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In This Issue

Volume 11 | Number 51

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SPECIAL FEATURES

- 04** **Hydrotreating Technologies as Enabler of Energy Transition in the Downstream Industry**
Dr. Marcio Wagner da Silva
- 31** **Estimating Instrument Air Requirements**
Jayanthi Vijay Sarathy
- 36** **Guidelines for Mist Elimination Equipment Selection, Sizing, Safety & Troubleshooting | Part 1**
Karl Kolmetz
Utami Ledyana Daulay
Apriliana Dwijayanti
- 42** **Refinery Turnaround Lesson Learnt**
Shahzeb H. M. Ismail

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Hydrotreating Technologies as Enabler of Energy Transition in the Downstream Industry

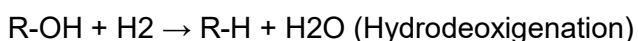
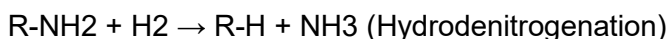
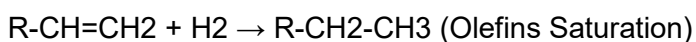
Dr. Marcio Wagner da Silva

Introduction and Context

One of the biggest challenges to the crude oil refining industry in the last decades is the development of technologies capable of reducing the environmental impact of the derivatives while raising the performance of these compounds. The hydroprocessing technologies allow the production of cleaner and better performance derivatives at same time that make possible the recovery of higher yields of added value products from bottom barrel streams in the crude oil refining.

The hydroprocessing technologies became essential to the downstream industry in the last decades once it's practically impossible to produce marketable crude oil derivatives without at least one hydroprocessing step. To achieve the goal of ensuring maximum added value to the processed crude oil, the refiners need an adequate hydroprocessing capacity in this refining hardware, especially those processing heavier crude oils, the hydroprocessing catalysts are the heart of the hydroprocessing technologies and his relevance is increasingly high to the refiners.

The main chemical reactions associated with the hydrotreating process can be represented as below:



where R represents a hydrocarbon.

Hydroprocessing Technologies – General Overview

The hydrotreating process involves a series of chemical reactions between hydrogen and organic compounds containing contaminants (N, S, O, etc.). According to the target contaminant of the hydrotreating, the process can be called hydrosulfurization (removing S), hydrodenitrogenation (removing N), hydrodeoxygenation (removing O) or hydrodearomatization when the main objective is to saturate of aromatic compounds, among others.

The most common hydrotreating forms are hydrosulfurization (where the objective is to remove compounds like benzothiophene, dibenzothiophene, etc.) and the hydrodenitrogenation (removing porphyrins, quinolines, etc.) These compounds, besides provoke emissions of SO_x and NO_x when they are burned, produce in the derivatives acidity, color and chemical instability.

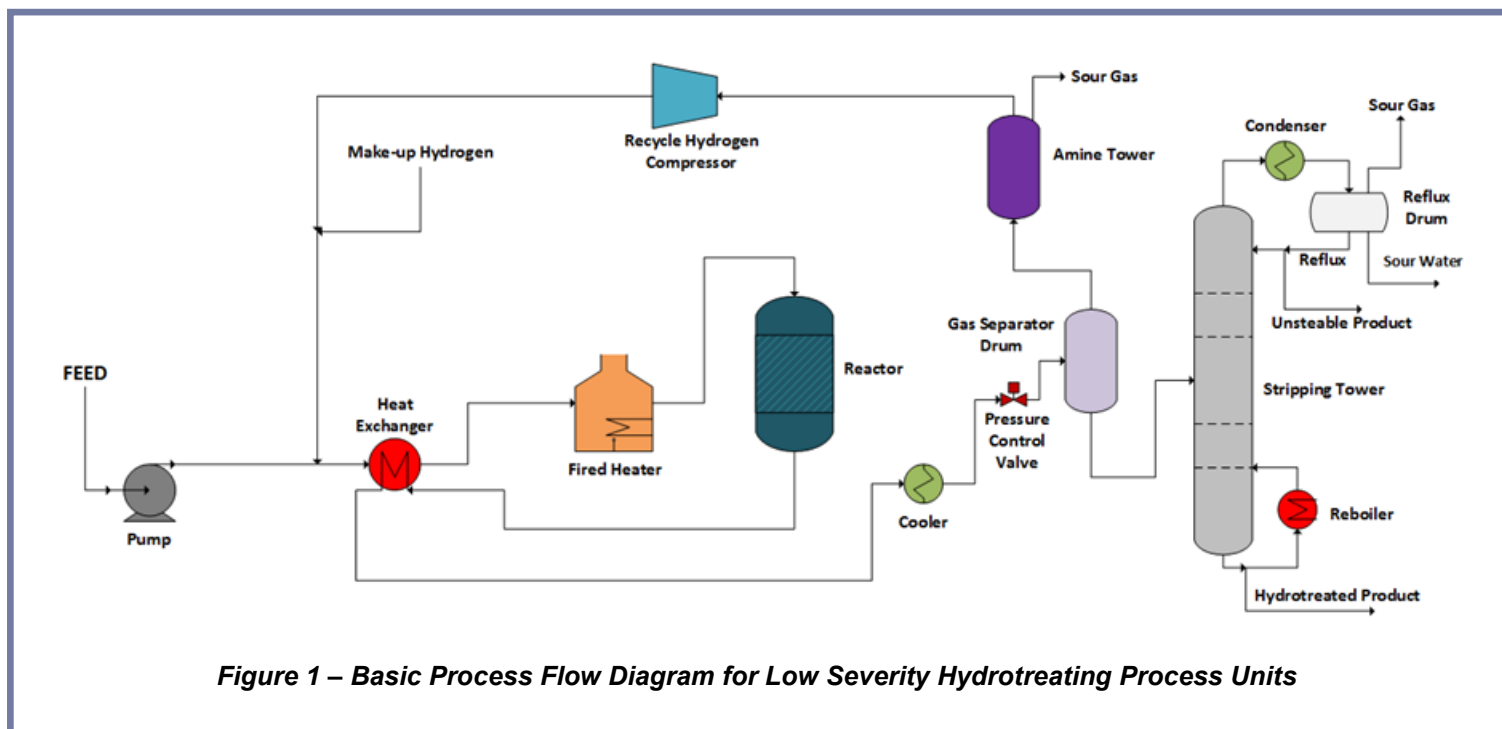
The hydrotreating process is normally conducted in fixed bed reactors and the most applied catalysts are Cobalt (Co), Nickel (Ni), Molybdenum (Mo) and Tungsten (W), commonly in association with them and supported in alumina (Al_2O_3). The association Co/Mo is applied in reactions that need lower reactional severity like hydrodesulfurization, while the catalyst Ni/Mo is normally applied in reactions that need higher severity, like hydrodenitrogenation and aromatics saturation.

Hydrotreating is applied in the finishing of the final products like gasoline, diesel or kerosene or like intermediate step in the refining scheme in refineries to prepare feed charges to other processes like Residues Fluid Catalytic Cracking (RFCC) or Hydrocracking (HCC) where the main objective is to protect the catalyst applied in these processes.

The basic process flow is like the various hydrotreating processes (hydrodesulfurization, hydrodenitrogenation, etc.), however, the process severity, determined by variables like hydrogen partial pressure, temperature and catalyst vary and the contaminants removal is affected.

The hydrotreatment process units are optimized aiming a equilibrium between cited operational variables, because chemical reactions are exothermic and the decontrolled raising in the temperature can affect negatively the reactional equilibrium besides it's possible the sintering of the catalysts, to minimize this risk normally the hydrotreating reactors have points between the catalyst beds where are injected hydrogen in lower temperature (quench lines) to permit a better control of the reactor temperature.

Figure 1 shows a typical arrangement for a hydrotreating process unit with a single separating vessel.



The configuration with a single separating vessel is normally applied in lower severity units, like hydrodesulfurization units. This arrangement is possible in this case because under reduced pressures the difference between water and hydrocarbons properties is large and the separation process needs reducing contact areas, so a single vessel can realize the separation process.

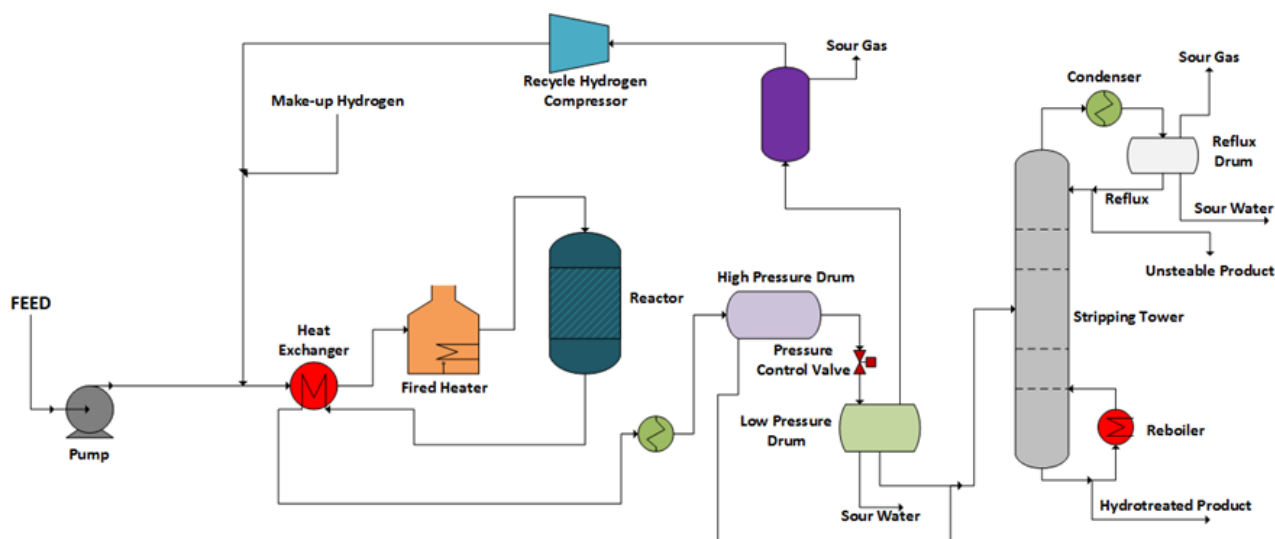


Figure 2 – Basic Process Flow Diagram for High Severity Hydrotreating Process Units

Higher severity units, like process units dedicated to treating unstable streams (Light Cycle Oil, Coke Gas Oil, etc.) or with the objective to remove nitrogen or aromatics saturation, operates with two separating vessels like presented in Figure 2.

In this case the difference between water and hydrocarbons properties is small and the phase separation process needs higher interface area so, two separating vessels are applied, one under high pressure where the separation among liquid and gaseous phase (H_2 , H_2S , NH_3 and light hydrocarbons) occurs and other under low pressure where the separation between aqueous and hydrocarbon phase is promoted, apart from the separation of the remaining gases.

For lower severity units the temperatures applied are about 300 to 350°C and pressures vary between 20 to 40 bar, in addition of lower residence times. Units with high severity operate under temperatures 350 to 400 °C and pressures vary from 40 to 130 bar.

Like aforementioned, great efforts was employed in the hydrotreating technology development, however, technology licensors like Axens, UOP, Exxon Mobil, McDermott, Lummus, Haldor Topsoe, Albemarle among others, still invest in research to improve the technology, mainly in the development of new arrangements that can minimize the hydrogen consumption (high cost raw material) and that apply lower cost catalysts and more resistant to deactivation process.

The hydrocracking process is a deep hydroprocessing technology where hydrogenation reactions are conducted at same time of cracking reactions. Table presents the main differences between the hydrotreating and hydrocracking processes.

The hydrocracking process is normally conducted under severe reaction conditions with temperatures that vary to 300 to 480 °C and pressures between 35 to 260 bar. Due to process severity, hydrocracking units can process a large variety of feed streams, which can vary from gas oils to residues that can be converted into light and medium derivatives, with high value added.

Among the feed streams normally processed in hydrocracking units are the vacuum gas oils, Light Cycle Oil (LCO), decanted oil, coke gas oils, etc. Some of these streams would be hard to process in Fluid Catalytic Cracking Units (FCCU) because of the high contaminants content and the higher carbon residue, which quickly deactivates the catalyst, in the hydrocracking process the presence of hydrogen minimizes these effects.

Table 1 – Hydrotreating and Hydrocracking Processes Comparison

Hydrotreating	Hydrocracking
Contaminants Removal (S, N,O, Metals, etc.) and C-C bonds saturation	Contaminants Removal (S,N,O, Metals, etc.) ,cracking of C-C bonds and reduction in molecular weight
Minimum Cracking	High Cracking rate
Low Conversion (< 20%)	High Conversion (> 50%)
Feed stream preparation for Conversion Units - FCC / RFCC, Catalytic Reform, Hydrocracking, etc.	Production of Final Products – Transportation Fuels (Diesel and kerosene) and lubricants.
Ni/Co/Mo Typical Catalysts	Ni/W/Pt/Pd Typical Catalysts (Dual Character)

Figure 3 shows a typical arrangement for hydrocracking process unit with two reactions stages, dedicated to producing medium distilled products (diesel and kerosene).

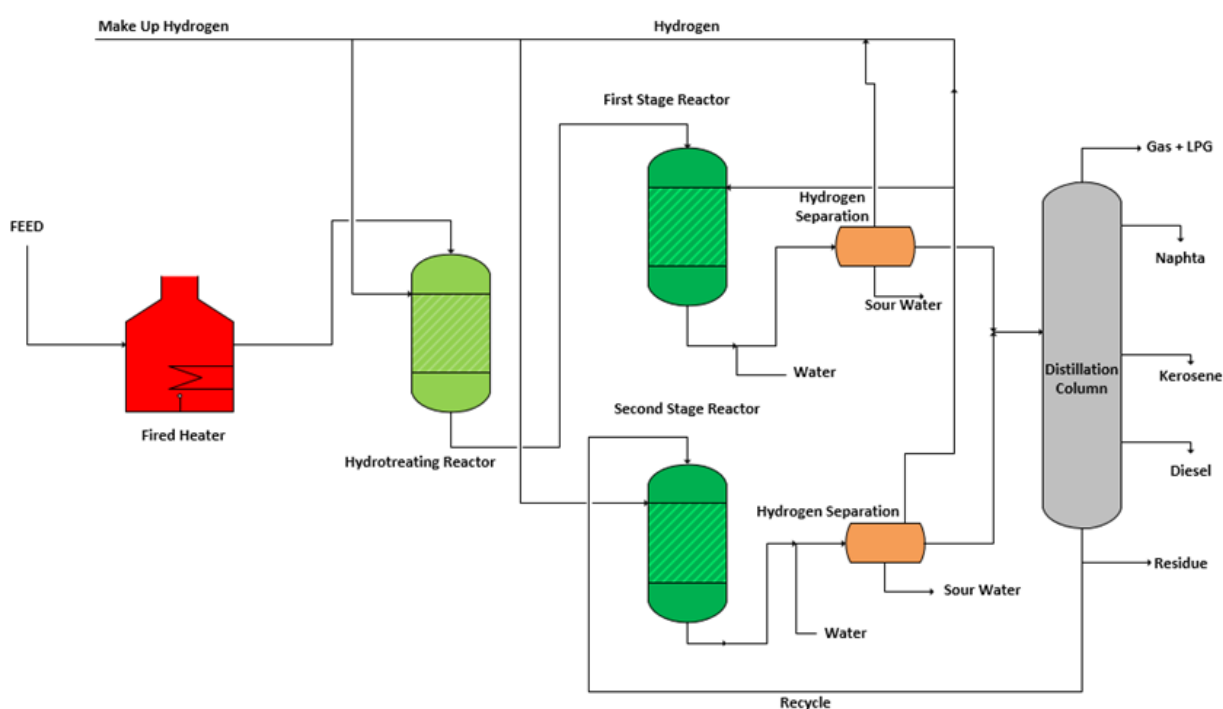


Figure 3 – Basic Process Flow Diagram for Two-stage Hydrocracking Units

According to the feed stream quality (contaminant content), is necessary hydrotreating reactors installation upstream of the hydrocracking reactors, these reactors act like guard bed to protect the hydrocracking catalyst.

Atmospheric Residue Desulfurization – An Especial Case

With the start of the validity of the new regulation over the quality parameters of marine fuel oil (BUNKER), some refiners and crude oil producers still question what will be the market behavior face to the new regulation. The IMO 2020 requires a deep reduction in the sulfur content of the marine fuel oil from the current 3,50 % in mass to 0,50 % in mass, leading to a necessity of changes in the production process of this derivative or higher control of sulfur content in the processed crude slate by the refiners.

To refiners with adequate bottom barrel processing capacity, the new regulation tends to don't be a great threat and can represent a good opportunity to raise the profitability, considering the competitive advantage which the high complexity refining hardware gives to these refiners.

The eventual devaluation of high sulfur crude oil can suffer due to the IMO 2020 can be translated into higher refining margins to refiners capable of processing these crudes.

