Unlocking the Potential of Existing Brownfield Gas Processing Assets by Solvent Swaps
Case Studies

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Gary Bow erbank
Manager Gas Processing Technology, Shell Global Solutions
Reserves: Our use of the term “reserves” in this presentation means SEC proved oil and gas reserves.

Resources: Our use of the term “resources” in this presentation includes quantities of oil and gas not yet classified as SEC proved oil and gas reserves. Resources are consistent with the Society of Petroleum Engineers (SPE) 2P + 2C definitions.

Resources and potential: Our use of the term “resources and potential” are consistent with SPE 2P + 2C + 2U definitions.

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Shales: Our use of the term ‘shales’ refers to tight, shale and coal bed methane oil and gas acreage.

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Agenda

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Summary
Introduction

Given global challenges of “lower for longer” for both Oil and Gas, there are fewer major new Gas Processing capital projects.

There is a clear trend to focus on maximising the profitability of existing assets, through increased focus on operations and selective investment in smaller scale Brownfield projects.

A solvent swap in an Acid Gas Removal Unit is a good example of such a small scale Brownfield project, requiring minimal (or no) capital expenditure.

Solvent swaps can bring a range of benefits including;

- Increased capacity
- Reduced energy consumption
- Deeper contaminant removal
- Less solvent degradation
Introduction

Based on our experience and owner, operator and licensor; Shell has assessed feasibility and implemented a range of solvent swaps.

Three case studies, which are most applicable in the Middle East, have been selected to demonstrate the potential benefits of solvent swaps:

- Case Study 1: Increase in feed gas contaminants
- Case Study 2: Reducing operating costs
- Case Study 3: Tighter treated gas specifications
Case Study 1

Increase in feed gas contaminants
Case Study 1: Increase in feed gas contaminants

Background

- When extending Gas Plant life, new fields/wells required to be developed. New wells were more contaminated (H₂S and CO₂) significantly impacting the feed gas to the Acid Gas Removal Unit
  - H₂S ~1.0 vol% ⇒ ~2.0 vol%
  - CO₂ ~2.5 vol% ⇒ ~3.3 vol%
- Nameplate capacity and treated gas specification unchanged
- Existing unit based on Shell Sulfinol-D process
Case Study 1: Increase in feed gas contaminants

Option A
- New Pre-treatment Acid Gas Removal Unit
  - Typical unit with numerous vessels, absorber, regenerator & associated pumps/ exchangers
  - Additional plot space

Options B
- Swap from Sulfinol-D to Sulfinol-X
  - Higher loading capacity of MDEA
  - Lower hydrocarbon pick-up (optimised formulation)
Case Study 1: Increase in feed gas contaminants

Swap from Sulfinol-D to Sulfinol-X

- Able to remove the additional contaminants (H₂S & CO₂) while still meeting specification, with same solvent circulation
- Due to increased rich loading, the reboiler duty requirements increased by approx. 10%
  - Detailed checks utilising the design margins of the reboiler showed that this was feasible
- Benefits:
  - Better quality acid gas (more H₂S, but also less hydrocarbons)
  - No major equipment modifications
  - Lower CAPEX and OPEX than Option A
  - Negligible change to operating philosophy
  - No additional plot space required
  - No change to overall availability
  - No additional equipment to maintain

![Diagram of Sulfinol-X Acid Gas Removal Unit and Sulphur Recovery Unit]
Case Study 2

Reducing operating costs
Case Study 2: Reducing operating costs

Background

- Although effective at removing CO\textsubscript{2}, DIPA based solvents such as Sulfinol-D do have a risk of forming DIPA-oxazolidone (similar issues are also apparent with other primary and secondary amine based solvents)
- Degradation products can have detrimental effect on the unit operation, ranging from increased foaming tendency to accelerated corrosion
- Traditional solutions revolve around Solvent management:
  - Bleed and Feed (natural or managed)
  - High OPEX: fresh solvent as well as disposal
  - Reclaiming (ion exchange or thermal)
    - Generates a waste stream
    - Increased operator attention
    - Hence, frequently not operated
    - Consumes utilities
Case Study 2: Reducing operating costs

Solution

- Working with the Operator, Shell proposed replacing Sulfinol-D with Sulfinol-X
  - Specifications (CO$_2$, H$_2$S, COS, Mercaptans) still achieved
    - In fact COS removal improved
  - Solvent circulation rate unchanged
  - Reboiler duty reduced (~10%)
  - No hardware changes or impacts to downstream units
  - Materials of construction acceptable

Additional Benefits

- As part of the study (due to lower reboiler duty) the unit can process an extra 10% gas throughput
Case Study 3

Tighter treated gas specifications
Case Study 3: Tighter treated gas specifications

Background

- An existing asset using an aqueous amine (DEA) wanted to meet a deeper total sulphur specification to improve the final product, which requires the removal of organic sulphur (mercaptans).
  - COS $\sim 50$ ppmv
  - RSH $\sim 120$ ppmv $\Rightarrow <5$ ppmv
- Mercaptan removal in such aqueous amines is quite limited

