Corrosion Management in Gas Processing Facilities Seminar
Bahrain – 28th November 2007

Corrosion Mitigation Strategies for Amine Gas Treating Plants

Maria Luisa Gonzalez-Barba
Lorenzo Spagnuolo
AGENDA

• Introduction and overview of Amine Units/Amine properties

• Corrosion in Amine Gas Treating Plants
  – Contaminants - type and origin
  – Corrosion causes
  – Corrosion effects

• Amine degradation
  – Heat Stable Amine Salts (HSAS) formation and management

• Typical corrosion locations

• Examples of corrosion in Gas Treating Plants

• First steps to mitigate corrosion in Gas Plants
AGENDA (cont.)

• Typical Metallurgy for Gas Plants

• Baker Petrolite’s Amine Gas Treating Management Program
  – Advanced analytical testing and results interpretation
  – Effective chemical treatment program
  – Innovative corrosion monitoring program

• Corrosion Case Studies from Europe

• Summary and conclusions

• Literary references
INTRODUCTION - ALKANOLAMINES

- Alkanolamines are bases used in Gas Plants and Refineries to remove H₂S, Mercaptans and/or CO₂ contaminants from natural gas, reformed gas or refinery gases and LPG by a chemical absorption mechanism.

  - NH₂ Group: is responsible of the acid gas absorption.
  - OH Group: is responsible of the amine solubility in water.

- Types of Alkanolamines
  - Primary Amine: MEA and DGA® (the most reactive amines).
  - Secondary Amine: DEA and DIPA amines.
  - Tertiary Amine: MDEA and TEA amines.

MDEA < DEA < MEA < DGA®

INCREASING BASE STRENGTH
MOLECULAR STRUCTURE OF AMINES USED IN GAS SWEETENING

PRIMARY AMINES
MONOETHANOLAMINE (MEA) MW = 61
\[
\begin{align*}
\text{H} & \quad \text{N} - \text{CH}_2 - \text{CH}_2 - \text{OH} \\
\text{H} & \quad \text{N} - \text{CH}_2 - \text{CH}_2 - \text{OH}
\end{align*}
\]

DIGLYCOLAMINE (DGA\textsuperscript{®}) MW = 105
\[
\begin{align*}
\text{H} & \quad \text{N} - \text{CH}_2 - \text{CH}_2 - \text{O} - \text{CH}_2 - \text{CH}_2 - \text{OH} \\
\text{H} & \quad \text{N} - \text{CH}_2 - \text{CH}_2 - \text{O} - \text{CH}_2 - \text{CH}_2 - \text{OH}
\end{align*}
\]

SECONDARY AMINES
DIETHANOLAMINE (DEA) MW = 105
\[
\begin{align*}
\text{HO} & \quad \text{CH}_2 - \text{CH}_2 - \text{N} - \text{CH}_2 - \text{CH}_2 - \text{OH} \\
\text{H} & \quad \text{CH}_3
\end{align*}
\]

DIISOPROPANOLAMINE (DIPA) MW = 133
\[
\begin{align*}
\text{HO} & \quad \text{CH} - \text{CH}_2 - \text{N} - \text{CH}_2 - \text{CH} - \text{OH} \\
\text{CH}_3 & \quad \text{H} \quad \text{CH}_3
\end{align*}
\]

TERTIARY AMINES
TRIETHANOLAMINE (TEA) MW = 149
\[
\begin{align*}
\text{HO} & \quad \text{CH}_2 - \text{CH}_2 - \text{N} - \text{CH}_2 - \text{CH}_2 - \text{OH} \\
\text{CH}_2 & \quad \text{CH}_2 - \text{OH}
\end{align*}
\]

METHYLDIETHANOLAMINE (MDEA) MW = 119
\[
\begin{align*}
\text{HO} & \quad \text{CH}_2 - \text{CH}_2 - \text{N} - \text{CH}_2 - \text{CH}_2 - \text{OH} \\
\text{CH}_3 & \quad \text{CH}_3
## COMMONLY USED AMINES – PROPERTIES