One of the technologies that have been widely considered in the downstream industry in the IMO 2020 scenario is the desulphurization of atmospheric residue, aiming to allow not only the compliance with the new regulation but the quality improvement of the other derivatives and reliability of the downstream process units like FCC or hydrocracking. As presented in Figure 4, the atmospheric residue corresponds to the bottom stream of the atmospheric crude oil distillation column

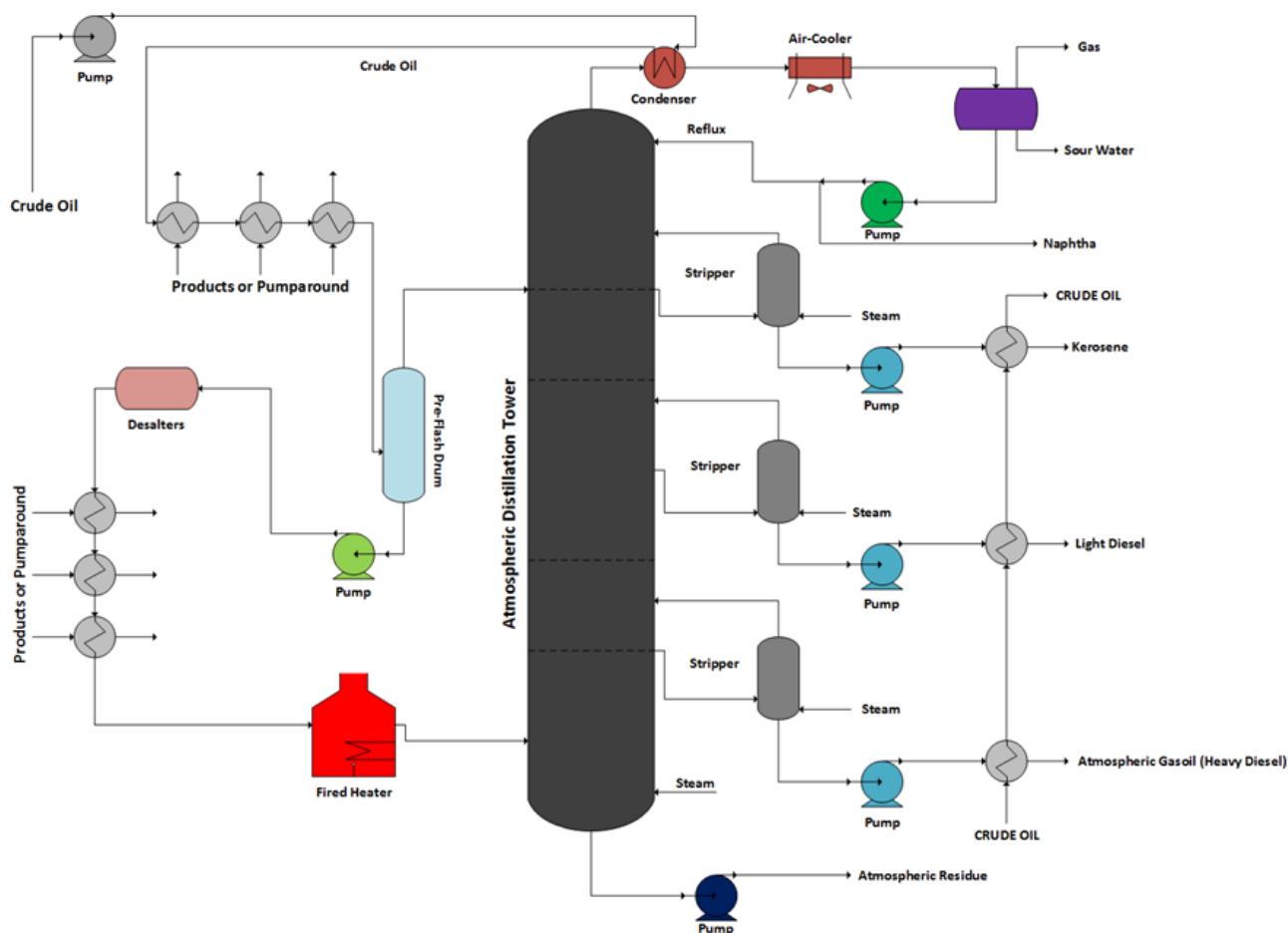


Figure 4 – Typical Process Arrangement of Atmospheric Crude Oil Distillation Unit

Once heteroatoms like sulfur, nitrogen, and metals tend to concentrate in the heavier fractions of the crude oil, the atmospheric residue drags a major part of the contaminants present in the crude oil. Considering the current quality and environmental requirements over the derivatives, posterior treatments are required aiming to reduce the contaminants content (mainly sulfur and nitrogen) in the derivatives.

Before January of 2020, the production of marine fuel oil (BUNKER) involves basically the dilution of vacuum residue (bottom barrel stream from vacuum distillation column) or deasphalted oil (to refiners that rely on solvent deasphalting unit in the refining scheme) with lighter streams like LCO (Light Cycle Oil) and gas oils, as presented in Figure 5.

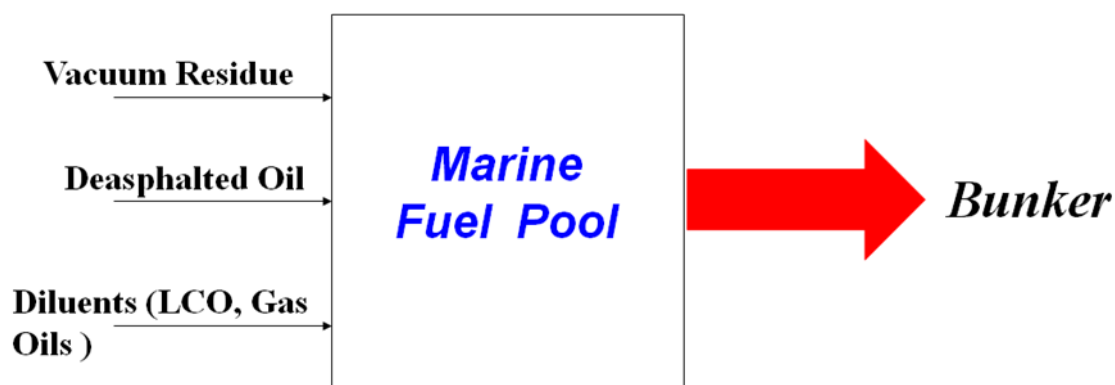


Figure 5 – Marine Fuel Oil (BUNKER) Production Process Before IMO 2020

The IMO 2020 makes necessary a better control of the sulfur content in the streams applied as diluents in the BUNKER production, to refiners with high bottom barrel conversion capacity the control of the sulfur content in the vacuum residue through the atmospheric residue applying hydrodesulphurization minimizes the necessity of treatment of other streams as well as can avoid the use of noblest streams like diesel and jet fuel as diluents in the BUNKER production.

The hydrodesulphurization process of atmospheric residue presents additional technologic challenges when compared with the hydrotreating process applied to final derivatives like diesel and gasoline, considering the high contaminants content, mainly metals, and the residual carbon due to the high concentration of resins and asphaltenes in the feedstream.

Beyond the sulfur removal, the main goal, the atmospheric residue hydrodesulphurization unit promotes the partial removal of metals, nitrogen and residual carbon (CCR) through catalytic hydrogenation mechanism.

Among the available atmospheric residue hydrodesulphurization technologies, we can quote the RCD Unionfining™ process developed by UOP Company, the process Hyvah™ by Axens Company, the technology RHU™ by Shell Company, and the RDS™ technology commercialized by Lummus Company.

Figure 6 present the basic process flow diagram for the RCD Unionfining™ technology by UOP Company.

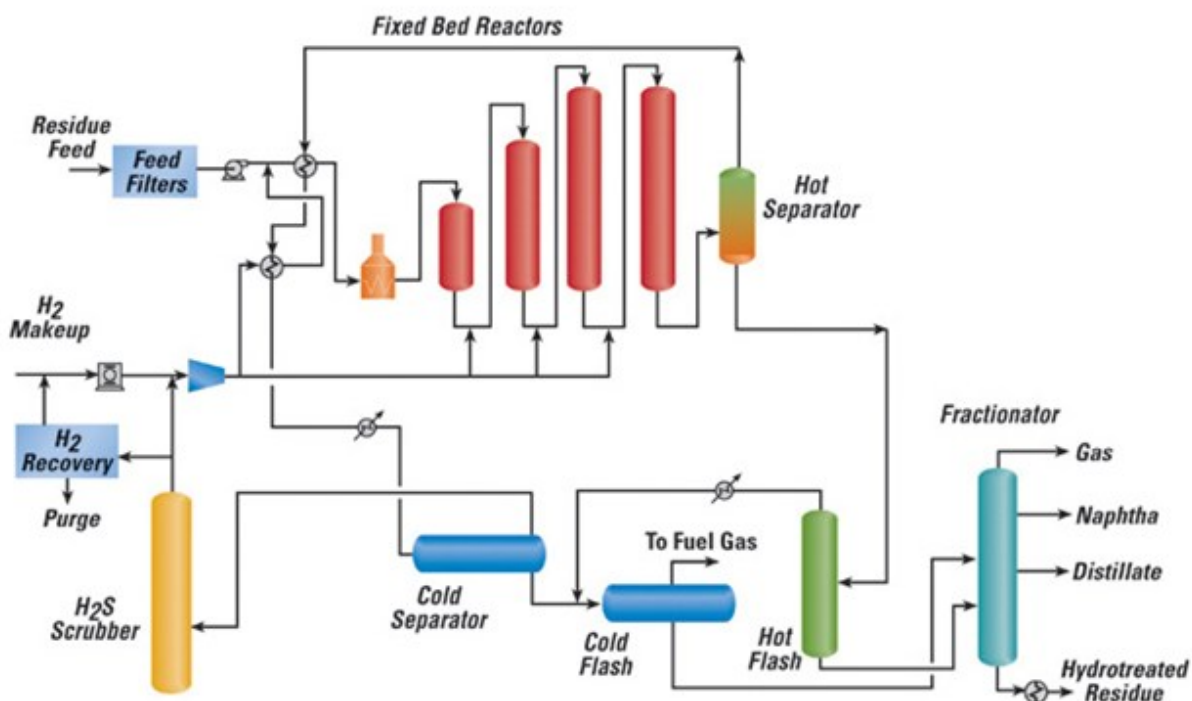


Figure 6 – UOP RCD Unionfining™ Atmospheric Residue Hydrodesulphurization Technology (UOP Company Website, 2019)

The role of the atmospheric hydrodesulphurization unit in the refinery goes beyond allowing the production of low sulfur fuel oil, in high complexity refineries the unit is applied as feedstock treatment step to conversion units as FCC/RFCC, hydrocracking, and delayed coking. The reduction of contaminants content and residual carbon promoted by the atmospheric residue hydrodesulphurization unit significantly raises the quality of derivatives produced by downstream units as well as raises the catalyst lifecycle of deep conversion processes like FCC and hydrocracking, contributing to reduce the operation costs.

The process conditions tend to be more severe in the case of atmospheric residue hydroprocessing. The feedstock characteristics lead to a strong tendency of coke deposition over the catalyst requiring higher hydrogen partial pressure (until 180 bar to fixed bed reactors) as well as higher temperatures (380 to 420 oC).

The hydrotreating process of atmospheric residue is normally conducted in fixed bed reactors and the most employed catalysts are Cobalt (Co), Nickel (Ni), Molybdenum (Mo), and Tungsten (W), normally in association between them and supported over alumina (Al₂O₃).

The combination Co/Mo is normally more active to hydrodesulphurization reactions while the Ni/Mo combination is responsible for hydrodenitrogenation and aromatics saturation reactions.

A typical atmospheric residue hydrodesulphurization unit can achieve 95 % of conversion in hydrodesulphurization reactions and 98 % in hydrodemetallization reactions, furthermore, it's possible to achieve a reduction of 65 % in residual carbon according to the employed technology. Normally, atmospheric hydrodesulphurization units rely on catalytic beds focused on remove metals also called guard beds aiming to protect the catalysts in the downstream reactors and improve the operational lifecycle.

Due to the severe operating conditions, the operation costs of atmospheric residue desulphurization units are higher when compared with hydrotreating units dedicated to processing distillates (Diesel, Jet fuel, and Naptha). The most intense hydrogenation process leads to a necessity of more robust quenching systems of catalytic beds, higher hydrogen make-up rates and more complex phase separation systems (multiple stages).

The Challenges of Renewables Processing in Hydrotreating Units –

The Hydrogen Matter

Despite the advantages of environmental footprint reduction of the refining industry operations, renewables processing presents some technological challenges to refiners. Figure 7 presents the chemical mechanism for the processing of vegetable/animal oils in hydrotreating units.

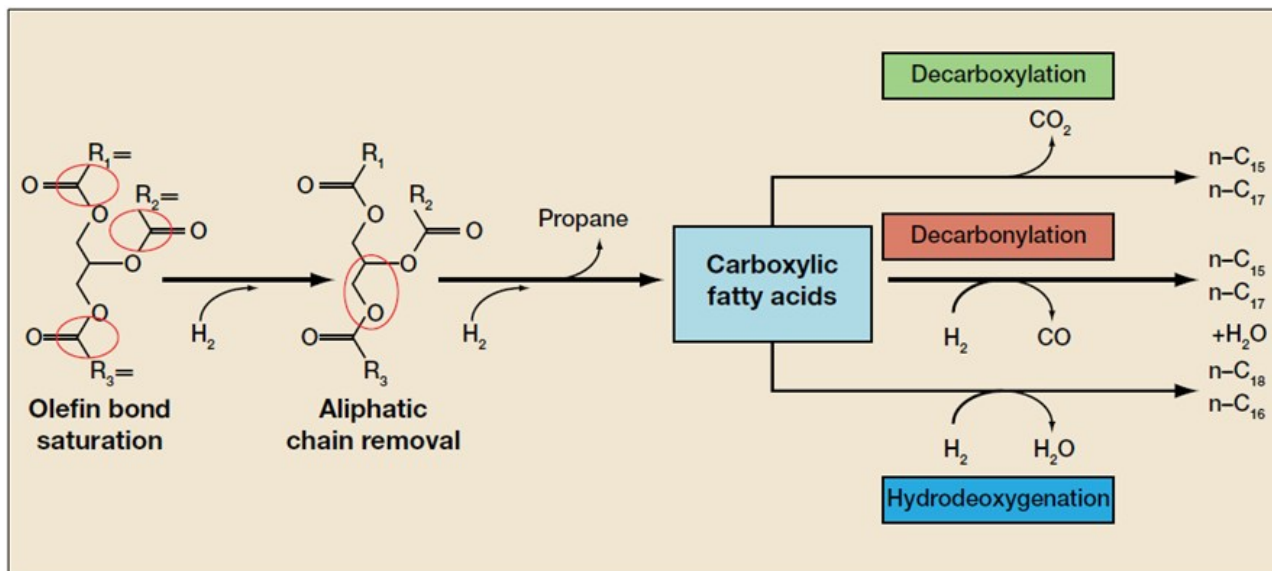
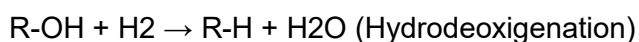
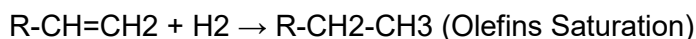


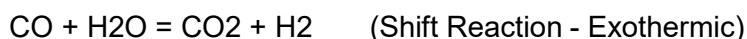
Figure 7 – Chemical Mechanism of the Renewable Feedstream Hydrotreating
(Article by ExxonMobil Company, 2011)

The renewable streams have a great number of unsaturations and oxygen in their molecules which lead to high heat release rates and high hydrogen consumption, this fact leads to the necessity of higher capacity of heat removal from hydrotreating reactors aiming to avoid damage to the catalysts. The main chemical reactions associated with the renewable streams hydrotreating process can be represented as below:



Where R represents hydrocarbons.

These characteristics lead to the necessity of higher hydrogen production capacity by the refiners as well as quenching systems of hydrotreating reactors more robust or, in some cases, the reduction of processing capacity to absorb the renewable streams. In this point it's important to consider a viability analysis related to the use of renewables in the crude oil refineries once the higher necessity of hydrogen generation implies in higher CO₂ emissions through the natural gas reforming process that is the most applied process to produce hydrogen in commercial scale.



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This fact leads some technology licensors to dedicate their efforts to look for alternative routes for hydrogen production on large scale in a more sustainable manner. Some alternatives pointed out can offer promising advantages:

- Natural Gas Steam Reforming with Carbon Capture – The carbon capture technology and cost can be limiting factor among refiners;
- Natural Gas Steam Reforming applying biogas – The main difficult in this alternative is a reliable source of biogas as well as their cost.;
- Reverse water gas shift reaction ($\text{CO}_2 = \text{H}_2 + \text{CO}$) – One of the most attractive technologies, mainly to produce renewable syngas;
- Electrolysis – The technology is one of the more promising to the near future.