![Diagram of gas treatment process](image-url)
Case Study 3: Tighter treated gas specifications

Option A
- Upgrade Molecular Sieve unit and add dedicated Regeneration Gas Treated
  - Multiple additional equipment
  - Additional plot space
  - Shorter MSU cycle times

Options B
- Swap from DEA to Sulfinol-X
  - Hybrid solvent allows required removal of mercaptans and COS with no increase in solvent circulation
Case Study 3: Tighter treated gas specifications

Swap from DEA to Sulfinol-X

- Able to meet new total sulphur specification of <5ppmv with same solvent circulation, equivalent to > 90% removal of Mercaptans and COS
- In MDEA based solvents such a swap may even be feasible without a unit shutdown (assuming solvent quality is acceptable)
- Such a swap can also address the challenge of Increased Mercaptans and COS in the feed gas for aqueous based units

Benefits:
- Lower CAPEX and OPEX than Option A and DEA
- Negligible change to operating philosophy
- No additional plot space required
- No additional equipment to maintain
Solvent Swap Best Practices
Recent Shell Experience

- Vary from on-the-run to offline
- Justification ranges from increased capacity, lower operating costs, changing feed or treated gas specifications
- In addition there are several examples where solvents were changed during the detailed engineering phase, including
  - Saudi Arabia and Oman

<table>
<thead>
<tr>
<th>#</th>
<th>Location</th>
<th>Type of Feed</th>
<th>Solvent Swap</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Italy</td>
<td>Natural gas</td>
<td>MDEA to Sulfinol-X</td>
</tr>
<tr>
<td>2</td>
<td>India</td>
<td>Natural gas</td>
<td>Sulfinol-D to Sulfinol-X</td>
</tr>
<tr>
<td>3</td>
<td>Singapore</td>
<td>Hydrogen manufacturing unit</td>
<td>Sulfinol-D to ADIP-X</td>
</tr>
<tr>
<td>4</td>
<td>USA</td>
<td>Hydrogen manufacturing unit</td>
<td>Sulfinol-D to ADIP-X</td>
</tr>
<tr>
<td>5</td>
<td>Brunei</td>
<td>Natural gas- ING</td>
<td>Sulfinol-D to ADIP-X</td>
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<tr>
<td>6</td>
<td>Russia</td>
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<td>7</td>
<td>Oman</td>
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<tr>
<td>8</td>
<td>Australia</td>
<td>Natural Gas- ING</td>
<td>Sulfinol-D to ADIP-X</td>
</tr>
</tbody>
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Solvent Swap Best Practices

“On-the-Run” Vs “Offline”

- When moving from an aqueous amine to a hybrid solvent it may be feasible to do this “on-line”
  - We have even done this from Sulfinol-D to Sulfinol-X
- On-the-Run swap requires
  - Current solvent to be good quality
  - Detailed procedure and close monitoring to avoid upset
- Offline solvent swap requires more time, ideally linked to a unit turnaround, but can provide the following benefits:
  - Clean system, both equipment and solvent
  - Opportunity to implement minor modifications, such as control valve or instrument upgrades

Decision based on a case to case basis, looking at risk and status of the current unit/ solvent
Solvent Swap Best Practices

Effective Execution

- Preparation is key:
  - Feasibility Study developed by Technology Provider (Licensor) with the Operator
    - Adequacy checks (tray hydraulics, exchanger & pump capacity, turndown)
    - Updated H&MB, Hazard Register (Safety Datasheets) and operating guidelines
    - Review of materials of construction and instrument calibration
  - Development of site specific procedures with Technology provider (Licensor) and Operator
    - Effluent disposal, storage and supply of new solvent
    - Cleaning procedures
    - Update of operating manuals
  - Other key checks
    - Detailed solvent analysis
Solvent Swap Best Practices

Effective Execution

- Implementation
  - Logistics
    - Procurement, supply and storage of new solvent
    - Disposal of effluent
  - Supervision and monitoring of the process
    - Operator and Technology Provider (Licensor)
    - Sampling and testing of the solvent and gases
    - Test-run to demonstrate performance
  - Long term support
    - Monitoring and routine checks to assure that new process being operated at optimum conditions
Summary
Unlocking the Potential of Existing Brownfield Gas Processing Assets by Solvent Swaps

Summary

- Significant gains may be available for limited investment by considering a solvent swap
- Important to invest in high quality feasibility study
- Operations input to any assessment and preparations is key
- Solvent swaps in Acid Gas Removal Units can
  - Increased capacity
  - Reduced energy consumption
  - Deeper contaminant removal
  - Less solvent degradation
- Applying solvent swaps in Tail Gas Treating Units, such as SCOT Ultra, can also bring benefits of lower SO$_2$ emissions or reduced operating costs (steam and solvent losses)
Questions and Answers