Treating Technologies of Shell Global Solutions for Natural Gas and Refinery Gas Streams

By J.B. Rajani

Shell Global Solutions International B.V., Amsterdam

ABSTRACT

Gas / liquid treating is often thought of as being a mature technology with little opportunity for improvements or innovations. However, changes in requirements from users continue to drive improvements in technology. These changes include: new and more complex feed sources, more demanding product specifications, and increasing demands on reliability and other plant performance improvements.

Technology offerings range from conventional liquid phase absorption, solid bed adsorption, catalytic gas reaction conversion, to bio-treating of H_2S. Owing to our experience across the range of offerings, Shell Global Solutions can offer solutions based on an integrated combination of processes that takes the feed stream and deliver the required end product in an optimal manner. Selecting the right technology to accomplish the objective results in a cleaner environment, improved reliability, and higher margins

R & D work within Shell is geared to these requirements so as to offer the best in treating technologies. In order to maintain this competitive edge, this paper reviews the traditional treating technologies and introduces new developments in the Shell treating portfolio.

1. INTRODUCTION

Gas /liquid treating encompasses a wide variety of technologies for the removal of sulphur compounds and other trace components from gases and light hydrocarbon liquids. Treating is an essential technology for the application of other core technologies in refineries and in gas plants. In addition, environmental pressure and more demanding product qualities means that treating units are being given an increased focus. To maximise refinery and gas plant returns utilisation should not be impaired by the performance or reliability of the treating units.

Gas/liquid treating is often thought of as being a mature technology with little opportunity for improvements or innovations. Although this may be the view of those using the technology for their particular application, Shell Global Solutions see changes driven by user needs for processing new streams to meet a variety of product specifications. 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 now in addition to traditional streams from refineries and sour gas reservoirs, there is a need to treat gas streams from: coal or residual oil gasification projects, associated gas from oil production, bio-gas generation, gas to liquids facilities (such as gas-to-liquid process SMDS), and to treat natural gas streams on floating platforms. These feed streams come with widely different temperatures and pressures, but in particular show extremes in composition. Product specifications also consist of a wide variety of requirements. At the same time, high reliability requirements, reducing capital and operating costs, and developments from competitors continue to add pressure to ensure that new developments continue. The process designer is thus faced with applying existing knowledge to extend the design envelopes of the process. Research efforts within Shell Global Solutions focus on improved solvent offerings and new applications of technologies. Some step outs work better than others, but all improve understanding of the processes that are employed and some provide opportunities for new or improved offerings.

Shell Global Solutions offer an integrated approach to natural gas and refinery gas treating requirements. In such treating requirements, the removal of sulphur compounds (H_2S, COS, mercaptan, sulphides) and CO_2 are often required. In industrial treating applications, feed gas and product streams are often very diverse and the technology employed is therefore also diverse. Technology offerings of Shell Global Solutions range from conventional liquid phase absorption, solid bed adsorption, catalytic gas conversion reactions for HCN and COS to biological gas desulphurisation process recently introduction to the market as Shell-Paques technology.

This paper reviews Shell Global Solutions treating portfolio and comments on some of the main developments that have taken place in the treating area over the last two years. Emphasis in the R&D field has been to widen the Shell treating portfolio so as to encompass as many as possible treating requirements in industrial processes.

2. GAS AND LIQUID REGENERABLE TREATING PROCESSES FOR SULPHUR AND CO2 REMOVAL

Shell Global Solutions offer a range of competitive technologies for the treating of sour gas streams using regenerable solvents. These compare favourably with conventional amine processes utilising MEA (monoethanolamine) or DEA (diethanolamine) especially in terms of selectivity, solvent circulation rate, corrosivity, foaming tendency, energy requirements and reliability.

The ADIP process is especially suitable for the removal of H_2S from natural gas, refinery gas, synthesis gas and SCOT (Shell Claus Offgas Treating Process) offgas and for bulk and deep CO_2 removal from natural gas.

The Sulfinol process is highly suited for the removal of both H_2S and CO_2 and especially COS, mercaptans and organic sulphides. This makes it the process of choice for treating natural gas and synthesis gas from coal/oil gasifiers and steam reformers.

Integrated approach for optimal operation of ADIP and Sulfinol units includes optimal designs, full process monitoring including chemical analysis of solvent, advice on solvent quality management such as reclaiming, filtration, active carbon beds, etc.

2.1. The ADIP Process

The Shell ADIP process is a regenerable amine process for acid gas removal utilising alkanolamines such as DIPA (di-isopropanolamine), MDEA (methyl di-ethanolamine) or a mixture of two or more alkanolamines.

