

# ENGINEERING PRACTICE

VOLUME 11 NUMBER 50

JULY 2025



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# Polishing Rough Diamonds – The Effects of Cracked Feeds in Hydrocracking Units

Dr. Marcio Wagner da Silva

## Introduction and Context

One of the biggest challenges for the oil refining industry is raising profitability or the so-called refining margin face to a scenario with environmental legislations increasingly restrictive, which requires high costly processes and the volatility of the crude barrel price. Restrictive regulations like IMO 2020 raised, even more, the pressure over refiners with low bottom barrel conversion capacity once requires higher capacity to add value to residual streams, especially related to sulfur content that was reduced from 3,5 % (in mass) to 0,5 %. Refiners with easy access to low sulfur crude oils present relative competitive advantage in this scenario. These players can rely on relatively low-cost residue upgrading technologies to produce the new marine fuel oil (Bunker) as carbon rejection technologies (Solvent Deasphalting, Delayed Coking, etc.), but they are the minority in the market. The most part of the players need to look for sources of low sulfur crudes, which present higher costs, putting under pressure his refining margins or look for deep bottom barrel conversion technologies to ensure more value addition to processed crude oils and avoid losing competitiveness in the downstream market.

The hydrocracking technologies are among the most flexible residue upgrading technologies available once can add value to heavy

and extra-heavy bottom barrel streams, but even this refining technology faces limitations related to the quality of the feed. An especial challenge to hydrocracking units, mainly for those applying fixed bed reactors, are the cracked feeds from thermal and catalytic cracking processes like Delayed Coking and FCC.

For refiners processing heavy and extra-heavy crude oils, the combination and synergy of residue upgrading strategies is a powerful tool to ensure higher added value to the processed crude oil, mainly considering the transitive

period faced in the downstream industry where the petrochemicals are the main driver in the consumption of crude oil in substitution to the transportation fuels.

## Hydrocracking Technologies – General Overview

Despite the high investment for hydrocracking units' implementation and operation, this process is what gives more flexibility to refineries to process heavy oils, so with lower cost, on the other hand, these oils produce a high quantity of derivates with lower value added and with restricted markets like fuel oils and asphalt. Table 1 presents the main differences between hydrotreating and hydrocracking technologies.

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)

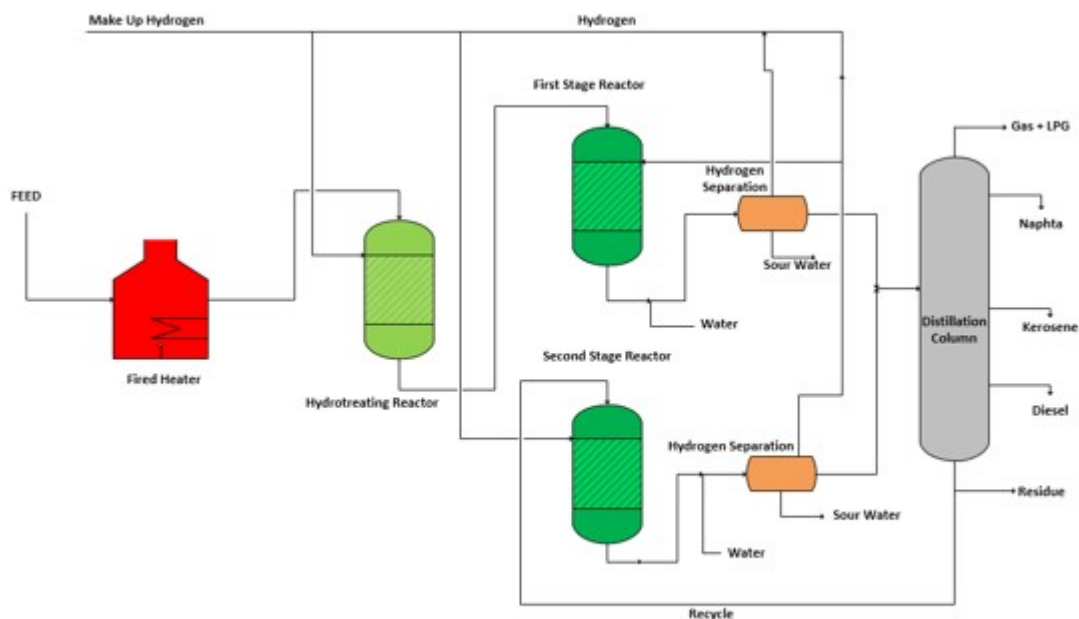


Figure 1 – Typical Arrangement for Two Stage Hydrocracking Units without Intermediate Gas Separation

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 (FCC) 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.

According to the catalyst applied in the process and the reaction conditions, the hydrocracking can maximize the feed stream conversion in middle derivatives (Diesel and Kerosene), high-quality lubricant production (lower severity process).

The principal contaminant of hydrocracking catalyst is nitrogen, which can be present in two forms: Ammonia and organic nitrogen.

Ammonia (NH<sub>3</sub>), produced during the hydrotreating step, have temporary effects reducing the activity of the acid sites, mainly damaging the cracking reactions. In some cases, the increase of ammonia concentration in the catalytic bed is used like an operational variable to control the hydrocracking catalyst activity. The

organic nitrogen has permanent effect blocking the catalytic sites and leading to coke deposits on the catalyst.

As in the hydrotreating cases (HDS, HDN, etc.), the most important operational variables are temperature, hydrogen partial pressure, space velocity and hydrogen/feed ratio.

Depending on feed stream characteristics (mainly contaminants content) and the process objective (maximize middle distillates or lubricant production) the hydrocracking units can assume different configurations.

Normally for feed streams with low nitrogen content where the objective is to produce middle distillates (diesel and kerosene), the configuration with two reaction stages without intermediate gas separation and a pre-treating hydroprocessing reactor is the most common. This configuration is shown in Figure 1.

Like the disadvantage, in this case, is the high concentration of ammonia and H<sub>2</sub>S in the hydrocracking reactors, which reduces the catalyst activity. In this configuration the hydrotreating reactor is applied to control the contaminants content in the feed aiming to protect the hydrocracking catalyst that have a relatively high cost.

The higher costly units are the plants with double stages and intermediate gas separation. These units are employed when the feed stream has high contaminant content (mainly nitrogen) and the refinery looks for the total conversion (to produce middle distillates). This configuration is presented in Figure 2.

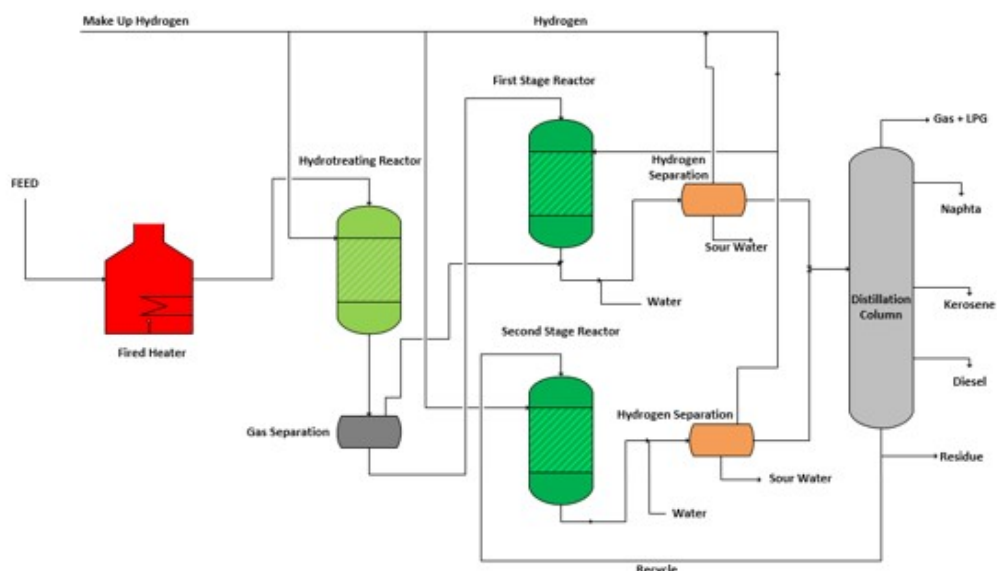


Figure 2 – Typical Arrangement for Two Stage Hydrocracking Units with Intermediate Gas Separation

In this case, the catalytic deactivation process is minimized by the reduction in the  $\text{NH}_3$  and  $\text{H}_2\text{S}$  concentration in the hydrocracking reactor. It's important to consider the feedstock quality to define better residue upgrading technology to the refining hardware, once the hydroprocessing of residual streams presents additional challenges when compared with the treatment 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.

Among the Hydrocracking Technologies which applies fixed bed reactors, it can be highlighted the RHU technology, licensed by Shell company, Hyvahl technology developed by Axens, the Isocracking Process by Chevron Lummus Company, and the Unicracking Process, developed by UOP. These processes

normally operate with low conversion rates with temperatures higher than  $400\text{ }^\circ\text{C}$  and pressures above 150 bar. Figure 3 presents a process flow diagram for the Unicracking Process by UOP Company.

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 technology developed by Axens and the LC-Fining Process by Chevron-Lummus Company. These reactors operate at temperatures above  $450\text{ }^\circ\text{C}$  and pressure to 250 bar. Another interesting technology is the Hycon™ process, developed by Shell global solutions and applies a moving bed reactor in association with a fixed bed reactor, as presented in Figure 4.