Refiners and technology developers are looking for alternatives to produce hydrogen on an industrial scale with lower CO_2 emissions and some attractive routes have been considered as competitive in the future, as presented in Figure 8.

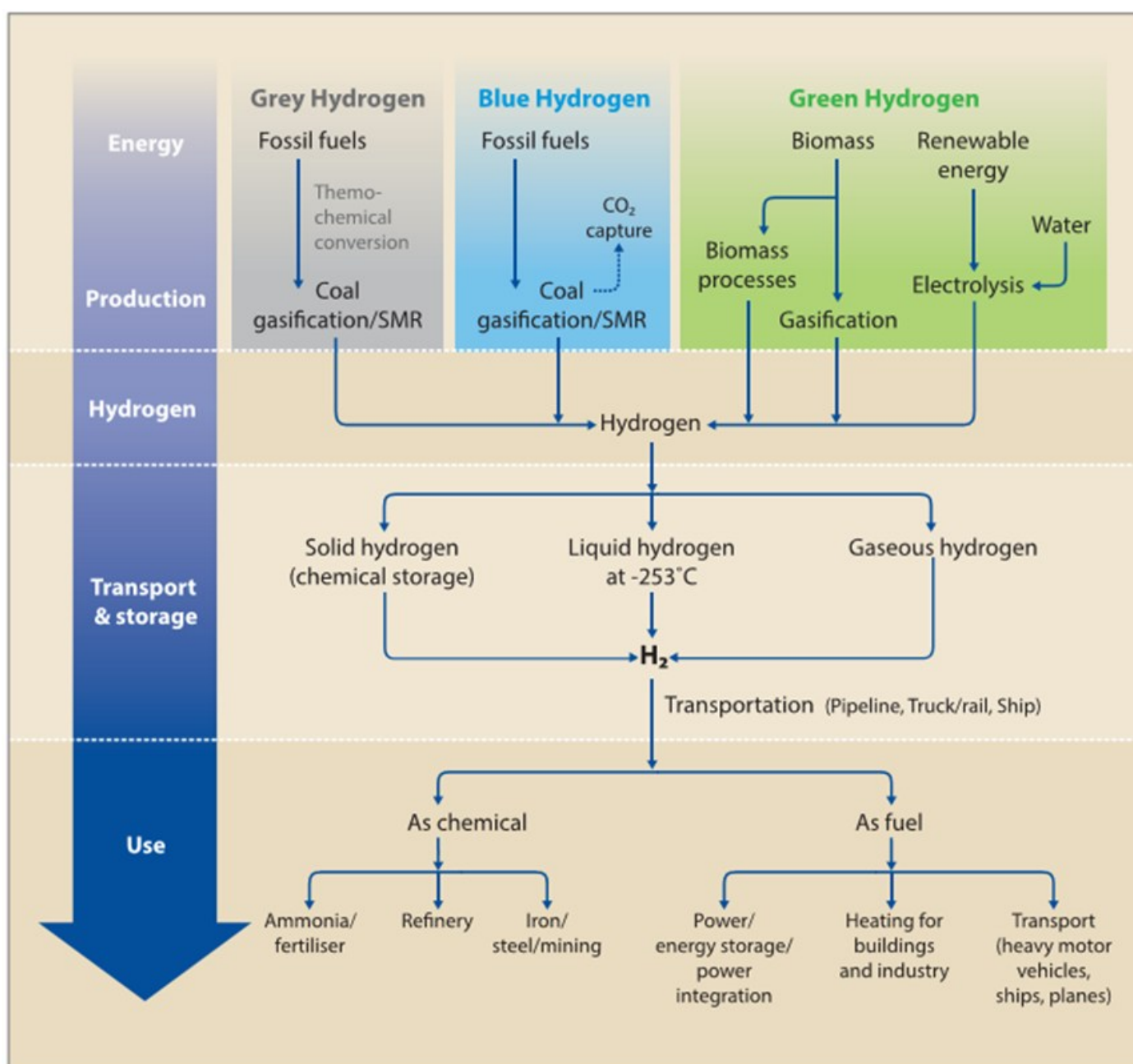


Figure 8 – Hydrogen Lifecycle and Potential Applications (Technip Company, 2020)

Despite the advantages of the green production routes of hydrogen, they are still in development and poor attractive to the most part of the refiners, in the current scenario the refiners to look for more efficient operations aiming to optimize the hydrogen balance the refining hardware as well as apply CO₂ capture technologies (the blue route), in this sense an attractive alternative is to apply technologies capable to recovery hydrogen from refinery off-gases and apply control strategies capable to minimize the hydrogen losses to flare system.

As exposed above, the hydrogen generation is a key matter to refiners, and refineries that rely on Catalytic Reforming units apply the hydrogen produced in this process unit to compose a relevant part of the hydrogen network becoming an important internal source of hydrogen. In some markets, where the demand by petrochemicals is lower, the main relevance of the catalytic reforming to the refining hardware is the hydrogen generation against the production of light aromatics. Figure 9 presents an example of hydrogen network in a crude oil refinery with high hydroprocessing capacity.

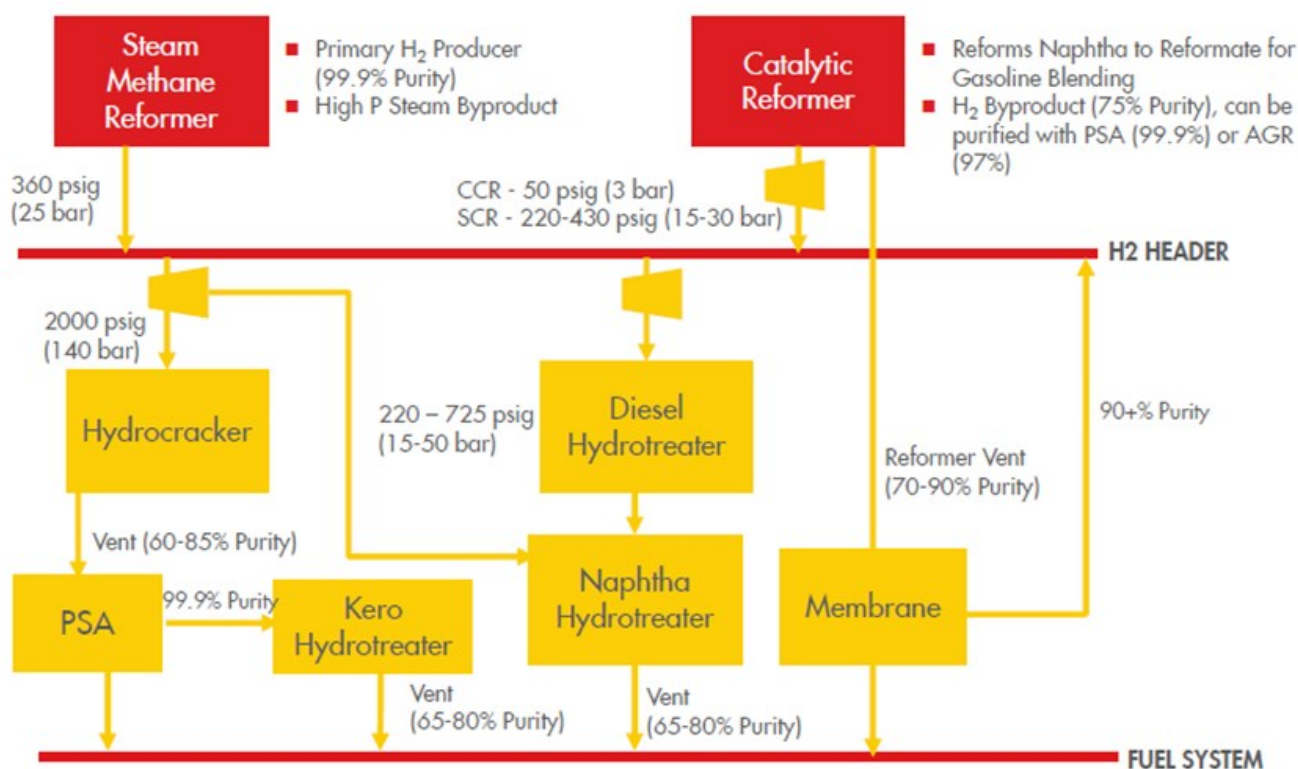


Figure 9 – Example of Hydrogen Network to a Crude Oil Refinery (LAFLEUR, 2017)

In refineries with bottlenecked hydrogen generation units, the hydrogen from catalytic reforming units is fundamental to ensure compliance with the current quality and environmental regulations, becoming a fundamental enabler to profitable and reliable operations of the refining hardware. Nowadays, it's not uncommon to find refiners operating catalytic reforming units with the main objective to hydrogen generation, especially to refiners that operate with octane giveaway in the gasoline pool.

Hydroprocessing Catalysts

The hydrotreating catalysts are normally composed of metal sulfides of Group VI (W and Mo) or/and Group VIII (Ni and Co) carried by an oxide like alumina, zeolite or silica-alumina. The most employed combinations in traditional hydrotreating processes are Co/Mo (Cobalt/Molybdenum), Ni/Mo (Nickel/Molybdenum), and Ni/W (Nickel/Tungsten). The Co/Mo combination is normally applied to hydrodesulfurization reactions once presents less activity to harder reactions as hydrodenitrogenation or aromatics saturation, in these cases the catalyst selected is based on Ni/Mo combination while the Ni/W catalysts is applied to deep hydroprocessing processes where the main objective is aromatics saturation. Normally, the hydroprocessing reactors are filled with a combination of these catalysts aiming to optimize the performance and operating costs.

Some promoters can be added to the hydrotreating catalysts aiming to improve performance in specific cases. Phosphorous is added to the Ni/Mo catalysts with the objective to improve the hydrodenitrogenation activity and the Fluor is applied to improve the catalyst performance in cracking reactions through the higher acidity in the carrier, this is a great advantage in mild hydrocracking processes.

Catalysts applied in hydrocracking processes can be amorphous (alumina and silica-alumina) and crystallines (zeolites) and have bifunctional characteristics, once the cracking reactions (in the acid sites) and hydrogenation (in the metals sites) occur simultaneously. The active metals used to this process are normally Ni, Co, Mo and W in combination with noble metals like Pt and Pd.

It's necessary to have a synergic effect between the catalyst and the hydrogen because the cracking reactions are exothermic and the hydrogenation reactions are endothermic, so the reaction is conducted under high partial hydrogen pressures, and the temperature is controlled at the minimum necessary to convert the feed stream. Despite this characteristic, the hydrocracking global process is exothermic, and the reaction temperature control is normally made through cold hydrogen injection between the catalytic beds.

To hydrocracking units, the catalyst activity is defined by the required temperature to reach a desired conversion, which is defined by Equation 1.

$$\text{Conversion (\%)} = [(1 - (\text{Fraction with Above TBP in the Product}) / (\text{Fraction with Above TBP in the Feed}))] \times 100 \quad (1)$$

Where TBP is True Boiling Point, which represents the desired cut point defined by the refiner.

Deactivation of Hydroprocessing Catalysts

The main deactivation mechanisms of hydroprocessing catalysts are:

- Metal deposition – Related to feedstock characteristics and drag of contaminants;
- Active phase sintering process – Related to over temperature and metal deposition;
- Coking deposition – Related to the processing conditions, feedstock characteristics, and operating issues. It is considered the only reversible deactivation process.

The metals deposition is mainly affected by Ni, V, Pb, As, Si, Fe, and Na. Nickel and Vanadium can be present in heavier fractions of crude oil and plug the catalyst pores and act as coke precursors. Lead (Pb) and Arsenic (As) can react with the active phases (metal sulfides) leading to sintering process and consequently reduction of active phase area, Pb is found in naphtha fractions and Arsenic can be found in all petroleum fractions.

Contamination by silicon occurs normally due to the injection of silicon based compounds in the crude oil extraction step and in downstream processes like Delayed Coking units where are applied anti-foaming agent. The silicon acts reducing the surface area and plugging the catalyst pore, leading to a severe activity reduction.

The deactivation by sodium (Na) is similar of the silicon (Si) process, in hydrocracking processes the feed contamination by sodium is a great concern once the basic character of sodium promotes the neutralization of acid function of the hydrocracking catalysts, leading to a drastic reduction in the conversion (Equation 1).

Coking deposition is related to condensation of high weight molecules (heavier aromatics and asphaltenes) present in heavier feeds. The coke deposition is also related with dehydrogenation, cracking, and polymerization reaction of heavier fractions, the deactivation occurs through the plugging of catalyst pores blocking the mass transfer from the hydrocarbon to the active phase, as presented in Figure 10.

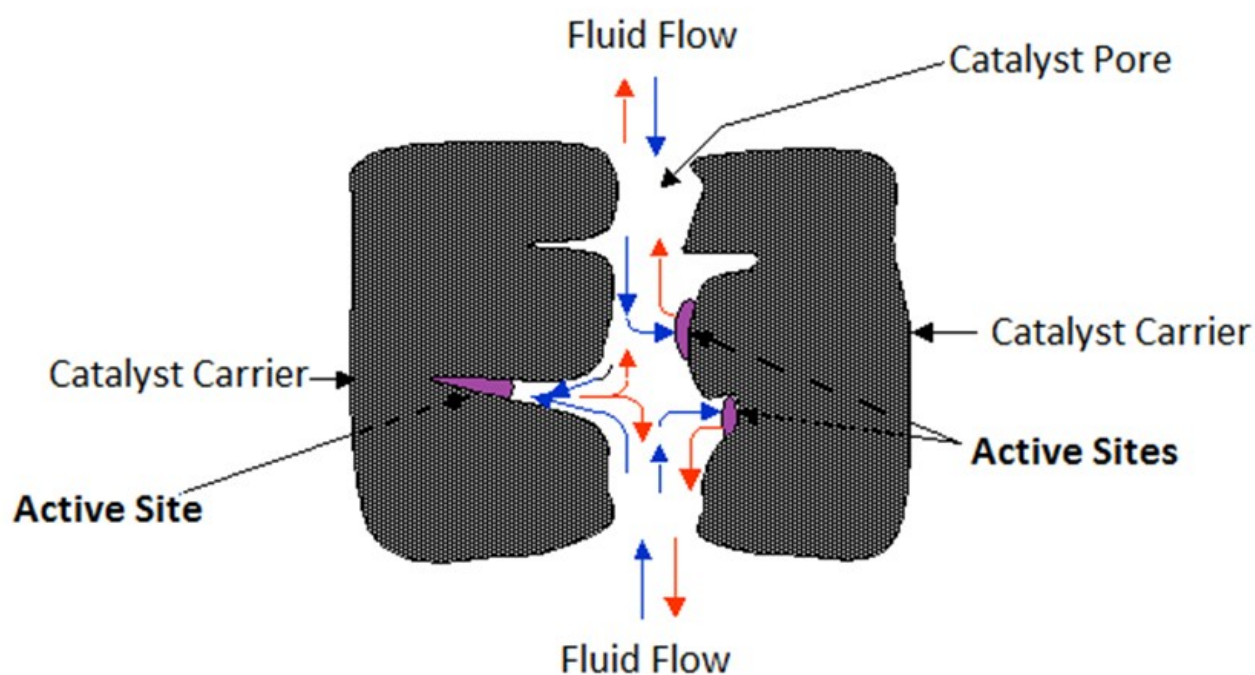


Figure 10 – Reactants and Products Flows in a Generic Porous Catalyst (GONZALEZ, 2003)

The coking deposition also reduces the active surface area and is normally followed by metals deactivation, mainly to hydroprocessing units dedicated to treat bottom barrel streams.

The Coking deposition process is positively affected by temperature and negatively affected by hydrogen partial pressure, by this reason, hydroprocessing units dedicated to process heavier feeds operates under higher pressures with the main objective to protect the catalysts that are responsible by great part of operating costs of the refiners.

In severe hydrocracking units, an inhibition effect of the NH_3 over the catalysts can be observed due to the acid function neutralization, in these cases this issue is minimized through the gas separation between the reaction stages, as presented in Figure 11.

The activity of hydrotreating catalysts is monitored through the temperature required to reach desired contaminant content (normally sulfur) in the product, the maximum temperature being limited by the metallurgy limits of the material applied in the design of the hydroprocessing unit.

The most known technology developers of hydroprocessing catalysts are Haldor Topsoe, Albemarle, ExxonMobil, UOP, Advance Refining Technologies (ART) Company, Criterion, Chevron Lummus Global (CLG), and Shell Catalysts Company.

