Best practice for deep treating sour natural gases (to LNG and GTL)

Author: Jeanine Klinkenbijl
Co-authors: Henk Grootjans and Jay Rajani
Presentor: Jeanine Klinkenbijl

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Summary

Natural gas fields to be developed in the near future contain considerable amounts of sour gas component such as sulphur components. Two criteria that are key in determining the best process line-up for treating:

- Treated gas specification
- Reduction of the sulphur dioxide (SO₂) emission to the lowest level without excessive capital investment

Meeting these criteria involves an economic optimisation of benefit and cost. Moreover, the sour gas treating train should maintain operability and flexibility for feed gas changes over time. This paper discusses several integration aspects of the treating processes involved. The chosen feed gas has a challenging hydrogen sulphide/carbon dioxide (H₂S/CO₂) ratio and a considerable amount of mercaptans (RSH). The carbonyl sulphide (COS) for this case is limited. An overview is provided for the treating concepts involved to prepare a treated gas that is suitable for Gas To Liquid (GTL) and Liquefied Natural Gas (LNG) applications. The treating trains for these applications show large resemblance.

In the past, individual treating units for component removal were evaluated on isolated basis. However, the choice of the process selected for the H₂S and CO₂ can have considerable influence on the choices for the process required for mercaptan removal, but also on the units that have to handle the sulphur rich streams.

The mercaptan removal optimization and SO₂ emission reduction have been evaluated in detail. The recommended mercaptan removal line-up has been used as basis for the emission reduction study. The results of both studies are discussed. Trace component removal, possible condensate and LPG treating are not discussed, but the influence on the SO₂ emissions is addressed briefly.

The detailed analysis has shown that individual unit optimization does not automatically guarantee an optimized treating train for the criteria given. It was concluded that the best practice to establish the optimum treating train for complex feed gasses should be critically examined, taking all the process and environmental limitations in account within a flexible, operable and economically justified window. This paper explains these principles using an example that gives the best option for one application.
Introduction

Gas fields taken into production in the near future, e.g. in the Middle East contain considerable amount of sulphur components. Such gas therefore poses challenges in adapting gas processing technologies, particularly for conditioning gas for Liquefied Natural Gas (LNG) and Gas to Liquids (GTL) projects. Shell Global Solutions offers solutions based on an integrated combination of processes that takes the contaminated feed gas stream and delivers the required end product in an optimal manner. The business driver is the selection of the best available technology to accomplish the objectives for cleaner environmental standards, an improved reliability and higher margins. The solutions offered are based on the research efforts in Shell Global Solutions and make use of the operational experience by Shell plants. The modelling tools used for process optimisation are unique in their excellence and fit actual performance data.

The fundamental objective in treating is to meet all outlet-stream specifications for a particular feed stream. The variations in feed gas streams are increasing and these feed streams come with widely different temperatures and pressures, but in particular show extremes in composition. In addition, environmental regulations and more demanding product qualities result in an increased focus on treating units. Capital and operating costs need to be minimized, while operability is maintained.

In a gas treating line-up, the removal of sulphur compounds (H₂S, COS, mercaptans, (di-) sulphides) and carbon dioxide (CO₂) are required. Removal of these components is often carried out by the use of regenerative amine or physical solvent solutions. The choice of a particular solvent is very much dictated by the concentrations of the above-mentioned contaminants. In addition, the sulphur recovery line-up to handle low H₂S/ CO₂ ratios and possible heavy hydrocarbons and mercaptans needs be assessed so as to meet environmental sulphur emissions level.

The evaluation presented in this paper is based on the challenges Shell Global Solutions experiences in developing treating solutions for LNG and GTL projects in the Middle East.
Process building blocks

A typical feed gas from the Middle East has 0.5 – 1.0 %v H2S, 2 %v CO2 and 300-400 ppmv RSH. COS and sulphides are present in the low ppmv range. The presence of mercaptans, aromatics and other heavy hydrocarbon (C5+) together with an unfavourable H2S/CO2 ratio require line-up optimization. Assumed feed gas pressure and temperature, for the purpose of this comparison, are around 70 bara and 25 °C respectively.