<table>
<thead>
<tr>
<th></th>
<th>MEA</th>
<th>DGA®</th>
<th>DEA</th>
<th>DIPA</th>
<th>MDEA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Molecular Weight</td>
<td>61.1</td>
<td>101.5</td>
<td>105.1</td>
<td>133.2</td>
<td>119.2</td>
</tr>
<tr>
<td>Typical Concentration, wt%</td>
<td>15-20</td>
<td>45-50</td>
<td>25-30</td>
<td>30</td>
<td>35-50</td>
</tr>
<tr>
<td>Typical Lean Loading, mol/mol</td>
<td>0.05-0.1</td>
<td>0.05-0.1</td>
<td>0.02</td>
<td>0.02</td>
<td>0.005-0.01</td>
</tr>
<tr>
<td>Typical Rich Gas Loading, mol/mol</td>
<td>0.35</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.45</td>
</tr>
<tr>
<td>Typical Steam Use, #/gal</td>
<td>1.5</td>
<td>1.5</td>
<td>1.2</td>
<td>1.1</td>
<td>1.0</td>
</tr>
<tr>
<td>Pure Amine Relative Price</td>
<td>0.50</td>
<td>0.95</td>
<td>0.50</td>
<td>0.95</td>
<td>1.00</td>
</tr>
<tr>
<td>Heat of Reaction with CO₂, BTU/lb</td>
<td>825</td>
<td>850</td>
<td>653</td>
<td>550</td>
<td>475</td>
</tr>
<tr>
<td>Heat of Reaction with H₂S, BTU/lb</td>
<td>820</td>
<td>674</td>
<td>511</td>
<td>475</td>
<td>455</td>
</tr>
</tbody>
</table>

© 2007 Baker Hughes Incorporated. All Rights Reserved.
## ADVANTAGES AND DISADVANTAGES OF EACH AMINE

**MEA (Monoethanolamine): Typical concentration 15 - 18 weight %**

<table>
<thead>
<tr>
<th>ADVANTAGES</th>
<th>DISADVANTAGES</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Low cost</td>
<td>• Not selective in presence of CO$_2$</td>
</tr>
<tr>
<td>• Degradation products can be removed by reclaiming</td>
<td>• CO$_2$, COS and CS$_2$ can irreversibly degrade the amine</td>
</tr>
<tr>
<td></td>
<td>• Degradation products are very corrosive</td>
</tr>
<tr>
<td></td>
<td>• Degraded amine has lower acid gas removal capacity</td>
</tr>
<tr>
<td></td>
<td>• High energy required for its regeneration</td>
</tr>
<tr>
<td></td>
<td>• Significant vaporization losses due to high vapor pressure</td>
</tr>
</tbody>
</table>
### ADVANTAGES AND DISADVANTAGES OF EACH AMINE

**DEA (Diethanolamine): Typical concentration 25 - 30 weight %**

<table>
<thead>
<tr>
<th>ADVANTAGES</th>
<th>DISADVANTAGES</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Moderate cost</td>
<td>- Not selective in presence of CO₂</td>
</tr>
<tr>
<td>- Degrades less with CO₂ and COS than MEA</td>
<td>- CO₂, COS irreversibly degrade the amine</td>
</tr>
<tr>
<td>- Degradation products are less corrosive than MEA</td>
<td>- Degraded amine has lower acid gas removal capacity</td>
</tr>
<tr>
<td>- Purification can be made by vacuum distillation</td>
<td></td>
</tr>
<tr>
<td>- Less energy required for its regeneration than MEA</td>
<td></td>
</tr>
</tbody>
</table>

© 2007 Baker Hughes Incorporated. All Rights Reserved.
## ADVANTAGES AND DISADVANTAGES OF EACH AMINE

**DGA® (Diglycolamine): Typical Concentration 50 weight %**

<table>
<thead>
<tr>
<th>ADVANTAGES</th>
<th>DISADVANTAGES</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Can achieve low specification also under critical conditions</td>
<td>• High cost</td>
</tr>
<tr>
<td>• Degradation products can be removed by reclaiming</td>
<td>• Not selective in presence of CO₂</td>
</tr>
<tr>
<td></td>
<td>• CO₂, COS and CS₂ irreversibly degrade the amine</td>
</tr>
<tr>
<td></td>
<td>• Degradation products are very corrosive</td>
</tr>
<tr>
<td></td>
<td>• High solubility of the aromatic, olefins and heavy hydrocarbons in DGA</td>
</tr>
<tr>
<td></td>
<td>• Very high energy required for regeneration</td>
</tr>
</tbody>
</table>