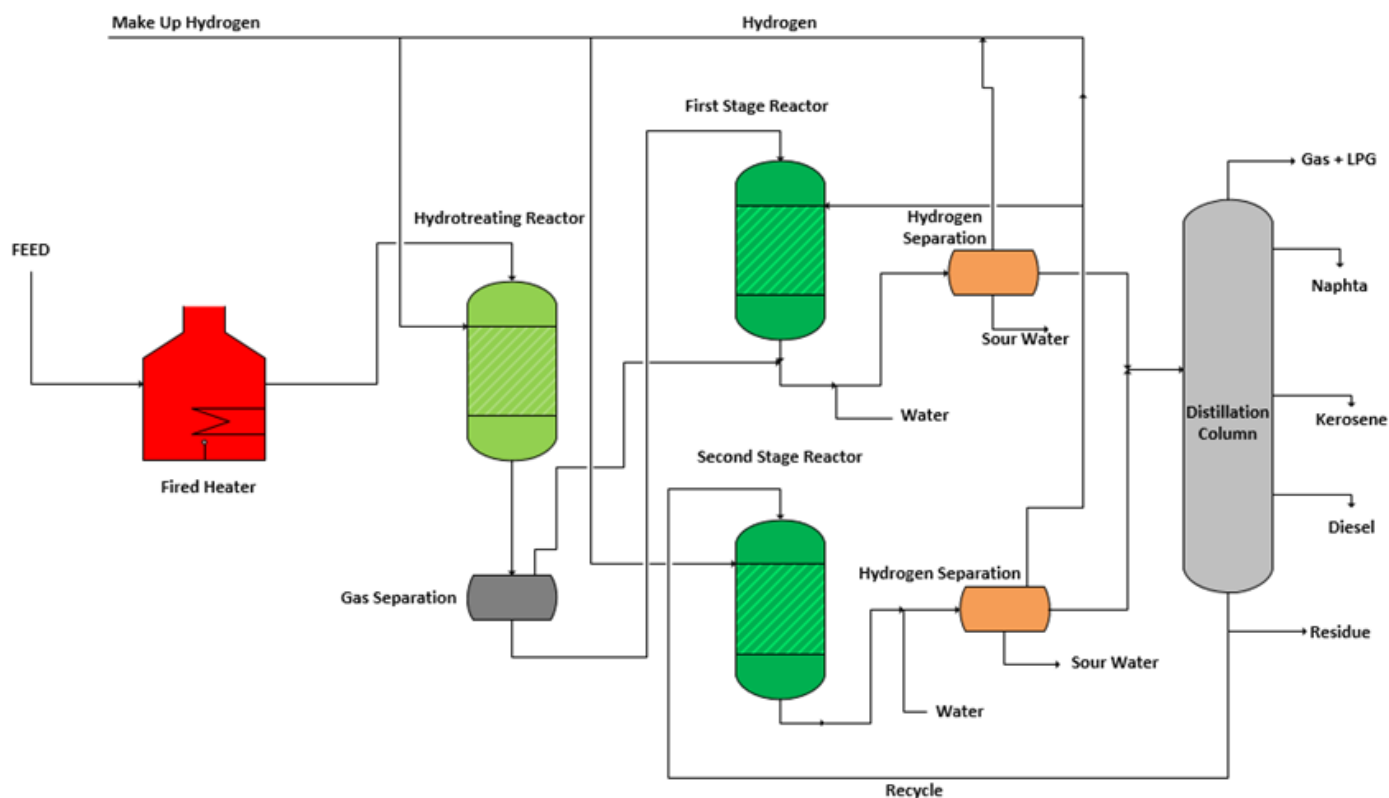


Figure 11 – Typical Arrangement for Two Stage Hydrocracking Units with Intermediate Gas Separation

How to Control the Pressure Drop in Fixed Bed Hydrotreaters?

The main causes of high pressure drop in hydroprocessing reactors are the internals like distributors and trays, particulates which are normally dragged with the feedstock, organic species like olefins and asphaltenes, and the coking deposition related to low hydrogen partial pressure, inadequate distribution, or hot points in the catalyst bed. Nowadays, the increasing participation of renewable raw material in hydrotreating reactors calls for even more attention due to the higher heat release, concentration of chemical unstable components, and higher total acid number.

Among the available strategies to mitigate the pressure drop issue in fixed bed hydroprocessing reactors, it's possible to quote:

- Filtration of the feedstock – This strategy is especially important to feed from delayed coking units due to the presence of coke particulates;
- Antifouling dosage in the hydroprocessing unit – The main objective here is controlling the corrosive process, avoiding the drag of corrosion material to the reactors;
- Sacrificial Catalysts – This strategy is applied mainly in hydrotreating units dedicated to processing bottom barrel streams, it's applied a high porosity catalyst to act as a filter, retaining particulates and contaminants in the top of the catalyst bed;
- Grading Catalyst – The grading is applied to retain the contaminants in the first section of the bed through the application of non-active material.

The size and shape of the catalyst particles have great effect over the pressure drop in the hydroprocessing reactor as well as the catalyst load strategy affects the pressure drop in the bed, aiming to improve the characteristics of the catalyst, the Criterion Company develop the ATX™ catalyst shape which, among other characteristics, can minimize the pressure drop in the catalyst bed. In dense load, one of the critical parameters is control the load speed to avoid the catalyst cracking during the load, raising the fines production.

During the startup of the hydroprocessing units it's important to analyze the procedures in order to avoid great quantity of liquid in the catalyst beds during the startup, the high quantity of liquid can vaporize abruptly during the final steps of the startup, leading to the catalyst broken and high pressure drop.

As aforementioned, controlling the catalyst lifecycle is a key issue to refiners and one of the main strategies adopted in the last years is the use of guard beds in hydroprocessing catalysts to protect the catalysts, ensuring longer and most profitable operating campaign.

The main objective of the guard bed is to protect the main and active catalyst against:

- Particulates from the feedstock that can be dragged like sediments, catalysts powder and corrosion products that are capable to produce physical fouling;
- Heavier hydrocarbons capable to lead of coking deposition;
- Chemical unstable hydrocarbons capable to produce gum, like olefins and diolefins;
- Metals and catalysts poisons like Ni, V, Fe, Si, Na, etc.

As aforementioned, due to the higher concentration of contaminants, the guard beds are most common in hydroprocessing units dedicated to processing heavier feedstocks, as quoted above. Normally is applied a grading strategy in the catalyst bed aiming to establish a staggering of pore diameter and activity to the catalysts, keeping the catalysts in the top more resistant to the contaminants acting as a filter, protecting then the most active catalyst in the bottom section, Figure 12 presents an example of hydroprocessing catalysts grading according to STAX™ technology by Albemarle Company.

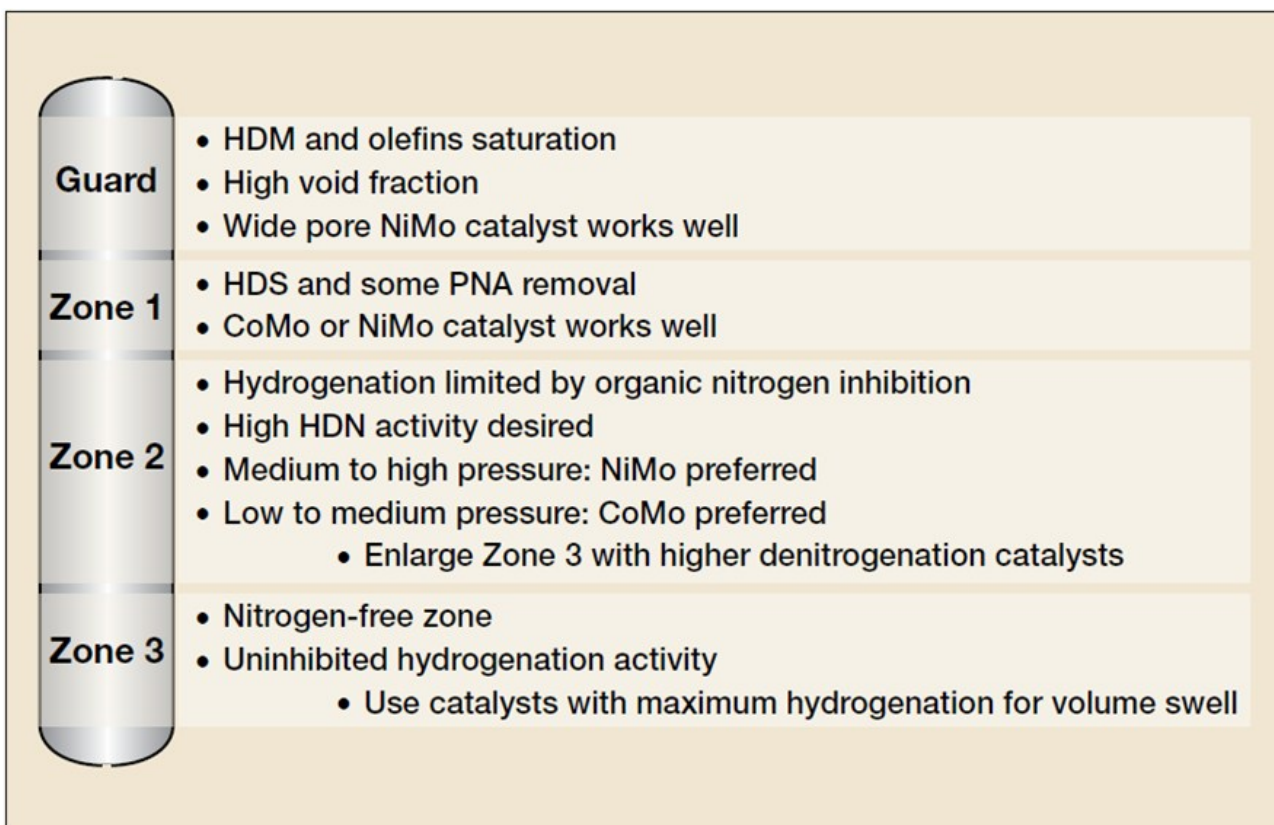


Figure 12 – Example of Hydroprocessing Catalysts Grading (LELIVELD & TOSHIMA, 2015)

In Figure 12, the guard bed will be responsible to control the contaminants content (mainly metals) to the next catalyst sections as well as to reduce the carbon residue (CCR) and particulates concentration, keeping the activity and improving the lifecycle of the hydroprocessing unit.

Among the most known catalyst protection technologies available in the market, we can quote the CatTrap™ technology developed by Crystaphase Company, this technology applies a ceramic bed acting as a filter to particulate materials, controlling especially the pressure drop in the catalyst bed.

For units dedicated to treat bottom barrel streams, the hydroprocessing catalyst needs present high activity and be resistant to the high contaminants content (sulfur, nitrogen, and silicon), some companies have been dedicated his efforts to develop catalytic systems capable to attend these requirements, as examples of these technologies we can quote the START™ system by Advanced Refining Technologies (ART) Company, the UNITY™ system developed by UOP Company, the SENTRY™ catalysts by Criterion Catalysts Company, and the TK-449 Silicon Trap™ by Haldor Topsoe Company. Figure 13 presents a comparative study developed by Haldor Topsoe Company related to the improvement of the cycle length of a naphtha hydrotreating unit applying grading particles to control the contaminants content over the main catalyst.

The increasing relevance of the hydroprocessing technologies to the downstream industry requires even more attention from refineries aiming to keep profitable and reliable operations in these units. The guard beds technologies have an important role to allow the achievement of this goal, as presented in Figure 13 these technologies can improve in a significant manner the operational lifecycle of the hydroprocessing units.

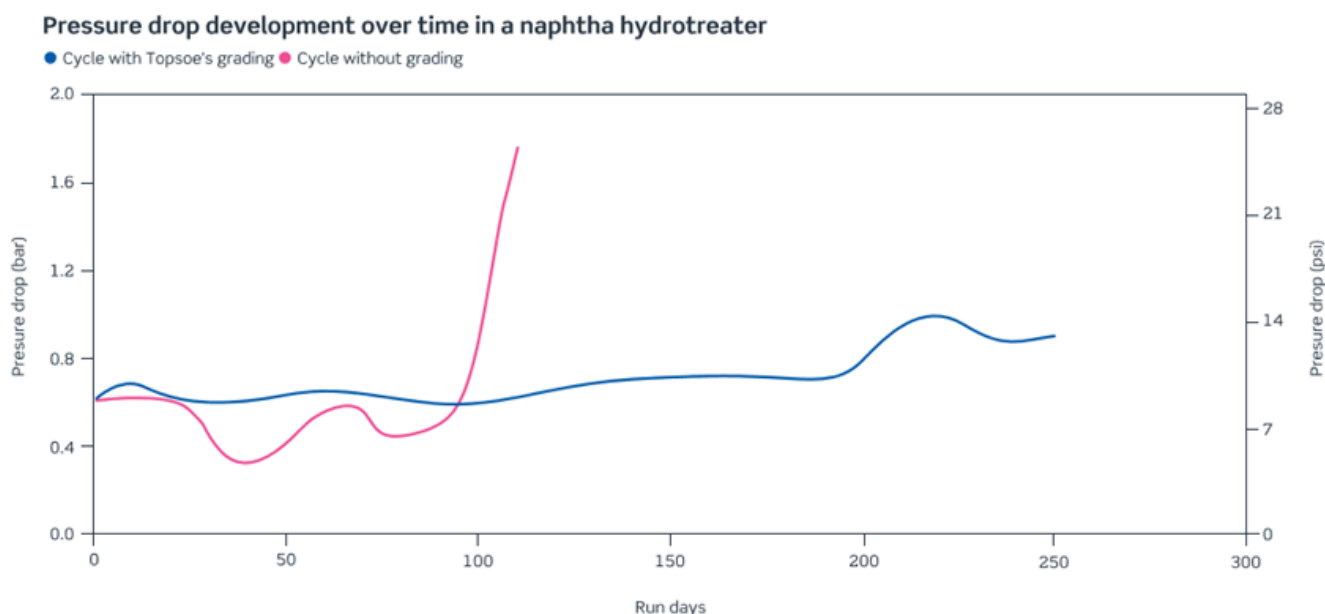











Figure 13 – Cycle Length Improvement in a Naphtha Hydrotreating Unit with Catalyst Grading (Haldor Topsoe Company, 2020)

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Processing Extra Heavy Crudes – The Deep Hydrocracking Solution

Refiners processing heavy and extra-heavy (or high sulfur) crudes face a great challenge to meet the IMO 2020 once it is extremely difficult to comply with the new regulation through carbon rejection technologies, in this case, the hydrogen addition technologies are fundamental.

The hydroprocessing of residual streams presents additional challenges when compared with the treating of lighter streams, mainly due to the higher contaminants content and residual carbon (RCR) related with the high concentration of resins and asphaltenes in the bottom barrel streams. Figure 14 shows a schematic diagram of the residue upgrading technologies applied according to the metals and asphaltenes content in the feed stream.

Higher metals and asphaltenes content led to a quick deactivation of the catalysts through high coke deposition rate, catalytic matrix degradation by metals like nickel and vanadium or even by the plugging of catalyst pores produced by the adsorption of metals and high molecular weight molecules in the catalyst surface.

By this reason, according to the content of asphaltenes and metals in the feed stream are adopted more versatile technologies aiming to ensure an adequate operational campaign and an effective treatment.

As exposed above, extra-heavy crude oils or with high contaminants content can demand deep conversion technologies to meet the new quality requirements to the bunker fuel oil. Hydrocracking technologies are capable to achieve conversions higher than 90% and, despite the high operational costs and installation can be attractive alternatives.

The hydrocracking process is normally conducted under severe reaction conditions with temperatures that vary to 300 to 480 °C and pressures between 35 to 260 bar. Due to process severity, hydrocracking units can process a large variety of feed streams, which can vary from gas oils to residues that can be converted into light and medium derivatives, with high value added.

