Appendix 1

List of participants
Participants EFC WP15 meeting 7th September 2011 Stockholm (Sweden)

<table>
<thead>
<tr>
<th>Name</th>
<th>Company</th>
<th>Country</th>
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<tbody>
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<td>Knut Tersmeden</td>
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<tr>
<td>Hennie de Bruyn</td>
<td>Johnson Matthey Catalysts</td>
<td>UK</td>
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<tr>
<td>Francois Ropital</td>
<td>IFP Energies nouvelles</td>
<td>FRANCE</td>
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Appendix 2

EFC WP15 Activities

(Francois Ropital)
Welcome to the EFC Working Party Meeting
"Corrosion in Refinery" WP15

Stockholm 7 September 2011

Presentation of the activities of WP15

European Federation of Corrosion (EFC)

• Federation of 31 National Associations
• 20 Working Parties (WP)
• Annual Corrosion congress « Eurocorr »
• Thematic workshops and symposiums
• Working Party meetings (for WP15 twice a year)
• Publications
• EFC - NACE agreement (20% discount on books price)

for more information  http://www.efcweb.org
EFC Working Party 15 « Corrosion in Refinery » Activities

Who is an EFC member

To be an EFC member you (individually or your company, university) has to be member of one of 31 national EFC "member societies". Your company or university can now also an affiliate member.

For example:
in Norway: Norsk Korrojonstekniske Forening
in France: Cefracor or Federation Francaise de Chimie
in Germany: Dechema or GfKORR
in UK: Institute of Corrosion or IOM or NACE Europe
in Israel: CAMPI or Israel Corrosion Forum
in Poland: Polish Corrosion Society

You will find all these information on www.efcweb.org or in the EFC Newsletter.

Benefits to be an EFC member:
- 20% discount on EFC Publications and NACE Publications
- reduction at the Eurocorr conference
- access the new EFC web restricted pages (papers of the previous Eurocorr Conference) via your national corrosion society web pages.

EFC WP15 Annual meeting 7 September 2011 Stockholm Sweden

EFC Working Parties

http://www.efcweb.org

- WP 1: Corrosion Inhibition
- WP 3: High Temperature
- WP 4: Nuclear Corrosion
- WP 5: Environmental Sensitive Fracture
- WP 6: Surface Science and Mechanisms of corrosion and protection
- WP 7: Education
- WP 8: Testing
- WP 9: Marine Corrosion
- WP 10: Microbial Corrosion
- WP 11: Corrosion of reinforcement in concrete
- WP 12: Computer based information systems
- WP 13: Corrosion in oil and gas production
- WP 14: Coatings
- WP 15: Corrosion in the refinery industry
  (created in sept. 96 with John Harston as first chairman)
- WP 16: Cathodic protection
- WP 17: Automotive
- WP 18: Tribocorrosion
- WP 19: Corrosion of polymer materials
- WP 20: Corrosion by drinking waters
- WP 21: Corrosion of archaeological and historical artefacts
EFC Working Parties
http://www.efcweb.org

• A task force on CO2 Capture and Sequestration (CCS) is launched

---

Presentation of the activities of WP15

**News from European Federation of Corrosion (EFC)**

The start of February 2011 has brought a change at the European Federation of Corrosion (EFC) with the appointment of a new Scientific Secretary/Public Relations officer.

**Juliet Ippolito** will now succeed Dr. Paul McIntyre who held this position for the past 14 years.
EFC Working Party 15 « Corrosion in Refinery » Activities

Chairman: Francois Ropital    Vice Chairman: Hennie de Bruyn

The following are the main areas being pursued by the Working Party:

Information Exchange
Sharing of refinery materials /corrosion experiences by operating company representatives.
Possibility to have a restricted web page on the EFC-WP15 page

Forum for Technology
Sharing materials/ corrosion/ protection/ monitoring information by providers

Eurocorr Conferences

WP Meetings
One WP 15 working party meeting in Spring,
One meeting at Eurocorr in September in conjunction with the conference.

Publications - Guidelines

Publications from WP15
Update in relation with Nace document 11106 "Monitoring and adjustment of cooling water treatment operating parameters" Task Group 152 on cooling water systems


•Future publications : suggestions ?
  • best practice guideline to avoid and characterize stress relaxation cracking ?
EFC Working Party 15 plan work 2011-2013

- Collaboration with Nace: exchange of minutes of meetings
  "NACE TEG 205X information exchange - corrosion in refineries"

- Sessions with other EFC WP at Eurocorr (2012 in Istanbul, 2013 Estoril-Portugal) on which topics?
  - Update of publications
    - CUI guideline
    - Amine acid gas treatment plants
  - New Publications: best practice guideline to avoid and characterize stress relaxation cracking?

- Education - qualification - certification
  List of "corrosion refinery" related courses on EFC website?

Information:
Future conferences related to refinery corrosion

- 20-24 November 2011
  18th International Corrosion Congress (ICC) Perth, WA, Australia,

- 11-15 March 2012
  CORROSION 2012/NACE Salt Lake City Website: www.nace.org

- 20-25 May 2012
  High Temperature Corrosion and Protection of Materials - Les Embiez (F)

- 9-13 September 2012
  EUROCORR 2012 Istanbul Turkey Website: www.efcweb.org/Events
Appendix 3

CUI and coatings

(J. Sentjens - Temati)
C.U.I.
EFC working party 15

Johan Sentjens

Agenda
- CUI
  Don’t only talk about the C but also about the I
- Life Cycle Engineering
- Inspection-detection
- Insulation Systems: “OPEN” versus “CLOSED”
- New development: Insulating Coatings

Tematī in a nutshell
- Technical Insulation
- Insulation System Supplier
- CUI Solutions

Statement
Insulation = Coating

Form of protection
Statement

CUI is not a Technical Issue but an Organisation Issue

Who’s or where is the insulation expert/expertice?

The reason for insulating

- Energy control
- CO₂ of NOₓ emission reduction
- Sound control
- Personal protection Past & Present
- Fire proofing
- Process conditions

Mission and Vision

We are committed to maintaining a safe work environment enriched by diversity and characterized by open communication, trust, and fair treatment.

Above all other objectives, we are dedicated to running safe and environmentally responsible operations.
Mission and Vision

Safety is always our top priority. We aim to have zero fatalities and no incidents that harm people, or put our neighbours or facilities at risk. This focuses on global development and environmental challenges linked to the impact of energy and globalisation.

We act in a responsible manner and support the Responsible Care® initiatives. Economic considerations do not take priority over safety and health issues and environmental protection.

Values:
- Integrity
- Respect for People
- Protecting Our Planet

Strategic Themes:
- Financial Discipline
- Sustainability
- Performance Culture
- Profitable Growth

The reason for insulating

Coal-fired power plant: 1100 MW 300,000m² insulated surfaces heat loss reduction 25% when insulated sustainable.

This saves around 25,500 tons of coal every year, reducing annual CO2 emissions by 27,000 tons. This is roughly equivalent to 12,890 cars with an annual mileage of 15,000 km. In financial terms, this would enable the plant operators to produce added power equivalent to €4.8 million.

Food for Thought

- Moisture doesn’t only cause:
  1. Corrosion
  2. Decreases life cycle insulation material
  3. Decreases thermal conductivity
The need for insulation expertise?