The first specification to be met is H2S removal to < 4 ppmv, total sulphur < 30 ppmv as S (and as low as possible for GTL applications) and CO2 to either 50 ppmv for LNG and possibly up to 1 or 2 %v for GTL applications. Both applications require< 0.1 ppmv water and removal of mercury to levels of 10 µg/Nm3. Pipeline specifications are comparable.

In Figure 1 the process building blocks are represented for a treating scheme that serves both the LNG and GTL applications. The relations between the building blocks and how the process selections within a building block influence the emissions are discussed later. The treating building blocks may represent up to 15 % of the total investment costs for e.g. an LNG plant, which is a significant part of the working capital of the plant. Selecting the processes, plant operability, capital investment and operational costs are determining factors for the final choice. In principle no exotic processes have been applied.

Natural gas from upstream typically arrives in an on-shore plant in a slug catcher. Here condensate is separated from the main gas stream. The slug catcher gas is generally combined with overhead gas from the condensate stabilization unit, before being routed to the gas treatment plants. To allow problem-free operation of the main Acid Gas Removal Unit (AGRU), it is very important to have efficient liquid knock out and gas cleaning facilities upstream of this unit so as to minimize impact of contaminants used in the upstream process or pipeline to the AGRU process downstream.

The knocked out hydrocarbon liquids/ condensate, may contain considerable amounts of the heavy sulphur components (mainly mercaptans), which remain in the condensate after stabilization.

Key elements in selecting the optimum process for the Acid Gas Removal Unit (AGRU) are the requirements for full or selective removal of CO2 and the co-absorption of hydrocarbons. The second step in the treating process is a Molecular Sieve Unit (MSU), which brings the gas at the final specification for water and mercaptans (RSH) content. Removal of RSH in a MSU necessitates treating the regeneration gas containing RSH in a separate treating unit. Such a unit could be operated with a physical or mixed physical/chemical solvent. One key element in the process selection is the integration of the solvent by shared regeneration with the upstream AGRU. Another key element is the optimal reduction of the co-absorption of hydrocarbons in the solvent.

The treated gas leaving the MSU can now be routed to an NGL extraction unit if recovery of NGL components is selected for a project. The NGL extraction unit is not described in detail in this paper. Two important aspects that should however be noted are that the CO2 content of the feed gas to a NGL extraction unit should always be reduced below the CO2 freezing limit. Secondly, some further treatment, i.e. sulphur removal of NGL streams will be required even with a suitable main gas treating unit.
After gas treating in the main AGRU and the MSU, the gas is on specification for feeding LNG units. The LNG end product quality is achieved in the liquefaction unit itself. If gas is to be used for GTL production, a more stringent sulphur specification is required. For this purpose a gas polishing unit is provided consisting of a unit which converts the mercaptans to hydrogen sulphide followed by a guard bed to remove last traces of sulphur components.

Sulphur components from the main AGRU, from the MSU regeneration gas treatment, and from NGL treating units all will be converted to sulphur in a Sulphur Recovery Unit (SRU) and Tail Gas Treating Unit (TGT). Key elements in the selection of the sulphur-recovery process are the requirement for acid gas enrichment (so as to make the operability of the SRU possible with minimum H$_2$S/CO$_2$ ratio), the processing of acid streams other than the main acid gas, and handling the variations of the acid-gas stream.

### Meeting the treated gas specification

Three types of treating processes are available. The physical solvents like the Morphysorb, Rectisol, Selexol and Purisol processes. The chemical processes that are based on aqueous amine processes. Examples are the aMDEA, Ucarsol, Flexsorb and ADIP processes. The mixed physical/chemical processes like the Sulfinol process.

To make the best selection for the removal of H$_2$S and CO$_2$, the following main issues should be addressed:

- The specification for CO$_2$ in the treated gas determines whether a selective H$_2$S removal process or a deep CO$_2$ removal process is necessary
- Can the process and the processing equipment be designed to cover the full range of feed gas conditions without intensive operator intervention? This question can only be adequately addressed if a full operating envelope, showing the range of feed gas contaminants, is available. A plant should be able to operate over this range both at full throughput and at turndown.
- What percentage of the feed gas hydrocarbons is lost from the treated gas through co-absorption and entrainment? What is the composition of this hydrocarbon loss in the various units and where will these losses end-up?
- Is there a minimum requirement on the H$_2$S content of the acid gas going to the Sulphur recovery Unit (SRU)?
- Does the solvent used for H$_2$S and CO$_2$ removal also have mercaptan-removal capacities?