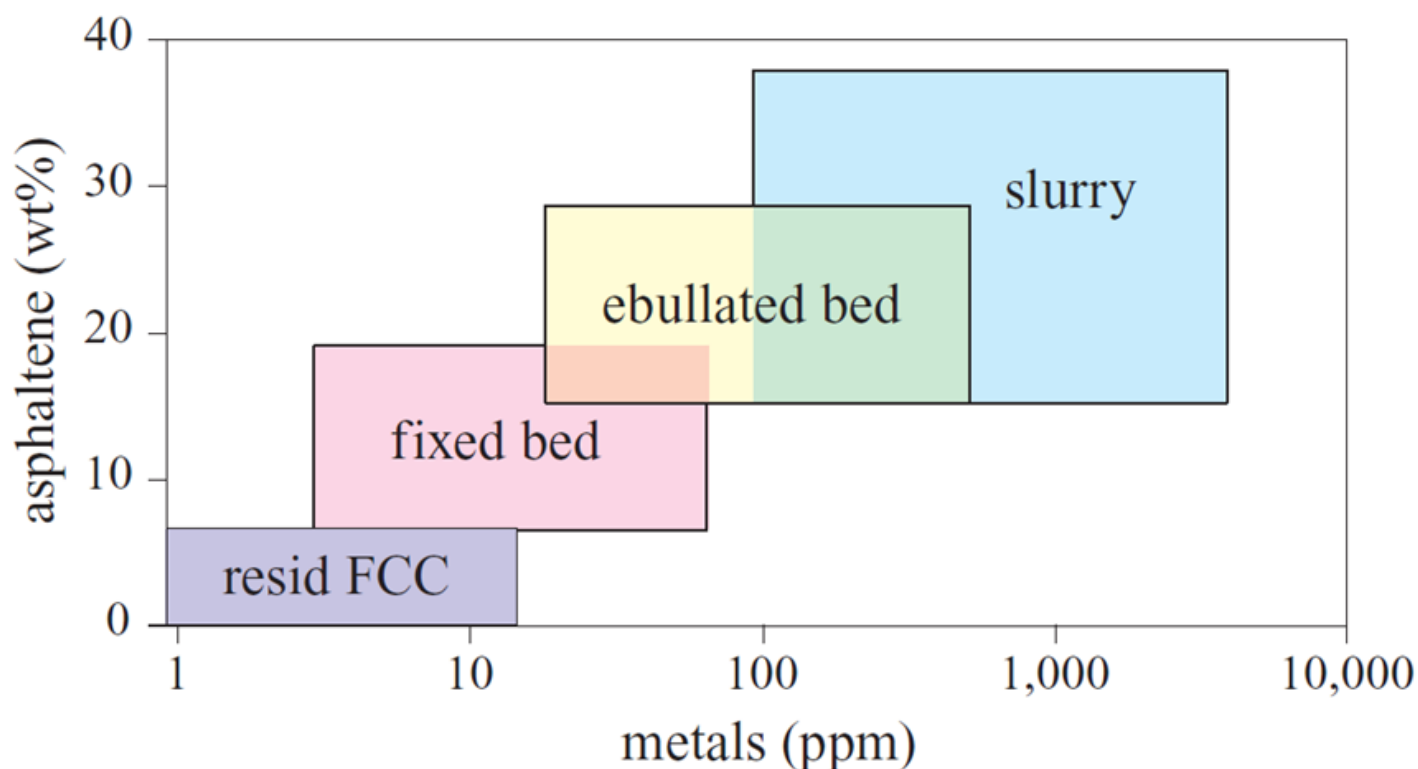


Figure 14 – Residue Upgrading Technologies According to the Contaminants Content
(Encyclopedia of Hydrocarbons, 2006)

Despite the high performance, the fixed bed hydrocracking technologies can be not economically effective to treat residue from heavy and extra-heavy due to the short operating lifecycle. Technologies that use ebullated bed reactors and continuum catalyst replacement allow higher campaign period and higher conversion rates, among these technologies the most known are the H-Oil and Hyvahl™ technologies developed by Axens Company, the LC-Fining Process by Chevron-Lummus, and the Hycon™ process by Shell Global Solutions. These reactors operate at temperatures above 450 °C and pressures to 250 bar. Figure 15 presents a typical process flow diagram for a LC-Fining™ process unit, developed by Chevron Lummus Company while the H-Oil™ process by Axens Company is presented in Figure 16.

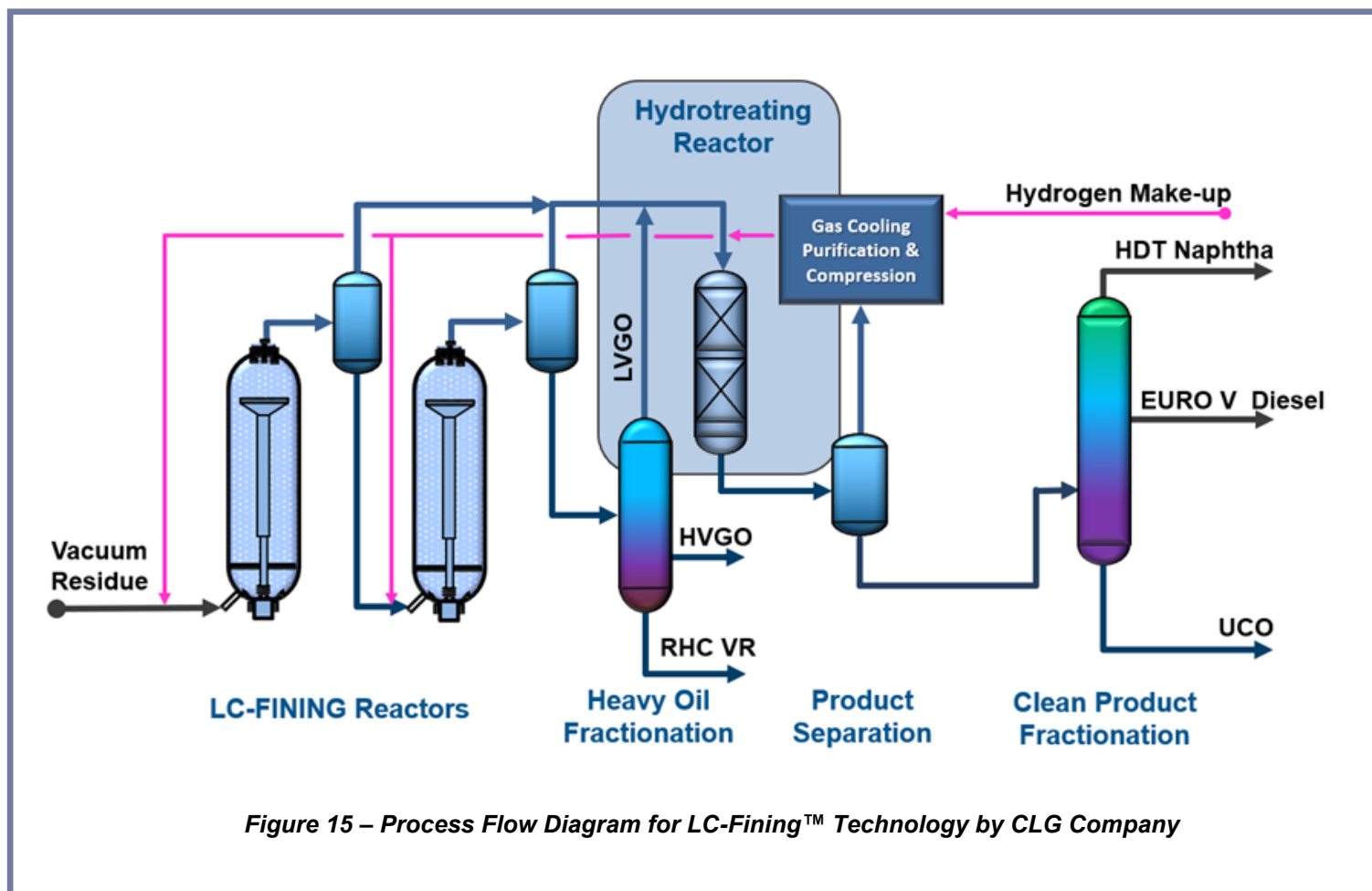


Figure 15 – Process Flow Diagram for LC-Fining™ Technology by CLG Company

Catalysts applied in hydrocracking processes can be amorphous (alumina and silica-alumina) and crystalline (zeolites) and have bifunctional characteristics, once the cracking reactions (in the acid sites) and hydrogenation (in the metals sites) occur simultaneously.

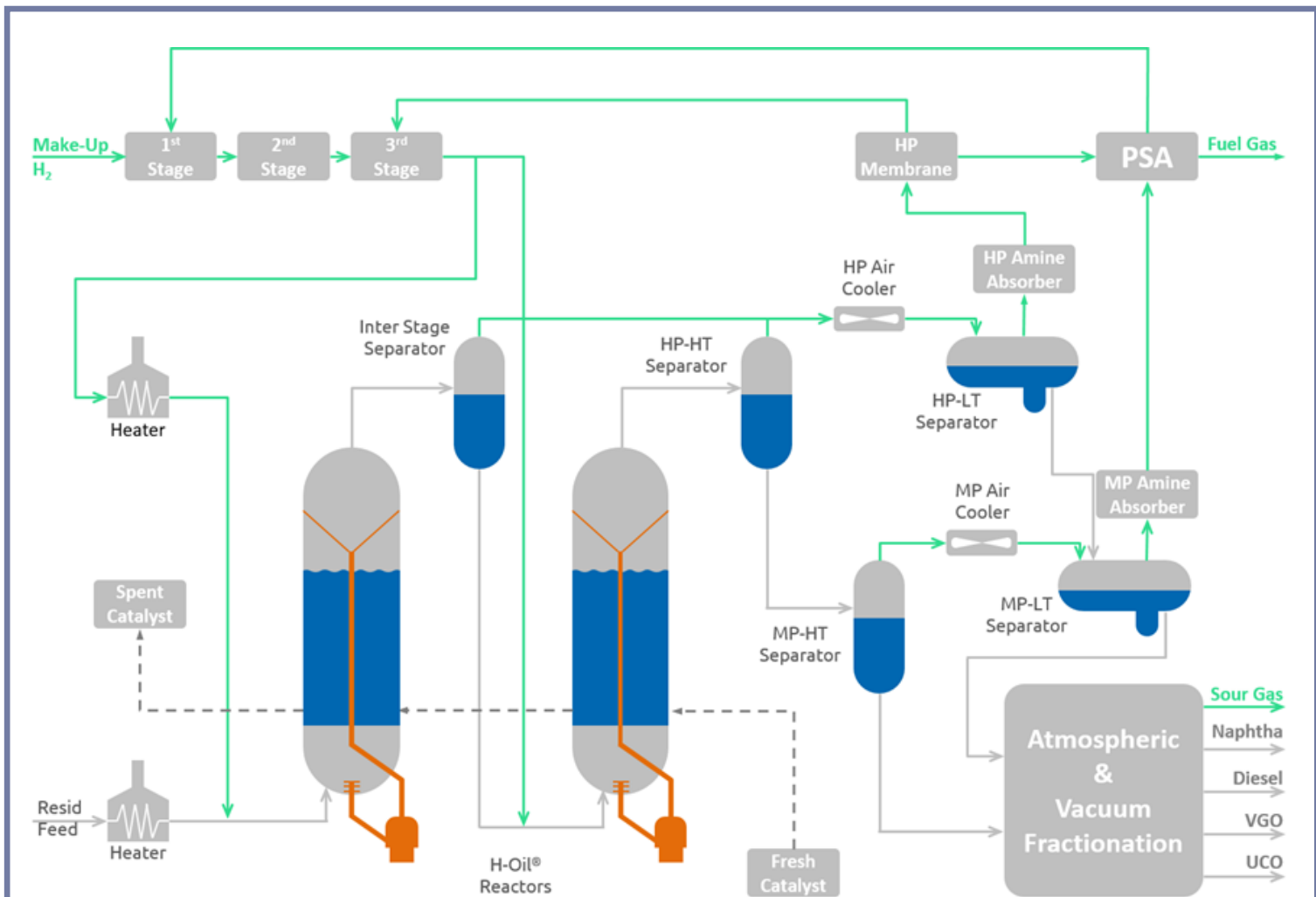


Figure 16 – Process Flow Diagram for H-Oil™ Process by Axens Company

An improvement in relation to ebullated bed technologies is the slurry phase reactors, which can achieve conversions higher than 95 %. In this case, the main available technologies are the HDH™ process (Hydrocracking-Distillation-Hydrotreatment), developed by PDVSA-Intevap, VEBA-CombiCracking Process (VCC)™ commercialized by KBR Company, the EST™ process (Eni Slurry Technology) developed by Italian state oil company ENI, and the Uniflex™ technology developed by UOP Company. Figure 17 presents a basic process flow diagram for the VCC™ technology by KBR Company.

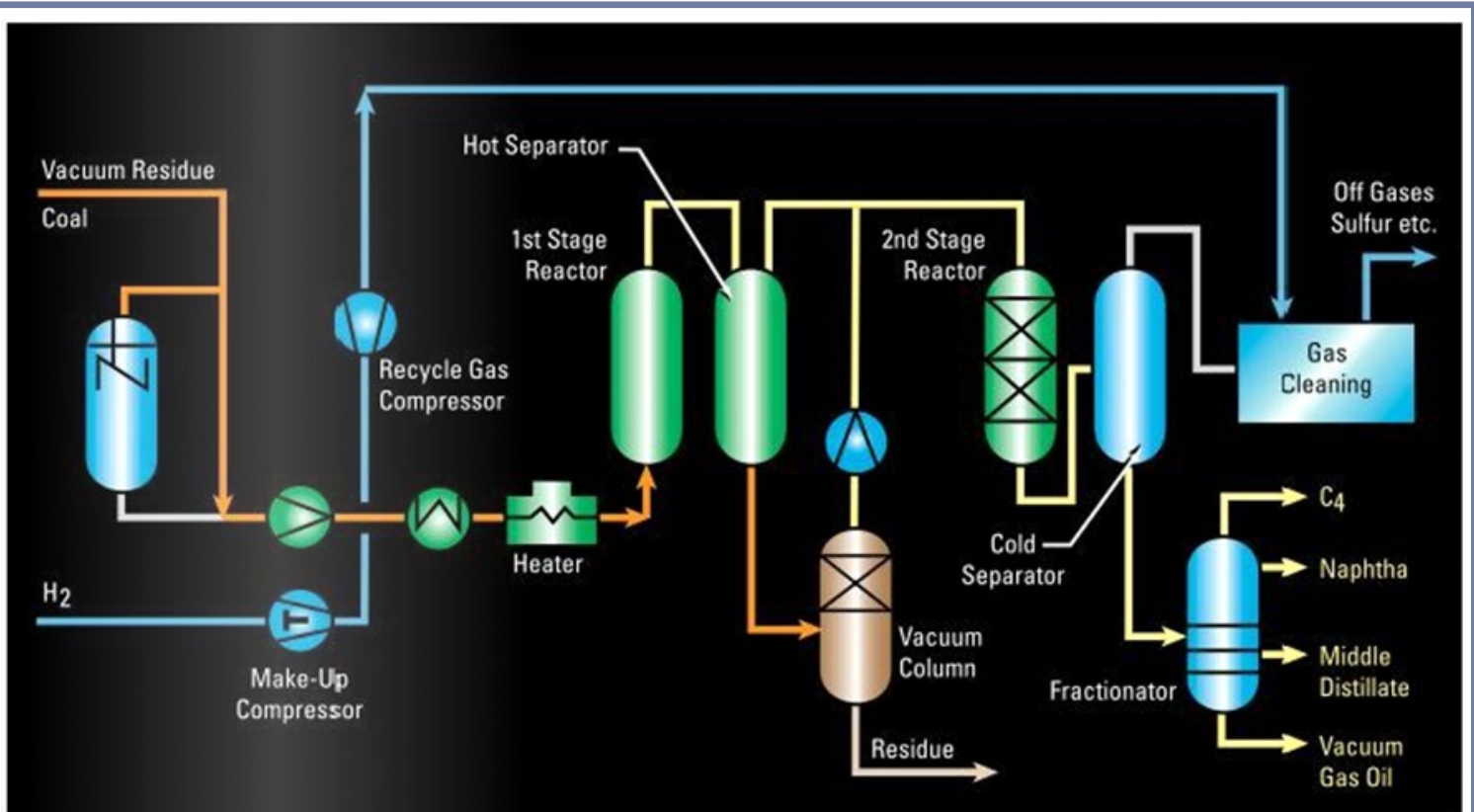


Figure 17 – Basic Process Arrangement for VCC™ Slurry Hydrocracking by KBR Company (KBR Company, 2019)

In the slurry phase hydrocracking units, the catalysts are injected with the feedstock and activated in situ while the reactions are carried out in slurry phase reactors, minimizing the reactivation issue, and ensuring higher conversions and operating lifecycle. Figure 18 presents a basic process flow diagram for the Uniflex™ slurry hydrocracking technology by UOP Company.