The ADIP (Figure 1) process is highly suitable for the following applications:

- Removal of H_2S and CO_2 from natural gas, synthesis gas and refinery gas streams
- Selective removal of H_2S from gases containing CO_2.
- Removal of H_2S and COS from light liquid hydrocarbon streams (LPG and NGL)
- Bulk removal of CO_2 from gas streams
- Deep removal of CO_2 from gas streams

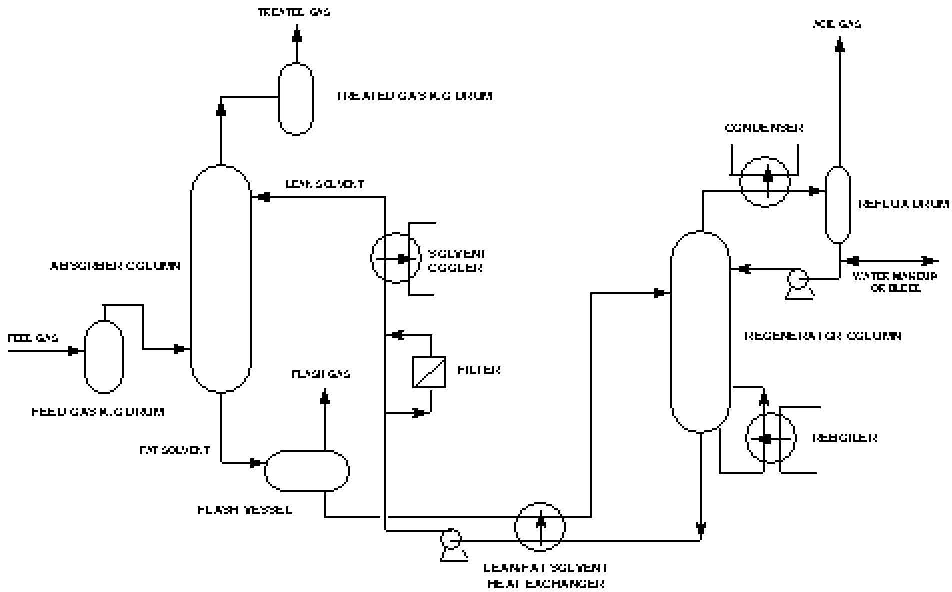


Figure 1: Typical process flow scheme of the Shell ADIP and Sulfinol Process

The process can be used over a wide range of operating pressures (units are in operation at pressures up to 180 bar) and contaminant levels.

Guaranteed specifications achievable are:

Gas stream H_2S

- 100 microbar partial pressure with a conventional regenerator
- 30 microbar partial pressure with a two stage regenerator

Gas stream CO_2

- 500 microbar partial pressure or 50 ppmv whichever is greater
- 1 bar partial pressure when using flash regeneration

Liquid stream H_2S

- 20 ppmv using an extractor only (LPG/NGL)
- 10 ppmv using an extractor plus mixer/settler cascade

Liquid stream COS

- 5 ppms (LPG/NGL)
- Number of ADIP units in operation exceeds 500.

2.2. The Sulfinol Process

The Shell Sulfinol process (also schematically shown in Figure 1) is a regenerable amine process for acid gas removal utilising alkanolamines such as DIPA (Sulfinol-D) and MDEA (Sulfinol-M). As the process uses a mixture of water, Sulfolane and one or more alkanolamine, removal capacity of COS, mercaptans and organic sulphides from gas streams is excellent by virtue of the improved physical solubility of these compounds in the solvent.

The Sulfinol process is the best choice in the following applications:

- Removal of H_2S, CO_2, COS, mercaptans and organic sulphides from gas streams
- Selective removal of H_2S from gases containing CO_2
- Deep removal of CO_2 from syngas and LNG plant feed gas
- Bulk removal of CO_2 from gas streams

The process can be used over a wide range of operating pressures (units are in operation at pressures of up to 80 bar) and contaminant levels.

Guaranteed specifications achievable are:

Gas stream H_2S

- 100 microbar partial pressure

Gas stream CO_2

- 500 microbar partial pressure or 50 ppmv
- 1 bar partial pressure when using flash regeneration

Gas stream COS

- 5 mg S/Nm3

Gas stream mercaptans

- 5 ppmv or 97% removal whichever is greater.

There are over 200 Sulfinol units in operation. In spite of such success in the use of ADIP and Sulfinol processes in the gas / liquid treating, Shell Global Solutions has continued to invest in improving these processes. This has lead to the following two new additional processes in the Shell technology portfolio.

2.3. Development of ADIP-X and Sulfinol-X

Aqueous MDEA has a high capacity for carbon dioxide, but the mechanisms of absorption are relatively slow. The addition of activating agents to the solvent can overcome this drawback and improve the absorption of CO_2. The addition of the activating agents provides a solvent well suited to some specific applications that results in designs with less circulation when compared to Sulfinol-D, and shorter absorbers when compared to regular aqueous MDEA. This particularly applied to applications in the natural gas fields with a feed gas CO_2 content of over 5 %v. Shell Global Solutions is now in a position to offer their own version of aqueous MDEA with an accelerating agent. Test runs have been underway at a gas plant in North America for almost a year. This has lead to the validation of the design parameters. The process will be known as Shell ADIP-X, and will provide an additional process to meet the needs of new treating units. Parallel developments has seen the introduction of Sulfinol-X. This shall also allow the removal of organic sulphur.

2.3.1 The ADIP-X process

The Shell ADIP-X process is a regenerable amine process for acid gas removal utilising a mixture of two or more alkanolamines, in general a base amine such as MDEA (methyl di-ethanolamine) and an accelerator. The process achieves a higher loading capacity compared to single amine solvents. This leads to the design of smaller absorber columns with reduced number of trays when compared with generic MDEA solvent.

The ADIP-X process is highly suitable for the following applications:

- Removal of H_2S and CO_2 from natural gas, refinery gas and synthesis gas streams
- Bulk removal of CO_2 from gas streams
- Deep removal of CO_2 from gas streams
- Particularly suitable for natural gas field with CO_2 content in the excess of 5 %v in the feed gas.

