Revamping hydrogen and sulphur plants to meet future challenges

Revamp opportunities for hydrogen and sulphur plant operations in the era of clean fuels production offer significant benefits for refiners

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A round the world, increasing demand for clean fuels has led refiners to alter operations for the production of low-sulphur gasoline and diesel. Furthermore, refinery operators are purchasing larger quantities of heavier, sourer crudes to take advantage of a discount over light, sweet crudes.

To support fuel and crude supply trends, the installed capacity of hydroprocessing technologies (ie, hydrotreating and hydrocracking) has increased steadily in recent years. FCC technology — the capacity of which has been on a similar upward trend — also plays a key role in clean fuels production and is considered a major emitter of \( \text{H}_2\text{S} \) and \( \text{SO}_x \).

The increases in these three processing technologies coincide with a five-year average increase in both refinery on-purpose hydrogen production (and recovery) and sulphur processing capacity. Figure 1 indicates worldwide growth in these areas in terms of refinery production capacity since January 2005. Worldwide refinery hydrogen production capacity has grown at an average annual rate of 2.15%. Average annualised growth for worldwide sulphur processing capacity since January 2005 was pegged at 2.9%.

In the past, the hydrogen production unit and the sulphur plant had been considered supporting units for the major refining processes; however, as hydroprocessing capacity continues to expand along with the processing of heavier crude, the impact of the operations of the hydrogen unit and the sulphur plant has grown. Modification and expansion of refinery hydrogen production and sulphur plants via revamp and retrofit projects will be necessary for meeting future process requirements while maximising the value of current plant configurations and assets. The following is intended to provide an overview of available technologies and operational goals that should be considered when revamping the hydrogen plant and/or sulphur recovery/production plant in a modern refinery.

**Hydrogen plant revamps**

The hydrogen production facility can now be considered a major component of the refinery and, like any utility, maximising the economics of producing and consuming hydrogen in the refinery affects the overall success of the plant. Technology for the production of refinery hydrogen is currently dominated by the use of steam reforming of natural gas or other light hydrocarbons. Figure 2 shows a refinery hydrogen network.

The revamp of an existing hydrogen plant is considered the cheapest way to add 10–30% capacity. A number of potential revamp projects, listed in order of increasing investment requirements, can be implemented to augment capacity: employ hydrogen management; increase reformer firing; improve PSA recovery; reduce steam-to-carbon ratio; add \( \text{CO}_2 \) recovery; install a low-temperature shift; and add a pre-reformer or post-reformer. However, several important constraints are involved in such revamps; namely, minimum hydrogen product pressure, hydrogen purity, process cooling duty, availability of plot space, available down time for revamps, utilisation of export steam, availability of other utilities, safety, and pollutant emissions. In addition, the debottlenecking and expansion of existing hydrogen plants depends on limitations to the reformer, such as tube metal temperature, burner heat release, catalyst bed pressure drop, induced draft/forced draft fan capacity and pressure swing.
Implementing hydrogen management is often the first step to revamping and/or improving a refinery’s hydrogen network. Hydrogen management using pinch technologies and mathematical modelling will result in improved process efficiency, reduced energy consumption, lower operating costs, and improved integration of hydrogen-producing and -consuming units. One drawback to hydrogen management is that the available capacity gain is constrained by the limitations of the current system. Hydrogen management services are becoming more prevalent as refiners look for economical ways to meet hydrogen demands. These offerings primarily take a phased approach to balance use of refinery hydrogen (often by hydrogen pinch techniques), to identify potential projects for improvement (new units, revamps, recovery schemes and so on) and to implement or evaluate changes.

As an example, engineers from Indian Oil Corporation discussed a novel in-house methodology to improve hydrogen management in a refinery. The process begins by defining the hydrogen network in the refinery: hydrogen production units (steam methane and/or naphtha reformers); purge gas and offgas streams as recovery sources (for instance, a catalytic reformer); and major hydrogen consumers (hydrotreating, hydroprocessing). The engineers identified the opportunity to limit spill-over hydrogen — excess gas that allows for continued operation of hydroprocessing units during a hydrogen supply disruption — that is routed to the fuel gas system during normal operations. Following the evaluation, two strategies were implemented to improve the use of spill-over stream: integrate all of the hydrogen-producing and -consuming units; and eliminate the spill-over stream by utilising an offsite storage facility and process optimisation.6

In many distribution systems for refinery hydrogen, hydrogen supply is cascaded through a number of hydroprocessing units in which higher-purity, high-pressure hydrogen-consuming units pass their purge gases to lower-purity, lower-pressure units. As demand for hydrogen increases, the optimum cost-effective recovery of gas streams with marginal hydrogen content is becoming more imperative.6,7 Generally, streams with less than 50% hydrogen are routed to fuel. Streams of greater than 50% hydrogen content, with sufficient pressures, are routed to various purification units like PSA, membrane and cryogenic systems for recovery. The cost of hydrogen recovery can be almost half the cost of production.