- Production man.
- Reliability eng.
- Sr. inspector
- Maintenance man.
- Insulation expert
- Contractor/manufacturer
- C.U.I. projects
- • Existing / older installations
C.U.I. projects

- Existing / older installation:
  - Little history
  - Full scale dismantling insulation
  - Fix / renew coating
  - TSA
  - Install new insulation

Same Insulation System ??

Can we learn from the past?

Life Cycle Engineering & C.U.I

L.C.E. & C.U.I ??

How to Prevent C.U.I.

Design "fit-for-purpose" insulation SYSTEM

Integrated Design Engineering
How to Prevent C.U.I.

Design "fit-for-purpose" insulation SYSTEM

CINI = Guideline

The need for insulation expertise?

Smart engineering

K I S S !
Smart engineering
Pipe line distance

Smart engineering
Steel structures

Smart engineering
Pipesupports

Finding C.U.I.
Inspection/Detection
- Direct
- Indirect

Finding C.U.I.
- Direct
  - Visual inspection
  - Dismantling insulation
  - VIP (Vessel Inspection Plug)

Finding C.U.I.
- Indirect
  - Guide Wave
  - Eddy Current pulsed wave
  - Incotest®
Finding C.U.I.

- Indirect
  - Thermografic

Why only inspect coating?

Quality

Insulation System

- "CLOSED" system
- "OPEN" system
- Non-Contact insulation

Insulation solutions for C.U.I.

"CLOSED" System

- Most implemented and traditional system
- Permeable insulation materials
- Non hygroscopic / water absorbing insulation material
- Cladding with sealed watertight joints
- 100% flashing of protrusions
The right Sealant for the right application

- Foster 95-44
- Kiiloflex
- Gasket Sealant
- Foster 60-44

Glass Reinforced Plastic (G.R.P.)

- Watertight joints
- High mechanical resistance
- Stepping on insulation

"OPEN" System

- Permeable insulation material
- Non hygroscopic / water absorbing insulation material
- Cladding with watertight joints
- 100% flashing of protrusions
- Aircavity
- Drainage

Solutions for C.U.I.

Aircavity Outside
- Temafol

Solutions for C.U.I.

Aircavity Inside

Non-Contact System
Solutions for C.U.I.
- PMU Drain Plug
- Protectem® Flangebelt™

Insulation Solutions for C.U.I.
- No insulation
  - Personnel Protection
  - Perforated sheet
  - Wired mesh

New developments for C.U.I.
- Insulating Coating
  - Based on ceramic technology

Insulation Coating
- Sprayable insulating coating
- Waterbased
- $T_{\text{service}} = 180^\circ\text{C}$
- $\lambda = 0,05 \text{ W/m.K}$

Field of application
- Personell Protection
- CUI: $T < 175^\circ\text{C}$
- $T_{\text{surface}} < 65^\circ\text{C}$

Field of application
- Surface condensation
C.U.I. challenges
Knowhow & solutions are at hand

Change the mindset

Insulation Knowledge

Thank you for your attention

Johan Sentjens
Appendix 4

TSA Implementation

Learnings from project deployment

(John Houben – ExxonMobil)
TSA Implementation
Learnings From Project Deployment
Corrosion 2011
John Houben, Stefan Winnik, Brian Fitzgerald

March 2011
2011CENGA 19
Overview

• Introduction to TSA
• TSA for CUI prevention
• TSA in the Petrochemical Industry
• Role of Materials Engineering – Project FEED
• Role of Materials Engineering – EPC Office
• Pressure Vessel Shop - TSA QC
• Piping Fab Shop TSA - QC
• Field Welds
• Supply Chain
• Summary
Introduction to TSA

- Thermal Spray Aluminum (TSA) is a thin 99+% metallic aluminum coating applied primarily with the following processes:
  - Flame spray, (shop and field), or
  - Electric Arc (shop, large surfaces in field)

- Most coating contractors have TSA capability in addition to the normal blasting and coating work

- The surface temperature of the substrate increases only slightly during application
TSA for CUI Prevention

- Corrosion Under Insulation (CUI) is a high maintenance cost item for fixed equipment
- Historically conventional coatings were used for CUI. These coatings have limited life. Also sub-standard coating systems were used
  - Epoxy or epoxy-phenolic coating are common for CUI. Most EP have upper temperature limit of 120°C. High solids EP can go to 150°C. If equipment temperature exceeds these limits, steam-out, regeneration, upsets these coatings fail
  - Inorganic Zinc (IOZ) is frequently used as shop primer. But multi-layer top coating system is needed for CUI protection, top coatings frequently “forgotten” in fieldwork
  - Cold Sprayed Aluminum (CSA) or coatings with aluminum flakes are no substitute for TSA
  - CUI has occurred under all insulation materials
- Field tests in the 80’s showed that TSA was best coating system for severe CUI conditions: sweating and cyclic service
- TSA coating with 250 micron thickness covers wide temperature range: -40°C to 540°C and long service life w/o maintenance. goal 30+ years
TSA in the Petrochemical Industry

- TSA is recognized as Best in Class for CUI prevention (EFC Publication #55)

- ExxonMobil Chemical Company has widely deployed TSA for CUI prevention in maintenance and projects

- TSA is included in Industry Standards:
  - NACE RP 0198 includes TSA covering widest temperature and long service life
  - CINI 7.4.04 includes TSA for CUI
  - Protection up to 540°C
  - EFC publication #55 lists TSA as first choice for CUI prevention
  - NORSOK M 501 recommends TSA for insulated tanks, vessels and piping

60m high by 5m OD tower - TSA coated
In FEED stage Materials Engineering (ME) selects coating systems based on atmospheric & service conditions, and company standards.

ME needs to make sure that FEED contractor is aware of company CUI prevention strategy. The importance of this topic needs to be highlighted to all engineering disciplines, early in project.

FEED contractor coating and vessel specialists need to be involved. CUI prevention starts in equipment design stage. General project engineers need guidance for this activity.

Keep systems simple; all CS equipment in CUI range shall be first TSA coated. Avoid multiple coating systems on one vessel: TSA first everything, than: fire-proofing EP top-coat, nozzles sealer.

Company and Industry specifications for TSA, Al-foil wrapping, Personnel Protection cages shall be referenced in FEED package and equipment datasheets.

FEED contractor does not need to re-invent TSA by writing new specifications for TSA, Al-foil wrapping, PP cages, etc.

Aluminum – foil wrapping of Stainless Steel piping needs to be included in insulation specification.

- Select system materials and details not covered in company standards by requiring compliance with industry standards.
- Use TSA for stainless shop fabrication, sweating service, steam-traced system.
- Use Al-foil for field application, stainless steel piping.