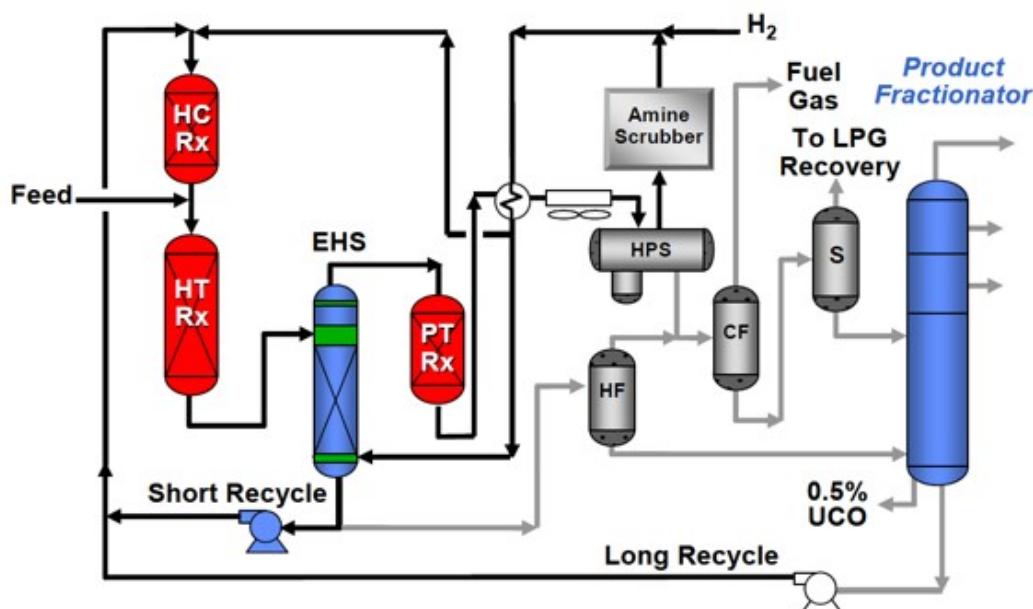


Figure 3 – Process Flow Diagram for Unicracking™ by UOP Company.

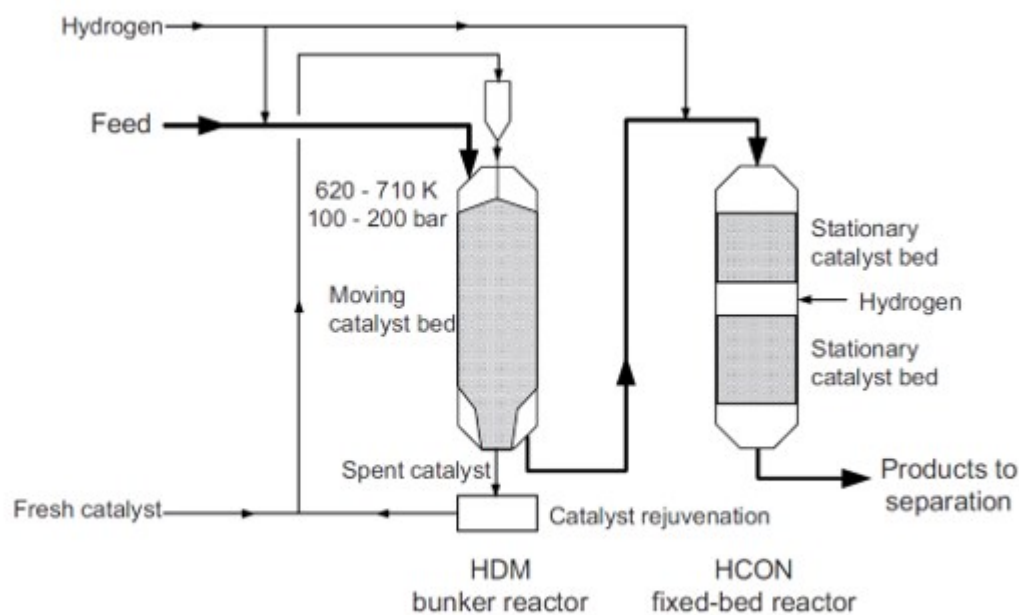


Figure 4 – Hycon™ hydrocracking Process by Shell Global Solutions.

An improvement in relation to ebullated bed technologies is the slurry phase reactors, which can achieve conversions higher than 95 %.

Despite the high capital investment and the high operational cost, hydrocracking Technologies produces high-quality derivatives and can make feasible the production of added value products from residues, which is extremely attractive, mainly for countries that have difficult access to light oils with low contaminants.

In countries, with a high dependency of middle distillates like Brazil (because his dimensions and the high dependency for road transport), and India, the high-quality middle distillate production from oils with high nitrogen content, indicate that the hydrocracking technology can be a good way to reduce the external dependency of these products. It's important to consider that, to middle distillates purpose, less severity hydrocracking units can be applied, mainly the fixed bed alternatives that present lower capital requirements.

### The Heart of the Hydrocracking Technologies – 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 such 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 be 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 these

characteristics, the hydrocracking global process is exothermic, and the reaction temperature control is normally made through cold hydrogen injections 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. Conversion (%) =  $[(1 - (\text{Fraction with Above TBP in the Product}) / (\text{Fraction with Above TBP in the Feed}))] \times 100$  (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 catalysts pore 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 the 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 anti-foaming agents are applied. 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 to dehydrogenation, cracking, and polymerization

reaction of heavier fractions, the deactivation occurs through the plugging of catalysts pores blocking the mass transfer from the hydrocarbon to the active phase, as presented in Figure 5.

### Synergy between Hydrocracking and FCC Units – High Conversion Refining Hardware

As aforementioned, sometimes the hydrocracking and FCC technologies are faced by competitors technologies in the refining hardware due to the similarities of feed streams that are processed in these units. In some refining schemes, the mild hydrocracking units can be applied as pretreatment step to FCC units, especially to bottom barrel

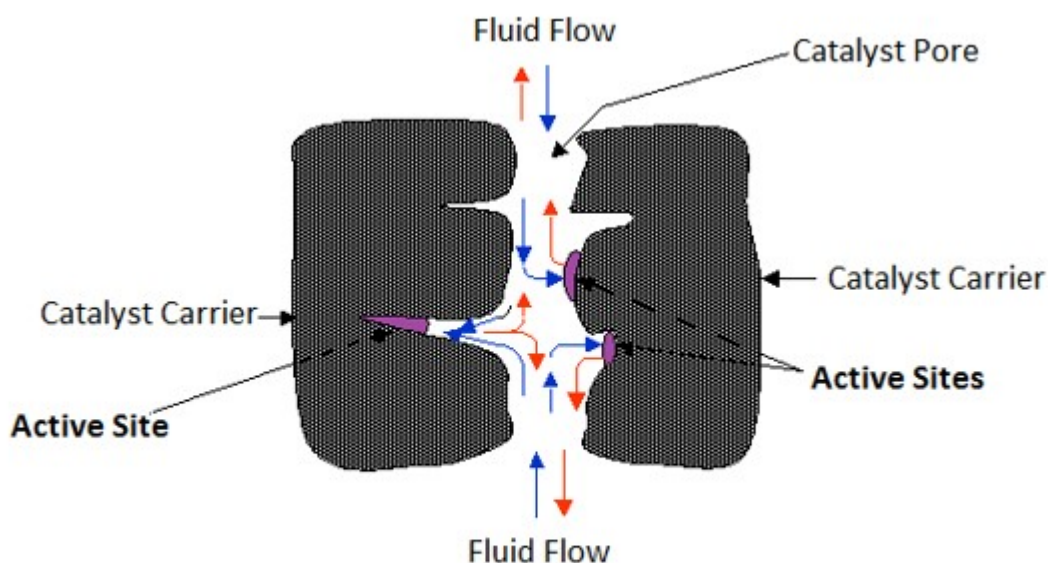


Figure 5 – Reactants and Products Flows in a Generic Porous Catalyst (GONZALEZ, 2003)





As presented in Figure 8, it's possible to achieve a highlighted deep bottom barrel conversion through the synergy of Delayed Coking and Hydrocracking units. The combination of hydrogen addition and carbon rejection technologies like hydrocracking and delayed coking ensures high capacity to process heavy and discounted crudes leading to an important competitive advantage to refiners. Despite the high bottom barrel conversion profile achieved through the synergy between hydrocracking and delayed coking technologies, there are some points related to the rise of cracked feeds proportion in the feedstock to hydrocracking units.

### Cracked Feeds – A Special Challenge

The most common cracked feeds directed to hydrocracking units are residual streams from FCC like Light Cycle (LCO) and Decanted Oil (DO) and Heavy Coker Gasoil (HCGO) from Delayed Coking units. Another less common feed is residue from Visbreaking units.

The main characteristics that influence the hydrocracking performance for each feedstock are presented below:

- FCC Cycle Oils – Present high aromaticity that are normally refractory to cracking reactions as well as refractory sulfur components, raising the sulfur content in the final products and reduction in diesel cetane number, on the other side, normally presents low basic nitrogen content that is a poison to the hydrocracking catalysts.
- Thermal Cracking Feeds – Normally presents low aromatics content but concentrate refractory sulfur components.

The Heavy Coker Gasoil (HCGO) is an interesting case study as a feed to hydrocracking unit. Refiners with high complexity refining hardware can rely on the synergy between delayed coking and hydrocracking technologies to ensure added value to bottom barrel streams, as presented in Figure 7.