For successful hydrogen recovery, the heating value of the fuel gas after hydrogen removal, the impact on the burners, the location where recovered hydrogen enters the network, and the impact on the whole system must be considered.8 Depending on the pressure and purity of residual hydrogen, recovery followed by purification might be an option to supplement production from steam reformers. The primary sources for hydrogen recovery are either high-pressure purge loops or low-pressure, high-purity off-gas streams. As a general advantage, recovering hydrogen that would be routed to the refinery’s fuel gas system will inherently increase the heating value of the fuel gas. Table 2 provides a selection guide to hydrogen recovery processes.9

![Figure 2 Refinery hydrogen network](image)

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**Table 1**

<table>
<thead>
<tr>
<th>Revamp project</th>
<th>Incremental hydrogen, %</th>
<th>Relative cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂ management</td>
<td>10–15</td>
<td>Low</td>
</tr>
<tr>
<td>Increase reformer firing</td>
<td>7–10</td>
<td>Low</td>
</tr>
<tr>
<td>Improve PSA recovery</td>
<td>1–2</td>
<td>Low</td>
</tr>
<tr>
<td>Reduce steam-to-carbon ratio</td>
<td>0–4</td>
<td>Low</td>
</tr>
<tr>
<td>Addition of CO₂ recovery</td>
<td>3–5</td>
<td>Low</td>
</tr>
<tr>
<td>Replace PSA with CO₂ recovery</td>
<td>15–20</td>
<td>Low/high</td>
</tr>
<tr>
<td>Low temperature shift</td>
<td>2–5</td>
<td>Medium</td>
</tr>
<tr>
<td>Pre-reformer</td>
<td>8–10</td>
<td>Medium</td>
</tr>
<tr>
<td>Post-reformer</td>
<td>20–30</td>
<td>High</td>
</tr>
</tbody>
</table>
Install pre-reforming technology
Pre-reforming technology — installed upstream of the primary reformer — offers refiners the ability to process efficiently a wide variety of refinery-related fuels. The most common feeds to the steam methane reformer (SMR) are natural gas and naphtha. However, the flexibility of the SMR will offer a unique opportunity to save operating costs by using refinery byproducts as feed. Market demand and prices, and seasonal considerations, will have an effect on the economics of refinery hydrogen production; most notably, the installation of the pre-reformer will enable processing of a greater quantity of heavy naphtha.

Pre-reforming technology offers several advantages as well as disadvantages and, as a result, the decision to install a pre-reformer should be evaluated on a case-by-case basis. For example, the installation of a pre-reformer incurs a more significant capital cost than some other revamp options such as hydrogen management. However, the presence of this technology will ultimately reduce the capacity requirements of the primary reformer, lowering overall operating costs. Similarly, the installation of a pre-reformer will require the purchase and frequent replacement of pre-reforming catalysts, but the presence of a pre-reformer will also help to remove many contaminants from the reformer feed that may limit the operating life of the primary reformer catalyst. Other important factors that must be considered prior to implementing pre-reforming technology are the effect on the heat balance of the hydrogen plant, and the ease of use and cost of the system.

Understand the effects of capacity expansion
Options to increase the capacity of a hydrogen plant without involving a radical, full-scale overhaul — including increased reformer firing, reducing steam-to-carbon ratio and replacing reformer catalyst — are limited to a 15–25% increase in capacity. Additionally, several problems can arise from increased throughput. In the primary reformer section, increases in throughput will result in a slight rise in tube wall temperature, as well as a pressure drop in the reformer tubes. The impact of these factors is minimal, but should be considered as a minor limitation to revamp operations.

Increased throughput will have a more severe effect on the flue gas duct/convection section of the reformer. High heat flux conditions in this section will lead to limitations in the capacity of the internal draft (ID) fan and increased tube wall temperatures, and structural problems will coil the bank supports. Increased production of flue gas is also viewed as a deterrent for increasing the capacity of hydrogen production units. If debottlenecking activities are not properly planned, the advantage gained by operating at increased throughput will ultimately be negated.