For the richer gases discussed (which have more heavy hydrocarbons in the gas), physical processes are not preferred to treat the main gas streams due to the excessive hydrocarbon losses and consequences in the sulphur units, affecting the process economics. In this paper the aqueous amine and mixed type processes are addressed.

The Molecular sieve unit (MSU) generally removes water from the gas, but can also be designed to remove mercaptans. There is an optimum between the amine-based AGRU and the MSU for mercaptan removal. There are two options: first, mixed physical/chemical processes can be used to remove part or all of the mercaptans from the feed stream, and the mol sieve unit can be used as a polishing step. The second option is to use an aqueous amine solvent, which removes little mercaptans (say 10 – 15 %), leaving most of the mercaptan-removal to the mol sieve unit. Importantly, the mechanism for removal of mercaptans in the amine solvents is similar for the hydrocarbons and mercaptans; thus, some degree of co-absorption of these components cannot be avoided. This optimization should take into account three main factors: operating flexibility over the feed gas range, environmental performance, and cost effectiveness. It is clear that this approach will not result in a fit-for-all-purposes design, but that a tailor-made approach for each gas composition and operating location is necessary.

**Option A Aqueous solvent in AGRU**

When the AGRU is based on an aqueous amine solvent, the solubility of the mercaptans is low and the MSU will be designed to remove the bulk of the mercaptans. For regeneration of the MSU a separate treating unit will be required. The main advantages and disadvantages are:

**Advantages**

- Low heavy hydrocarbon co-absorption in AGRU
- The AGRU is smaller compared to a mixed physical/chemical AGRU line-up
**Disadvantages**

- The molecular sieve capacity must be sized for nearly the full mercaptan load. This not only means that the number and size of beds is high, but also that the required amount of regeneration gas is high.
- During molecular sieve regeneration, mercaptans de-sorp from the molecular sieve beds in a time dependant manner, resulting in large peaks mercaptan concentration in the regeneration gas. This time dependence has been measured by Shell Global Solutions at an operating plant using molecular sieves for mercaptan removal, and can be used to design effective means for coping with the time-dependent composition.
- A separate solvent is required for treatment of regeneration gas, adding to complexity and issues of heavy hydrocarbon co-absorption.
- Poor operational flexibility when the mercaptan slate or quantity is changed as the operation is fully determined by the molecular sieve design basis (quantity and life time of the molecular sieve).
- Meeting low mercaptan specifications may be difficult within reasonable costs due to the adsorption competition between mercaptans and other components.

This option line-up is shown in Figure 3.

![Figure 3: Block scheme for the aqueous amine (option A)](image)

**Option B Mixed solvent in AGRU, total RSH removal**

When the AGRU is based on a **mixed physical/chemical solvent**, the mixed solvent can be designed to remove all mercaptans. This specification is easily met, when the CO₂ also has to be removed to deep specification and the solvent circulation is high as for LNG. Subsequently, the MSU has only to meet the water specification.

**Advantages**

- Total removal of H₂S, CO₂ and mercaptans in AGRU
- Simple mol sieve unit for dehydration only
- Operational flexibility since the physical component in the mixed solvent can be reduced when the actual feed gas composition is lower in mercaptans
- Reduced BTX content in the treated gas due to the co-absorption of heavy hydrocarbon can be advantageous for the downstream processing
Disadvantages

- Requires a high solvent circulation
- High hydrocarbon losses due to co-absorption of heavy hydrocarbons (C₅⁺, BTX)

This line-up is only competitive if the mercaptan removal can be achieved in a design that is based on H₂S and CO₂ removal only. Generally this will not be the case resulting in an expensive AGRU design with a hydrocarbon co-absorption that is too large to be acceptable.