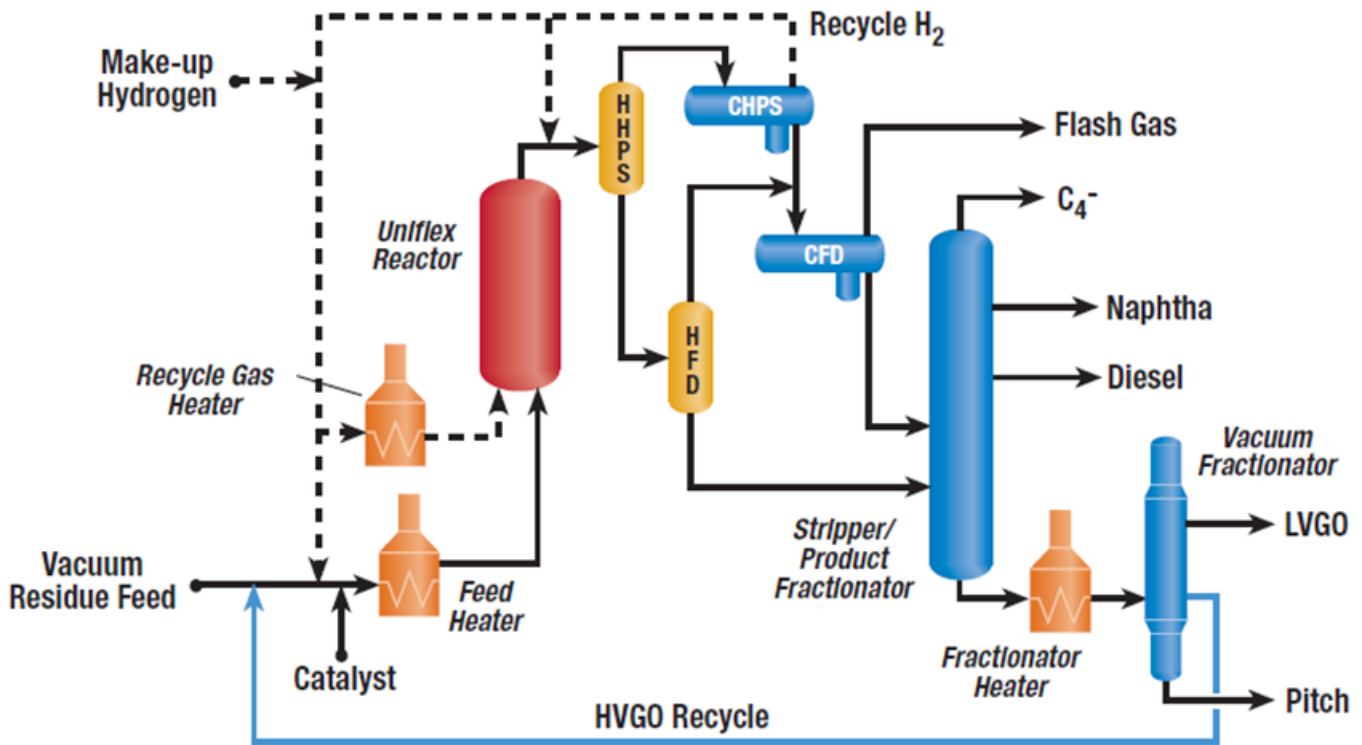


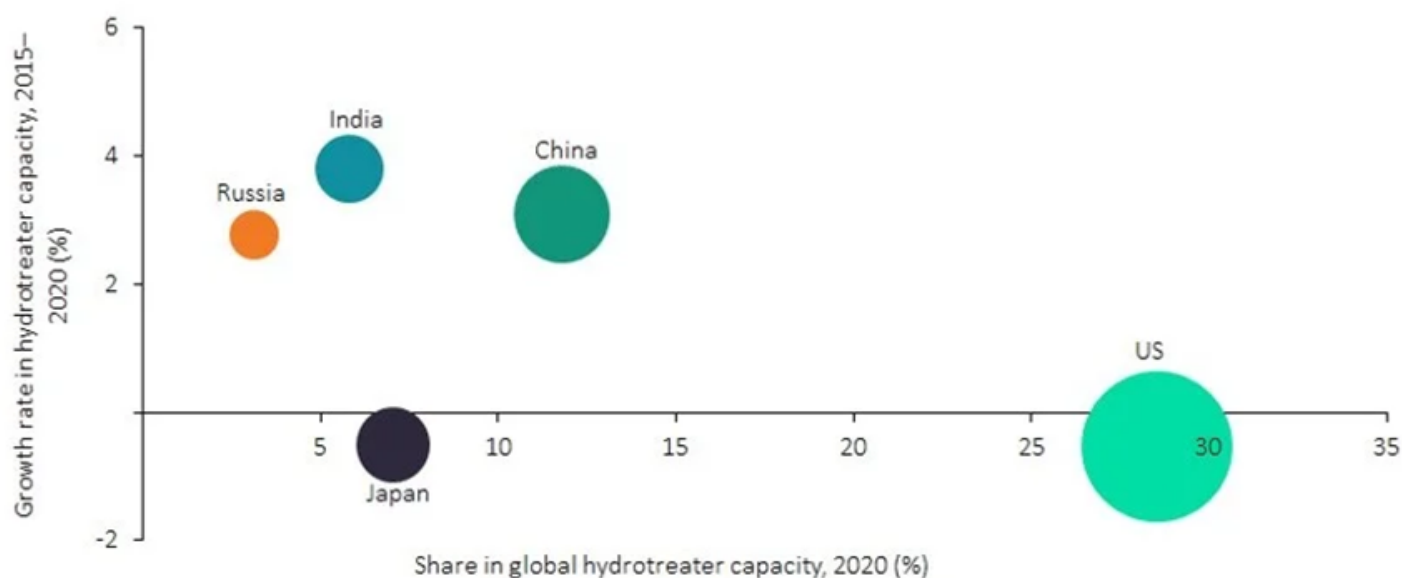
Figure 18 – Process Flow Diagram for Uniflex™ Slurry Phase Hydrocracking Technology by UOP Company (UOP Company, 2019)

Aiming to meet the new bunker quality requirements, noblest streams, normally directed to produce middle distillates can be applied to produce low sulfur fuel oil, this can lead to a shortage of intermediate streams to produce these derivatives, raising their prices. The market for high sulfur content fuel oil should strongly be reduced, due to the higher prices gap when compared with diesel, his production tends to be economically unattractive.

As presented above, hydrotreating and hydrocracking technologies are fundamental to allowing the production of cleaner crude oil derivatives and ensure the necessary energy security. According to Global Data Company, the global hydrotreating installed capacity grew from 56,777 thousand barrels per day (Mbd) in 2015 to 56,951 thousand barrels per day in 2020 and is expected to reach 68,438 Mbd in 2025 under an annual growth rate of 2,6 %.

Nowadays, the United States lead the global hydrotreating capacity with 17,097 Mbd according to data from 2020, the another most relevant players in this market are Russia, China, India, and Japan which are responsible together for 56,3 % of the global hydrotreating installed capacity as presented in Figure 19.

Refinery Hydrotreater Units, Global, Capacity Market Share Vis-à-vis Growth by Key Countries, 2015–2020



Size of the bubble indicates hydrotreater capacity (mbd) in 2020

Source: GlobalData

© GlobalData

Figure 19 – Global Hydrotreating Installed Capacity 2015-2020 (Global Data Company, 2021)

Considering the increasing necessity of reduction in the contaminants content of the crude oil derivatives, the growing market by petrochemicals which demand lighter and cleaner intermediate streams, the necessity to decarbonize the crude oil derivatives through the biomass coprocessing in the crude oil refineries, the hydrotreating units tend to become even more essential for the competitiveness of downstream players, probably above than the expected growth projected above.

Conclusion

The hydroprocessing technologies became essential to refiners in the last decades once it is practically impossible to produce marketable crude oil derivatives without at least one hydroprocessing step, even to refiners processing lighter crudes. Hydroprocessing units have a fundamental role in the downstream industry not only in the economic sustainability of the industry but to keep under acceptable levels the environmental impact of the crude oil derivatives, in this sense, adequate management of hydroprocessing catalysts is a key factor to ensure lower operating costs and competitiveness to refiners in the downstream market.

Comply with IMO 2020 put under pressure the refining margins of low complexity refineries and reduced conversion capacity, once there is the tendency to raise the prices of low sulfur crude oils, furthermore, the higher operational costs depending on the technological or optimization solution adopted by the refiner. The challenge is even harder to refiners processing heavy and extra-heavy crudes, in this case, despite the high capital spending the hydrocracking technologies can offer an attractive alternative, beyond this, hydrocracking technologies appear like a fundamental enabler to ensure high conversion of bottom barrel streams, especially considering the growing trend of integration between refining and petrochemical assets.

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Estimating Instrument Air Requirements

Jayanthi Vijay Sarathy

The objective of installing an instrument air (IA) package is to provide instrument air to various pneumatic systems that rely on air as a motive force to operate. Under normal operations, the IA Package must be able to operate the buffer vessel / IA Receiver at least at 8 barg. Considering line losses, the supply piping must deliver to the instruments at 6.9 barg (100 psig).

To estimate the total instrument air requirements, a summary of all the various pneumatic devices, such as control valves, ESD valves, transmitters, purge lines, calibration units, etc must be considered. In reality, the actual IA requirements depend on the actuator volumes. However during design phase, such information is not always available since unless manufacturers provide them. For this reason, certain rules of thumb and typical consumption rates followed in the industry can be employed.

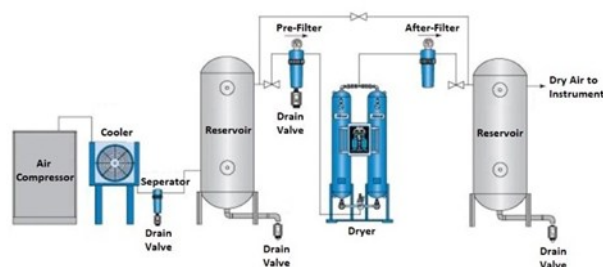


Figure 1. Instrument Air Package Schematic [1]

One of the industry standard to specify an IA package is ANSI/ISA S7.0.0.1. The ISA S7.0.0.1 standard though provides the air quality specifications (such as particle size, dew point, allowable lubricant oil content in air, and max contamination levels), it does not specifically provide individual consumption rates of different pneumatic devices and equipment. Therefore, in the current article, some typical air consumption values are taken. To make IA capacity estimations, the IA demand is based on Continuous Load, Intermittent load and peak load.

General Notes

1. Continuous load refers to instruments and devices that need instrument supply 24/7 to ensure normal operations continue and also keep the basic process control system (BPCS) operational. Some examples are control valves, analyzers, and IA purge.
2. Intermittent load refers to instruments / equipment that are actuated infrequently, such as during an emergency, testing or a process upset. To quote examples, emergency shutdown (ESD) valves, On/Off valves, purge lines and calibration units.
3. Peak demand refers to the maximum possible flow when all the instruments / valves operate simultaneously whether during steady state or transient operations. Peak demand is not continuous, but intermittent in nature. Hence it can also be referred to as Peak Intermittent flow.
4. As per ANSI/ISA S7.0.0.1 specification for instrument air systems
 - A maximum particle size of > 40 microns is acceptable for majority of pneumatic devices.
 - Pressure dew point at the dryer outlet shall be atleast 100C below the minimum temperature to which any part of the IA system is exposed
 - The lube oil content in the instrument air must be ≤ 1 ppm
5. The instrument air consumers can be,
 - Control valves which are pneumatic devices for flow, pressure and temperature
 - ESD Valves for emergency shutdown and isolation

- On-Off Valves for non-throttling duties
 - Analyzers tracking parameters such as H₂S content, Fluid composition, Oil in Water (OiW), water quality, etc
 - Gas Purging in locations such as MCC panels, Analyzer house, DCS room, etc
 - Calibration of instruments
 - Pneumatic transmitters, controllers and Recorders
 - Utility Air Hoses in Workshops / plant
 - Nitrogen [N₂] generation system
6. The instrument air compressor can be oil free rotary screw type. In actual practice, to ensure reliability, a 1 working + 1 standby (1W+1S) configuration can be used, i.e., 2 x 100%
7. The air dryer can be a desiccant type with the installed filters being coalescing type.

The normal demand availability is as follows,

Table 2. Normal Demand Availability

Users	Availability	
Control Valves [Steady State]	95	%
Control Valves [Transient]	5	%
ESD Valves [Transient]	10	%
On/Off Valves [Transient]	25	%
Analyzers [H ₂ S ppm, OiW, H ₂ O Quality]	75	%
Pneumatic Transmitters / Recorders / Controllers	100	%
Purge Locations	1	Actuation hrs/day
Calibration Units	1	Actuation hrs/day

Case Study

A Gas Oil separation unit consists of the following Instrument Air users. The number of units and avg. consumption is as follows,

Table 1. Instrument Air Users

Users	No of Units	Average Consumption
Control Valves [Steady State]	10	0.75
Control Valves [Transient]	10	6.00
ESD Valves [Transient]	6	6.00
On/Off Valves [Transient]	8	0.20
Analyzers [H ₂ S ppm, OiW, H ₂ O Quality]	4	0.75
Pneumatic Transmitters / Recorders / Controllers	5	0.20
Purge Locations	3	0.75
Calibration Units	1	0.50

The Peak Air demand availability is,

Table 3. Peak Demand Availability

Users	Availability	
Control Valves [Steady State]	70	%
Control Valves [Transient]	30	%
ESD Valves [Transient]	20	%
On/Off Valves [Transient]	75	%

The site conditions and Instrument Air compressor operating conditions are,

Table 4. Site Data & Operating Conditions

Parameter	Value	Units
Compressor Type	Oil Free Rotary Screw Type	
IA Compressor Discharge Pressure [Saturated] [P ₂]	116 (8)	psig (barg)
IA Receiver Temperature [T ₂]	35 (95)	°C (°F)
Utility Air Demand		
Utility Air - No of Hoses	6	-
Consumption per hose	0.5	SCFM

The nitrogen generation package capacities and nitrogen purity is as follows,

Table 5. Nitrogen Generation Specifications

Nitrogen Generator Package		
No of Nitrogen [N ₂] Units	1	-
N ₂ Package Capacity	20	SCFM
Nitrogen Purity	99	%

For preliminary sizing of the IA receiver, the discharge time after a power loss is taken as 5 min [300 sec]. The upper and lower pressure band considered is 150 psig and 90 psig respectively.

To account for the air feed to the nitrogen generation unit, the air demand is considered as a factor of the nitrogen purity. The air factor based on the N₂ purity is as follows,

Table 6. Air factor for N₂ Generation Unit

Nitrogen Purity	Air Factor
[%]	[-]
99.5	2.9
99	2.5
98	2.3
97	2.1
95	1.9

For the current undertaking, the nitrogen generation package has one N₂ generation package with capacity of 20 SCFM. The purity required is 99%.

Assumptions

- For continuous operation, the normal air demand is taken as 95% of Control Valve at steady state + 5% of control valve at transient state + 10% of ESD Valve at transient state + 25% of On-Off Valve at transient state + 75% of analyzers at steady state + 100% of pneumatic devices at steady state + 1 hr/day purging operation of all locations + 1 hr/day calibration.

- For peak operation, the normal air demand is taken as 70% of Control Valve at steady state + 30% of control valve at transient state + 20% of ESD Valve at transient state + 75% of On-Off Valve at transient state.
- The instrument air at the outlet of the dryer is taken as 8 barg [116 psig], and the instrument air is delivered at 6.9 barg [100 psig] to all the IA users.
- The maximum and minimum IA receiver pressure is taken to be 150 psig and 90 psig respectively. In case of loss of power the IA receiver is sized to deliver instrument air upto 5 min.
- Since the instrument air requirements are preliminary in nature, a safety margin of 25% is taken on the maximum IA load (Maximum between peak and normal operation). No margin is considered on the utility air requirements.
- For the IA receiver volume, the safety margin for surge & backup is taken as 30%.
- To estimate the power requirements, the thumb rule taken is 4 to 5 SCFM of instrument air for 1 hP
- To convert ACFM to SCFM, the sea level properties at 14.7 psia, 600F and 36% relative humidity as per NIST and OSHA is considered [2]. The conversion is,

$$ACFM = SCFM \times \frac{460 + T_1, \text{degF}}{530} \times \frac{14.7}{14.7 + P_2, \text{psig}} \quad (1)$$

Methodology

Normal Air Demand

The Normal Air demand (NAD) is estimated from Table 1 and Table 2 as,

$$NAD = [10 \times 0.75 \times 0.95] + [10 \times 6 \times 0.05] + [6 \times 6 \times 0.1] + [8 \times 0.2 \times 0.25] \\ + [4 \times 0.75 \times 0.75] + [5 \times 0.2 \times 1] + \left[\frac{1}{24} \times 3 \times 0.75 \right] + \left[\frac{1}{24} \times 1 \times 0.5 \right] \quad (2)$$

$$NAD = 7.13 + 3 + 3.6 + 0.4 + 2.25 + 1 + 0.09 + 0.02 = 17.49 \text{ SCFM} \quad (3)$$

Peak Air Demand

The Peak Air demand (PAD) is estimated from Table 1 and Table 3 as,

$$PAD = [10 \times 0.75 \times 0.7] + [10 \times 6 \times 0.3] + [6 \times 6 \times 0.2] + [8 \times 0.2 \times 0.75] \quad (4)$$

$$Peak\ Air\ Demand = 31.65\ SCFM \quad (5)$$

Utility Air Demand

The utility air demand is estimated as,

$$Q_U = No\ of\ Hoses \times Consumption\ per\ hose \quad (6)$$

$$Q_U = 6 \times 0.5 = 3\ SCFM \quad (7)$$

Nitrogen Generator Package

The instrument air demand for the N₂ generation package for a purity [A] of 99% and 20 SCFM is as follows,

$$Air\ Factor\ [A],\ 99\% \ purity = 2.5 \quad (8)$$

$$IA\ to\ N_2\ package = No\ of\ Units \times N_2\ generator\ package \times A \quad (9)$$

$$IA\ to\ N_2\ package = 1 \times 20 \times 2.5 \quad (10)$$

$$IA\ to\ N_2\ package = 50\ SCFM \quad (11)$$

Instrument Air Compressor Capacity

The IA compressor capacity [Q] can be estimated as,

$$Q_p = Peak\ Air + IA\ to\ N_2\ Package \quad (12)$$

$$Q_p = 31.65 + 50 = 81.65\ SCFM \quad (13)$$

Adding Safety margin of 25% to Q_p,

$$Q_p = 81.65 \times 1.25 = 102\ SCFM \quad (14)$$

The total compressor capacity [Q] is,

$$Q = Q_p + Q_U = 102 + 3 = 105\ SCFM \quad (15)$$

Based on the thumb rule, 4 SCFM per hP, the IA compressor power is,

$$P_{calc} = 105/4 = 26.25\ hP \quad (16)$$

The selected compressor size is 30 hP. Based on the selected size of 30 hP, the revised IA compressor capacity is,

$$Q_c = \frac{105 \times 30}{26.25} = 120\ SCFM \quad (17)$$

To estimate the Actual cubic feet per minute (ACFM), the conversion is made as follows,

$$Q_{C,ACFM} = 120 \times \left[\frac{460 + 95}{530} \right] \times \frac{14.7}{14.7 + 116} \quad (18)$$

$$Q_{C,ACFM} = 14.13\ ACFM \quad (19)$$

Preliminary IA Receiver Size

The preliminary receiver size is computed as,

$$V_{IA\ Receiver} = \frac{Q_{C,ACFM} \times f \times P_a}{(P_U - P_L)} \quad (20)$$