<table>
<thead>
<tr>
<th>Process</th>
<th>Types of ROG</th>
</tr>
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<tbody>
<tr>
<td>PSA</td>
<td>Hydrocracker low-pressure flash, hydrocracker vent, hydrodesulphurisation vent, catalytic reformer offgas</td>
</tr>
<tr>
<td>Membrane</td>
<td>FCC offgas, hydrocracker low-pressure flash, hydrocracker vent, HDS vent, catalytic reformer offgas</td>
</tr>
<tr>
<td>Cryogenic separator or cold box</td>
<td>FCC offgas, hydrocracker low-pressure flash</td>
</tr>
<tr>
<td>PSA-membrane</td>
<td>Hydrocracker high-pressure vent</td>
</tr>
<tr>
<td>PSA-cryogenic</td>
<td>Catalytic reformer offgas, FCC offgas, hydrotreater offgas</td>
</tr>
<tr>
<td>Membrane-cryogenic</td>
<td>Gas oil hydrotreater offgas, FCC offgas</td>
</tr>
</tbody>
</table>

Table 2
Catalyst and hardware upgrades require significant capital investment and can result in improved hydrogen production for the refiner. Refiners can overcome the constraint of the reformer’s tube metal temperature and achieve a 3–8% increase in hydrogen production by reducing the steam-to-carbon ratio, lowering the outlet temperature or increasing the inlet temperature. Another option, which can increase throughput by about 10%, is to replace the reformer tubing with a new microalloy. This new metallurgy has higher stress values, enabling the tube walls to be made thinner and higher reformer outlet temperatures to be used. The larger inner diameter of the tubes increases the flow area and lowers the pressure drop. This type of revamp is especially suitable when tubes are reaching the end of their run life (about ten years) and need to be replaced. Refiners should also consider renewing the outlet system and upgrading the flue gas tunnels for more uniform heat distribution.

At least two problems can occur in the convection section when extra hydrogen production is required; namely, high coil temperatures and limited draft capacity due to high flue gas volumes or temperatures. The removal of tubes from the process preheat coil will reduce heat input and result in additional capacity. Another option is to modify the reformer in order to push some heat back to the radiant section so that the radiant heat and firing rate are reduced and the entire reformer can be unloaded. In one case, capacity was boosted by 10% without raising the arch temperature.

Another debottlenecking option is to modify the PSA unit in order to improve hydrogen recovery by 1–2%. One such adjustment involves altering the PSA cycle, which consists of adsorption, depressurisation, dump, purge and represurisation steps. Other options include reducing the purge gas pressure, performing an adsorbent change-out or utilising additional adsorbent vessels. Finally, existing PSA capacity can be increased through the addition of an upstream CO₂ removal system. However, the net hydrogen benefit, which can reach 5%, is generally not high enough to justify this option unless CO₂ is a desired byproduct.
Cogeneration with steam reforming
Depending on the operational setting of the steam reformer, different amounts of export steam can be produced for utilisation in the SMR and throughout the refinery. Furthermore, a significant opportunity to cogenerate power and steam via waste heat recovery is available in steam reforming. In many plant configurations, substantial benefits can be realised by installing a heat recovery steam generator and/or a turbine during a revamp project. Power recovery will not only improve the energy efficiency and environmental performance of the hydrogen plant, but it will also effectively lower the cost per unit of hydrogen being produced. The key to effectively cogenerating usable utilities from a steam reforming unit is to meet efficiently the demands of the plant and to reduce any additional losses. Each refinery has a unique utility balance, and finding the optimum ratio of hydrogen to steam to power production is important to ensure efficient and economical operations in the hydrogen plant.

Compare revamp and replacement
In some cases, rising demand for hydrogen cannot be met by simple revamp activities, and significant capital investment in new reforming technology is necessary. It is important to evaluate the previously mentioned revamp options prior to determining the most suitable upgrade method for each plant.

In a study, engineers from CB&I Howe-Baker considered and evaluated alternative options for increasing hydrogen-producing capacity: debottlenecking and revamping an old plant or installing a state-of-the-art hydrogen production unit. The engineers attempted to evaluate and compare the overall hydrogen production cost in the old plant and the modern plant over the entire life cycle of the unit, including the significant capital investment required for a new plant. For this evaluation, a modern plant (producing 99.9% pure hydrogen) and an old-style plant (producing 95% pure hydrogen) — each with a capacity of 90MM scf/d — were compared. Both plants were based on natural gas feed. The estimated utility costs show that the efficiency improvement of the modern plant resulted in a significant annual savings ($16.4MM). This finding, however, does not include the capital investment required to construct the new plant. After allowing for a $5 million investment for the new plant, the price of hydrogen was calculated again. The new plant still showed a significant improvement on a cost-per-unit basis — $1.602/kscf of hydrogen for the new plant, against $1.996/kscf of hydrogen for the older facility.