DGA is registered trademark of Huntsman Petrochemical Corporation
ADVANTAGES AND DISADVANTAGES OF EACH AMINE

DIPA (Di-isopropanolamine): Typical Concentration 27 weight %

<table>
<thead>
<tr>
<th>ADVANTAGES</th>
<th>DISADVANTAGES</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Some selectivity in presence of CO₂</td>
<td>• High cost</td>
</tr>
<tr>
<td>• Purification can be made by vacuum distillation</td>
<td>• CO₂ and COS irreversibly degrade the amine</td>
</tr>
<tr>
<td>• Relatively moderate energy requirement for regeneration</td>
<td></td>
</tr>
</tbody>
</table>
MDEA (Methyldiethanolamine): Typical Concentration: 35-50 wt %

**ADVANTAGES**
- High selectivity removing $\text{H}_2\text{S}$
- Higher acid gas removal capacity at the concentration of use
- Does not degrade with $\text{CO}_2$ or with COS
- Virtually not corrosive at the concentration of use
- Lower energy required for regeneration

**DISADVANTAGES**
- Higher cost than MEA, DEA and DIPA
- More soluble than DEA in liquid hydrocarbons
# CORROSIVE CONTAMINANTS

<table>
<thead>
<tr>
<th>CONTAMINANT</th>
<th>TYPICALLY FOUND IN ......</th>
</tr>
</thead>
<tbody>
<tr>
<td>HYDROGEN SULPHIDE ($H_2S$)</td>
<td>ALL Units</td>
</tr>
<tr>
<td>CARBON DIOXIDE ($CO_2$)</td>
<td>Gas Plant, FCCU, DCU</td>
</tr>
<tr>
<td>CARBON MONOXIDE (CO)</td>
<td>FCCU</td>
</tr>
<tr>
<td>CARBONYL SULPHIDE (COS)</td>
<td>Gas Plants, FCCU, DCU, SRU</td>
</tr>
<tr>
<td>AMMONIA ($NH_3$)</td>
<td>HDS, MHC, FCCU, DCU, VB</td>
</tr>
<tr>
<td>HYDROCYANIC ACID (HCN)</td>
<td>HDS, MHC, FCCU, DCU, VB</td>
</tr>
<tr>
<td>OXYGEN ($O_2$)</td>
<td>Gas Plant, FCCU, DCU, VACUUM</td>
</tr>
<tr>
<td>ORGANIC ACIDS (RCOOH)</td>
<td>Gas Plants, FCCU, DCU, VB</td>
</tr>
</tbody>
</table>
CAUSES OF CORROSION

1. High Inlet Contaminants Concentrations:

- High CO$_2$ concentration in the feed gas degrades the amine:
  - MEA degrades to HEED (hydroxyethylethylendiamine)
  - DEA degrades to THEED tris (hydroxyethyl) ethylenediamine.

- Oxygen: 100 ppm v/v or less are enough to degrade the amine due to organic acids formation (formic, acetic, glycolic and oxalic acids mainly).
CAUSES OF CORROSION

1. High Inlet Contaminants Concentrations:

- Presence of low molecular weight organic acids degrade the amine solution.

- High HCN concentration disrupt the protective FeS layer by formation of Fe(CN)$_6^{4-}$

  $$\text{FeS} + 6 \text{CN}^- \rightarrow \text{Fe(CN)}_6^{4-} + \text{S}^2^-$$

- High ammonia concentration from the treated gas form corrosive ammonium bisulphide

  $$\text{NH}_3 + \text{H}_2\text{S} \leftrightarrow \text{NH}_4^+\cdot\text{HS}^- \text{ (Ammonium bisulphide)}$$

  $$\text{Fe} \rightarrow \text{Fe}^{2+} + 2\text{e}^-$$

  $$\text{Fe}^{2+} + \text{NH}_4^+\cdot\text{HS}^- + 2\text{e}^- \rightarrow \text{FeS} + \text{NH}_3 + \text{H}_2$$
CAUSES OF CORROSION

2. High H₂S loading in the rich amine
   • Max. loading recommended: 0.35 mol H₂S/mol MEA, 0.4 mol/mol DGA, 0.4 mol/mol DEA, 0.45 mol/mol MDEA.