The quality of the HCGO relies on the quality of the feed to the delayed coking unit as well as the operating mode of the unit, mainly the recycling ratio. Higher recycling ratios produces better quality HCGO once reduces Conradson Carbon Residue (CCR), reducing the contaminants content like metals, sulfur, and nitrogen.

Despite this advantage, the delayed coking operators normally minimize the recycle ratio to minimum as possible aiming to raise the

fresh feed processing capacity and the quality of HCGO is not an optimization focus of the refinery. For this reason, normally HCGO is a hard feed to hydrocracking units due to the high content of refractory sulfur components, high CCR, high nitrogen content, and aromatics concentration.

The sulfur and nitrogen content raises the heat release in the first bed (Higher exothermal profile) that can produce damage to the catalysts, the nitrogen tends to inhibit the cracking reaction leading to lower conversion in the unit. Hydrocrackers processing feeds with high nitrogen content tend to apply processing configuration with intermediate gas separation as presented in Figure 2 to control the catalyst activity. The higher production of H<sub>2</sub>S and NH<sub>3</sub> due to the higher concentration of sulfur and nitrogen reduces the hydrogen partial pressure, raises the necessity of washing water to the units, and can raise the corrosion rate in the processing unit.

Aromatics compounds tend to raise the hydrogen consumption, the heat release in the catalyst bed, and are precursors of coking deposition that deactivate the catalyst. Other side effects of the cracked feeds to hydrocracking units are the impact over the quality of the final products like lower cetane number of diesels, higher smoke point of kerosene, lower viscosity index in the lubricating oils and higher sulfur content.

As described above, processing cracked feeds in hydrocracking units present some additional challenges to refiners related to hydrogen consumption, better quench design of the catalyst bed due to the higher exothermic profile of the reactions, and lower global activity of the catalyst due to the higher poison content, like basic nitrogen. These characteristics lead the refiners processing cracked feeds in hydrocracking units to invest more capital in feed treating systems like filtering and guard beds, despite this apparent disadvantage, refiners able to add value to bottom barrel streams can face highly competitive advantage considering the downstream market post IMO 2020. For refiners processing extra-heavy bottom barrel streams, the deep hydrocracking technologies like slurry phase hydrocracking can be an interesting option, despite the high capital and operating costs.

### Guard Beds against Contaminants – Fundamental Tool for Cracked Feeds

As aforementioned, cracked feeds requires

even more care with the catalyst due to the high contaminants content and necessity of high activity to treat refractory molecules, in this sense, control the catalyst lifecycle became, even more, 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 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.

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 a grading strategy is applied 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.

The guard bed will be responsible for controlling 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.

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.

### **Adding Value to Extra Heavy Crudes – The Deep Hydrocracking Alternative**

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 contaminated content and residual carbon (RCR) related with the high concentration of resins and asphaltenes in the bottom barrel streams. Figure 9 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.

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 oC and pressures to 250 bar. Figure 10 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 11.

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.

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-Intevp, 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 12 presents a basic process flow diagram for the VCC™ technology by KBR Company.

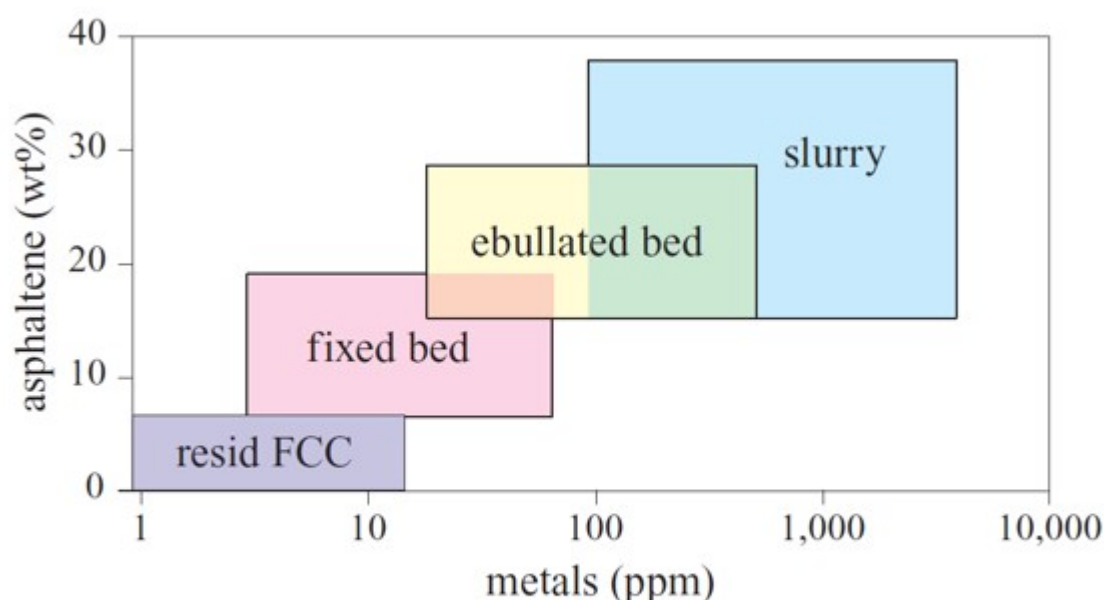


Figure 9 – Residue Upgrading Technologies According to the Contaminants Content (Encyclopedia of Hydrocarbons, 2006)

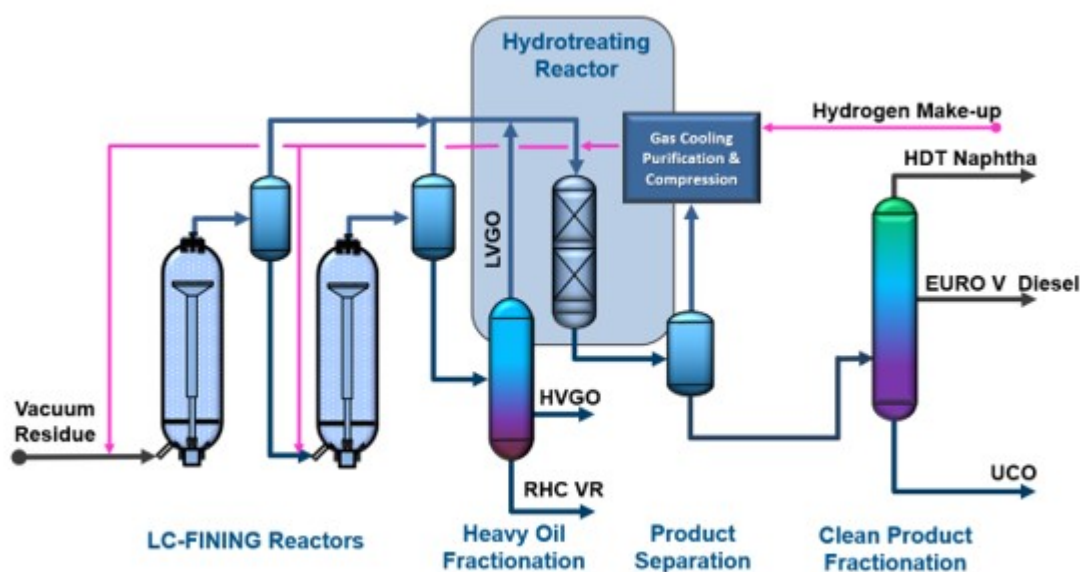


Figure 10 – Process Flow Diagram for LC-Fining™ Technology by CLG Company,

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 13 presents a basic process flow diagram for the Uniflex™ slurry hydrocracking technology by UOP Company.

Other commercial technologies to slurry hydrocracking process are the LC-Slurry™ technology developed by Chevron Lummus