Sulphur plant revamps
Existing sulphur recovery technologies are numerous, to say the least, but most solutions are linked to the modified Claus process. For this reason, revamp options are grouped into three main categories: acid gas removal, Claus unit and tail gas treatment. The synergy of these processes can be seen in Figure 3.

Acid gas removal
Hydrogen sulphide (H₂S) and carbon dioxide (CO₂) are acid gases that should be removed from refinery streams for numerous reasons. While the former is poisonous and combusts to produce the primary reactant in acid rain formation, the latter lowers the capacity and efficiency of the sulphur recovery unit (SRU). Commercial processes offer various features ranging from types of chemical and physical solvents — methyldiethanolamine (MDEA), diglycolamine (DGA), diisopropanol-
amine (DIPA), N-methyl-2-pyrrolidinone (NMP), polyethylene glycol dimethyl ethers and sulpholane — to two-absorber or two-regenerator configurations. Often, a reduction in utilisation cost via increased amine circulation is mentioned as the key benefit in these processes.

Upgrade solvent for increased capacity
MDEA and DGA can be used to replace existing amines in order to achieve an increase in sulphur unit capacity. This type of conversion also enables a higher amine concentration to be used before corrosion becomes a problem. As a result, the circulation requirement of MDEA and DGA is lower than that of solvents like monoethanolamine (MEA) or diethanolamine (DEA). MDEA also provides the added advantage of higher selectivity for H₂S in the presence of CO₂ while DGA offers high CO₂ selectivity. Amine conversion can be performed online or during unit shutdown. According to Dow Chemical Company, it is important to purge the system entirely and start clean when implementing a new amine because a mixture of two amines will not provide the full benefits offered by the individual components. Over the years, several refiners have commented, at past NPRA Q&A sessions, on solvent change-out in the AGR unit. In three cases, a switch was made from DEA to MDEA with the goal of increased capacity. In two of these cases, low concentrations of solvent were utilised to avoid losses in the liquid contactors. Two other refiners commented on the switch from MEA to DGA with the goals of increasing capacity and reducing conversion, respectively. In the first case, a 15% increase in plant capacity was observed. In the second, the switch to DGA resulted in significant solids accumulation in the flash drum.

Explore design modifications
Typical amine-based acid gas removal processes consist of a counter-current absorber followed by a flash stage (for high-pressure sour gases) to remove dissolved and entrained hydrocarbons from the rich amine. The rich amine is then sent to a steam stripper to regenerate the amine solvent and produce acid gas to be sent to the SRU. Technologies for revamping absorbers are available from several licensors.

Claus unit
The predominant sulphur recovery technology is the modified Claus process. Commercially, several designs of the Claus plant are available: oxygen enrichment, sub-dew point and direct oxidation. Selection between the various Claus configurations or switching from one to another via revamp may provide significant benefits to a refiner, depending on plant configuration.

Utilise oxygen enrichment
A sizeable portion of the volumetric flow to the SRU is the air feed. The high fraction of nitrogen in the air contributes to a significant amount of the gas in the reactor, leading to limitations in operational pressure drop. Oxygen enrichment can be used to eliminate the feeding of unnecessary nitrogen to the SRU, thereby reducing the pressure drop through the unit and increasing its processing capacity. This option is especially attractive to refiners with an existing excess oxygen supply.

Several refiners are using oxygen enrichment technologies to increase the processing capacity of the SRU. These technologies are divided into three categories: low-level, mid-level and high-level oxygen enrichment. Low-level enrichment involves the injection of oxygen through a diffuser into the furnace combustion air. The concentration of oxygen can be raised to a maximum of 30 vol%, resulting in a 20–30% capacity increase in the SRU. Oxygen concentrations greater than 30 vol% require special materials. Mid-level oxygen enrichment technologies send pure oxygen into a specially designed burner through ports separate from those through which the air flows. These technologies generally utilise an overall oxygen concentration of up to 45 vol% to increase capacity by up to 75%. High-level oxygen enrichment requires that certain modifications be made to maintain the temperature of the reaction furnace at an acceptable level. To avoid unacceptable temperatures, the acid gas must not be burned directly with the enriched air stream. These types of processes can operate at oxygen concentrations of 45–100 vol% and increase SRU capacity by up to 150%. The benefits and drawbacks of oxygen enrichment are listed in Table 3.