Where,

Q_c = Instrument Air Capacity [ACFM]

f = Charge/Discharge per IA Receiver Cycle [sec]

P_U-P_L = Pressure band of IA Receiver [psia]

P_a = Barometric Pressure at Location [psia]

Taking the IA receiver's max and min operating pressure of 150 psig and 90 psig, the pressure band is,

$$P_U - P_L = 150 - 90 = 60\ psi \quad (21)$$

Taking 30% safety margin to account for pressure surge and backup, the flow rate for which the IA receiver would be sized is,

$$Q_{T,ACFM} = Q_{C,ACFM} \times 1.3 \quad (22)$$

$$Q_{T,ACFM} = 14.13 \times 1.3 = 18.37\ ACFM \quad (23)$$

Therefore, for a discharge cycle (f) of 5 min (300 sec), barometric pressure of 14.7 psia, and flow capacity of 18.37 ACFM, the IA receiver size is,

$$V_{IA\ Receiver} = \left[\frac{18.37}{60} \right] \times \left[\frac{300 \times 14.7}{60} \right] \quad (24)$$

$$V_{IA\ Receiver} = 22.51\ ft^3 = 0.64\ m^3 \quad (25)$$

$$OR, V_{IA\ Receiver} = 168\ US\ Gallons \quad (26)$$

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ANSI/ISA S7.0.0.1-1996 Compressed Air Specifications

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Instrument Air [IA] Requirements

Users	No. of Units	Avg. Consumption	Normal Demand Availability		Normal Demand	Peak Demand Availability	Peak Demand
		[SCFM]	[%]	[Actuation hrs /day]	[SCFM]	[%]	[SCFM]
Control Valves [Steady State]	10	0.75	95	-	7.13	70	5.25
Control Valves [Transient]	10	6.00	5	-	3.00	30	18
ESD Valves [Transient]	6	6.00	10	-	3.60	20	7.2
On/Off Valves [Transient]	8	0.20	25	-	0.40	75	1.2
Analyzers [H ₂ S ppm, OiW, H ₂ O Quality]	4	0.75	75	-	2.25	-	-
Pneumatic Transmitters / Recorders	5	0.20	100	-	1.00	-	-
Purge Locations	3	0.75	-	1	0.09	-	-
Calibration Units	1	0.50	-	1	0.02	-	-
Total					17.49		31.65

Utility Air Demand

Workshop [Utility Air] [No. of Hoses]	6	-
Consumption per hose	0.50	SCFM
Utility Air Demand [Q _U]	3.0	SCFM

Compressor Capacity

Compressor Type	Oil Free Rotary Screw Type	
IA Users + IA N ₂ Generator [Q _P]	81.65	SCFM
Safety Margin on IA Users + IA N ₂ Generator	25	%
IA Users + IA N ₂ Generator [Q _P] with Safety Margi	102.1	SCFM
Total Compressor Capacity [Q]	105.0	SCFM
IA Comp Discharge Pressure [Sat] [P ₂]	116	psig
IA Receiver Temperature [T ₂]	35.0	°C
SCFM per horsepower	4	SCFM
Calculated IA Compressor Size [P _{calc}]	26.25	hp
Selected IA Compressor Size [P _{select}]	30.0	hp
CFM for Selected Compressor Size [Q _C]	120.0	SCFM
	14.13	ACFM

Nitrogen Generator Package

No of Nitrogen [N ₂] Units	1	
Nitrogen Package Capacity	20	SCFM
Nitrogen Purity	99.0	%
Air Factor [A]	2.5	-
Instrument Air to N ₂ Generator [Q _N]	50	SCFM
	5.89	ACFM

Preliminary Instrument Receiver [IA] Sizing

Discharge per IA Receiver Cycle [f]	300	sec
Upper Pressure Band [P _u] [Max P]	150	psig
Lower Pressure Band [P _l] [Min P]	90	psig
Pressure Band [P _u - P _l]	60	psi
Safety Margin for Surge and Backup	30	%
QT = QC + Safety Margin of 30%	18.37	ACFM
IA Receiver Size [V _{IA Receiver}]	22.51	ft ³
	0.64	m ³
Preliminary IA Receiver Size	168	US Gallons

Guidelines for Mist Elimination Equipment Selection, Sizing, Safety & Troubleshooting | Part 1

Karl Kolmetz, Utami Ledyana Daulay, Apriliana Dwijayanti

INTRODUCTION

Mist elimination, or the removal of entrained liquid droplets from a vapor stream is one of the most encountered processes equipment requirements regardless of unit operation. Mist elimination can be defined as the mechanical separation of liquids from gases. The equipment used for the removal of this entrainment is referred to as a mist eliminators.

A properly engineered mist eliminator may reduce liquid carryover by a factor of more than one hundred percent (100%) relative to a standard vanilla unit. Pressure drop head losses reduced by fifty percent (50%) or more and increase production capacity by factors of three to four hundred percent (400%).

In the chemical process industry, there are a number of processes where gases and liquids come into contact with each other and whenever this happens the gas will entrain a small amount of the liquid particles. This liquid phase which gets carried away with the gaseous phase may lead to a number of problems like loss of product quality, equipment damage for example as in a compressor, process inefficiency, and needs to be eliminated and / or reduced.

Proper mist elimination equipment selection can reduce the size of the separation vessel leading to a large cost saving in capital of a project. Proper selection of fouling resistant mist elimination equipment can increase run length significantly.

Unfortunately, mist eliminators are often considered commodity items and are specified without the proper attention to available technologies and design approaches. Many times, they are specified incorrectly leading to lower capacity, fouling, high pressure drop and failure.

One would think that the multiple failures would lead to better design practices. The challenge of mist elimination design is having some experience in installation, operation and troubleshooting to build these best practices. There are very few groups that have the knowledge of all three – installation, unit operation and troubleshooting.

The one piece that most group lack is unit operation and being able to estimate the failure mechanisms. Ensure that your designer has knowledge in all three areas before designing mist elimination or in fact any process equipment.

DESIRED FEATURES IN A MIST ELIMINATOR

- Simple structure.
- Lightweight.
- High porosity.
- Low pressure drops.
- Large surface area.
- High mist separating efficiency.
- Easy to install, operate and maintain.
- Easily tailor made to suit most vessel shapes and sizes.
- Durable and long service life.
- Corrosion resistance

KLM Technology Group would be happy to assist in your needs for mist elimination. We are one of the few groups that have all three requirements to professionally design process equipment - installation, unit operation and troubleshooting. We can engineer, supply, or troubleshoot your application. Please contact us at info@klmtechgroup.com.

SELECTION OF EQUIPMENT

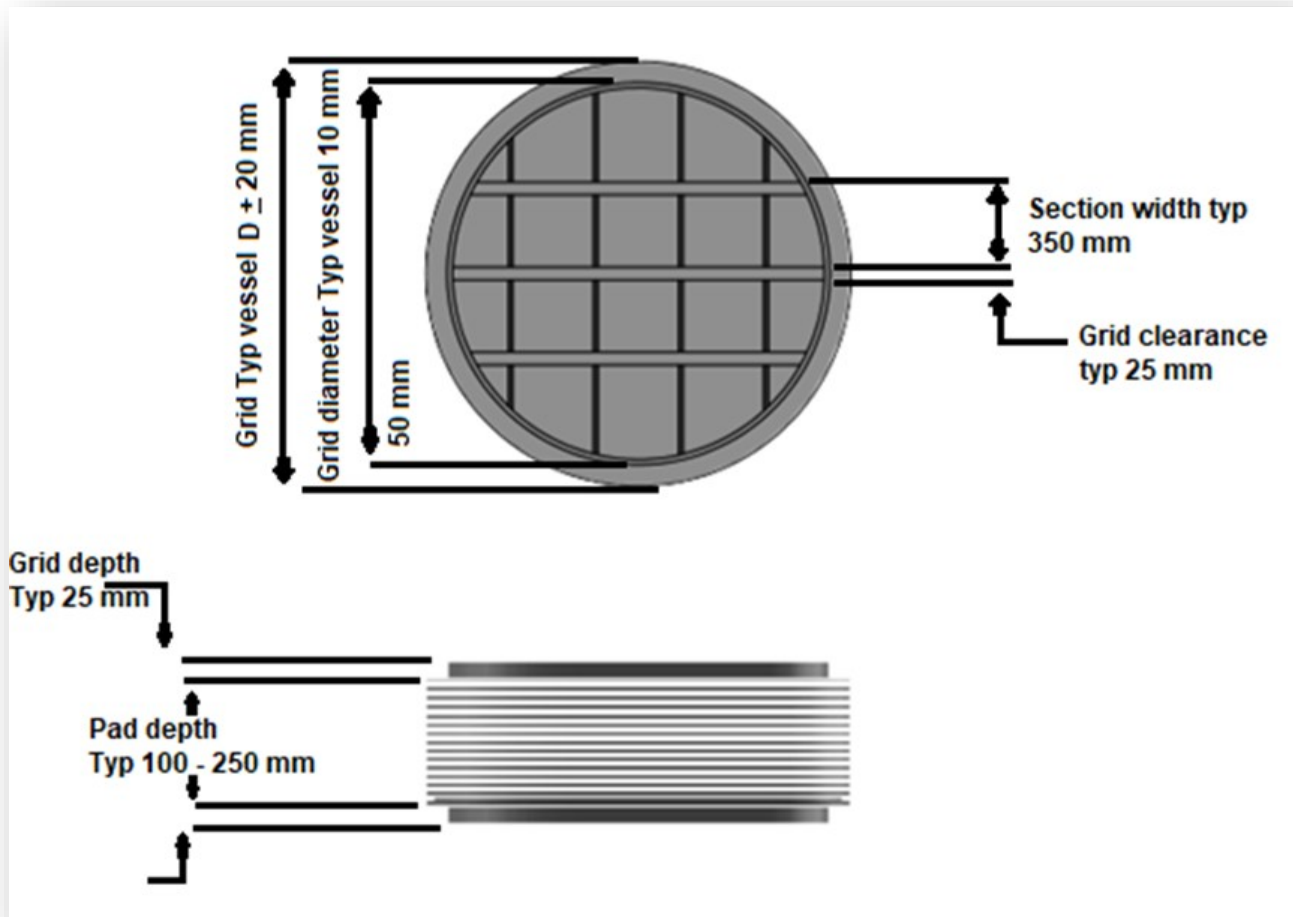
Mist eliminators find a wide variety of applications such as evaporators, three phase separators, knockout vessels, scrubbers, distillation columns and others. The choice of mist eliminator must be done on the basis of the application requirements. Products are available in a wide array of metals, plastics, and thermoplastics to suit a variety of applications.

1. **Wire Mesh Pad Mist Eliminator:** The mesh pad mist eliminator removes droplets by impingement on surface of a wire. The liquid collected on the filament is drained off under gravity. These mist eliminators provide may provide removal of droplets down to 3 to 5 microns.
2. **Plain Vane Pack Mist Eliminator:** The plain vane pack mist eliminator is a high efficiency mist eliminator commonly used for removing entrained liquids from vapor flowing vertically upwards. These mist eliminators use corrugated vanes as a mechanism for mist elimination.
3. **Pocketed Vane Pack Mist Eliminator:** The high capacity vane pack mist eliminators use a hooked vane mechanism for higher capacity mist elimination. They provide for efficient droplet removal and superior resistance to fouling for high rate horizontal vapor flow.
4. **Mist Eliminators for high efficiency mist elimination:** The high efficiency mesh pad mist eliminators remove droplets by impingement on the wire surface. The liquid collected on the filaments drains off under gravity. They provide removal of droplets down to about 3-5 microns. They provide a turndown range of vapor rate of around 3:1.

WIRE MESH DEMISTER PADS

The simplest and most commonly specified is the wire mesh mist eliminator, the wire mesh eliminator, in the most general sense, is a simple porous blanket of metal or plastic wire that retains liquid droplets entrained by the gas phase. The separation process in the wire mesh mist eliminator includes three steps:

1. The first, being 'inertia impaction' of the liquid droplets on the surface of wire. As the gas phase flows past the surface or around wires in the mesh pad the streamlines are deflected, but the kinetic energy of the liquid droplets associated with the gas stream may be too high to follow the streamline of the gas and they impinged on the wires.
2. The second stage in the separation process, is the coalescence of the droplets impinging on the surface of the wires.
3. In the third step, droplets detach from the pad. In the vertical flow installations, the captured liquid drains back in the form of large droplets that drip from the upstream face of the wire mesh pad. In the horizontal flow systems, collected liquid droplets drain down through the vertical axis of the mesh pad in a cross flow fashion.



Typically, maximum allowable velocity for a mist eliminator is limited by the ability of the collected liquid to drain from the unit. In vertical up flow mesh demister, when the gas velocity increases past design levels, liquid begins to accumulate in the bottom of the unit. The liquid buildup results in re-entrain of the liquid with the gas stream. This is because the inertia of the incoming gas prevents the liquid from draining out of the bottom of the unit. In horizontal units, the gas inertia pushes the captured liquid toward the downstream face and with the gas stream.

As a rule, smaller diameter wire targets collect smaller liquid droplets more efficiently. For example, a 10 mm wire removes smaller droplets than a 200 mm wire. However, a bed of 10 mm wires normally has the tendency to flood and re-entrain at much lower gas velocities than a bed of 200 mm wire. This is because the thinner wires provide dense packing that can trap the liquid by capillary action between the wires.

Interweaving of small diameter wires with larger diameter wire has been used often to tackle some of the most difficult mist removal problems. This design uses the metallic or plastic wires as a support structure to hold the wires apart. Special internal mesh geometry modifications are now available that allow these bi-component (that is, small fiber and large-diameter wire mesh) configurations to operate at velocities essentially the same as conventional mesh designs.

These ultra-high-efficiency designs can be substituted for conventional mesh and used, for example, in the dehydration towers of natural gas production plants, where even small losses of absorption chemicals, such as ethylene glycol, can be a significant operating expense.

Construction materials for the wires include metal, fiberglass, plastics, or polymers such as polypropylene or Teflon. Recently, three new alloys have been made available in wire form, which routinely provide three to five times the service lives of the traditional materials.

They can offer improved service depending on the temperature and acid concentration of the gas stream. The gas phase velocity should be limited to 4 ± 5 m/s to prevent any re-entrain of the water droplets captured in the wire mesh pad.

WIRE MESH DEMISTER PAD

INSTALLATIONS IN COLUMNS/ VESSELS / TOWERS

Wire Mesh Demister Pads may be installed in columns, vessels or towers in various positions depending upon the shape, vapor inlet nozzle location, vapor outlet nozzle location, liquid outlet nozzle location and process applications.

