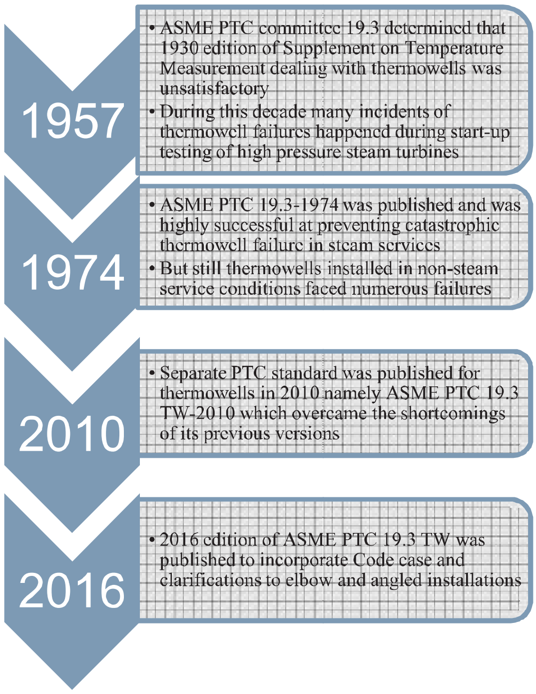
1974 version conceived that thermowell vibrates in only one plane transverse to the flow. The thermowell vibrates in an oscillating fashion which also include an inline component which was missed in 1974 version.

ASME PTC TW-2010 includes the effect of flow induced inline stressin determining the frequency limit for thermowell stress calculation in addition to transverse stress. In-line resonance happens at half the frequency (and hence half the velocity) of transverse resonance. While in-line resonance is not typically an issue for gas systems, it is a serious issue for liquid systems and has resulted in many thermowell failures in past.

Comparison between 2010 and 2016 version

The latest 2016 version include the reference of ASME B40.200 for standard design of thermowell.
2010 version gives no meaningful guidance on the installation of thermowells in an elbow or angled installation.However,2016 does give brief insight about elbow and angled installation, but still the calculations of thermowells in these installations are out of the scope of standard. In such cases the bending stress shall be calculated based on computation fluid dynamics or experimental measurement.
PTC 19.3 TW-2016 states the requirement of minimum tip thickness of 3 mm whereas nothing is mentioned about this in 2010 version.
Furthermore,2016 version of standard also limits the usage of thermowell dwelling in inline resonance region though they had passed the static and dynamic stress and the change in compliance to frequency limit for low density gases.

Chronology of ASME PTC standards



ASME PTC 19.3 TW-2016

Basic Intent

Mechanically design a thermowell (of straight, tapered or stepped shank) which can perform reliably in a broad range of service applications.

Prerequisites before designing thermowells in accordance with this standard

- Intended installation
- All possible operating process conditions (minimum, normal, maximum, start-up, shut down, upset, pressure relief, etc.) are available
- Flange rating and the attachment method should follow the established standards
- Thermowell material should be compatible with the process fluid, pressure, temperature, fluid velocity, application, weldability, etc.