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

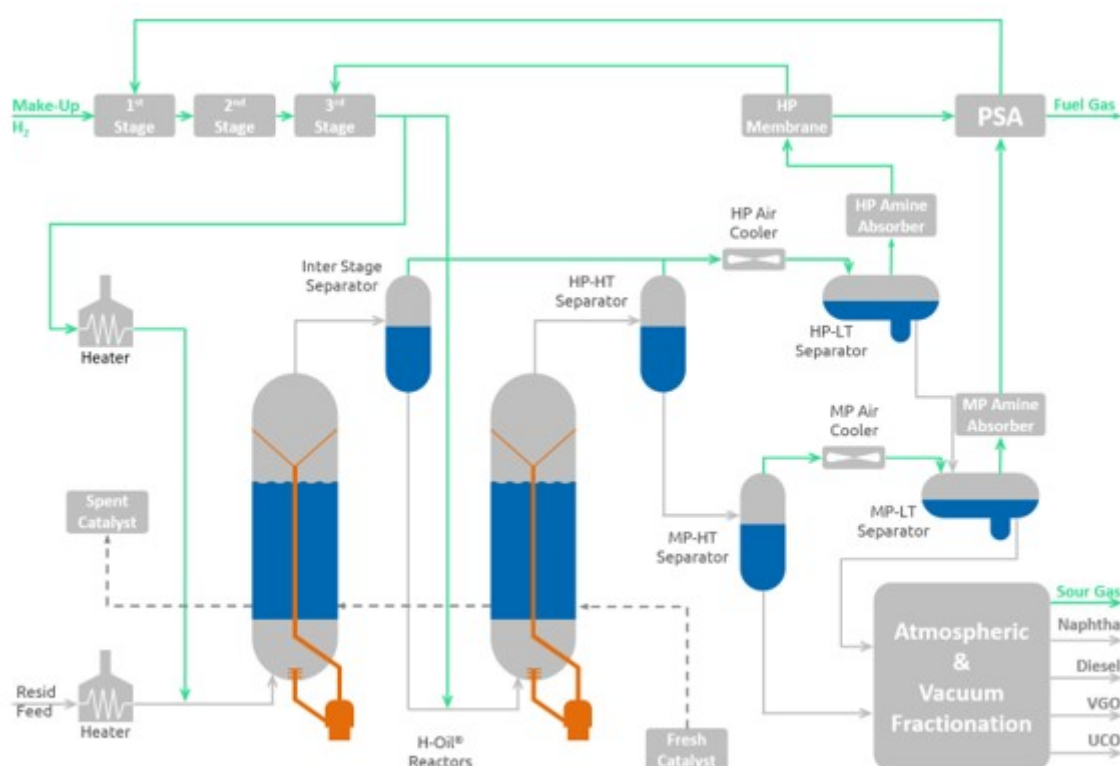


Figure 11 – Process Flow Diagram for H-Oil™ Process by Axens Company

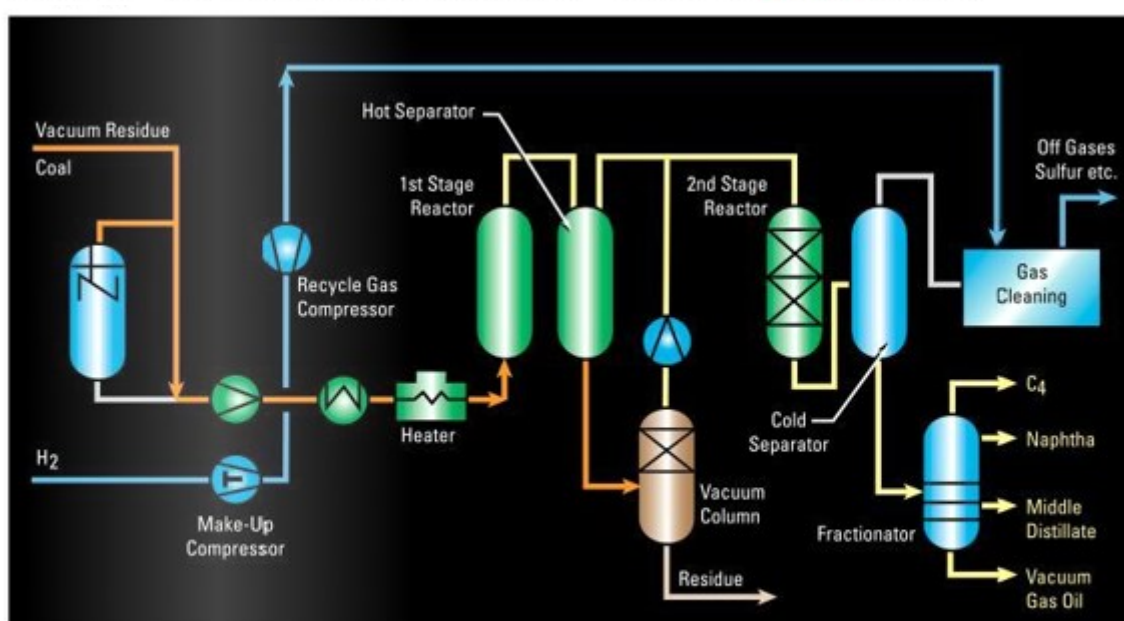


Figure 12 – Basic Process Arrangement for VCC™ Slurry Hydrocracking by KBR Company (KBR Company, 2019)

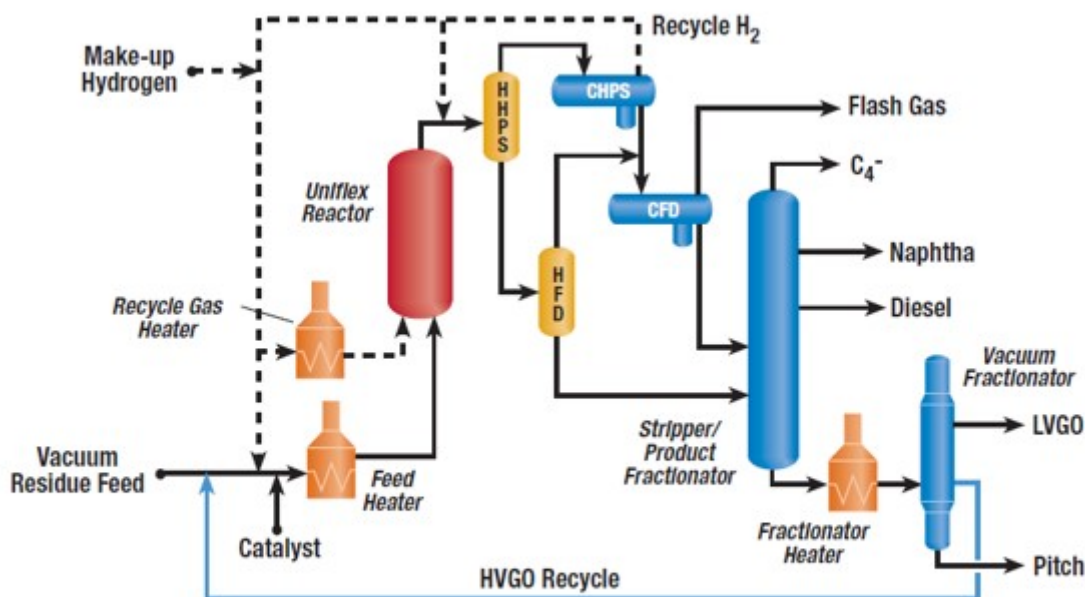


Figure 13 – Process Flow Diagram for Uniflex™ Slurry Phase Hydrocracking Technology by UOP Company (UOP Company, 2019).

## Conclusion

The capacity to add value to bottom barrel streams is among the most important competitive characteristics of the refining hardware, especially considering the downstream industry post IMO 2020. Furthermore, the trend of reduction in transportation fuels demand and the growing market of petrochemicals requires even more conversion capacity to ensure adequate refining margins and competitiveness in the refining industry.

Despite the issues mentioned above, there are available processing technologies capable of allowing profitable and reliable operations of hydrocracking units while processing cracked feeds. For refiners processing extra-heavy feeds, the deep hydrocracking technologies like ebullated bed and slurry phase reactors can offer an attractive alternative, despite the high capital spending.

No doubt, the hydrocracking technologies have a fundamental role in the future of the downstream industry and refiners relying with these refining technologies can enjoy a significant competitive advantage and the synergy of hydrocracking and carbon rejection residue upgrading technologies like delayed coking, FCC, and Solvent Deasphalting can improve, even more, the added value to the processed crude.

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# Renewable Hydrogen Gas (H<sub>2</sub>) Production a Sustainable Source of Energy from Wastewater (WW) Monography

Hamid Reza Seyed Jafari, Jiang Chouyu, Nayyereh Khalili

## **Abstract**

In the subject of climate crisis mitigation, most of the currently hydrogen production about 96% of the 60 million tons of hydrogen produced annually is not sustainable and is generated by fossil-based feedstock (Natural gas, Naphtha, LPG, Refinery catalytic reforming unit recycle gas ...). In this article focused on hydrogen production from wastewater (WW) as a renewable and sustainable source of energy. A few applications of hydrogen is used in sweetening of crude oil products from sulfur ( such as :kerosene, Naphtha , Diesel , .... ) , ammonia production, the food industry, metal extraction, pharmaceuticals, fuel cells, power plants, marine fuel, chemicals (for example to produce olefin by reaction of CO<sub>2</sub>&H<sub>2</sub> to produce methanol then production of olefin ,known as MTO) and grid natural gas pipeline.

Firstly, we treat wastewater (WW) in a wastewater treatment plant (WWT) to produce treated and clarified water & organic sludge (known as: substrate or bio-waste solid and as an organic typical biomass). Secondly, renewable hydrogen may be synthesized by following processes:

- To produce renewable green hydrogen gas (GH<sub>2</sub>) with electrolysis technology of treated wastewater (WW)
- To produce renewable bio-hydrogen (Bio-H<sub>2</sub>) by biogas with anaerobic digestion (AD) technology. Biogas, which is derived from dark fermentation of bio-waste of wastewater includes Bio-CH<sub>4</sub>+CO<sub>2</sub> mixture then direct its bio-methane to produce renewable hydrogen in reforming process by steam (SMR).
- To produce directly renewable bio-hydrogen (Bio-H<sub>2</sub>) with anaerobic digestion (AD) technology of bio-waste of wastewater (WW) by relevant bacteria in light-dependent or light-independent fermentation process.

Producing renewable and sustainable hydrogen gas in the form of green hydrogen gas (GH<sub>2</sub>) or bio-hydrogen (Bio-H<sub>2</sub>) from treated wastewater (WW) and organic sludge biomass are innovative cases to generate clean sustainable hydrogen gas as an energy source from wastewater (including organic materials)and as an enhancement effectiveness of using it to mitigate climate crisis and prevent global warming due to its decarbonization solution during its combustion to produce electricity or heat in relevant industries (power plants , steel , ... ) as an effective action plan of net zero carbon emission program in energy transition of the worldwide by the year of 2100.