Do NOT create blind spaces

Do TSA complete vessel, supports, nozzles.
Materials Engineering – EPC Office

• If EPC contractor has no project experienced with TSA coated equipment, increase support activity, provide detailed guidance

• Discuss with EPC requirements and specifications in FEED package:
  • ME needs to make sure that EPC contractor is aware of CUI prevention strategy. Importance of this topic needs to be highlighted to all disciplines - many times
  • Kick-off with EPC: coating, insulation, vessel, piping, QA/QC engineers, construction, etc.
  • Review typical vessel and piping “Standard Drawings”; NACE RP 0198 gives guidance
    • Can all surfaces be grit blasted: support rings, support beams, skirt ID? If not, change details
    • No lifting lugs, use trunnions for insulated vessels, 10 mm stand-off for insulation support rings
    • Support welds shall be continuous and full. Avoid dead ends / blind corners
    • First CUI leaks are in small bore CS piping. Avoid field run and field coated CS small bore piping
    • Maximize shop prefab piping with shop TSA. Weld gussets on valve body & flange disk
  • EPC needs to make coating system spreadsheet, supported by detailed coating specification. Spreadsheet lists coating systems applicable to pressure vessels and piping, including field touch-ups and field welds
  • Company “coating specifications” may not be acceptable to use as “The Coating Specification”
  • Me shall review, with his process and equipment know-how, EPC’s pressure vessel datasheets, equipment sketches to make sure that correct coating requirements and CUI friendly details are included. Can surface be grit blasted, no sharp corners, etc?
  • Use TSA for stainless shop fabrication, equipment in sweating service, steam-traced equipment. Use Al-foil for field application like stainless steel piping
  • Locate piping field welds at grade and group these together. For grit blasting and TSA pipe spacing in pipe rack at field welds shall be 0.3 m minimum. Model review suggested
  • Flanged valves do not need TSA coating
Pressure Vessel Shop - TSA QC

- ME shall attend Pre-award meeting and PIM of bulk PV’s with TSA
  - Does PV manufacturer understand TSA application? No sharp corners, grit blasting, TSA, etc.
  - Does PV manufacturer or his in-house coating contractor have experience with TSA?
  - Does PV manufacturer have qualified (NACE) coating inspector on-hand?
  - Request at general PIM separate PIM for TSA Overall: Provide guidance

- TSA coating is not more expensive in competitive bidding; costs about same as 2 layers EP

- For TSA extra PIM is needed when welding of PV is almost finished. At TSA PIM specific ITP for coating work shall be reviewed:
  - PIM presence: TSA shop supervisor, coating inspector, PV QC, ME, EPC project eng
  - Go over TSA specification. No sealer needed under insulation. Who does inspections? ITP points:
    - Check if surface can be grit blasted, walk down pressure vessels to check this in shop
    - Is grease and oil present from machining (flanges), MPE, LPE, UT, who removes this?
    - Grit blasting medium, angular sharp profile needed, no grit-shot mixtures
    - Are sharp corners rounded to 3 mm radius
    - Check surface profile: 75 micron
    - Check ventilation for preventing dust from blasting & electric arc application contaminates surface
    - When are TSA test plates made, witness by coating inspector? TSA equipment shall function without wire feeding or spray problems. Both electric arc and flame-spray equipment & operator qualification
    - Agree on TSA method and QC for TSA application inside vessel skirts, supports, bolt holes and bolting
    - TSA operator shall perform in-process thickness measurements, 250 micron required on all places
    - QC inspector shall witness & document final TSA thickness measurements and water spray test
      Equipment that fails water spray shall not be seal coated or shipped from shop
      - It is acceptable to do TSA before hydro test
  - Every surface that can be grit blasted can be TSA coated, no excuse for using wet coatings replacing TSA for repairs, difficult to reach areas
Piping Fab Shop - TSA QC

- ME should attend PIM for bulk piping & TSA PIM
- Be critical that piping crew does not re-engineering the TSA spec
- Maximize shop TSA application, go over pipe support details, gussets, full welds, no dead spaces or pockets. TSA welded supports
- Small bore piping shall also be shop TSA coated, avoid field-run and field coated small bore piping
- Piping contractor needs to radius to 3mm sharp edges and remove slag, spatter, welding wire etc.
- Grit-blasting of piping is more critical, convex shape requires higher skills for obtaining good 75 micron sharp surface profile, all around pipe
- Both electric arc (large diameter piping, watch dust) and flame-spray can be used; later reduces overspray on small diameter piping
- TSA can be applied before hydrotest
- Keep 10-25 mm TSA free from bevels field welds
- Water-spray test is key QC test
- Pipe coatings are often damaged in handling. With TSA scratches and nicks do not need repair
- Nylon lifting bands, rubber wraps around chains, plenty of wood in shop, trucks and lay-down yards prevent damage
- In the unusual event TSA needs repair watch for touch-up with IOZ or sealer by paint brush QC check point
- TSA coated pipe shall not be wrapped in plastic
Piping Field Welds – TSA QC

• If engineering work is done correctly field welds can be TSA coated without problems:
  • Maximize shop TSA work
  • Are field welds located at grade and grouped together in pipe-rack?
  • Are pipes spaced 0.3 m min for grit blasting and TSA in pipe-rack?
  • Has TSA contractor experience with TSA’ing field welds?
  • All vents and drains should already be TSA coated in shop

• Discuss in detail field TSA with Project Safety group
  • Take them to the TSA shop and preview the field grit blasting and field flame-spray application
  • Safety concerns for field TSA with flame spray is similar to grinding & welding
  • Safety procedures, with realistic hazard evaluation, are essential
  • Consider garnet or vacuum-blasting tools for surface preparation to minimize dust of surface preparation. Do not use “standard grit-blasting kettle and compressors. Bristle blaster for remote welds

• EPC contractor shall have dedicated TSA field supervisor, that coordinates the field weld TSA activity with all skills:
  • Scaffolding, weather sheeting (tent) if needed
  • Field weld completion, do not let these rust
  • If needed NDT, (hydrotest can be done after TSA)
  • Surface preparation, can be on hot weld; followed immediately by TSA application
  • TSA QC, layer thickness (often too thick) and “dull chisel” test

• Visually inspect complete pipe spool for damage on field and shop TSA before TSA crew moves to next TSA station
Supply Chain

- Many fabricators and TSA contractors are available worldwide

- TSA is nothing new: India, South Korea, Malaysia, Italy, France, UK, Benelux, Singapore, USA, regions all delivered TSA coated equipment for projects

- On site, TSA frequently is done by existing painting contractors. Has proven to be very good approach

- EPC’s can be bottleneck, if not familiar with TSA. Increase ME support

- TEC of new shop fabricated equipment with TSA is similar to 2 layer epoxy-phenolic coating if supplier has experience with TSA

- No extra cost, no longer delivery time. Worldwide projects have proven this already

- Supply chain is making quick progress on TSA application, investing in people and TSA equipment

- TSA spray equipment suppliers are available to assist TSA contractors or existing painting contractors with TSA applicator training, equipment lease. Turn key field TSA application service for “remote” locations are available from some equipment suppliers

Shop TSA of Tower:
60 m high x 5m OD.
Notice stand-off insulation support rings - shell
Summary

- Plant reliability is improved and maintenance cost is reduced by implementation of CUI prevention strategy in projects, *good value for your money*

- **TSA is Best in Class for CUI prevention**
  - Guidance by knowledgeable ME’s is effective in helping EPCs and the supply chain quickly climb the learning curve
  - TSA is nothing new, know-how for projects is available
  - TSA is cost competitive with two layer epoxy-phenolic coating
  - Large multi M$ projects have shown that TSA is widely available
    Experience and supply chain is growing WW
  - ExxonMobil spends 10% of the maintenance budget on CUI inspections and repairs. This bad actor can be reduced by implementing CUI prevention in projects