3. Low H₂S loading in the lean amine
   • < 0.08 mol H₂S/mol MEA, < 0.02 mol H₂S/mol DEA,
     < 0.004 mol H₂S/mol MDEA.

4. Amine degradation products
   • Heat Stable Amine Salts (HSAS).
   • Chelating agents formation:
     – THEED: tris (hydroxyethyl) ethylenediamine
     – Bicine: bis (2-hydroxyethyl) glycine
CAUSES OF CORROSION

5. Velocity accelerated corrosion.

6. High solids concentration and high velocities may remove the protective FeS layer.

7. High temperature of rich amine solution.

8. High temperature of lean amine may cause amine degradation.

9. Inadequate metallurgy.
CORROSION IMPACTS

- Increase in foaming and loss of amine solution.
- Equipment fouling due to accumulation of corrosion products (“black shoe polish” formation).
- Increased filtration cost (due to more frequent filter replacements).
- High concentration of corrosion products: Fe, Cr, Ni and Mn.
- Equipment (exchangers, pumps) and pipe failures.
# AMINE DEGRADATION CAUSED BY CONTAMINANTS

<table>
<thead>
<tr>
<th>AMINE</th>
<th>H\textsubscript{2}S</th>
<th>CO\textsubscript{2}</th>
<th>COS</th>
<th>O\textsubscript{2}</th>
</tr>
</thead>
<tbody>
<tr>
<td>MEA</td>
<td>NO</td>
<td>YES</td>
<td>YES</td>
<td>YES</td>
</tr>
<tr>
<td>DEA</td>
<td>NO</td>
<td>YES</td>
<td>YES</td>
<td>YES</td>
</tr>
<tr>
<td>DGA</td>
<td>NO</td>
<td>YES</td>
<td>YES</td>
<td>YES</td>
</tr>
<tr>
<td>DIPA</td>
<td>NO</td>
<td>YES</td>
<td>YES</td>
<td>YES</td>
</tr>
<tr>
<td>MDEA</td>
<td>NO</td>
<td>NO</td>
<td>NO</td>
<td>YES</td>
</tr>
</tbody>
</table>
CONSEQUENCES OF AMINE DEGRADATION

• Low pH of the amine solution.
• HSAS formation.
• Reduced acid gas removal capacity.
• Corrosion.
• High suspended solids concentration.
• Foam formation and stabilization.
WHAT ARE HEAT STABLE SALTS (HSAS) ?

• Organic or inorganic salts are formed by
  – Oxidative degradation of the amine (reaction with oxygen),
  – Irreversible reaction between amine and organic and inorganic acids,
  – Other side reactions due to contaminants like CO or HCN.

• Once HSAS are formed, they cannot be regenerated under normal regenerating conditions in the Stripper.

• Neither mechanical nor activated carbon filters can remove them from solution.
IMPACTS OF HSAS

• HSAS reduce the effective amine strength by the irreversible reaction of the amine with acids.

• HSAS can cause corrosion
  – When under specific operation conditions they dissociate, releasing ionic acids, i.e. Reboiler (highest temperature and lowest pressure).
  – By precipitation of the corrosive salts

⇒ If HSAS concentration exceeds a critical level, it is necessary to remove or neutralize them:
  ⇒ To avoid corrosion
  ⇒ To restore the proper acid gas removal capacity of the solution.
### MOST COMMON HSAS IN GAS TREATING

<table>
<thead>
<tr>
<th>ACID ANION</th>
<th>CHEMICAL FORMULATION</th>
<th>MAX. ALLOWABLE CONCENTRATION</th>
<th>CORROSION LOCATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acetate</td>
<td>CH$_3$CO$_2^-$</td>
<td>1,000 wppm</td>
<td>Reboiler &amp; Lower parts of Regenerator</td>
</tr>
<tr>
<td>Formate</td>
<td>CHO$_2^-$</td>
<td>500 wppm</td>
<td>Reboiler &amp; Lower parts of Regenerator</td>
</tr>
<tr>
<td>Oxalate</td>
<td>O$_2$CCO$_2^{2-}$</td>
<td>250 wppm</td>
<td>Reboiler &amp; Lower parts of Regenerator</td>
</tr>
<tr>
<td>Glycolate</td>
<td>HOCH$_2$CO$_2^-$</td>
<td>1,000 wppm</td>
<td>Reboiler &amp; Lower parts of Regenerator</td>
</tr>
<tr>
<td>Thiocyanate</td>
<td>SCN$^-$</td>
<td>10,000 wppm</td>
<td>Condenser &amp; Upper parts of Regenerator</td>
</tr>
<tr>
<td>Thiosulfate</td>
<td>S$_2$O$_3^{2-}$</td>
<td>10,000 wppm</td>
<td>Condenser</td>
</tr>
<tr>
<td>Sulfate</td>
<td>SO$_4^{2-}$</td>
<td>500 wppm</td>
<td>Condenser</td>
</tr>
<tr>
<td>Chloride</td>
<td>Cl$^-$</td>
<td>250 wppm</td>
<td>If SS metallurgy is in place</td>
</tr>
</tbody>
</table>
HSAS MANAGEMENT