**Keywords:** Renewable and fossil feedstock-based hydrogen, green hydrogen (GH<sub>2</sub>), Bio-hydrogen (Bio-H<sub>2</sub>), Electrolysis of water, Fermentation of bio-waste solid, anaerobic digestion (AD), Dark & Photo fermentation by bacteria, Wastewater treatment (WWT), Chemical oxygen demand (COD), Climate change crisis, Biomass, Sustainable energy, Energy transition; decarbonization

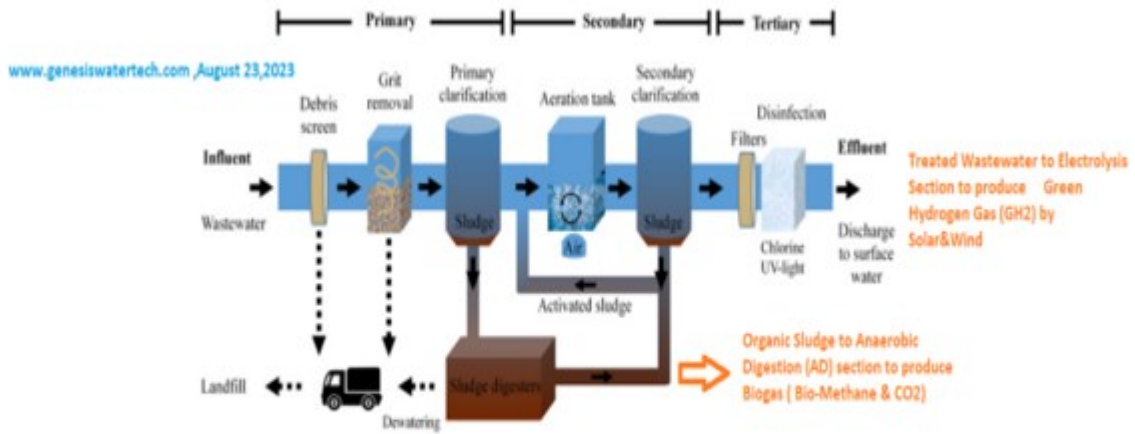


Figure 1-Schematic Wastewater Treatment (WWT) Plant  
(Ref.: Genesis Water Technologies Company; 2023)

**Hydrogen (H<sub>2</sub>) production alternatives from wastewater (WW)**

There are two alternatives employed in the production of renewable hydrogen gas from wastewater, as follows [1] [2], figure-1.

**1st. alternative OF renewable H<sub>2</sub> from WW (Electrolysis):**

In this alternative, electrical renewable energy (solar, wind, hydropower) is used to split treated wastewater (WW) of wastewater treatment (WWT) into renewable (green) hydrogen gas and oxygen gas. Studies indicate that electrolysis can be successfully applied to wastewater streams, allowing for hydrogen production alongside oxygen, which can also be utilized in wastewater treatment processes [3] figure-2.

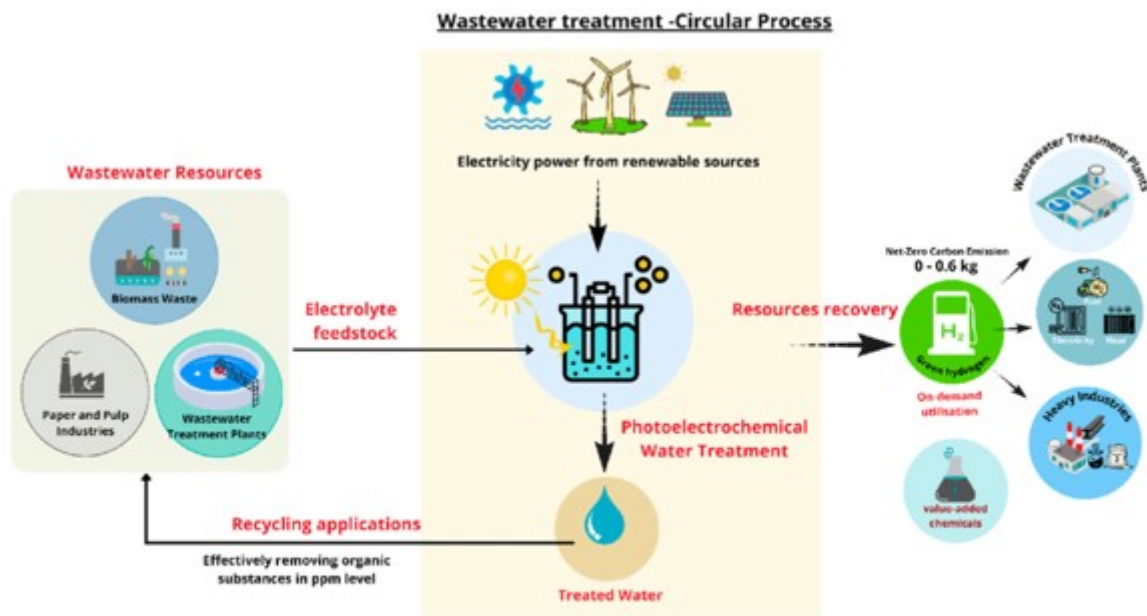


Figure 2-Wastewater (WW) treatment to produce Renewable hydrogen production

(Ref. iH2WWTP. Energy, decarbonisation, renewables, hydrogen published, Rickey Donald, Australia, 2023)

## 2nd. alternative OF renewable H2 from WW (ANAEROBIC DIGESTION):

This alternative involves the breakdown of organic matter (bio-waste solid of wastewater as biomass) by bacteria in the absence of oxygen. It produces bio-methane, which can subsequently be reformed to produce hydrogen gas via SMR (steam methane reformer). This process utilizes the organic content in which is stored in organic sludge of the wastewater treatment (WWT) plant as its feedstock (substrate, bio-waste), thereby direct to anaerobic digestion (AD) plant and changes to biogas (CH<sub>4</sub> [50-75%] + CO<sub>2</sub>[25-50%]) in the reactor as a source of bioenergy or may direct to

a steam methane reformer (SMR) plant to synthesize renewable (bio) hydrogen. Anaerobic digestion (AD) technology is known as dark fermentation also and in this process specified bacteria are used to ferment organic materials (bio-waste solid) inside wastewater to produce biogas ( bio-methane and carbon dioxide ) or directly hydrogen [4],figure-3 and figure-4.



Figure 3 - Anaerobic Digestion (AD) plant

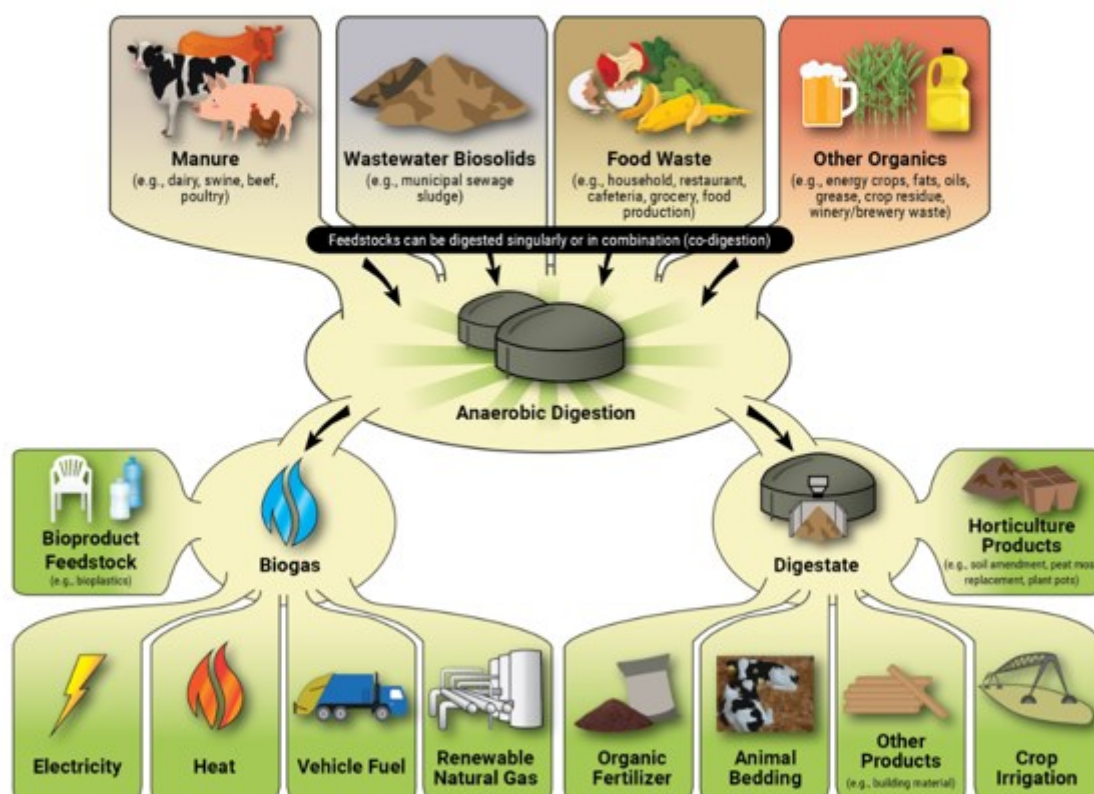


Figure 4 - Anaerobic digester (AD) output

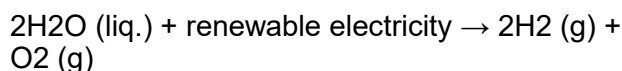
Ref.: EPA (united states environmental protect agency); USA; 2024

## Producing Renewable Green Hydrogen Gas (GH<sub>2</sub>) from treated wastewater (WW)

Green hydrogen gas production from treated wastewater represents a decarbonization solution. Producing green hydrogen from treated wastewater involves the electrolysis technology of treated wastewater to produce hydrogen, where renewable energy sources power split water molecules into hydrogen and oxygen, figure-5. The significance of using treated wastewater of wastewater treatment (WWT) plants lies in its potential as a new resource for renewable hydrogen generation[5].