Guaranteed specifications achievable are:

Gas stream H_2S

- 100 microbar partial pressure with a conventional regenerator
- 30 microbar partial pressure with a two stage regenerator

Gas stream CO_2

- 500 microbar partial pressure or 50 ppmv whichever is greater
- 1 bar partial pressure when using flash regeneration

2.3.2 The Sulfinol-X process

The Shell Sulfinol-X process is a regenerable amine process for acid gas removal utilising a mixture of two or more alkanolamines, in general a base amine such as MDEA or DIPA and an accelerator. As the process uses a mixture of water, Sulfolane and one or more alkanolamine, removal capacity of COS, mercaptans and organic sulphides from gas streams is excellent by virtue of the improved physical solubility of these compounds in the solvent. The process achieves a higher loading capacity thus enabling a design of smaller absorber columns with reduced number of trays when compared to the Sulfinol process..

The Sulfinol-X process is the best choice in the following applications:

- Removal of H_2S, CO_2, COS, mercaptans and organic sulphides from gas streams
- Sulfinol X is highly suitable to revamp deep/bulk CO_2 removal plants

Guaranteed specifications achievable are:

Gas streamH$_2$S

- 100 microbar partial pressure

Gas stream CO_2

- 500 microbar partial pressure or 50 ppmv

- 1 bar partial pressure when using flash regeneration

Gas stream COS

- 5 mg S/Nm3

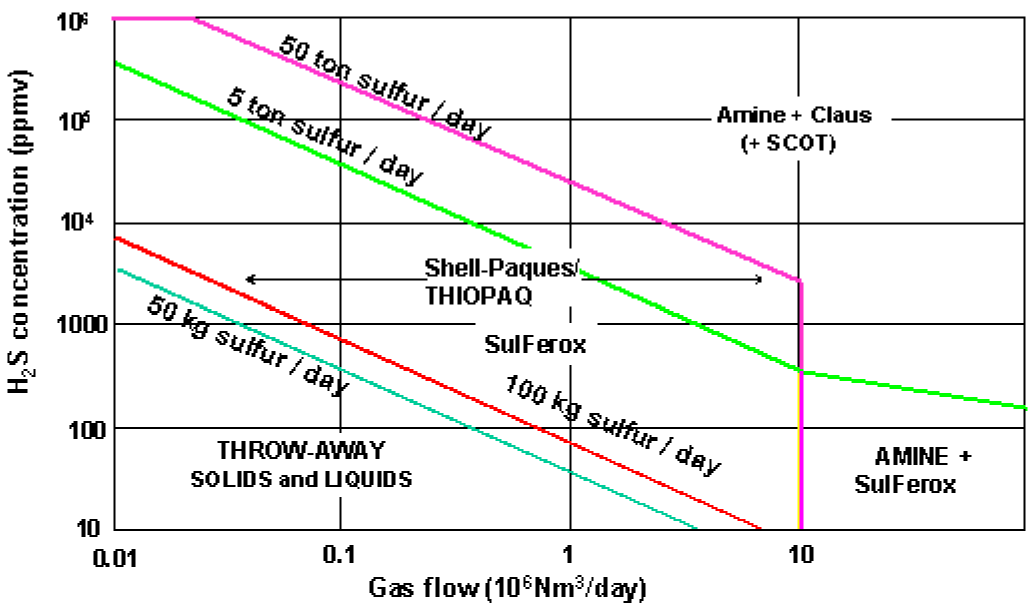
Gas stream mercaptans

- 5 ppmv or 97% removal whichever is greater

Shell Global Solutions licenses all the above mentioned treating processes. A significant advantage of Shell processes is that the client is able to buy the chemicals on the open market and is not locked in to a single supplier.

3. SULPHUR PROCESSES

Depending on gas flow and H_2S concentration, the most favourable choice can be made between four main processing options, as shown in the figure below.



Typical H_2S removal process

3.1. The Claus Process

If H_2S is present in the feed, sulphur emissions will be subject to local legislative restrictions. The most appropriate process to convert the H_2S and organic sulphur to elemental sulphur is mainly dependent on the quantity of sulphur present in the feed.

To minimise Claus unit size (Figure 2) and maximise efficiency the feed gas can be enriched by selectively removing the H_2S from the regenerator off-gas. For very low H_2S levels in acid gas there are also other processes available, e.g. Selectox that replaces the thermal stage of a conventional Claus plant with a direct oxidation stage. There is little experience with such units at commercial scale natural gas processing plants.

For lower quantities of sulphur (< 5-20 t/d) the Claus unit can be replaced by a redox type process, such as the SulFerox process or the new biological Shell-Paques process which are not restricted by a minimum H_2S content in the feed gas.

As stated above it is important to identify the best integrated and economic solution to the overall treating needs. The SCOT tail gas technology can readily be integrated with the main amine gas treatment, with or without an acid gas enrichment step and, if necessary, treatment of regeneration gas from molecular sieve regeneration.