- Different technologies can be used to eliminate or mitigate the detrimental impact due to the presence of HSAS:
  - Conventional thermal reclaiming on (MEA and DGA only)
  - Neutralization with a strong base like $K_2CO_3$ or KOH
  - Ion exchange resins
  - Vacuum distillation
  - Electro dialysis

- Selection of the most appropriate technology requires careful evaluation of operating conditions.
TYPICAL CORROSION LOCATIONS

WET ACID GAS CORROSION

Sweet gas → KO DRUM → H₂S, CO₂

Inlet Separator

Sour gas → HC

Absorber

Lean Amine

CO₂, H₂S

Cooler

L/R Exchanger

Rich Amine

Flash Tank

HC

Condenser

Rich Amine

Regenerator or Stripper

Rich Amine

 Accumulator

LP Steam

Filter

LP Steam

Filter

AMINE DEGRADATION CORROSION

© 2007 Baker Hughes Incorporated. All Rights Reserved.
BLISTERING CORROSION

- Defined as the mechanical damage of a metal surface due to its interaction with hydrogen.
- Hydrogen is produced by wet acid gas corrosion reaction.
PITTING CORROSION

• Very localized and aggressive corrosion. Destructive penetration occurs rapidly and in relatively few spots.
• Failures can occur in an unexpected way.
• The presence of chloride anions can promote this type of corrosion, especially in stagnant areas.
CORROSION CAUSED BY HSAS

- Example of uniform HSAS corrosion in bundle tubes of an amine exchanger.
- Regenerator bottoms, reboiler and pipes are other common places for this type of corrosion.
• The corrosion rate of the metal attack is increased if the velocity of the corrosive flow (amine solution in this case) is high. The protective FeS layer can be removed leaving the bare metal exposed to further corrosion.

• If the concentration of the suspended solids in the amine solution is high, these corrosion effects can be aggravated.
STEPS TO MITIGATE CORROSION IN GAS PLANTS

1. Conduct complete survey of the Gas Plant process.
2. Review historical analysis results and methodology.
3. Review the most critical process parameters and compare actual values to recommended KPI´s.
4. Review current analysis program and KPI´s.
5. Review feed contaminants and develop possible mitigation options. Prevent Rather Than Cure!
STEPS TO MITIGATE CORROSION IN GAS PLANTS

6. Review available corrosion monitoring records and corrosion reports; corrosion history and failures.

7. Review previous TAR inspection reports and deposit analysis.

8. Review metallurgies used in the unit, especially in most exposed corrosion areas.
TYPICAL METALLURGY FOR GAS PLANTS

• Equipment metallurgy
  – Shells of CS material
  – Internals and tubes of SS
    – 304 and 316 series most recommended

• Vessels
  – CS common metallurgy choice.

• Piping and Pumps
  – CS and SS metallurgies normally recommended.
BPC AMINE GAS TREATING MANAGEMENT PROGRAM

• **BPC Amine Gas Treating Management Program**
  – Identifies and addresses specific gas plant and amine unit corrosion problems.
  – Assures optimal performance of the unit following best practice recommendations.

• **The program includes:**
  – Advanced analytical testing and interpretation of results *(this section will be shown and explained in detail to the audience within the presentation).*
  – Effective chemical treatment program.
  – Innovative corrosion monitoring program.