### ELECTROLYSIS technology OF TREATED WASTEWATER:

Electrolysis technology, powered by renewable energy sources (solar, wind, etc.), is the primary method for hydrogen production from water (here treated wastewater). The process involves the following steps:



Equation 1-Electrolysis reaction of water to produce green hydrogen (GH<sub>2</sub>)

1st. Step - Treated wastewater preparation: Wastewater is treated to eliminate COD and other contaminants of wastewater (WW) in a wastewater treatment (WWT) plant.

2nd. Step - Electrolysis: The electrolysis process splits water into hydrogen and oxygen using renewable electricity. Some of commercial electrolyzer types are such as:

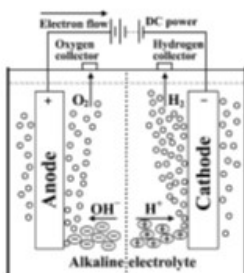


Figure 5- Electrolysis of water to produce hydrogen gas (H<sub>2</sub>)

Ref.: ASME 2017 Power Conference

- Alkaline Electrolyser Technology
- Proton Exchange Membrane (PEM) Electrolyser Technology
- Solid Oxide Electrolysis Cell (SOEC) Technology
- Anion Exchange Membrane (AEM) electrolysis Technology
- Acidic/Alkaline Amphoteric Electrolyser Technology

### Light-Dependent Process (green-H<sub>2</sub>)

There is another method known as: Light-dependent process in which involves the use of sunlight to catalyze reaction that produces renewable green hydrogen (GH<sub>2</sub>). Solar energy is used to produce hydrogen from water, and this process includes:

Hydrogen Photosynthesis: Micro-organisms such as cyanobacteria use sunlight to split water molecules directly, producing hydrogen gas and oxygen gas. This process operates under sunlight and is mediated by enzymes like hydrogenase[6], figure-6.

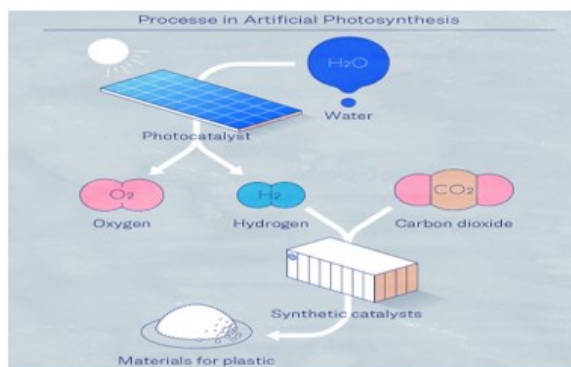


Figure 6 - Light dependent hydrogen production by sun light photosynthesis

Ref.: Mitsubishi chemical group, KAITEKI Solution Centre (KSC), 2024

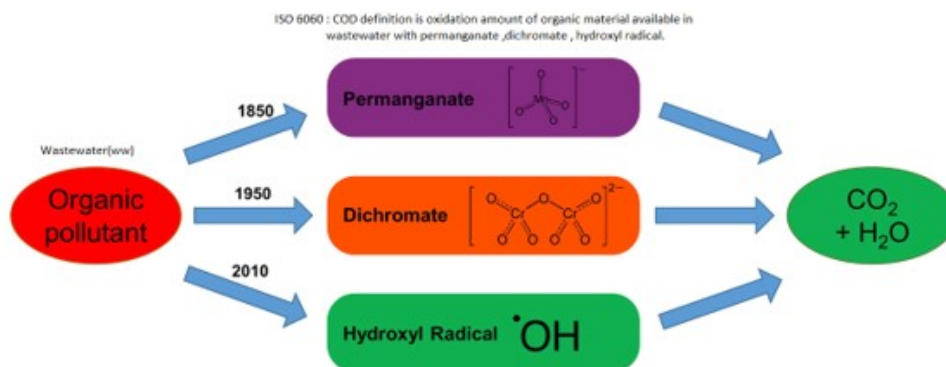


Figure 7- Chemical oxygen demand (COD) of wastewater

(Ref.: ELSEVIER, Analytica Chimica Acta Volume 961, 8 April 2017, Pages 1-11)

### Producing Renewable Bio-Hydrogen gas (Bio-H<sub>2</sub>) from Bio-waste of wastewater (WW)

Producing bio-hydrogen gas (Bio-H<sub>2</sub>) from bio-waste of wastewater (WW) involves firstly, fermentation process of organic materials present in wastewater (bio-waste) by the metric chemical oxygen demand (COD), figure-6, as main substrate to produce biogas (mixture of CH<sub>4</sub>;CO<sub>2</sub>;H<sub>2</sub>S) then secondly, after separation of CH<sub>4</sub> gas and direct to a SMR plant bio-hydrogen is produced. There are other processes that can be broadly categorized into light-dependent and light-independent fermentation directly methods to produce bio-hydrogen. Below is a detailed overview of these technologies. Bio-hydrogen production from wastewater technology showcases a multipronged approach that incorporates microbiology, fermentation technology. As research progresses, optimizing these processes will aid in enhancing energy recovery while addressing the critical issue of wastewater treatment, paving the way for sustainable energy and decarbonization solutions.

### Why EXTRACTION OF ORGANIC POLLUTANTS (COD) from WASTEWATER?

Chemical oxygen demand (COD) indicates the relative content of organics matter (bio-waste solid) in wastewater (WW). High COD levels in wastewater indicate excessive organic material (bio-waste solid as biomass), which can harm aquatic environments but extracting of this organic pollutants from wastewater (including organic material) is essential for optimizing wastewater efficiency recycling and a new source of energy from biomass (bio-waste of wastewater) in the form of bio-methane (Bio-CH<sub>4</sub>) and bio-hydrogen (Bio-H<sub>2</sub>) renewable fuel production gases.

### Bio-Hydrogen (BIO-h<sub>2</sub>) Production processes:

Other than dark fermentation anaerobic digestion (AD) process to produce bio-hydrogen (Bio-H<sub>2</sub>) via SMR, there are other fermentation processes to produce (synthesize) bio-hydrogen(Bio-H<sub>2</sub>) from

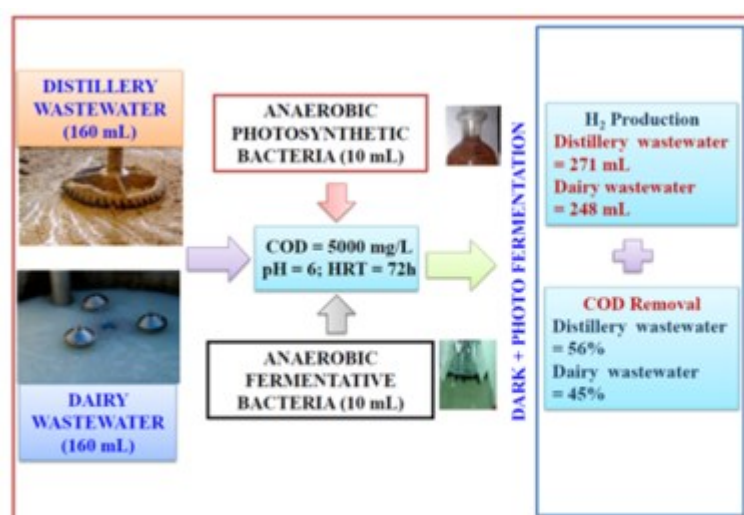


Figure 8- Photo & Dark fermentation of bio-waste of wastewater to (Bio-H<sub>2</sub>)

wastewater (WW) in which utilizes various micro-organisms to ferment organic substrates (bio-waste solid), converting them into hydrogen gas directly while treating the wastewater by light dependent or independent as following technologies:

### 1. Light-Dependent (Bio-H<sub>2</sub>) Processes

Light-dependent processes involve the use of sunlight to catalyze reactions that produce hydrogen. These processes include:

**Photo-Fermentation:** In this process, certain bacteria metabolize volatile organic compounds in the presence of light to generate hydrogen. This method shows potential for higher conversion rates, achieving up to 4 moles of hydrogen per mole of substrate.

Phototropic bacteria produce renewable hydrogen gas via photo fermentation, where the hydrogen is sourced from organic compounds (bio-waste of wastewater).

$C_6H_{12}O_6$  (Organic bio-waste of WW) +  $6H_2O$  + sun light  $\rightarrow$   $6CO_2$  +  $12H_2$

### Equation 2-Photo fermentation of bio-waste of wastewater to produce (Bio-H<sub>2</sub>)

### 2. Light-Independent (Bio-H<sub>2</sub>) Processes

These processes do not rely on light and are advantageous for utilizing organic waste materials (bio-waste solid) directly:

**Dark Fermentation:** Anaerobic bacteria oxidize organic substrates (such as sugars) to produce hydrogen without the need for light. This method tends to be more effective in treating complex organic wastes, yielding up to 4 moles of hydrogen per mole of glucose under optimal conditions.