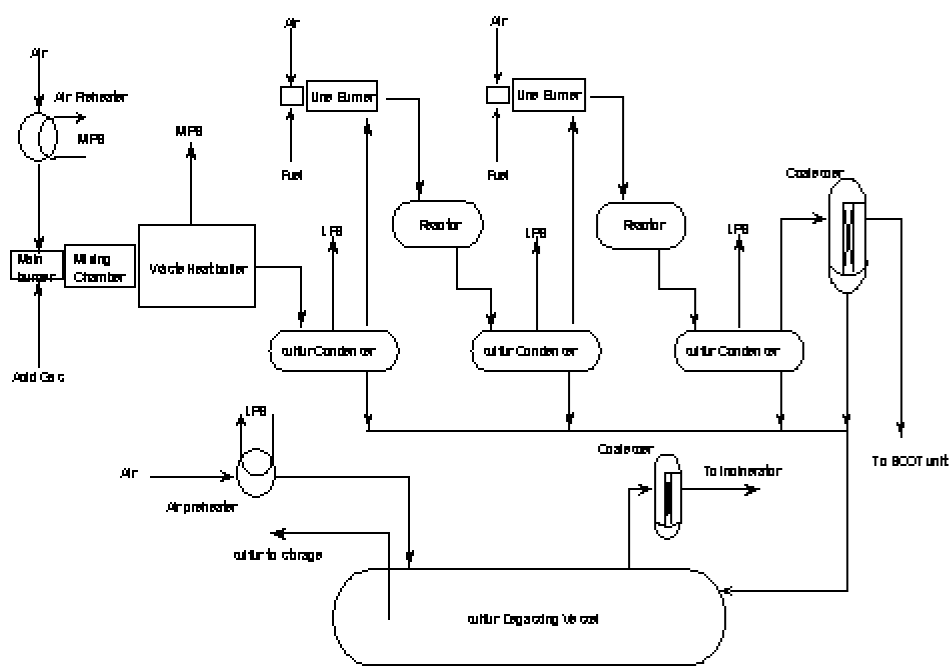


Figure 2: The Claus Process

3.2. The SCOT Process

The Shell Claus Off-gas Treating (SCOT) process (Figure 3) was developed in the early seventies. Today more than 180 SCOT units operate throughout the world, with capacities ranging from 3 to more than 4000 tons per day of sulphur in the feed to Claus units.

With a SCOT unit an overall sulphur recovery efficiency of higher than 99.8% can be achieved, with a SUPER SCOT the recovery can be increased up to 99.95%. The SCOT process has a great tolerance to variation in the tailgas composition of the upstream Claus unit.

It has a turndown ratio to less than 10% of the design throughput. The unit can be integrated with the refinery amine treating units. Capital costs are thus reduced, as no dedicated regenerator is necessary for the SCOT amine absorber. The unit requires little operational attention and has a very high (>99%) record of reliability.

The main advantages of the SCOT unit are:

- The unit is robust and forgiving when compared to most other tailgas treating units. The overall sulphur recovery efficiency of the Claus - SCOT configuration remains about the same within a relatively large operating window of the upstream Claus unit.
- The sulphur recovery efficiency in the upstream Claus unit is not critical for the performance of the SCOT unit and the overall sulphur recovery efficiency of the Claus SCOT combination. A Claus unit with two catalytic stages is sufficient.
- The SCOT unit is not sensitive to ammonia and does not require complete ammonia destruction in its upstream Claus unit for trouble free operation.
- The overall sulphur recovery efficiency is consistently very high when compared to other tailgas treating units.

Shell Global Solutions International has a number of proven solutions for integrating new SCOT unit and existing Claus unit(s), including interaction of the amine absorber as a cascaded design.

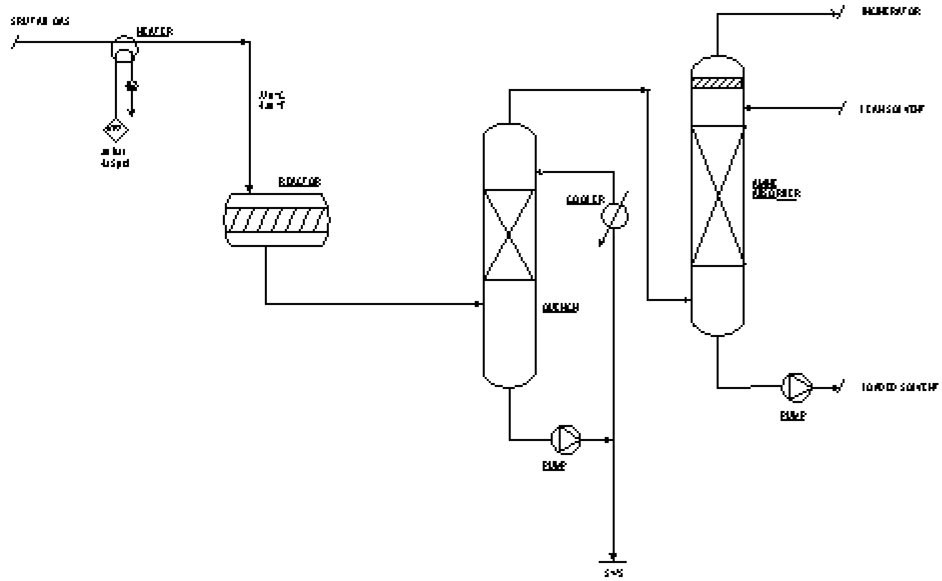


Figure 3: Shell Low Cost SCOT Process

3.3. The Shell-Paques process

The Shell Paques process (Figure 4) is a biological process for removal of hydrogen sulphide from gas streams and recovery of the sulphur in the form of elemental sulphur. The process is attractive for quantities of hydrogen sulphide in the range of 0.5 to 30 tons per day. Shell Global Solutions International B.V. and Paques Natural Solutions BV, an innovative biotechnological company in the Netherlands, have developed the process jointly.