Option C Optimised physical/chemical mixed solvent – molecular sieve arrangement for RSH removal

The optimum solution in many cases is the distribution of the mercaptan removal capabilities over the mixed solvent in the AGRU as well as the MSU (option C). In this design the regeneration of the MSU gas can be integrated with the AGRU, using shared regeneration. The optimization is based on reducing the MSU size by addition of mercaptan removal capacity in the AGRU.

The capital and operating costs for the three different options have been compared for an application where a certain slip of CO₂ is allowed, e.g. GTL. Option A represent the aqueous amine, option B the total removal of mercaptans with mixed physical/chemical solvent and option C the optimized mercaptan removal option. The results are shown in figure 5.

The possibility to optimize the mercaptan removal between a mixed physical/chemical solvent and the molecular sieve proves to be cheaper in capital/operational cost when compared to a complete mercaptan removal in a mixed solvent option. The aqueous amine line-up represents the lowest hydrocarbon losses, but requires a higher capital cost from the increased molecular sieve unit and the need for a separate regeneration gas unit. Moreover, concentrating the mercaptan removal in one process reduces the flexibility for changed feed gas compositions and optimization during processing.

The optimized mercaptan removal between the mixed solvent and the molecular sieve (option C), with integrated mixed solvent for the regeneration gas treating, represents the most flexible, operable and cost efficient solution at the expense of increased hydrocarbon co-absorption. When the acid gas from the MSU regeneration gas treating unit can be directly routed to an SRU, then the entrained/dissolved hydrocarbons represent a fuel value. When the hydrocarbon content is excessive, special line-ups are required.

For GTL projects the specification for total sulphur cannot be met with the AGRU and MSU units alone. Additional non-regenerative guard bed arrangements must be added for the removal of trace sulphur components to protect reforming and Fischer-Tropsch catalysts. The sulphur components are converted over a conversion bed to hydrogen sulphide subsequently absorbed on a sulphur guard bed. Flexible sulphur components removal in the AGRU/MSU means that the chosen line-up can cope well with the feed gas fluctuations and unit upsets. Because the risk of sulphur component increase due to operational upsets in the treated gas ex AGRU/MSU is reduced, the guard bed arrangement can be
smaller. When the achieved sulphur content in the AGRU/MSU is lower than expected, the lifetime of the guard bed system can accordingly be increased.

### Cost Comparison of Mercaptan Removal

![Cost Comparison of Mercaptan Removal](image)

**Option A**  
- CAPEX: 57  
- Heat Duty: 100  
- Hydrocarbon losses: 40

**Option B**  
- CAPEX: 100  
- Heat Duty: 100  
- Hydrocarbon losses: 84

**Option C**  
- CAPEX: 136  
- Heat Duty: 100  
- Hydrocarbon losses: 84

Figure 5: Cost comparisons for mercaptan removal optimization depending on AGRU solvent

### Reduction of sulphur emissions and hydrocarbon losses

The main emission sources from the gas-treating complex will be sulphur dioxide (SO₂) from non-recovered sulphur in streams that are routed directly to the incinerator and a CO₂ rich stream that is combusted with hydrocarbons in the SRU and incinerator. Additionally the hydrocarbons, which are not used in the sulphur recovery units, contribute to an increase in CO₂ emission.

In reducing these emissions for a large LNG or GTL project, a number of key issues will need to be addressed:

- When both CO₂ and H₂S (and other sulphur components) are removed in the AGRU, can the Sulphur Recovery Unit (SRU) handle the resulting acid gas composition, taking into account the full range of feed gas compositions and turndown?
- If a standard SRU cannot cope with the acid gas, a more complex SRU design can be utilized or alternatively an Acid Gas Enrichment Unit (AGEU) can be installed. In case an acid gas enrichment unit is used, a new waste stream is created consisting of mainly CO₂, but also sulphur containing components and heavy hydrocarbons.
- Can all the waste streams (flash gas, sour gas ex regenerator, gas from LPG treating) be handled in the SRU or tail-gas treating (TGT)?
- When a TGT is present in the line-up, is it possible to combine the TGT absorber process with the process in the AGRU or AGEU?
- Which additional components are removed from the feed gas with the acid gases, such as heavy hydrocarbons and aromatic components (BTX) and how does this affect the performance of the AGRU and TGT units?
- To what extent will co-adsorption of hydrocarbons on the MSU affect the performance of the AGRU off gas treating (AGEU, SRU, TGT)?
In refineries, the sulphur recovery is generally defined as the recovery of the sulphur out of and into the SRU/TGT, thereby allowing sulphur-containing streams to be sent immediately to the incinerator, which then do not count in the sulphur recovery calculation.