### Benefits and drawbacks of oxygen enrichment

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
</table>
| • Retrofitting a unit for oxygen-enriched operation costs 5–25% less than building a new unit and takes a relatively short amount of time | • High temperatures and poor mixing in the furnace can cause refractory damage
| • The flame is hotter, which often eliminates the need to use a portion of the acid gas to raise its temperature | • If the oxygen is not introduced to the SRU in the proper manner, breakthrough can occur, resulting in damage to the waste heat boiler
| • Operating flexibility exists in that the oxygen-enriched SRU does not have to run at full capacity | • The cost of oxygen delivery to the reactor can be substantial, especially for remote locations
| • The higher furnace temperatures destroy more ammonia, which can form salts that can cause plugging problems in downstream Claus beds | • The increases in the sulphur flow rate and the H₂S content of the sulphur may necessitate a revamp of the sulphur handling, degasification and forming facilities
| • Emissions are lower due to the improved performance of the absorber | • The higher temperature of the sulphur could lead to combustion, unless a cooling method is utilised to lower its temperature prior to entry into the pit
| • The conversion of H₂S in the Claus process is higher |

Table 3
Switch to sub-dew point operation
Sulphur produced in the Claus reaction is a gas at temperatures above 130°C. At operating temperatures below 130°C, sulphur condenses and is adsorbed on the catalyst. Loss of sulphur to the catalyst reduces its partial pressure in the vapour phase, which in turn produces more sulphur via the Claus reaction to restore gas phase equilibrium. Operating in this temperature regime, however, also favours sulphur deposition on the catalyst, which can result in deactivation of the catalyst and the development of a large pressure drop through the bed. To solve this problem, several companies have developed processes that utilise Claus reactors followed by reactor beds that alternate between sub-dew point operation and online catalyst regeneration.

Implement direct oxidation
Direct oxidation processes increase sulphur recovery by using a selective oxidation catalyst that promotes the irreversible reaction of H$_2$S with O$_2$ and limits the reversible reaction of H$_2$S with SO$_2$. Since the desired reaction is exothermic and high temperatures increase the occurrence of side reactions, the feed gas to the oxidation reactor must have a low H$_2$S concentration. This technology typically works well as an addition to the end of a Claus train to meet regulations on SO$_2$ stack emissions. It is necessary to ensure that the sulphur in the feed is in the proper form for oxidation, which can be accomplished by using a hydrogenation step to convert the sulphur compounds to H$_2$S or by operating the Claus combustion system with an excess of H$_2$S.

Increase sulphur yield by adding a reduction oxidation section
Reduction oxidation processes focus on reducing SO$_2$ to elemental sulphur with H$_2$ and/or CO in addition to selectively oxidising H$_2$S to sulphur and water downstream of the traditional Claus converter. Using a selective reduction catalyst helps reduce side reactions that lead to H$_2$S formation. This method is important because the H$_2$S concentration in the selective oxidation reactor must be kept relatively low to avoid temperature excursions and the shortening of catalyst life.

Tail gas treatment
Tail gas treaters are used to increase sulphur recovery by up to 99.9+% from the SRU while lowering operating costs and hydrogen consumption. Tail gas treaters can reduce SO$_2$ emissions, improve reliability and increase run lengths.

Treatment of Claus tail gas is now a necessary part of the SRU to maximise sulphur recovery from residual H$_2$S, SO$_2$, COS and CS$_2$ and to meet strict SO$_2$ stack emission standards that are generally <10 ppmv. Typically, Claus tail gas is reduced and hydrolysed over a CoMo catalyst to convert SO$_2$, COS and CS$_2$ to H$_2$S before absorbing the H$_2$S out of the stream and sending it back to the feed to the Claus unit. Another alternative is to selectively oxidise the tail gas feed to elemental sulphur.

Recently, Alon USA installed a new tail gas treating (TGT) unit at its refinery in Big Spring, Texas, to reduce SRU emissions. In designing this unit, the company chose not to rely on the existing TGT design at its other sulphur plant, as this unit experienced several operational problems. Instead, various design elements were modified in order to improve reliability, run length and operator approval. Adjustments were made to the air blowers, H$_2$S/SO$_2$ ratio, the analyser at the outlet of the amine contactor, pumps, heat exchangers, lean/rich amine exchangers, TGT unit contactor, reactor catalyst support, reboiler tube bundle and return line, sight glasses, and process control system.