The process is based on contacting a gas stream containing hydrogen sulphide with an aqueous soda solution containing sulphur bacteria in a scrubber. The hydrogen sulphide is absorbed in the soda which is transferred to a regenerator. The regenerator consists of an aerated atmospheric tank where hydrogen sulphide is biologically converted to elemental sulphur. The sulphur is removed from the tank in the form of a slurry, which can be worked up to a dry powder or to a molten sulphur with the same high purity as Claus Sulphur.

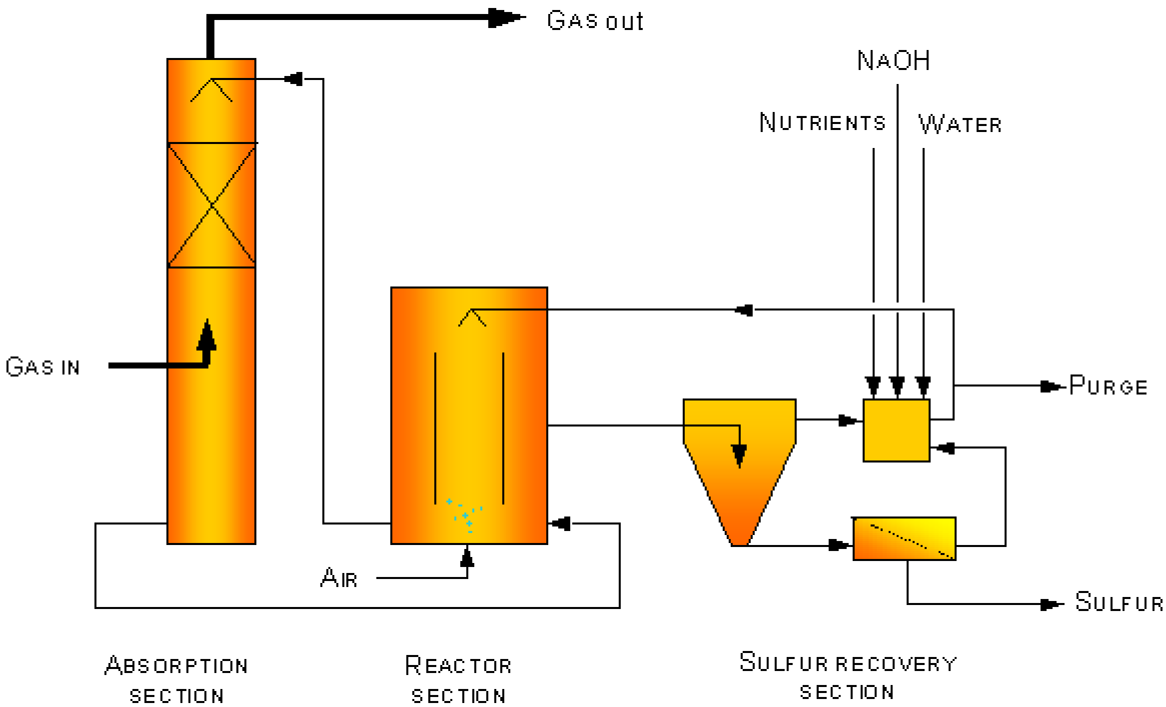


Figure 4 : The Shell-Paques process

The process can be applied for the following types of streams:

- Natural gas within the pressure range of 0.1 - 90 barg.
- Amine regenerator offgas.
- Refinery or chemical plant fuel gas.
- Synthesis gas
- Oxygen containing waste gases like vacuum offgas, which cannot be successfully treated with other solvents.

The main advantages of the Shell Paques process when compared to conventional schemes are:

- Simple and reliable and safe unit design that is very easy to operate.
- Very low H_2S contents can be achieved in the treated gas (less than 5 ppmv).
- No plugging and blocking problems due to the hydrophilic nature of the biological sulphur.

- Wide turndown in gas flow and/or inlet H_2S concentration.
- Can operate at ambient temperature giving easy start up and shutdown.

3.4. The Bio-SCOT process

The Bio-SCOT process is a combination of the SCOT and Shell-Paques processes. This process can reduce the sulphur emissions from the sulphur recovery facilities to a very low level thanks to the higher efficiency of the scrubber in the Shell-Paques technology. This process also eliminates the need to recycle hydrogen sulphide back to the inlet of the Claus unit. The hydrogen sulphide is converted to solid elemental sulphur in the form of a slurry, which can be melted and mixed with the sulphur from the Claus unit.

3.5. The SulFerox Process

SulFerox is an iron redox process in which the H_2S is directly oxidised to elemental sulphur while the ferric ions are reduced. These are subsequently regenerated by oxidation with air. Sulphur may be recovered as a moist filter cake or as pure liquid sulphur. The SulFerox process (Figure 5) is mainly used for the treatment of H_2S-containing gases such as natural gas, amine unit regenerator offgas, geothermal gas streams and Enhanced Oil Recovery (EOR) carbon dioxide stream.

The process is most competetive in the 0.1-15 tonne/day sulphur capacity range. Thanks to its unique patented chelate chemistry, the SulFerox process can maintain an aqueous solution of iron in high concentrations.