- **Critical for success is hands-on ME support and project understanding of the importance of the CUI Prevention Strategy**

- Implementing a CUI Prevention Strategy after project start-up is 10X more expensive than the EPC stage
100 ton vessel with TSA lifted in place
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Appendix 5

Rightrax Corrosion Monitoring

(C. Laverde- GE Energy Services)
GE Energy Sensing & Inspection Technologies

Rightrax Corrosion Monitoring
Reduce Total Corrosion Costs

Why Rightrax is used

Aging
- Most assets are old
- 40% of the world’s pipelines are more than 40 years old
- This increases the inspection requirements

Cost
- Inspections are expensive
- Corrosion abatement is expensive
- Loss of production is the biggest cost factor

Safety
- HSE is expensive
- Safety comes first
- Remote monitoring reduces access to dangerous sites

Image
- If accidents happen the company image is damaged
- Multi million dollar fines could be imposed

Where Rightrax is used

Access
- Build scaffolding
- Remove insulation
- Bury pipelines

Remote
- Offshore facilities
- Desert facilities
- Jungle facilities
- Artic facilities

Hazards
- Chemical areas
- High temperature areas
- Radiations
- High altitude installations
- Explosions

Process
- Corrosion
- Erosion

Product versions

Flexible array (LT)
- Both manual and automatic versions
- Flexible array with 14 individual transducer elements
- Bonded to the object
- Repeatability up to +/− 0.1mm / +/− 0.004"
- Wall thickness 5mm to 100mm / 0.2" to 3.9"
- Pipe sizes of 6" and over, and flat surfaces
- Operational temperature −40°C up to 120°C / 248°F
- Certified for ATEX zone 2

Advantages:
- Non intrusive, easy installation
- Array coverage area = 12X200mm

High temperature (HT)
- Both manual and automatic version
- Single point transducer
- Clamped to the object
- Repeatability up to +/− 0.0025mm / 0.001"
- Wall thickness 3mm to 16mm / 0.12" to 0.6"
- Pipe sizes of 3" up to 42"
- Surface temperature -20°C up to 350°C and 500°C / 662°F and 932°F
- Certified for ATEX IS for use in zone 1

Advantages:
- Non intrusive, easy installation
- Process related events due to high resolution

Online Corrosion Monitoring
Two product lines for corrosion and wall thickness monitoring available

Non Intrusive sensors

Sensors are simply bonded or are clamped onto the inspection area
Sensor Placement Possibilities

Remote access to corrosion data, eliminating, excavations, erect scaffolding, remove insulation or shut down plants.

Cost of gaining access to the pipe for measurement is high, Hazard to personnel…

HT System

Rightrax HT – The System
Consists of four basic elements:
- The HT350x ultrasonic high temperature sensor
- The CMX-HT sensor interface (CMX X 4 Sensors, 32 CMX X System)
- The Node Interface and IS Barriers
- Data acquisition and data analysis software

Core element the HT-350x sensor
**The HT350x Sensor, Key Features**
- Single element sensor
- Intrinsically safe certification
- Thickness range 3 mm - 19 mm
- Temperature range -20°C up to 350°C/500°C
- 5 m cable length to CMX-HT sensor interface
- Suitable for pipe diameters of 3” up to 24” with standard clamping design
- Customization for larger diameters
- Nominal operating frequency of 5MHz
- Coupling is achieved through gold foil

**The CMX-HT node**
- Intrinsically safe sensor interface box
- Supports up to 4 HT350x sensors
- Connect to the system node interface using a RS485 cable
- Each sensor returns
  - Time of flight interface echo
  - Time of flight back wall echo
  - A-scan
- Driven by the CMX data acquisition software
- Does not store data

**Data Acquisition & Data Analysis Software**
- Provides:
  - Thickness temperature-corrected
  - Alarms for thickness levels and corrosion rates
  - Minimum/Maximum/Average thickness
  - Short term and long term corrosion rates
  - Maximum corrosion rates
  - A-scans to verify signal accuracy
- All values can be exported to third party systems by industry standard OPC, Modbus, or in CSV data file

**Integration to Plant Asset Management Systems**
- Interface with any asset management systems and with Bently Nevada System 1, enables the time stamped correlation of absolute wall thickness and corrosion rates to critical process variables such as temperature, pressure, flow, crude quality, and chemical injection.

**Data Acquisition & Data Analysis Software**
- Screen displays tailored to suit specific requirements.
  - Global view, showing sensor locations
  - Local view, showing site locations
  - Node views
  - A-scan
  - Trend plot
  - Alarm lists
  - Tabulated data
  - Diagnostics overview

**LT System**
Rightrax LT – The System

Consists of four basic elements:
• The Multi element sensor: 14 sensors elements
• The Sensor Interface (1 sensor interface X 10 sensors; 2 Sensors interface X System)
• The Node Interface
• Data acquisition and data analysis software

The M2 Sensor, Key Features
• Multi element sensor: 14 sensors elements
• 12mm by 200mm inspection coverage
• Thickness range 5 mm <> 100 mm
• Temperature range -40°C / 120°C
• Self Calibrating, programmable identification, Built in Temperature chip
• Suitable for pipe diameters of 6" and above

Functionality DL2
• DL2 Works with M2 Rightrax sensors
• Store up to 100 complete M2 measurements
• View M2 sensor elements in live mode
• Ease of use, unskilled personnel
• Connect to PC with RS232 to download measurements
• Using the complementary software packet WinHost
• Carry case, battery charger and cables included

The ATMS Data Logger (Automated Thickness Measurement System)
• Flaw detector with intelligent Decision making software
• Makes direct measurements in millimeters
• Software converts to inches
• Built-in 10 way multiplexer to connect 10 M2 sensors
• Connect to LD2 line driver with multi-core cable
• Providing Serial RS232 connectivity with the PC

The LD2 Line driver
• Powers the data logger with 24 Volts DC
• Provides RS232 communication between the ATMS data logger and the PC
• Is placed within the control room or other nominated safe area
• Can be supplied in a 19" rack mount enclosure
• Can be supplied in wall mounted cabinet for installation outside safe areas
• Provides MODBUS RTU and VFC outputs

Rightrax LT Reporting & Analysis Views

A-scan View Showing individual measurements
Map View and B-scan View Showing Overall
Trend View Showing Overall Corrosion Rates
Value Proposition – Online Corrosion reliable data

Improve Productivity:
- Plant uptime is maximized

- Support to process opportunity crude:
  Wall-thickness data taken at selected critical points can help support chemical injection systems to effectively manage corrosion rates.