• **BPC has developed proprietary knowledge and expertise in amine gas treating management.**
EFFECTIVE CHEMICAL TREATMENT PROGRAM

CORROSION CONTROL – CORROSION INHIBITOR BPR 81330

• Water soluble corrosion inhibitor.
• Formulated specifically for amine units.
• Non-volatile at stripper conditions.
• Recommended dosage program:
  – Initial dosage:
    • based on total amine inventory in system.
  – Daily dosage:
    • based on daily amine losses
      – if unit performs very well and amine losses are very low, this amount can be very small.
EFFECTIVE CHEMICAL TREATMENT PROGRAM

CORROSION CONTROL – CORROSION INHIBITOR BPR 81330

• Additional dosages may be required in corrosive areas
  – Regenerator O/H System and/or Reboiler.
  – Dosage adjusted according to corrosion monitoring results.

• Use of a slip stream is recommended for better dispersion and performance of the additive.

• Fresh amine can be delivered with the corrosion inhibitor to protect the system. Once the amine is diluted to its proper strength, the corrosion inhibitor protects the system at the recommended dosage.
EFFECTIVE CHEMICAL TREATMENT PROGRAM

FOAM CONTROL – ANTIFOAM PROGRAMS

• Amine degradation and corrosion products can result in foam formation and stabilization.
• BPC has developed different types of antifoams.
• Most appropriate additive selection requires lab screening
  – Foam and stability test of amine solution.
• Antifoams:
  – BPR 45004 (silicon base)
  – BPR 45145 (glycol base)
  – BPR 41903 (non silicon base)
CORROSION MONITORING PROGRAM

• Purpose of Monitoring
  - Evaluate effectiveness of corrosion control program
  - Establish operational constraints/limits
  - Serve as an early warning of changes in system corrosion

• Corrosion monitoring techniques
  - ER probes and weight loss coupons
  - Ultrasonic thickness measurements
  - Digital radiography
  - Field Signature Method (FSM®)
  - Hydrogen permeation technology

FSM is a registered trademark of CorrOcean AS
HYDROGEN PERMEATION MONITORING TOOL

© 2007 Baker Hughes Incorporated. All Rights Reserved.
HYDROGEN PERMEATION MONITORING MEASUREMENTS

• Advantages
  – Mobile and portable instrument
  – Temperatures up to 600 °C
  – Non-intrusive measurement in minutes
  – Reliable measurement reflects real-time corrosion activity at the internal pipe wall

• Other features
  – Available model features transmitted output
  – Fixed collectors available for under-insulation uses
  – Intrinsically safe for amine gas treating plants and refinery application
HYDROGEN PERMEATION MONITORING MEASUREMENTS

• Hydrogen permeation is an innovative technology to monitor corrosion in amine treating gas plants and other units recommended and used by BPC.

• BPC has developed proprietary knowledge and expertise in the use and interpretation of this technique within the last seven years.

• BPC conducts detailed unit surveys to recommend the best monitoring locations.
1. **European amine unit. Application currently in place for 7 years.**

Technical advice and support for successful elimination of severe corrosion caused by hydrolysis of COS in LPG storage spheres. Corrosion in the propane was highest when processing high sulfur crude.

\[ \text{COS} + \text{H}_2\text{O} \leftrightarrow \text{H}_2\text{S} + \text{CO}_2 \] (reversible reaction)

Baker Petrolite provided two solutions to solve the corrosion problem:

- **a) Non chemical treatment.** Operational changes in the amine unit resulted in successful reduction of >50% of COS content in the treated LPG.

- **b) Chemical treatment.** Injection of a non-ferrous corrosion inhibitor in the LPG prior to storage was extremely efficient.
  - Untreated LPG - severe corrosion measuring 4a - out of spec
  - Treated LPG – corrosion drastically decreased to 1a - in spec

**Economic benefit to the refinery estimated at $217K**

3. European amine unit. Application currently in place for 1 year. Technical support and advice to mitigate the corrosion effects due to high HSAS concentration using BPC Amine Unit Management Program: corrosion inhibitor, analytical testing, corrosion monitoring using hydrogen permeation technology.

SUMMARY AND CONCLUSIONS

• Corrosion is a common problem in gas treating plant that has to be properly addressed.

• Detailed investigation of the corrosion causes and mitigation options have to be carefully studied.

• Baker Petrolite Amine Gas Treating Management Program identify and address specific gas plant and amine unit corrosion problems. The program includes:
  – Advanced analytical testing and interpretation of results
  – Effective chemical treatment program
  – Innovative corrosion monitoring program

• Baker Petrolite’s Best Practices, key parameters and targets are recommended to minimize corrosion and assure optimal performance of the gas treating plant and amine units.
Thank you for your attention!
LITERARY REFERENCES