As a result the amount of liquid circulated is low and the equipment is surprisingly small, resulting in significantly lower investment cost. The SulFerox process is particularly attractive for natural gas treatment, when low H_2S and high CO_2 contents would normally make conventional amine-based units uneconomic. The small equipment size makes the process very attractive for offshore applications.

SulFerox has the following advantages over absorption based treating processes :

- Very selective H_2S removal as essentially no CO_2 is removed.
- Very low H_2S contents can be achieved in the treated gas (less than 5 ppmv).
- Wide turndown in gas flow and/or inlet H_2S concentration.

- Can operate at ambient temperature giving easy start up and shutdown.

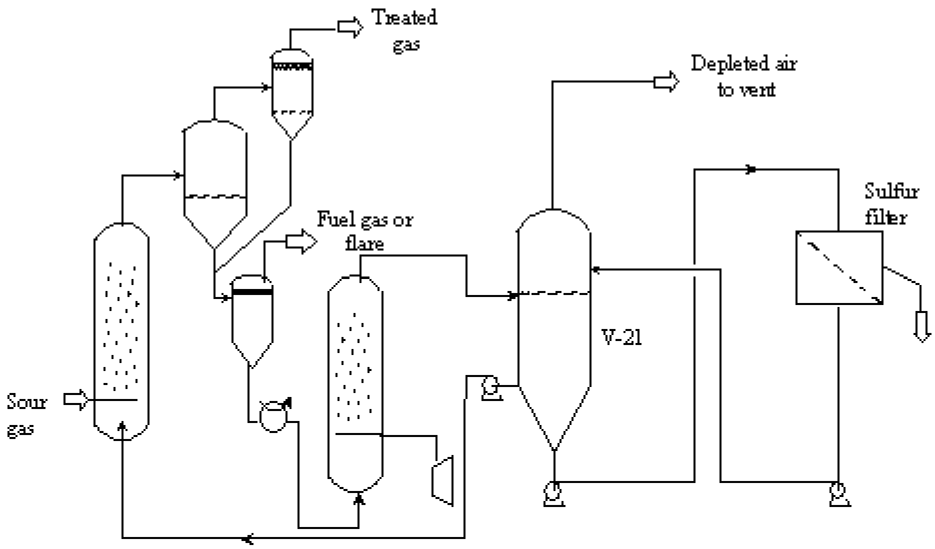


Figure 5: The SulFerox process

More than 30 SulFerox units are currently in operation covering a wide range of gas treating applications.

3.6. Incineration

Incinerators are installed to convert H_2S in the tailgas to SO_2 before discharge to atmosphere. The two main types of incinerators are thermal and catalytic. A thermal incinerator downstream of a Claus/SCOT usually operates at a temperature of 650 - 850 °C, oxidising all sulphur components, as well as CO and H_2. A catalytic incinerator operates at about 300 °C with the sulphur components (only) being selectively oxidised to SO_2.

Shell developed catalyst (Criterion 099, previously known as C 099 and S 099), was by 1990 in use in over 30 catalytic incinerator units worldwide. It is characterised by a high activity for the oxidation of all sulphur components to SO_2 and excellent selectivity, within the specified temperature range no SO_3 is formed and no oxidation of CO and H_2 occurs.

3.7. Shell Sulphur Degassing

Liquid sulphur from Claus units still contains about 250 - 300 ppmw hydrogen sulfide and hydrogen polysulfides (H_2S_x). To meet environmental and safety restrictions, the liquid sulphur should contain less than 10 ppmw H_2S. In the Shell Sulphur Degassing process (Figure 6) the sulphur is circulated over a stripping column, open in top and bottom, by bubbling air through the sulphur.

By agitating the sulphur this way the H_2S is released. The whole system is located in a separate vessel or in the intermediate sulphur storage.

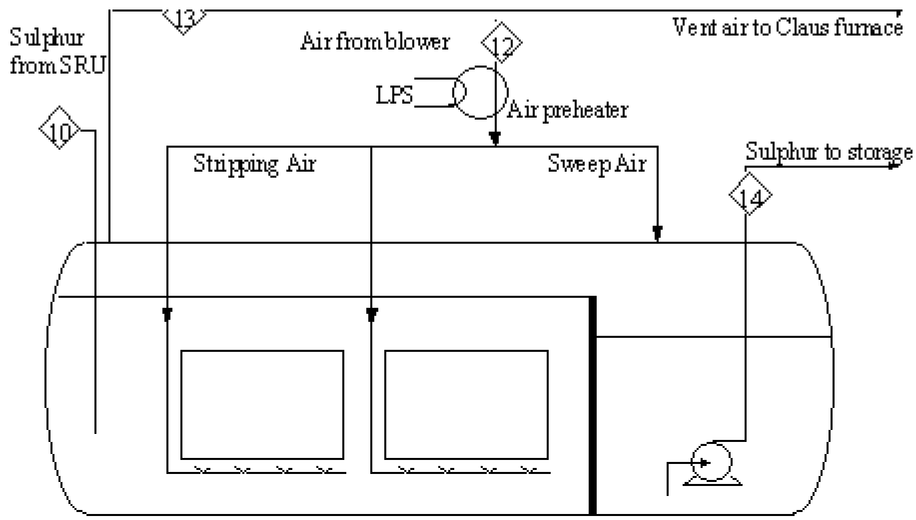


Figure 6: The Shell sulphur degassing process

The new Shell Sulphur Degassing process has been developed to decrease residence time (and consequently capital expenditure) while still meeting the sulphur product specification of 10 ppmw H_2S without the utilisation of a catalyst or any equipment employing moving parts. The process provides a reliable and safe operation, with very little attention required.