The sulphur recovery for natural gas projects is defined as sulphur produced from the SRU and TGT divided by the sulphur components in the AGRU feed gas. To achieve a high sulphur recovery, > 99 %, all streams to be disposed and containing sulphur elements need to be processed in the SRU/TGT. In fact this means for the feed gas given earlier, that the mercaptans should be included in the sulphur recovery optimization. Furthermore, the sour gas from the LPG treating unit needs to be processed in the SRU/TGT.

Optimization of the overall treating complex means striving for the highest sulphur recovery possible, reducing the SO₂ emission to a practical level, and minimizing costs.

With respect to the LNG and GTL applications there are two major differences:

- LNG application demands deep CO₂ removal, which in some cases is not necessary for the GTL applications. The complication of deep CO₂ removal is that the H₂S/CO₂ ratio in the SRU/TGT becomes too low causing unstable operation.
- Overall in the GTL application, the sulphur specifications are more restricting.

When compared to refinery applications the main difference when discussing the sulphur recovery in the natural gas line-up, if compared with refinery conditions, is the large amount of co-absorbed CO₂ and (heavy) hydrocarbon and BTX in the AGRU and/or AGEU.

For this paper 4 alternative process line-ups are discussed. Basis of the study was the case with the highest CO₂ co-absorption: i.e. the LNG treating application. The optimized mercaptan removal line-up was chosen as the base case.

**The Base case**

Following the mercaptan removal recommendation (Option C) the process line-up for an LNG plant is shown in Figure 6 and will be referred to as Base case.

![Figure 6: Base case optimized mercaptan removal](image-url)
Properties of the Base case

- Optimized mercaptan removal
- Stable operable acid gas supply to SRU in flow and composition fluctuations
- The SRU/TGT unit will be capable to handle the enriched sour feed gas without any specific process optimization
- Because of the low H₂S/CO₂ ratio there is a need to improve the H₂S/CO₂ ratio in the SRU feed gas. This is done in an aqueous amine unit, which is best choice for economic reasons. The selective enrichment absorber can be integrated with the TGT absorber with a common regenerator for optimization of capital and operating expenses
- An advantage of a dedicated enrichment unit is the possibility to separate the H₂S/CO₂ stream from the mercaptan stream
- The sulphur recovery is relatively low, and the SO₂ emissions are unacceptably high (> 5000 mg SO₂/Nm³). This is due to the direct routing of the AGEU treated gas to the incinerator. This stream contains mercaptans and heavy hydrocarbons removed in the AGRU by the mixed solvent and hence the mercaptans are lost from the recovery
- The SRU process is based on the partial oxidation of hydrogen sulphide. To maintain the desired conditions, the amount and type of the co-absorbed hydrocarbon from the molecular sieve regeneration gas treating has to be taken in account in the oxygen- (air-) demand to ensure a sufficiently high flame temperature. A moderate hydrocarbon concentration in the feed gas to the SRU can be used to accommodate for a lower H₂S/CO₂ ratio, as the hydrocarbons are co-fired to result in acceptable conditions. With special control and burner types, the ability of SRU units has been widened
- For the type of gas routed to the SRU, the SRU recovery is around 92 %. This rather low efficiency is caused by the presence of CO₂ and N₂ from the process air.

The different line colours represent the process units that can be integrated. The AGRU solvent is of the mixed type.

H₂S enrichment in the AGRU, by means of heated flashes, could be considered to avoid a dedicated enrichment unit in the sour gas ex AGRU. The enrichment with this heated flash mechanism is not as efficient, but can in some cases be sufficient. The flash gas is treated in a flash gas enrichment absorber, where the H₂S and mercaptans are re-absorbed in the solvent and the CO₂, and preferably hydrocarbons, are concentrated in this absorber off gas. The direct sulphur loss to the incinerator is reduced as most of the sulphur species have been co-absorbed. With this type of enrichment, most of the mercaptans remain in the solvent if the solvent is of the mixed physical/chemical type.