Sulphur production
Additional processes can be implemented to improve the value of recovered sulphur products from the refinery sulphur plant.

Adding a redox process for increased sulphur recovery
Iron redox and chelated iron processes are among the alternatives to Claus technologies. These processes have demonstrated their ability to remove up to 80 tonnes/day of sulphur from gas feeds, but they are typically used to yield less than 20 tonnes/day. Operational issues related to these processes include the high cost of chemicals, chelate degradation during regeneration and foaming. Approximately 30–90% of the product sulphur obtained from these processes is obtained as elemental sulphur and can be used as chemical feedstock, while the end use of the remaining portion (10–70%) may be limited to the fertiliser market because of the presence of entrained water.

Improve sulphur yield with high-activity catalyst
To increase sulphur yield, refiners can modify the catalytic section of the SRU by adding improved traditional Claus catalysts, adding catalysts to improve sub-dew point operation and upgrading catalysts for oxidation and/or reduction processes. High-activity catalysts for Claus converters and TGT units are commercially available from a number of companies. High-grade titania or activated alumina are most often used in Claus converters to provide high conversion of CS$_2$ and COS to H$_2$S, and H$_2$S to elemental sulphur via the Claus reaction.

Produce sulphuric acid
Improvements in sulphuric acid-based processes are providing refineries with an economic option for increased sulphur recovery outside of Claus production.
Hydrogen sulphide is combusted to form sulphur dioxide, which is subsequently oxidised to sulphur trioxide (SO₃). The SO₃ is reacted with water in the vapour phase to form H₂SO₄. A unique advantage of producing sulphuric acid is the inherent synergy with the alkylation unit, which uses sulphuric acid as a catalyst. Where demand exists, the product-quality acid can be sold.

**Case study**

As an example of a revamp that integrates several solutions, WorleyParsons was awarded a project to increase a large refinery’s SRU capacity. Two reactor trains, each consisting of two Claus reactors and a Shell Claus off-gas treating (SCOT) unit, produced 681 tonnes/day of sulphur at 70% capacity. The project involved increasing each train’s capacity to 1300 tonnes/day and improving unit reliability. The changes made to increase capacity are summarised in Table 4.

<table>
<thead>
<tr>
<th>Table 4</th>
<th>Summary of an integrated SRU revamp</th>
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<tbody>
<tr>
<td><strong>Desired outcome</strong></td>
<td><strong>Revamp modification</strong></td>
</tr>
<tr>
<td>Reduction of pressure drop</td>
<td>• Replaced reaction furnace burner</td>
</tr>
<tr>
<td>Minimise amine solvent loss</td>
<td>• Replaced quench tower trays with random packing</td>
</tr>
<tr>
<td>More catalyst required for increased throughput</td>
<td>• Replaced TGU absorber trays with structured packing</td>
</tr>
<tr>
<td>Increase capacity without modifying amine regenerator</td>
<td>• Water wash section was installed at the top of the amine absorber</td>
</tr>
<tr>
<td></td>
<td>• Installed more catalyst in Claus reactors and tail gas hydrogenation reactor</td>
</tr>
<tr>
<td></td>
<td>• MDEA solvent was replaced with ExxonMobil Flexsorb, allowing 33% more tail gas to be processed at a 20% reduction in amine circulation rate</td>
</tr>
<tr>
<td>Extra cooling water circulation</td>
<td>• New circulation water pump and extra air coolers were installed</td>
</tr>
</tbody>
</table>

**Conclusion**

As refiners are faced with the global recession, impending legislation restricting CO₂ emissions, the increasing use of heavy sour crudes and additional clean fuel specifications, hydrogen production and sulphur plant technologies will need to be adapted to meet changing market demands.

In terms of hydrogen production — an energy-intensive process — the increase in demand for clean fuels will, ironically, conflict with efforts to curb CO₂ emissions. Furthermore, the use of clean-burning natural gas as fuel for energy production and transportation may have an effect on the feedstock for hydrogen production as power plants and chemical companies are eyeing the same fuel/feedstock to reduce their carbon footprints.

The economics of sulphur plants are adversely affected by demand destruction, which could stretch over the next few years, putting further pressure on already poor refining margins. For the long term, refiners should examine emerging, novel hydrogen production and sulphur recovery technologies for plant expansion and revamp opportunities as a means to satisfy environmental legislation and market requirements.

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