Currently more than 120 Shell Sulphur Degassing units are in operation, at capacities ranging from 3 to 4000 tons of sulphur per day.

4. SOLID BED ADSORPTION PROCESSES

Solid bed adsorption process is used for the removal of water or for hydrocarbon dew pointing so as to condition the gas for pipeline spec. Such processes are known as temperature swing regenerative adsorption process. Two types of adsorbents given below are routinely applied in such processes.

4.1. SORDECO (Hydrocarbon dew pointing process)

The SORDECO process (Figure 7) is an economically attractive process applied to improve the dew point specification of natural gas feed streams. Shell Global Solutions designs, markets and licenses this process in co-operation with Engelhard, the supplier of Sorbead, a special grade of silica gel. The SORDECO Process applies Sorbead adsorbent packed into an adsorber column. The adsorbent selectively removes water and hydrocarbons from natural gas. When the adsorbent is saturated, it is regenerated by stripping with hot regeneration gas. Water and heavy hydrocarbons are separated by condensing the stream leaving the regenerating adsorber. In a typical natural gas plant two, three or four adsorbers are applied to allow for on-line regeneration. The process is very flexible with respect to feed gas diet and turndown ratio; this only influences the cycle time, which is an operational variable. The excellent turndown capabilities, short start-up time, and long adsorbent lifetime make the process ideal for peak shaving and underground storage facilities. The process can be designed to selectively remove aromatics for membrane protection applications.

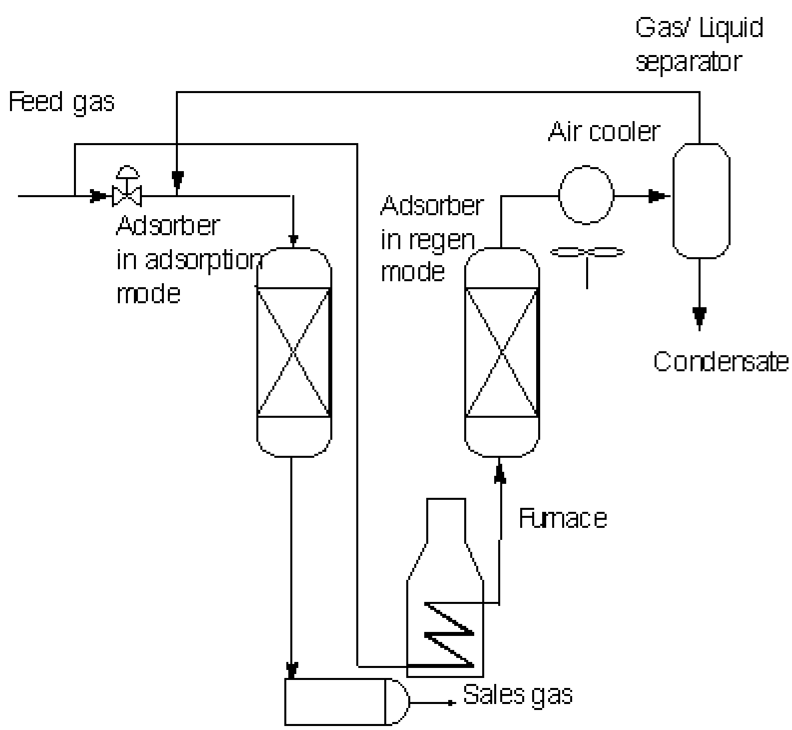


Figure 7: The SORDECO process

4.2. Molecular Sieves

Dehydration with molecular sieves is typically used in gas and LNG plants to remove water from gas or liquids from a level of up to 1000 ppmv to a level of less then 1 ppmv. Also in chemical plants and refineries, molecular sieves are often used for drying of process streams. The challenge for dehydration units is their reliability as has been shown by Shell Global Solutions involvement in monitoring the dehydration units of three Shell advised LNG plants.

Shell Global Solutions has conducted test runs on two mole sieve units at a gas plant in Scotland in the fall of 1999 and identified a problem with the top half of one of the dryers. The test run data was also used to optimize the run cycle time and predict the capacity available. The predicted capacity was less than that required to meet the peak demand expected for the winter of 2000. This provided justification for replacement of the mole sieve during the summer of 2000.

Another example for mol sieve reliability service has been a design review of the Canadian gas plant mole sieve unit. Data indicated that the upstream knockout vessel was grossly undersized relative to our design specifications and current plant throughput. This has been identified as the major contributor to short life of the mole sieve material and recommendations for improvements are being evaluated.

Shell Global Solutions also has developed sophisticated mathematical models for the prediction of free water formation during regeneration of mol sieves. If free water is formed, the uptake water capacity of the sieve is drastically decreased over a short period of time. This leads to premature change out of the mol sieve inventory and thus production losses due to unscheduled shut down. Such optimization of regeneration procedures and cycle time has been carried out at other LNG locations in Brunei, Malaysia and Australia.

5. Catalytic gas conversión process

The catalytic conversion of HCN and COS is a cost effective technology to abate the harmful effects of these components in gas streams. Hydrolysis technology has three main fields of application viz. (1) syngas treatment upstream of an amine unit for coal or oil gasification processes, (2) other syngas treatment where presence of HCN and/or COS is not acceptable to downstream processing units.