WIRE MESH ELIMINATOR DESIGN SIZING

Wire Mesh Eliminator Demister Pads should be designed so that the face area provides a vapor rate of approximately 80% of maximum allowable re-entrainment velocity. For the purpose of estimation, suitable design velocities occur at a K-factor of 0.107 m/s for vertical flow or 0.150 m/s for horizontal gas flow (due to better drainage) where,

$$v_s = K \sqrt{\frac{\rho_L - \rho_V}{\rho_V}} \quad \text{Eq 1}$$

Where,

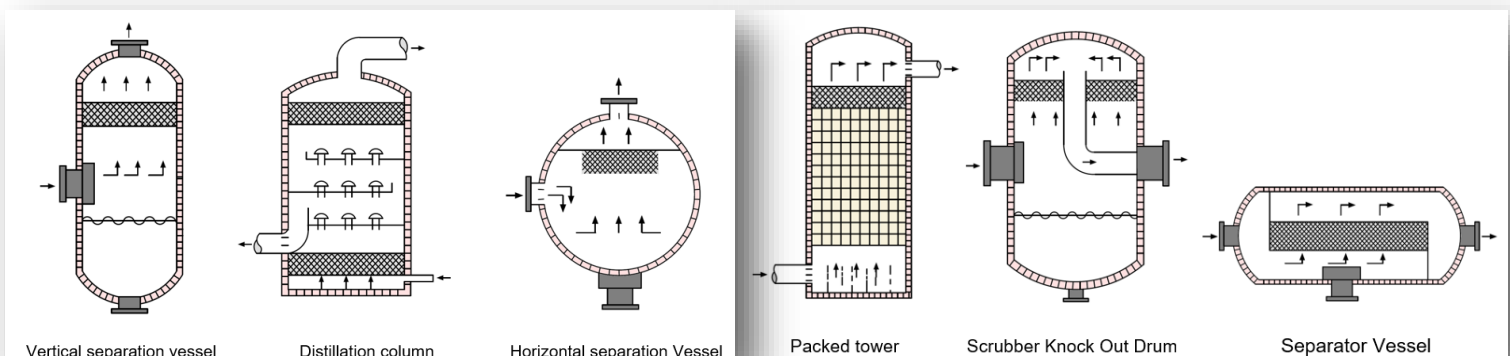
- V_s = Actual vapor velocity (m/s)
- ρ_V = Vapor density
- ρ_L = Liquid density

An approximate pressure drop can be estimated from the following formula

$$P \text{ (kPa)} = C(\rho_L - \rho_V) K^2 t \quad \text{Eq 2}$$

Where $C = 0.20$ for a typical mesh pad demister, and t is the pad thickness in meters. Note that the dry pressure drop is half of the wet figure.

The method of droplet creation will often give a good indication about the difficulty of separation. Physical properties of each phase and other data need to be collected:



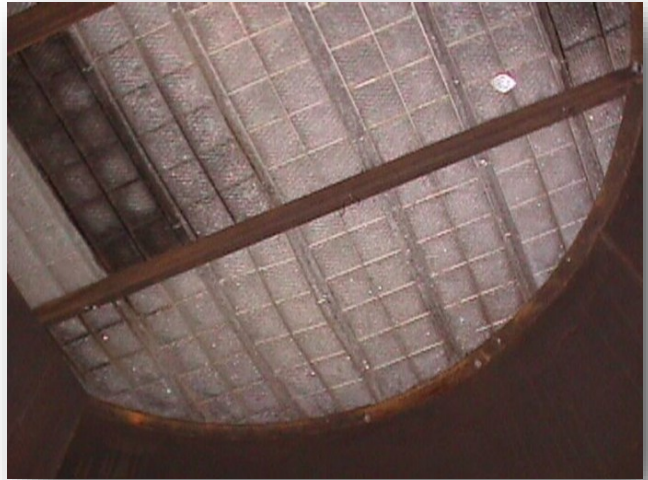
1. Density differences and viscosity determine how fast the droplets will disengage,
2. Flow rates will determine the ultimate size of the required separation equipment,
3. Desired separation performance must be defined,
4. Interfacial tension, which is a measure of the ease of droplet coalescing and how it is affected by pH and temperature, is extremely helpful when available,
5. presence of impurities and solids will often create a more difficult separation, since they can collect at the interface between the liquids, making coalescing difficult and also limiting equipment choices,
6. Relative solubility at operating temperature will help the designer understand whether the desired separation is being prevented by solubility limits.

WIRE MESH ELIMINATOR TROUBLESHOOTING

In fouling services wire mesh eliminator demister pads have a high failure rate. A typical fouling service would be an ethylene plant caustic tower. This is a picture of a fouled demister pad in an ethylene plant caustic tower. You can see the fouling that will lead to high pressure drop across the demister pad. If the pressure drop becomes high enough it will lift the demister pad leading to vapor bypassing.



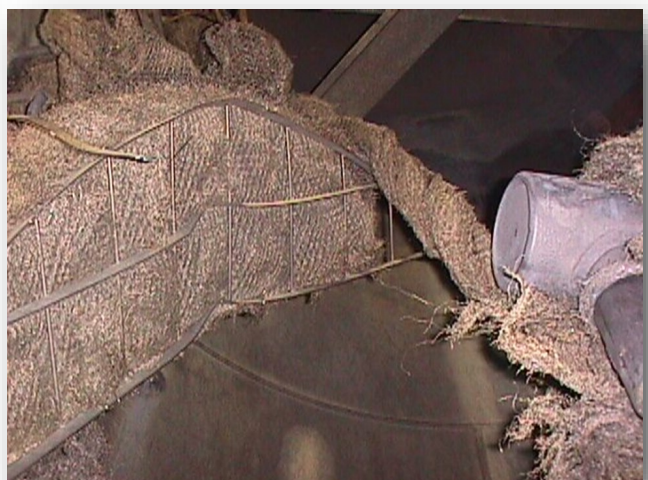
Here is a new demister pad that was had one panel not delivered. Notice the difference between the new panels and the old panel.



As the pressure drop increases the demister pad will lift leading to vapor bypassing the demister pad. Here is demister pad failure.



This picture is from an ethylene plant steam generator tower, they are used to recycle water. Any time you have steam generation you have the high probability of pressure surges, and you should design for this possibility. This demister pad is not fouled, so this probability was a pressure surge.



SAFETY

From a safety perspective after reviewing pictures like this failure, many people want to limit the possibility of a failed demister pad plugging a Pressure Relief Device. Newer designs in fouling service are placing the Pressure Relief Device below the demister pad,

CONCLUSIONS FOR PART 1

Mist elimination seem simple to design, and there are multiple groups providing mist elimination equipment leading to many failures. One would think that the multiple failures would lead to better design practices. The challenge of mist elimination design is having some experience in installation, operation and troubleshooting to build these best practices. There are very few groups that have the knowledge of all three – installation, unit operation and troubleshooting. The one piece that most group lack is unit operation and being able to estimate the failure mechanisms. Ensure that your designer has knowledge in all three areas before designing mist elimination or any process equipment.

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Refinery Turnaround Lesson Learnt

Shahzeb H. M. Ismail

INTRODUCTION

A refinery turnaround is a planned shutdown for inspection, maintenance, equipment upgrades, and safety checks. It ensures reliability, efficiency, and regulatory compliance. Typically scheduled every five years but vary company to company, turnarounds involve extensive manpower, high costs, and strict timelines. Proper planning is required to minimize downtime, complete startup checks and ensure safe plant startup.

TYPICAL LESSON LEARNT

1. WATER WASHING BEFORE STEAMING OUT

After a refinery shut down, it is a best practice to begin with water washing of the piping systems, particularly in the Crude Distillation Unit (CDU), before proceeding to steaming out. Water washing effectively displaces residual hydrocarbons, salts, and contaminants from the lines, ensuring a safer and cleaner transition to subsequent steaming operations. If steaming out alone is performed without prior water washing, the process becomes significantly more time-consuming, as it takes longer to push crude oil and associated residues out of the piping. Additionally, the entire plant can retain a strong hydrocarbon odor, creating unsafe working conditions.

More critically, there remains a substantial risk that some lines may still contain crude, even after the plant is handed over to contractors or maintenance teams. This poses a severe fire and explosion hazard, especially if hot work is undertaken in the vicinity or directly on those lines. Such oversights can lead to catastrophic consequences, both in terms of personnel safety and asset integrity.

Therefore, declaring the facility hydrocarbon-free is a fundamental responsibility of operations teams. Through rigorous water washing followed by controlled steaming out, operations can ensure safe conditions, protect maintenance crews, and uphold the highest safety standards during turnaround activities.

2. P&IDS MARKUP AND PROPER PLANNING FOR DECONTAMINATION

Decontamination is a critical shutdown activity aimed at removing H₂S, toxic residues, pyrophoric material, acids, and other hazardous contaminants from process equipment, piping, and vessels to ensure a safe environment for maintenance work. The process must be completed within the planned timeline, as delays can extend the overall turnaround duration or compromise the effectiveness of the activity.

To achieve successful decontamination, early preparation is essential. Developing and reviewing marked-up P&IDs helps clearly define the required lineups, identify correct drain points, and determine appropriate steam injection locations. Depending on the strategy—vapor phase decontamination or boil-out—equipment must be properly prepared in advance. Chemical requirements should be theoretically calculated and finalized in coordination with the vendor. Furthermore, guarantees and key performance indicators (KPIs) must be established to verify effectiveness.

3. PRESERVATION PROCEDURE FOR IDLE EQUIPMENT

During a refinery turnaround, equipment that is not scheduled for opening must be preserved to ensure reliability at startup. Preservation is typically achieved using either nitrogen blanketing or appropriate chemical treatment, depending on the equipment type and service.

For example, fin fan exchangers in overhead systems should be thoroughly drained after decontamination and then nitrogen sealed. This prevents stagnant water from remaining inside, which could otherwise lead to fouling, internal corrosion, or microbial growth during the extended shutdown period.

Failure to implement proper preservation can create significant challenges during plant restart. In the case of fin fans, inadequate preservation may result in impaired cooling performance, restricting the ability to achieve the required condensation duty. This limitation directly impacts throughput and can become a major bottleneck in stabilizing operations. A well-defined preservation procedure safeguards equipment integrity, ensures smooth startup, and supports achieving planned production targets.

4. CAPTURE MAJOR FINDINGS WITH IN 1ST WEEK OF THE TURNAROUND

The initial week of a refinery turnaround is particularly critical, as it involves opening major equipment such as columns, vessels, and heat exchangers for inspection. During this phase, all "as-found" observations must be documented carefully and communicated promptly. For instance, if damaged trays are identified inside a distillation column, the availability of spares becomes a decisive factor. In the absence of readily available spares, immediate action is required to place procurement orders to ensure delivery within the turnaround window.

Any delay in sourcing critical internals, such as trays or packing, can result in extended downtime. Given the high daily financial impact of lost production, even minor procurement delays can escalate into substantial losses. Therefore, close coordination between inspection, operations, and procurement teams is essential. Timely reporting, quick decision-making, and proactive spare management during this first week help ensure that turnaround schedules are maintained and financial risks minimized.

5. SPLITTING OF PROJECT PACKAGES

A refinery turnaround typically occurs every five years, and during this interval, multiple process improvement projects are initiated across various disciplines, including mechanical, electrical, reliability, and inspection. The Management of Change (MOC) system forms the foundation for these projects, ensuring proper evaluation and approval before execution. In the final stages, project execution responsibilities are transferred to the project management department's execution team.

To ensure efficiency, all projects planned for the turnaround must first be listed and categorized based on their profitability and business impact. A structured classification into Critical, Medium, and Low priority projects enables better resource allocation. Dedicated teams should be assigned to each category to ensure focused execution. Contractors must be aligned well in advance, with fabrication of required materials completed before the turnaround begins. Additionally, all project-related P&IDs should be thoroughly reviewed with operations to confirm accuracy of lineups, tie-ins, and work scope.

During field execution, challenges such as incorrect or delayed material deliveries may arise. In such cases, immediate actions should be taken—such as establishing tie-ins—so that pending projects can be safely completed later under normal operation once the correct material is available. This structured approach ensures all projects are executed effectively within the turnaround window, minimizing risks of delays and maximizing operational benefits.

6. FUNCTIONAL TEST PLANNING OF EIVS AND INSTRUMENTS

Functional testing of Emergency Isolation Valves (EIVs) and critical instruments is essential before plant startup to prevent operational upsets and equipment damage. For instance, in a Crude Distillation Unit (CDU), when the top column temperature reaches 100 °C and the overhead accumulator level rises, the reflux pump is activated to maintain temperature. If the pump discharge EIV is stuck closed, the column may overheat, damaging internals or triggering relief systems. Performing thorough functional testing of EIVs, control valves, pumps, and instruments ensures proper operation, safeguards equipment, maintains process stability, and minimizes safety risks during startup.

7. SPARE COLUMN TRAYS

It is a good practice to procure at least 10% additional trays for critical columns, such as the top three trays of a distillation column, which are highly susceptible to HCl corrosion. Maintaining this buffer helps mitigate unexpected damage during turnaround inspections and ensures timely replacement without impacting the schedule.

Additionally, reviewing past turnaround inspection reports in detail allows the operations and maintenance teams to anticipate potential failures, identify high-wear areas, and plan spare requirements in advance. Proactive spare management minimizes delays, supports smooth execution, and ensures that turnaround activities are completed within the planned timeframe.

8. CHEMICAL INJECTION QUILLS AVAILABILITY

It is good practice to have new injection quills every turnaround and stock already in hand as per required specifications. If any unforeseen happen then the quill can be replaced quickly. Usually, the quills installed in corrosive service like caustic and high temperature (290-300 C) region like the upstream of the furnaces in Crude distillation unit. This quills are more like to be replaced.

9. FURNACES REFRACTORY DRYOUT REQUIREMENT EVALUATION

Refractory dry out is a carefully controlled heating process performed after the installation or repair of refractory linings in process heaters, reformers, or furnaces. The objective is to safely remove residual moisture from mixing water and chemical binders without causing cracking, spalling, or compromising mechanical strength. During startup, a common question arises—whether refractory dry out is required. The decision depends on the extent of refractory replacement within the heater’s radiation and convection zones. Dry out is mandatory after new installations, significant repairs, or if refractory has absorbed moisture during extended outages.

The procedure must follow a vendor-approved heat curve with controlled temperature ramp-up and defined soaking periods to ensure uniform drying. Inspectors play a critical role during execution by monitoring refractory integrity and performing thermography on heater tubes to detect hot spots at each stage

10. STARTUP & COMMISSIONING CHECKLIST

Startup of any plant is very crucial with respect to safety because historically most of the incidents at plant occurs during startup. It is required that startup checklist should be developed in advance based on the available approve procedure and handed over to the unit console/supervisor team to sign each step performed.

The process engineer should be available during startup for any clarification required and supporting emergency cases if occurs. The operating conditions should be carefully monitor by the process engineer. The checklist helps to cover all steps safely and smooth startup of the plant.

11. PROPER HANDINGOVER BETWEEN DAY/NIGH SHIFTS

Proper handing over and taking over between shifts during a turnaround is critical to ensure smooth execution of activities, avoid duplication, and maintain progress within the tight schedule. Clear communication ensures that ongoing and completed tasks are tracked effectively. For example, if a column inspection has been completed and the equipment is ready for box-up, this status must be communicated to the incoming shift. Without proper handover, the next shift supervisor may request a repeat inspection, leading to unnecessary delays in box-up activities. To prevent such inefficiencies, both written and verbal communication should be maintained between shift supervisors. Written records provide traceability and accountability, while verbal discussions allow for clarification of any outstanding issues. This disciplined handover practice minimizes confusion, ensures continuity of work, and contributes to achieving turnaround milestones on time. Strong coordination between shifts is therefore a key element of successful turnaround management.

12. RISK ASSESSMENTS COMPLETION

Completion of risk assessments for major activities, such as decontamination, is essential before the turnaround begins. This proactive evaluation helps identify potential hazards, including chemical exposure, pressure risks, or equipment failures, and ensures that appropriate safeguards are in place. By assessing risks in advance, teams can implement engineering controls, protective equipment, and emergency response measures, reducing the likelihood of incidents. A thorough risk assessment also enhances workforce awareness, improves coordination among operations, maintenance, and contractors, and ensures compliance with safety regulations. Ultimately, early risk identification and mitigation are vital to protect personnel, equipment, and turnaround timelines.

13. NITROGEN AVAILABILITY FOR STARTUP REFERENCES

Nitrogen plays a critical role during refinery and petrochemical plant startups, often proving more important than steam for certain operations. Nitrogen is required for purging, blanketing, inerting, leak testing, and drying of equipment before hydrocarbons are introduced. Unlike steam, nitrogen is an inert gas and eliminates the risk of oxidation or explosive mixtures, making it essential for achieving hydrocarbon-free and oxygen-free conditions. For example, nitrogen purging ensures safe displacement of oxygen before startup, preventing fire or explosion hazards.

Steam, while useful for line heating, decontamination, and stripping, cannot replace nitrogen's inerting function. Many industry standards—such as API 521 (Pressure-relieving and DE pressuring Systems) and NFPA 69 (Standard on Explosion Prevention Systems)—emphasize the role of inert gas, particularly nitrogen, for safe purging and startup operations. API Recommended Practices also highlight nitrogen as a mandatory utility for commissioning and startup activities.

Thus, adequate nitrogen availability, with redundancy in supply systems, is considered a startup-critical safeguard, directly impacting plant safety, reliability, and compliance with international standards

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His accomplishments as a Chartered Chemical Engineer have also been featured in a case study by the Engineering Council UK, available on their official website. Beyond his engineering practice, He has also delivered knowledge-sharing sessions as a guest speaker to young engineers.

In addition, Shahzeb supports the development of fellow engineers as an Initial Professional Development (IPD) Assessor for IChemE, where he evaluates the professional growth of both new and experienced engineers.

His expertise over 12 years of experience Covers Oil refinery & petrochemical plants Process engineering. He has completed 5 turnarounds in his career in different companies and countries.





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