Value Proposition – Online Corrosion reliable data

Decrease inspection cost
Provides wall-thickness data on-line without the need to erect scaffolding, remove insulation or excavations. Reduce inspection cost

Value Proposition – Online Corrosion reliable data

Improve plant safety
Prevent failure and unscheduled shutdowns or accidents are very costly
- Environmental damage
- Loss of production
- Large fines
- Repair cost
- Damage of reputation & image

Appendix Slides
References

Solvay Belgium

- **Application:** gas liquid mixture HCL, DCE, VC, PVC facility
- **Main Concern:** Avoid all human error factors
- **Rightrax Solution:**
  - Rightrax HT Full Automatic System
  - Fluid: gas liquid mixture HCL, DCE, VC
  - Max temp: 165°C
  - Max thickness: 9.5mm
  - Material: 904L
  - Pipe diameter: 11.8 inches
- **Main advantages provided by the Rightrax:**
  - Increasing safety
  - Reliable data due to the same point being monitored with no errors as all human error factors have been removed,

Current Customers

- TOTAL
- BP
- ExxonMobil
- OXY
- Solvay Belgium
- Rightrax – GE Water

**Rightrax Work History**

**BP**
- *Corrosion Monitoring on Sour Gas Scrubbers on Encore TLP Offshore Norway:
- SAGA Petroleum 1996
- Corrosion Monitoring on Sour Gas Scrubbers on SNOORE TLP OFFSHORE NORWAY.
- SHELL SCOTLAND 1996
- Corrosion Monitoring on Heat Exchanger ST FerGUS SCOTLAND. (Set of Gas processing plants)
- SHELL HOLLAND 1996
- Monitoring on Shell Kavern Cooler End Plates SHELL PERNIS. Refinery
- SHELL HOLLAND 1997
- Monitoring on Shell Kavern Cooler End Plates SHELL PERNIS. Refinery
- SHELL BRUNEI 1997
- Flowline Monitoring
- BROWN & ROOT 1997
- Wellhead Monitoring on SANGU PLATFORM BANGLADESH & DUPLEX RISERS FOR SAND EROSION
- SAUDI ARAMCO 1997
- Monitoring on Refinery Process PipeWork SAUDI ARABIA

**Rightrax – GE Water**

- Solvay Belgium
- Rightrax Work History
- Current Customers
- References

**Downstream – recent project summary**

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<thead>
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<th>Customer</th>
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<td>Refinery USA</td>
<td>Performance trial for HT sensors and system</td>
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<tr>
<td>ExxonMobil</td>
<td>Refinery USA</td>
<td>Performance trial for HT sensors and system</td>
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<td>OXY Oman</td>
<td>Refinery OMAN</td>
<td>Manual System: 2 LT sensors, 2 HT sensors</td>
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RIGHTRAX WORK HISTORY

BP COLOMBIA 1998
- 9 OFF SUBTERRANEAN CORROSION MONITORING STATIONS, 10 OFF RX UNITS AT EACH SITE WITH DATA TX TO THE CENTRAL PROCESSING FACILITY USING THE FLIGHT REFUELLING DATA TRANSMISSION SYSTEM.

PHILIPS OCTOBER 1998
- SABE 3200 MONITORING OF PROCESS PIPEWORK ON BP ANDREW OFFSHORE NORTH SEA.

SHELL AUGUST 1998
- MORRIS MONITORING OF PROCESS PIPEWORK ON SHELL WYTON FARM PROJECT.

RIGHTRAX WORK HISTORY

BP COLOMBIA 1998
- 3 OFF SUBTERRANEAN CORROSION MONITORING STATIONS. 10 OFF M1 UNITS AT EACH SITE WITH DATA TX TO THE CENTRAL PROCESSING FACILITY USING THE FLIGHT REFUELLING DATA TRANSMISSION SYSTEM.

PHILIPS OCTOBER 1998
- SABE 3200 MONITORING OF PROCESS PIPEWORK ON BP ANDREW OFFSHORE NORTH SEA.

SHELL AUGUST 1998
- MORRIS MONITORING OF PROCESS PIPEWORK ON SHELL WYTON FARM PROJECT.

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- 3 OFF SUBTERRANEAN CORROSION MONITORING STATIONS. 10 OFF M1 UNITS AT EACH SITE WITH DATA TX TO THE CENTRAL PROCESSING FACILITY USING THE FLIGHT REFUELLING DATA TRANSMISSION SYSTEM.

PHILIPS OCTOBER 1998
- SABE 3200 MONITORING OF PROCESS PIPEWORK ON BP ANDREW OFFSHORE NORTH SEA.

SHELL AUGUST 1998
- MORRIS MONITORING OF PROCESS PIPEWORK ON SHELL WYTON FARM PROJECT.
RIGHTRAX WORK HISTORY

SHELL BRUNEI WEST PHASE III AUGUST 2004
EROSION MONITORING ON OFFSHORE PLATFORM MONITORING EXPORT LINE FROM EGIERT WITH ONSHORE DATA COLLECTION.

BIWELL OIL & GAS SCOTLAND AUGUST 2004
SUPPLY & INSTALLATION OF OVER 300 MARKERS FOR ON/OFFSHORE INFLATION.

SHELL BRUNEI CHAMPION WELL JKT 2 APRIL 2004
WELL FLOWLIN No. INJETION & PRODUCTION HEADERS AND EXPORT LINE MONITORING.

SYRACUSE, CANADA AUGUST 2004
CONSIDERATION FOR ON-SHORE MONITORING ON PROCESS PIPEWORK.

BP OIL GAS KASHAGAN IRAN 1ST SEPTEMBER 2004
CORROSION / EROSION MONITORING ON VESSEL.

TOTAL-FINA-ELF DALIA FPSO TOPSIDES ANGOLA DECEMBER 2004
A FULLY AUTOMATED ON-LINE FLOWLINE MONITORING SYSTEM WITH ALARMS TO THE ICSS.

MSE Eng SHELL BRUNEI CHAMPION WEST PHASE III DECEMBER 2004
FULLY AUTOMATED PROCESS PIPEWORK MONITORING SYSTEM WITH DATA RETRIVAL ONSHORE VIA Ethernet.

IMPRO TECHNOLOGIES USA (BP Pipelines) DECEMBER 2006
SUBTERRANEAN MONITORING ON REMOTE PIPELINES.

ROSE CORROSION EVENT BP MAGNA PROJECT AUGUST 2007
DE-ENTREATMENT PIPE MONITORING.

TOTAL-EMIRATES OIL & GAS DECAN DEC 2008
SOUR GAS APPLICATION.

OXYDANTAL OMAN 2008
2 HT SENSORS FOR WET SOUR GAS.

SOLVAY BELGIUM 2008
4 HT SENSORS FOR FULL AUTOMATIC PVC APPLICATION.

BP TEXAS CITY 2008
3 HT SENSORS FOR CRUDE LINE.

CONOCO PHILLIPS BAYWAY NJ 2008
5 HT SENSORS FOR CRUDE LINE.

EXXONMOBIL BAYTOWN 2008
1 HT SENSORS FOR CRUDE LINE.

YPF ARGENTINA 2008
9 CMX, 19 HT TRANSDUCERS, CONTROL SYSTEM AND CIMPURITY SOFTWARE.

TOTAL DONGES 2008
4 HT SENSORS FOR VACUUM RESIDUE.

PETROBRAS 2008
FLUIDS AT RPBC - CUBATAO REFINERY. THE MAIN PRODUCTS ARE: JET FUEL, FORMULA 1 FUEL, COKE FOR EXPORT.