**Integrated Dark and Photo-Fermentation:** Combining dark fermentation with photo-fermentation can enhance overall hydrogen yields. This two-stage method allows residual substrates from dark fermentation to be further processed under light conditions, potentially increasing hydrogen production rates to between 3.8 to 10 moles of hydrogen per mole of substrate.

### Conclusion

Producing sustainable and renewable hydrogen gas in the form of green (GH<sub>2</sub>) or bio (Bio-H<sub>2</sub>) from wastewater (including high COD, in which represents organic compound in wastewater as bio-waste solid as a type of biomass) by using relevant technologies such as: electrolysis of treated wastewater (WW), dark & photo fermentation of anaerobic digestion (AD) of bio-waste solid of wastewater (including organic compound as biomass, in which is remarked by COD metric) only contributes to energy sustainability but also addresses environmental concerns related to wastewater management and It is a very practical way and solution for net zero carbon emission (NZE) and to prevent greenhouse gas emission and to mitigate the climate change crisis now and future in the worldwide [7].

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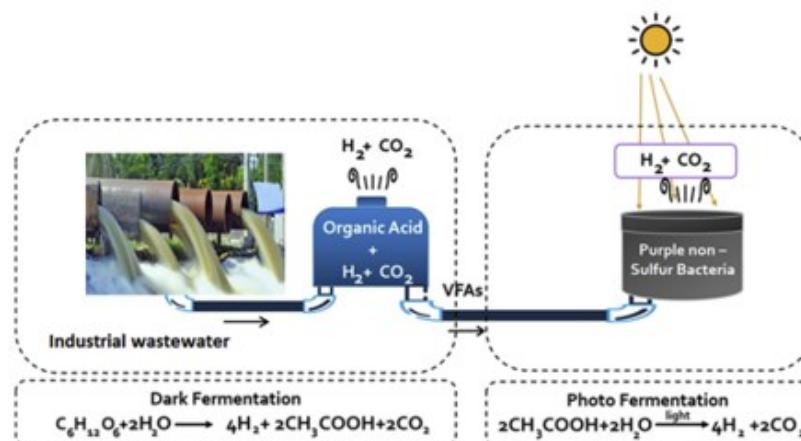


Figure 9. Integrated process of Bio-hydrogen (Bio-H<sub>2</sub>) production [3]

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# Netback Pricing Analysis for Gas Oil Separation Unit

Jayanthi Vijay Sarathy

Netback pricing is a method used in the oil & gas industry to determine the value and economic viability of crude oil or natural gas at a wellhead or a pipeline. The netback price is calculated by subtracting the various expenses incurred due to production, transportation, taxes, regulatory fines, royalties, exchange rates, tariffs, production losses, etc.

Although there are other pricing methods available such as spot pricing, fixed pricing and formula pricing, each of them has their pros & cons. Spot pricing is based on the current market price of the commodity which is subject to fluctuations. Fixed pricing provides stability but may not represent the true value of the commodity. Therefore, the type of analysis employed depends on various factors such as location differences and market conditions. With netback pricing, it allows investors to compare the value of oil/gas sold between different producers.

The following article provides a netback analysis of a Gas-Oil Separation unit considering various operating scenarios.

## Case Study

A Gas-Oil Separation Unit (GOSU) produces 10,000 bbl/d and 5 MMscfd of natural gas which is partly transported via a pipeline and the remaining by trucking. The netback price analysis is to be performed for a timeline of 30 days. The various prices and tariffs to run the production unit is as follows,

**Table 1. Gas-Oil Separation Unit Capacity**

Crude Oil Production Rate	10,000	bbl/d
Gas Production Rate	5.00	MMscfd
Timeline	30	days
Crude Oil Market Price	70	USD
Natural Gas Market Price	4.00	USD/Mscf

The various costs incurred to produce the separated hydrocarbons is as follows,

**Table 2. Costs and Tariffs for Gas-Oil Unit**

<b>Production Costs</b>		
Oil Production cost per bbl	5.00	USD/bbl
Gas Production cost per Mscf	0.50	USD/Mscf
<b>Pipeline &amp; Trucking Costs</b>		
Pipeline Oil Transport %	80.00	%
Trucking Oil Transport %	20.00	%
Pipeline Oil Transport Tariff	3.00	USD/bbl
Trucking Oil Transport Tariff	6.00	USD/bbl
Pipeline Gas Transport Tariff	0.30	USD/Mscf
<b>Export Tariffs</b>		
Export Tariff	5.00	USD/bbl
% of Exported Oil	25.00	%
<b>Carbon Tax</b>		
CO <sub>2</sub> e / Mscf	53	kg CO <sub>2</sub> e/Mscf
Carbon Tax	60	USD/metric ton CO <sub>2</sub> e
Flaring from Equipment	3.0	%
Flaring from Flare Stack	10.0	%

- For the oil sales made, the government receives a royalty of 10% on the oil revenue. In return the government gives a subsidy of 2 USD for every barrel of oil sold.

- To meet environmental regulations, a regulatory fine is imposed if the producer exceeds the daily permissible flaring rate of 0.3 MMscfd. The regulatory fine is set at 5,000 USD / MMscf of gas flared.
- Additionally, a carbon tax is imposed to meet emission norms. Based on 100% methane, the CO<sub>2</sub>e released for every MMscf of gas is taken as 53 kg CO<sub>2</sub>e / Mscf. The emission from flaring is 10% of the gas production rate, while the emission from equipment is 3% of the gas production rate.
- Prior to performing a netback analysis, it was discovered that a new competitor had entered the market, due to which oil prices fell by 6% due to competition.
- Due to labour cost cutting issues, a factory strike was also declared, which halted production for 10 days.

### Assumptions

Taking all the various costs and tariffs, a netback analysis is performed under the following assumptions,

1. The production costs include costs due to labour, maintenance, power, utilities. Prices are made in US Dollar (USD), represented as '\$' in this article.
2. Crude oil and Natural Gas prices are assumed to stay constant over the 30-day period. All incurred costs such as production costs, tariffs, labour, maintenance, royalties, carbon tax are also assumed to be fixed for the 30-day period.
3. The percentage of oil & gas transported is assumed to stay fixed at 75% via pipeline and 25% via trucking. The government subsidy and export tariff are assumed to be only for the oil produced and excludes gas.
4. There is no location differential assumed between the producer and the new competitor, i.e., crude oil market price variation due to locational differences is assumed to be 0 \$ /bbl.
5. In calculating Netback price, it is assumed despite downtime, overhead costs persist.

### Base Production & Revenues

Netback price can be estimated by beginning with the base production and the revenue it generates. The oil production volume is,

$$\text{Oil Prod Vol} = 10,000 \text{ bbl/d} \times 30 \text{ days} \quad (1)$$

$$\text{Oil Prod Vol} = 300,000 \text{ bbl/d} \quad (2)$$

$$\text{Gas Prod Vol} = 5 \text{ MMscfd} \times 30 \text{ days} \quad (3)$$

$$\text{Gas Prod Vol} = 150,000 \text{ Mscf} \quad (4)$$

$$\text{Oil Revenue} = 300,000 \text{ bbl} \times 70 \text{ \$/bbl} \quad (5)$$

$$\text{Oil Revenue} = 21,000,000 \text{ \$} \quad (6)$$

$$\text{Gas Revenue} = 150,000 \text{ Mscf} \times 4 \text{ \$/Mscf} \quad (7)$$

$$\text{Gas Revenue} = 600,000 \text{ \$} \quad (8)$$

$$\text{Total Revenue} = 21,000,000 + 600,000 \quad (9)$$

$$\text{Total Revenue} = 21,600,000 \text{ \$} \quad (10)$$

Therefore, the total revenue generated from oil & natural gas sales over the 30-day period is 21,600,000 \$.

### Production Costs

The production costs are then estimated based on the cost to process per barrel of crude oil, and cost to process per Mscf of gas,

$$\text{Oil Prod cost/bbl} = 5 \text{ \$/bbl} \times 300,000 \text{ bbl} \quad (11)$$

$$\text{Oil Prod Cost/bbl} = 1,500,000 \text{ \$} \quad (12)$$

$$\text{Gas Prod Cost/bbl} = 150,000 \text{ Mscf} \times 0.5 \text{ \$/Mscf} \quad (13)$$

$$\text{Gas Prod Cost/bbl} = 75,000 \text{ \$} \quad (14)$$

$$\text{Total Prod Cost} = 1,500,000 + 75,000 \quad (15)$$

$$\text{Total Prod Cost} = 1,575,000 \text{ \$} \quad (16)$$

Therefore, the total cost of processing the crude oil & natural gas supplied to the Gas-Oil Separation Unit is 1,575,000 \$.