A TGT is a standard requirement for all alternatives. The TGT unit uses reduction conditions to convert the sulphur components not processed in the upstream SRU to hydrogen sulphide in a burner and catalyst (reactor) step. The resulting stream is routed, after water removal in the quench tower, to a selective amine absorber. The treated gas from the TGT absorber is routed to the incinerator and this contributes to the emission. The absorbed gases are recycled to the SRU. Improving the selectivity will reduce the amount of CO₂ in the TGT regenerator off gas which has 2 advantages: there is less CO₂ routed to the SRU, thereby improving the H₂S/CO₂ ratio; and the size of the SRU is reduced when the CO₂ is removed from the recycle.

Alternative 1 Application of aqueous solvent for the AGRU

As the first alternative the use of aqueous solvent in the AGRU is evaluated (option A of the mercaptan removal evaluation). In this option only a limited amount of mercaptans are absorbed in the AGRU and the sulphur content of the AGEU off gas will be significantly reduced. In this option, either a mixed solvent or a physical solvent can perform the molecular sieve regeneration gas treating to remove all mercaptans. Comparison of these process routes, results in a considerable reduced level of hydrocarbon co-absorption for the mixed solvent. Particularly the heavy C₄⁺ and BTX are co-absorbed in a physical process. Not only is that causing a loss of hydrocarbon from the system, but also the SRU may have problems to handle the sour gas from the regeneration gas treating regenerator. The peak handling may require both peak shaving facilities and dedicated burner arrangements in the SRU. Therefore this option is evaluated with a mixed solvent for the regeneration gas treating.

The line-up is represented in Figure 7.
Figure 7: Alternative 1. Aqueous amine line-up with mixed solvent for molecular sieve regeneration gas treating

**Advantages**
- Low hydrocarbon loss in AGRU
- No interference of mercaptans in SRU
- Some reduction in SO₂ emission

**Disadvantages**
- Overall line-up requires an increase in capital cost compared to the base case, as previously shown in this paper
- High BTX and heavy hydrocarbon content in acid gas from the MSU regeneration from co-absorbed hydrocarbons in the MSU
- SO₂ emission still higher than target
- The peaks of mercaptans and hydrocarbons into the regeneration gas will need to be catered for in the SRU design or alternatively a peak shaving system will need to be included in the regeneration gas treatment unit. Both these requirements increase the capital and operational cost of the overall treating complex considerably
- With excessive amounts of heavy hydrocarbon no soot free operation of the SRU can be guaranteed and the heavy hydrocarbon should not be routed to a reducing flame

It should be noted that the advantage of the difference in hydrocarbon losses as presented in figure 5 reduces considerably due to the lower hydrocarbon removal by the mixed regeneration gas treating process compared to the physical process used in Option A.

**Alternative 2: Use of separate Acid Gas Removal Units**
The simplest and straightforward option is to remove selectively the H₂S with aqueous amine solvent, remove the CO₂ with a different aqueous amine solvent and have separate mercaptan removal by a mixed physical/chemical solvent. Additional enrichment is not required and the aqueous amine processes selected reduce the hydrocarbon co-absorption. The collected CO₂ from the CO₂ removal step is send to the incinerator. All other sulphur streams are collected in the SRU/TGT system.
Advantages
- Proven processes involved
- SO₂ emission reduced
- Sulphur recovery close to target
- No time dependence or peaks in the SRU/TGT feed gas

Disadvantages
- Very high capital investment
- Processing per unit to be optimally separated from the other processes in the sequence to maintain operability. Cross mixture of the process solvents will destroy the unique treatment required from each solvent step
- The mercaptan removal should be optimized as discussed before, possibly introducing a fourth process for the MSU regeneration gas treating.