HIGH TEMPERATURE SENSOR

High Temperature Sensor
**Probe Setup**

- Probe coupled to the pipe with gold foil.
- 2 mil Gold foil
- Coupling mark about 3mm wide

**CIVA model**

- Crystal
- Probe Delay
- .7" thickness
- Beam analysis

**Acoustic beam in the delay**

- Beam profile at the delay tip or probe/pipe IF
- 3 dB width = 1.9 mm
- 6 dB width = 2.8 mm

**Axial Acoustic beam- Near field**

- Near field about the same as delay length .7"

**High Temperature Clamping Systems**

- The HT Sensor Clamp
  - Large pipes: 8"-30"
  - SS Chain
  - <660°F
The HT Sensor Clamp
Small pipes: 3”-8”

Small HT Piping Clamps

Small HT Piping Clamps

Adjustable HT Clamping Systems

Chain Clamp system on actual 30” pipe

Chain Clamp mounted on 24” crude line
Four (4 ea.) Chain Clamps mounted on actual 24” crude line

Low Temperature Sensor

The M2 Sensor, Schematics

Rightrax Intelligent Monitoring SENSOR COVERAGE
( Beam Spread )

The M2 Sensor, Inspection Area

Mid Stream Application
Pipelines were designed to transport dry gas, but will now transport wet gas so the client has decided to monitor both lines at their most vulnerable point i.e. the lowest point on the lines due to the possibility of moisture causing corrosion.

2 off Righttix MZ Sensors were fitted at the locations as instructed on site located from the 3 O Clock to 9 O Clock position on both pipelines.

Both Sensors wrapped in Pipeline coating prior to soil reinstatement.

18 Mtr Extension Cable wired back to Data collection post.

The Value Chain - Your Choice

The Transfer Function

Wall thickness loss = Crude Quality + Chemical Inhibitors + Operating Temp + Ageing Assets + Fluid Dynamics

Improve Safety and Reduce Inspection Costs

Safety = less labor + less scaffolding + automation + less risk + defined damage mechanisms

Improve Environmental Health & Safety & Revenue

EHS & Revenue = reduce unscheduled shutdowns + loss of capital equipment + hazards to personnel + pollution to the environment + increase revenue
Appendix 6

Acid gas unit treatment corrosion

Survey of WP15 to update EFC n°46 guideline
# Update of EFC guideline n°46

## Amine unit corrosion in refineries

## 1. INTRODUCTION

## 2. TECHNICAL BACKGROUND

### 2.1 Process layout

- 2.1.1 Furnaces
- 2.1.2 Absorbers
- 2.1.3 Regenerators

### 2.2 Important zones

- 2.2.1 General factors
- 2.2.2 Mechanicals
- 2.2.3 Ruthenium
- 2.2.4 Lean amine
- 2.2.5 Acid gas attack
- 2.2.6 Brackish water intake
- 2.2.7 Make-up water quality
- 2.2.8 Evaporators

### 2.3 Corrosion issues

- 2.3.1 Corrosion issues
- 2.3.2 Corrosion issues
- 2.3.3 Corrosion issues
- 2.3.4 Corrosion issues
- 2.3.5 Corrosion issues

## 3. EXPERIENCES OF FAB PLANTS USING METHYL DISTILLATION

### 3.1 Gas composition

### 3.2 Materials of construction

## 4. EXPERIENCES OF FAB PLANTS USING METHANOLAMINE

### 4.1 Gas composition

### 4.2 Special applications

### 4.3 Reactors, storage and cooling

### 4.4 Operating parameters

### 4.5 Corrosion control

### 4.6 Corrosion protection

## 5. EXPERIENCES OF FAB PLANTS USING N-METHYL URIL

### 5.1 Materials of construction

### 5.2 Operating parameters

### 5.3 Corrosion control

### 5.4 Corrosion protection

## 6. EXPERIENCES OF FAB PLANTS USING DISAMINOMETHANE

### 6.1 Materials of construction

### 6.2 Operating parameters

### 6.3 Corrosion control

### 6.4 Corrosion protection
Revision of EFC46 "Amine units corrosion"
Some feed backs from the enquiry

Survey of industrial units:
1 MDEA unit (H₂S, NH₃, CO₂) without any specific corrosion problems
1 MDEA unit (H₂S, NH₃, CO₂) with:
- Leakage at reverse flow chamber of regenerator overhead air cooler - two times; affected material CS; mechanism Erosion/Erosion-Corrosion; remedy action change the metallurgy of tubes from CS to SS X8CrNiTi 18-10.
- Damage of the reflux pump casing of regenerator, affected material SS X20Cr13, mechanism Erosion/Erosion-Corrosion

1 proposal for a chapter on non intrusive on line monitoring:

1 comment on treatment, monitoring, control parameters for overhead
Appendix 7

High Temperature Hydrogen Attack

Failure of a Dissimilar Metal Weld in a Texas Tower Heat Exchanger of a Platformer Unit.

(J. Van Roij Shell Global Solutions)
High Temperature Hydrogen Attack

Failure of a Dissimilar Metal Weld in a Texas Tower Heat Exchanger of a Platformer Unit.

European Federation of Corrosion WP15 "Corrosion in Refinery" Annual Meeting

Johan van Roij
Senior Materials & Corrosion Engineer

Outline

- What happened?
- Heat Exchanger Design
- Field Inspection
- Metallography
- What is HTHA?
- Contributing Factors
- Conclusion & Key Learning
**HE - Design**

**Design Temperatures**

<table>
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**Construction Materials**

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<tr>
<td>Lower shell</td>
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</table>

**Design Code:** BS 5500 ed. ’76

**Welding QC:** BS 4870 Part 1 - 1981

**Design Press:** 3.81 MPa (552.6 psi)

**PWHT Details**

- **Upper Section**
  - 680 °C, 4h 10m Furnace
- **Lower Section**
  - 620 °C, 2h Induction (local)
Small leak found at fusion line between DMW and carbon steel base metal.
Field Inspection

- 1 Cr ½ Mo – DMW fusion line
- Carbon steel – DMW fusion line (crack)

Metallography

Crack precisely follows the fusion line on the carbon steel side of the dissimilar metal weld (DMW) (arrows).
Cracks started in the notch between the weld and base metal, then propagated along the fusion line.

Local decarburization and fissuring in steel around main crack. This is typical of localized High Temperature Hydrogen Attack (HTHA).

Inter-granular nature of the cracks can be seen in this image. This is typical of localized HTHA.
What is High Temperature Hydrogen Attack (HTHA)?

**Definition:** Irreversible degradation of the mechanical properties of steel by high temperature reaction of absorbed hydrogen with carbon in the steel, resulting in decarburisation and internal fissuring.