Shell Global Solutions can provide a basis of design, proprietary catalyst, and operating guidance for this process. Figure 8 shows the process scheme for a typical HCN/COS hydrolysis unit.

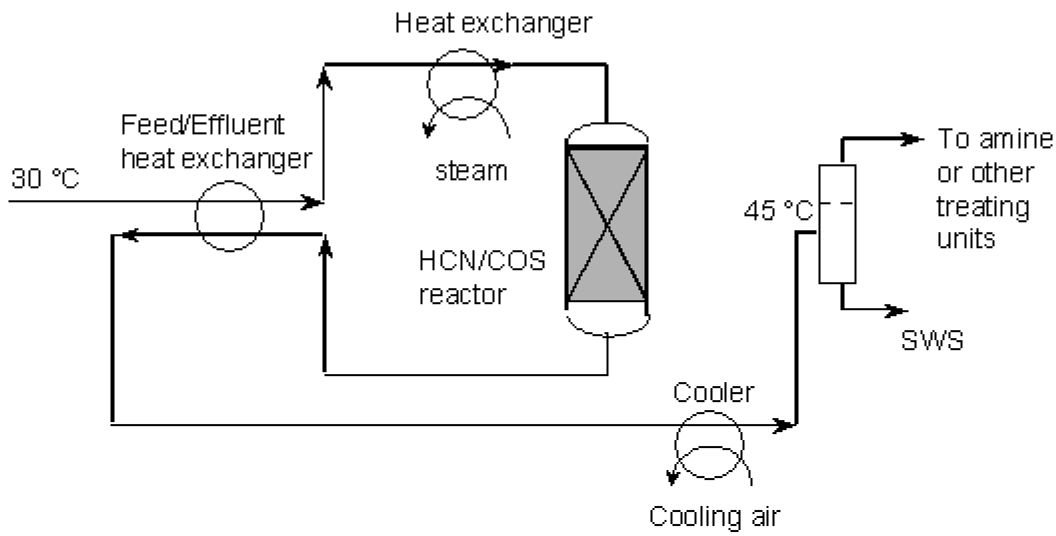


Figure 8 : The Shell HCN/COS hydrolysis process

6. Non-regenerable adsorption processes

Non-regenerative adsorption processes are used for the removal of trace impurities from hydrocarbon streams. Adsorbents are recycled or disposed of at the end-of- run, so selection of the adsorbent and sizing of the unit become key parameter for optimum performance. There are many adsorbents on the market and the correct choice requires knowledge of the adsorbents available and the product stream requirements. Shell Global Solutions can provide service and advice on solid bed units to remove trace amounts of sulphur, fluorides, chlorides, and mercury.

6.1. Mercury speciation and removal

Mercury is a toxic, volatile and noble metal that is a common trace contaminant in natural gas, natural gas liquids, and other hydrocarbon sources. Mercury can be present in hydrocarbons in the form of ionic mercury species, organic mercury compounds, and metallic mercury. Mercury problems can be related to its toxicity (exposure during maintenance and inspection) and to the properties of the liquid metal regarding corrosion by embrittlement of sensitive alloys. The solubility of mercury in hydrocarbons depends on the species involved, temperature, and the type of hydrocarbons. In addition, mercury can be converted from one species to another during various refinery processes. Mercury can be removed from hydrocarbon feedstocks or products by a number of processes, but the mercury species must be known for the most effective method to be employed. Shell Global Solutions can provide expertise and advice on analysis and speciation of mercury, selection of removal processes, and operational aspects of absorption units. Support has recently been provided to Bukom refinery, Port Dickson refinery, Woodside LNG and to Sakhalin Energy.

7. Technology selection

Simple rules for the selection of the most effective treatment technology are difficult to arrive at given the array of possibilities in feed gas conditions and resultant requirements for one or more of stage gas treatment (one or two stages), acid gas enrichment, mercaptan removal, sulphur recovery technology, Claus tail gas treatment, high pressure operation, low temperature operation etc. Added to this are other considerations such as reliability record, corrosion performance, quality of process guarantees and availability of professional after sales technical service.

Given the magnitude of the investment in a treating facility it is appropriate to carry out a rigorous treating process selection study to identify the most cost effective and fit for purpose treatment package. The consultant chosen to do the study must be experienced in the field of gas treatment design, familiar with all the technologies available, able to discern effective integration options and ideally be able to draw upon actual operating experience to identify a robust operating line up. The investment in a high quality consultant to provide process selection will be well rewarded with a reliable fit for purpose and cost effective treatment package.

8. Conclusions

Up until recently the levels of CO_2 and sulphur encountered in natural gas developments have allowed a fairly open selection of solvent based treatment technology although preference has most often been given to well proven technologies. However with increased sulphur levels, mercaptans and more extreme operating requirements the available choices for a cost effective integrated treating package narrow dramatically. Additionally environmental constraints to waste streams have to be taken in account. Use of the Shell ADIP and Sulfinol technology can be the decidedly more attractive option in these cases. It is critical that each new gas development undergoes a rigorous selection study to identify the most cost effective and fit for purpose treating package.

Shell Global Solutions offer a portfolio of treating processes that can assist in solving treating problems effectively. Shell Global Solutions shall be more than happy to discuss any specific situation and determine in which areas Shell Global Solutions can assist in overcoming design or operational problem (s).