Alternative 3: Treatment of Acid Gas Enrichment Off gas in TGT
It was identified above that the loss of the mercaptans from the AGEU is the main cause of reduced sulphur recovery for the most economic process line-up, and a solution should be found to capture the mercaptans from this AGEA treated gas stream. This flow is in principle constant in flow and conditions. To include the mercaptans in the sulphur recovery, this stream should either be routed to the SRU or to the TGT. Direct routing to the SRU is not feasible due to the composition of this stream. The routing of this stream to the TGT is feasible. The TGT is specifically designed to process the non-hydrogen sulphide components. With optimized reduction conditions in the TGT, taking in account the hydrocarbons in this stream, a dedicated TGT reactor can be designed, as the AGEU stream is separately available. The line-up is represented in Figure 9.

Advantages
- Low sulphur emission figure
- Sulphur recovery specification met
- Separate mercaptan flow at steady conditions available from AGEU
- The required hydrogen is formed in the Claus main burner and can be topped up with the line burner. The available hydrogen should be sufficient to convert the non-hydrogen sulphide components to hydrogen sulphide (no source of hydrogen required) at stable operation.

Disadvantages
- Increased capital requirement
- The acceptable hydrocarbon/RSH ratio is unknown
- Additional control in the TGT
- Possible soot formation and problems with the acidification of the quench column, not SO₂ related: This has been experienced in line-ups where the gas was mixed with the main TGT feed in a common reactor. It is expected that this can be avoided with a separate reactor

The results of the above alternatives are summarized in Figure 10.
Overall Emission Results

Figure 10. Sulphur emission results for the LNG example

Note: the SO\textsubscript{2} emission for the Base case is >> 125 %, and only for the figure indicated as 125 %.

From these results, it can be deduced that recovery of the mercaptans can be achieved, within reasonable cost increase for the aqueous and mixed solvent in the AGRU. When taking the operational excellence in account, the AGRU mixed solvent option is most promising. In this line-up, always the major part of the mercaptans is processed, where as in the aqueous amine option, SRU/TGT upsets (also due to time dependence) will immediately increase the SO\textsubscript{2} emissions to thousands of mg SO\textsubscript{2}/Nm\textsuperscript{3}.

Conclusions

Process selection for complex feed gases should not be limited to process-unit optimization in isolation. It is important to optimize over the complete treating train and to take account how processes selected can affect the downstream and units. A standard solution can only be applied for a certain range of feed gas compositions where the most important parameters are H\textsubscript{2}S/CO\textsubscript{2} and (H\textsubscript{2}S + CO\textsubscript{2})/RSH. The secondary, but not less important, parameter is the hydrocarbon loss in the process line-up. Particularly C\textsubscript{6}+ and BTX have a large influence on the operability of the treating string.

The conclusion specifically for the typical Middle East-feed gases is: The best line-up with respect to maximization of treating train operability and flexibility is the route with the optimized mercaptan removal with a mixed physical/chemical solvent in the Acid Gas removal Unit where the enrichment unit off-gas is routed to the Tail Gas treating Unit as a separate stream.

When the value of the hydrocarbon products streams is high, the option with an aqueous amine in the Acid Gas removal Unit is the best choice since such a solvent exhibits a much less hydrocarbon co-absorption. However, some operational flexibility is lost. This process line-up results in maximum peak concentration in hydrocarbons and mercaptans to the Sulphur Recovery Unit. Meeting acceptable sulphur recovery in the Sulphur Recovery Unit is not possible without extra investment in the Molecular Sieve Unit.

When GTL applications are evaluated, the relaxation of the CO\textsubscript{2} specification often results in an acceptable H2S/CO2 ratio in the acid gas to the Sulphur Recovery Unit. The requirement to enrich the acid gas is not necessary to meet an acceptable sulphur emission. The handling of the Molecular Sieve Unit regeneration gas unit sour gas is the most difficult when an aqueous solvent is selected in the Acid Gas Removal Unit. The mixed physical/chemical solvent with mol sieves as a polishing step has a high probability of being the optimal solution. The exception being the case where heavy hydrocarbon recovery makes a large contribution to the profitability of a plant.
Shell Global Solutions offer a portfolio of treating processes that can assist in solving treating design or operational problems effectively.

**Acronyms**

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<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>GTL</td>
<td>Gas To Liquid</td>
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<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
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<td>RSH</td>
<td>Mercaptans</td>
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<td>Acid Gas Enrichment Unit</td>
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