- Above approx. 7 bar H₂ and 230 °C
- Atomic hydrogen diffuses into steel
- Reaction with carbides in the steel:
  \[ \text{Fe}_3\text{C} + 2\text{H}_2 \rightarrow 3\text{Fe} + \text{CH}_4 \]

**Main Variables:**
- H₂ Partial Pressure
- Temperature
- Exposure Time
- Steel Chemistry

**Design Basis:** “Nelson Curves” (API - RP 941)

---

**HTHA – Nelson Curves**

**High Temperature Hydrogen Resistance Curves**

**API 941 (Nelson Curves)**

- Hydrogen Attack: \( \text{Fe}_3\text{C} + 2\text{H}_2 = \text{CH}_4 + 3\text{Fe} \)
- Increasing Amount of Alloying (Cr-Mo-V) Required to Maintain Resistance
- 2.25%Cr-1Mo Steel
- 1%Cr-0.5Mo Steel
- 1%Cr-0.5Mo + 1.25%Cr-Mo Steel

**Partial Pressure of H₂**

API 941: “Because the Nelson curves are based largely upon empirical experience, an operating company may choose to add a safety margin, below the relevant curve, when selecting steels.”
Design

The original design basis operating temperature for the dissimilar metal weld (DMW) was 250 °C and an assumed H₂ partial pressure of 21 bar. This is about 40 °C below the CS Nelson curve.

Fouling Caused Increase in Temperature

Tube-side fouling increases the temperature of reactor effluent, which causes an upward shift in the temperature profile of the shell.

Site estimate results in operation within 5 °C of the CS Nelson curve.

Other estimate results in operation 32 °C above the curve.

API 941: “Because the Nelson curves are based largely upon empirical experience, an operating company may choose to add a safety margin, below the relevant curve, when selecting steels”.
Conclusions

- Primary causal factor in this failure was local HTHA of the fusion line between Dissimilar Metal Weld (DMW) and CS base metal due to operation above the Nelson curve.

- The fusion line was more susceptible than weld metal or base metal due to its relatively low strength and the high reactivity of grain boundary carbides.

- Stress concentration effect of DMW design and pre-existing weld defects explains the location and timing of the failure.

Key Learning

- Current design guidelines recommend the equipment to operate ~15 °C and ~1.7 bar below the appropriate Nelson curve versus ON the Nelson curve as was practiced in the past. Hence old equipment operating under similar conditions may be at similar risk.

- Crack formation due to HTHA is known to accelerate in areas of high stress. Due to its design and construction, the dissimilar metal weld closure joint had two types of stress concentrators at the fusion line (notch and weld defects).
Appendix 8

Carbon Steel Degradation in High Temperature Hydrogen Service – API Alert
Industry Alert

The purpose of this alert is to inform you that there have been several reports of cracking-related issues with carbon steel piping and equipment in high temperature, high pressure hydproprocessing service at operating conditions where carbon steel was previously thought to be resistant to high temperature hydrogen attack (HTHA). One published report of such incidents can be found in the paper PVP2010-25455, Proceedings of the 2010 ASME Pressure Vessels and Piping Conference, July 18-22, 2010, Bellevue, WA.

API RP 941, Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants, 7th Edition, 2008, Figure 1, shows the operating limits for steels in hydrogen service to avoid decarburization and fissuring from HTHA. One curve on that graph is for carbon steel. At temperatures and hydrogen partial pressures below the curve, HTHA is not expected to occur in carbon steel.

Prior to these recent reports, the only reported failures of carbon steel below the API RP 941, Figure 1 curve were in cases of exceptionally high stress, as discussed in Sections 5.2 and 5.3 of API RP 941. All of the new reports of HTHA involve carbon steel equipment that was not postweld heat treated. Past research summarized in API TR 941, The Technical Basis Document for API RP 941, states that non-postweld heat treated welds not only retain high residual welding stresses but also have lower carbide stability in the weld heat affected zone that further increases HTHA susceptibility. The API RP 941 Task Group of the API Subcommittee on Corrosion and Materials is now in the early stages of collecting and verifying data and information to determine if the recommended practice might need to be altered as a result of this new information.

API is notifying all refining operating companies of this new issue should owner-operators decide to alter their inspection plans or risk assessments for carbon steel piping and equipment, especially if not postweld heat treated and/or highly stressed, and particularly in hydproprocessing services. Section 6 of API RP 941 provides recommended practices for inspection of equipment that may be susceptible to HTHA.

If any of your operating sites have experienced unexpected cracking issues associated with carbon steel equipment that may be due to HTHA, please bring those to the attention of API by participating in the Corrosion and Materials Subcommittee and the RP 941 Task Group. The form found in Annex F of API RP 941, Datasheet for Reporting High Temperature Hydrogen Attack (HTHA) of Carbon and Low-alloy Steels, provides a recommended format for internal company data collection.

For information on API’s Refining Standards and the API RP 941 Task Group please contact David Soffrin, Manager, Downstream Standards, at soffrind@api.org.
Appendix 9

Lean Duplex Stainless Steel Upgrades for Critical Cooling Water Heat Exchangers

(John Houben – ExxonMobil)
Lean Duplex Stainless Steel Upgrades for Critical Cooling Water Heat Exchangers

Corrosion 2011

Brian Fitzgerald & John Houben

March 2011

2011CENGA 16
Agenda

• Background / Case for Action
• Maintenance Example
• Exchanger Upgrade Options
• Economic Evaluation of LDSS vs Carbon Steel (CS) Exchanger Bundles
• Conclusions
Background / Case for Action

• **Background**
  + Mitigation of Cooling Water (CW) and/or process-side corrosion required for all CW exchangers
  + Upgrading exchangers from CS to austenitic SS has potential risk of SCC

• **Incentives for upgrading critical exchanger metallurgy include:**
  + Improves reliability and effectively eliminates process safety risk of leaking exchanger mitigation
  + Enables extended runs between T/As
  + Improves environmental performance
  + Moves us closer to goal of “maintenance / inspection free” equipment

• **Premature exchanger failures result in significant financial losses / cost**
  + Critical exchanger leaks can cost millions of dollars in lost production and maintenance expense
  + Repairs require extensive engineering and planning to manage associated Process Safety risk
Critical Exchanger Leak Example

- **Process Gas Compressor intercooler exchangers leak**
  - Forced choice of a shut-down or a hot tap / stopple
  - Significant organizational disruption and engineering to manage
  - Stopple is essentially putting a valve in a live process line

- **Key hot tap and stopple “fun facts”**
  - Each 30" hot tap was followed by 30" stopple
  - Each stopple set is 12.5 tons and ~ 22 feet long
  - Hot tap set up is 10.7 tons and approximately 17 feet long
  - Total lost production was $2-4 M
  - Total mechanical cost was $2-3 M

**Proprietary**
Lean Duplex Stainless Steel

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<td>3.1</td>
<td>1.0</td>
<td>0.18</td>
<td>450</td>
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<tr>
<td>SAF2304</td>
<td>S32304</td>
<td>23</td>
<td>4.8</td>
<td>0.3</td>
<td>1.0</td>
<td>0.10</td>
<td>400</td>
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<tr>
<td>LDX2101</td>
<td>S32101</td>
<td>21.5</td>
<td>1.5</td>
<td>0.3</td>
<td>5</td>
<td>0.22</td>
<td>450</td>
</tr>
<tr>
<td>AL 2003</td>
<td>S32003</td>
<td>21.6</td>
<td>3.8</td>
<td>1.8</td>
<td>1.3</td>
<td>0.18</td>
<td>450</td>
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<tr>
<td>AL 201 HP</td>
<td>S20100</td>
<td>16.3</td>
<td>4.5</td>
<td>--</td>
<td>7.1</td>
<td>0.07</td>
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<tr>
<td>AISI 430</td>
<td>S43000</td>
<td>16.3</td>
<td>0.3</td>
<td>--</td>
<td>0.5</td>
<td>0.05</td>
<td>310</td>
</tr>
</tbody>
</table>

• **Intermediate Tanks – In service**
  + Organic acids settle out in CS tanks; service life <5 yr; coating fail
  + 316 SS Tanks @ 160K$; 2101 Tanks @ 110K$

• **Heat Exchangers, Fresh Cooling Water – Current Upgrade Targets**
  + Critical CS HE with life < 8-15 yr life
  + Margin loss for bundle switch 1000K$ plus
  + Mechanical costs (hot tap & stopple) 1000K$ plus
  + Environmental reportable
Upgrade & Alternatives

• Opportunity Identified
  + Lean Duplex SS (LDSS) tube bundles commercially available with welded tubing at ~ 1.2 to 1.4 times cost of CS tube bundles

• Scope of Evaluation
  + Critical exchangers in fresh recirculating CW service
    + No spare exchanger
    + No bypass
    + Leak will cause business disruption or safety, health or environmental incident / report
  + Compare LDSS tube upgrade versus other carbon steel tubes and alternatives including installation of spare exchangers and bypasses
Exchanger Upgrade Options

<table>
<thead>
<tr>
<th>Tube Material Options</th>
<th>Description</th>
<th>Cost (TEC)</th>
<th>TEC Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Steel</td>
<td>CS tubes &amp; tubesheet w/ welded TS joint</td>
<td>115 k$</td>
<td>Base</td>
</tr>
<tr>
<td>Lean Duplex</td>
<td>1. Upgrade tubes w/ welded TS joints</td>
<td>140 k$</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td>2. Upgrade tubes w/ welded TS joints and baffles / ties / etc.</td>
<td>160 k$</td>
<td>1.4</td>
</tr>
<tr>
<td></td>
<td>3. Upgrade tubes, baffles / ties / etc, and tubesheet w/ welded TS joints</td>
<td>195 k$</td>
<td>1.7</td>
</tr>
</tbody>
</table>

- Upgrading tubes alone is a significant improvement, but baffles / etc. remain “weak link” if the shell side is corrosive
- Upgrading baffles / ties / etc to SS along with tubes should effectively extend bundle life “indefinitely”
- Upgrading tubesheet to SS is costly and not req’d based on 2205 duplex experience
- Other tube upgrade options (coated tubes, admiralty, 2205 duplex) are more costly
- Spare exchangers and bypasses are more costly
Economic Evaluation of LDSS vs CS Exchanger Bundles

- DCF Screening example based on initial bundle replacement cost only

- Additional credits for mechanical costs and lost production costs can be taken. For example, every 1000K$ of mechanical or lost production costs in year 9 (of 10 year run) at 20% DCF adds 194K$ to the carbon steel TEC
Conclusions

• CS bundles remain a viable option for non-critical heat exchangers
• Upgrades expected to generate 15-30+% DCF for critical CW exchangers
Attachments – CS TS with 2205 DSS tubes

CTW Tube Side 6 years Service
Attachments – CS TS with 2205 DSS tubes
CTW Tube Side
Attachments – CS TS with 2205 DSS tubes
CTW Shell Side 15 years Service
Attachments – CS TS with DSS tubes

Hydrocarbon Service
Attachments – CS TS with LDSS tubes

TS Mock Up Test

Tubesheet after rolling
Manometer 75 bar
Sealweld
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Appendix 10

Stress Relaxation Cracking Recent Project Experience

(Hennie de Bruyn – Johnson Matthey)
Preventing Stress Relaxation Cracking

- New catalyst production plant
  - Location: Kanpur, India
  - High temperature equipment; hydrogen & other gas environments
  - Cyclic service up to 700°C
  - Austenitic stainless steel type 304H selected for most high temperature equipment
  - Potential for stress relaxation cracking identified during early project stages
  - TNO input for PWHT/ageing heat treatment procedure

- Manufacturer Resistance
  - PWHT requirements for 304H became an obstacle with EPC and equipment manufacturers
  - Some vessel manufacturers in India declined to quote because of PWHT requirements
  - Most would not guarantee the design (ASME Sec. VIII Div. 1) because of PWHT
  - Requalification of all welding procedures (PWHT is essential variable)
  - Acceptance only after lengthy explanations of stress relaxation cracking
Preventing Stress Relaxation Cracking

• Practical Considerations
  – Finding a large enough heat treatment furnace
  – Supporting a reactor and other equipment inside the heat treatment furnace
  – Avoiding thermal stresses in the equipment
  – Some equipment (for example heat exchangers) too complex to heat treat; do not want to heat treat bellows, etc.
  – Ensuring even temperature distribution during PWHT
  – Heating rate: large furnaces can only maintain 40 – 50°C/hr (well below TNO recommendations) – uncertainty
  – Cooling down: getting equipment out of the furnace quick enough

• Welding
  – Base material properties well above minimum requirements (ASTM A240 gr. 304H)
  – Mechanical properties after PWHT still above minimum requirements

Open questions

• Long-term effect of ageing heat treatment of creep properties of the material?
  • Big uncertainty!
  • How can we establish this?

• Can stress relaxation cracking be avoided in another way (avoid PWHT)?
  • Grain size control of the base material; additional costs; not sure this is sufficient
  • Ni-content of the alloy; additional costs; might be prohibitive; unaffordable

• Is PWHT (ageing) sufficient?
  • Testing of production test plate at TNO
  • Very little information on PWHT conditions available in public domain
  • Urgent need for an open guideline; EFC WP15 has been discussing this since 2007
  • What is the status of Total/Cefracor work on this subject?
Appendix 11

New JIP on Stress Relaxation Cracking

(Chretien Hermse - TNO)
Stress relaxation cracking

September 22nd discussion at TNO

Chrétien Hermse
Hans van der Veer

H. van Wortel, NACE 2007, Nashville, USA, paper 07423
Stress relaxation cracking: a new project?

• Several JIPs between 1995 and 2000
• Susceptibility test
• Prevention strategy using PWHT
• Recommended practice in 2000

Stress relaxation cracking under control

Nevertheless:
• Several requests from industry!

Stress relaxation cracking: new questions

• Effect of PWHT on creep life time
  • Can creep reduction factors be avoided?

• SRC susceptibility of new alloys not in the previous JIP
  • Supplement to existing recommended practice

• Alternative remediation strategies
  • PWHT is inconvenient, are alternatives thinkable?

• Dissimilar welds
• Determination of the effect of wall thickness
• …

Is this a real problem?
Discussion meeting

- September 22nd discussion meeting at TNO in Apeldoorn, Netherlands
- Draft proposal available for discussion
- Several engineering companies, material and welding consumable suppliers, and end users will attend
- Other interested industrial partners are also welcome

- Please send an email to chretien.hermse@tno.nl to register
Stress relaxation cracking

- Temperature range 500-700 degrees Celsius
- Mechanical form of degradation
- Sensitivity test available, remediation and repair strategy developed: TNO recommended practice (H. van Wortel, RC-00-43)
- Most materials susceptible, good suppliers give information about appropriate treatment to prevent SRC