### Pipeline and Transportation Costs

The pipeline and transportation costs are estimated based on the fraction sent via pipeline and trucking. For 80% transport by pipeline and the remaining by trucks,

$$\text{Pipeline Oil Cost} = 3 \text{ \$/bbl} \times 0.8 \times 300,000 \text{ bbl} \quad (17)$$

$$\text{Pipeline Oil Cost} = 720,000 \text{ \$} \quad (18)$$

$$\text{Truck Oil Cost} = 6 \text{ \$/bbl} \times 0.2 \times 300,000 \text{ bbl} \quad (19)$$

$$\text{Truck Oil Cost} = 360,000 \text{ \$} \quad (20)$$

$$\text{Pipeline Gas Cost} = 0.3 \text{ \$/Mscf} \times 150,000 \text{ Mscf} \quad (21)$$

$$\text{Pipeline Gas Cost} = 45,000 \text{ \$} \quad (22)$$

$$\text{Total Trans Cost} = 720,000 + 360,000 + 45,000 = 1,125,000 \text{ \$} \quad (23)$$

### Export Tariffs

The costs associated with export tariffs are,

$$\text{Export Tariff} = 0.25 \times 300,000 \text{ bbl} \times 5 \text{ \$/bbl} \quad (24)$$

$$\text{Export Tariff} = 375,000 \text{ \$} \quad (25)$$

### Government Subsidy

Since the government gives a subsidy on every barrel of oil produced, the subsidy is,

$$\text{Govt Subsidy} = 300,000 \text{ bbl/d} \times 2 \text{ \$/bbl} \quad (26)$$

$$\text{Govt Subsidy} = 600,000 \text{ \$} \quad (27)$$

### Royalties

For every barrel of oil sold, a royalty of 10% is paid on the revenue. Therefore,

$$\text{Royalties} = 0.1 \times 21,000,000 \text{ \$} \quad (28)$$

$$\text{Royalties} = 2,100,000 \text{ \$} \quad (29)$$

### Carbon Tax

A carbon tax is applied due to the emissions produced while operating the gas oil separation unit. The amount of CO<sub>2</sub> produced for every Mscf of gas is 53 kg CO<sub>2</sub>e, and a carbon tax of 60 \$ per metric ton of CO<sub>2</sub>e emitted. Taking 3% emissions from equipment during operations, and 10% from flare stack emissions,

$$\text{Flaring Rate} = [0.1 + 0.03] \times 5 \text{ MMscfd} \times 1000 \times 30 \text{ days} = 19,500 \text{ Mscf} \quad (30)$$

$$\text{CO}_2\text{e from flaring} = \frac{19,500 \times 53 \text{ kg CO}_2\text{e}}{1000} \quad (31)$$

$$\text{CO}_2\text{e} = 1,034 \text{ Metric tons of CO}_2\text{e} \quad (32)$$

$$\text{Carbon Tax} = 1,034 \times 60 \text{ \$/mtons CO}_2\text{e} \quad (33)$$

$$\text{Carbon Tax} = 62,010 \text{ \$} \quad (34)$$

### Regulatory Fines

Given the permissible flaring rate per day is to be kept to a maximum of 0.3 MMscfd, the gas-oil separation unit flares upto 0.5 MMscfd. Therefore, for the difference of 0.5 - 0.3 = 0.2 MMscfd, a regulatory fine at the rate of 5,000 \$/MMscf is to be paid for the 30 days of flaring.

$$\text{Permissible flaring} = 0.3 \text{ MMscfd} \quad (35)$$

$$\text{Flaring Rate per day} = 0.5 \text{ MMscfd} \quad (36)$$

$$\text{Excess Flaring} = 0.5 - 0.3 = 0.2 \text{ MMscfd} \quad (37)$$

$$30 \text{ days of flaring} = 0.2 \times 30 = 6 \text{ MMscf} \quad (38)$$

$$\text{Regulatory Fine} = 6 \times 5,000 = 30,000 \text{ \$} \quad (39)$$

### Presence of New Competitor

With a new competitor entering the market, the company management realizes that the crude oil market price at which it sells must be reduced by 6% to stay competitive. This would directly influence the revenues generated and revenue lost. Therefore,

$$\text{Revised Oil price} = [1 - 0.06] \times 70 \quad (40)$$

$$\text{Revised Oil price} = 65.80 \text{ \$/bbl} \quad (41)$$

$$\text{Revised Oil Revenues} = 65.80 \times 300,000 \quad (42)$$

$$\text{Revised Oil price} = 19,740,000 \text{ \$} \quad (43)$$

$$\text{Revenue Loss} = 21,000,000 - 19,740,000 \quad (44)$$

$$\text{Revenue Loss} = 1,260,000 \text{ \$} \quad (45)$$

### Factory Strike

Due to the revenue losses incurred on oil sales, the management decides to cut labour costs, which results in a factory strike for 10 days. To prevent further production loss, the management rolls back its cost cutting measures, and reinstates the workers.

However, the 10 days of strikes represents a production and monetary loss. Therefore, for the 10 days of production loss,

$$\text{Oil Prod Loss} = 10 \text{ days} \times 10,000 \text{ bbl/d} \quad (46)$$

$$\text{Oil Prod Loss} = 100,000 \text{ bbls} \quad (47)$$

$$\text{Gas Prod Loss} = 10 \text{ d} \times 5 \text{ MMscfd} \times 1000 \quad (48)$$

$$\text{Gas Prod Loss} = 50,000 \text{ Mscf} \quad (49)$$

$$\text{Revised Oil Prod} = 300,000 - 100,000 \quad (50)$$

$$\text{Revised Oil Prod} = 200,000 \text{ bbl} \quad (51)$$

$$\text{Revised Gas Prod} = 150,000 - 50,000 \quad (52)$$

$$\text{Revised Gas Prod} = 100,000 \text{ Mscf} \quad (53)$$

$$\text{Oil Revenue Loss} = 65.80 \frac{\text{\$}}{\text{bbl}} \times 100,000 \text{ bbl} \quad (54)$$

$$\text{Oil Revenue Loss} = 6,580,000 \text{ \$} \quad (55)$$

$$\text{Gas Revenue Loss} = 4 \frac{\text{\$}}{\text{Mscf}} \times 50,000 \text{ Mscf} \quad (56)$$

$$\text{Gas Revenue Loss} = 200,000 \text{ \$} \quad (57)$$

$$\text{Total Revenue Loss} = 6,580,000 + 200,000 \quad (58)$$

$$\text{Total Revenue Loss} = 6,780,000 \text{ \$} \quad (59)$$

The total revenue loss due to 10 days of factory strikes is 6,780,000 \$.

### Adjusted Revenues

The adjusted revenues after a new competitor enters the market and factory strike is computed as,

$$\text{Oil Revenue} = 65.80 \frac{\text{\$}}{\text{bbl}} \times 200,000 \text{ bbl} \quad (60)$$

$$\text{Oil Revenue} = 13,160,000 \text{ bbl} \quad (61)$$

$$\text{Gas Revenue} = 4 \frac{\text{\$}}{\text{Mscf}} \times 100,000 \text{ Mscf} \quad (62)$$

$$\text{Oil Revenue} = 400,000 \text{ bbl} \quad (63)$$

$$\text{Total Adjusted Revenue} = 400,000 + 13,160,000 = 13,560,000 \text{ \$} \quad (64)$$

$$\text{Adjusted Royalties} = 0.1 \times 13,160,000 \quad (65)$$

$$\text{Adjusted Royalties} = 1,316,000 \text{ \$} \quad (66)$$

The carbon tax cost continues to be the same since the flaring from the equipment and minimum flaring due to the pilot flame does not change. Hence, the carbon tax is,

The carbon tax cost continues to be the same since the flaring from the equipment and minimum flaring due to the pilot flame does not change. Hence, the carbon tax is,

$$\text{Carbon Tax} = 62,010 \text{ \$} \quad (67)$$

The regulatory fines do not change since the flaring of 0.5 MMscfd during the 30 days

continues to stay above the permissible limit of 0.3 MMscfd. Hence the regulatory fine is,

$$\text{Regulatory Fines} = 30,000 \$ \quad (68)$$

The pre-strike export tariffs would continue to apply since 75,000 bbl of oil is exported from the 288,000 bbls during the 10 days of strike.

$$\text{Export Tariffs} = 375,000 \$ \quad (69)$$

Since the government subsidy of 2 \$/bbl applies on the base production & revenue of 300,000 \$, the subsidy is the same as pre-strike value. Therefore, the govt subsidy is,

$$\text{Govt Subsidy} = 600,000 \$ \quad (70)$$

The total expenses are computed,

$$\begin{aligned} \text{Total Expenses} = & \text{Oil Prod Cost} + \text{Gas Prod Cost} + \\ & \text{Total Transport Costs} + \text{Adjusted Royalties} + \\ & \text{Carbon Tax} + \text{Regulatory Fines} + \text{Export Tariffs} \end{aligned} \quad (71)$$

$$\begin{aligned} \text{Total Expenses} = & 1,500,000 + 75,000 + 1,125,000 + \\ & 1,316,000 + 62,010 + 30,000 + 375,000 = \\ & 4,483,010 \$ \end{aligned} \quad (72)$$

The net cost post competitor entry & strikes is,

$$\text{Net Cost} = \text{Total Expenses} - \text{Subsidy} \quad (73)$$

$$\text{Net Cost} = 4,483,010 - 600,000 \quad (74)$$

$$\text{Net Cost} = 3,883,010 \$ \quad (75)$$

### Netback Price

In computing the netback price of oil, since it is assumed that despite downtime due to factory strikes, there would be overhead costs. As a result for the netback estimation, the oil production costs would remain at 1,500,000 \$, which was calculated at a monthly production volume of 300,000 \$, instead of 288,000 \$ during factory strike. The same applies to pipeline transport via both pipeline and trucking.

Therefore, to estimate the netback value,

$$\begin{aligned} \text{Netback Value} = & \text{Adj. Oil Revenues} - \\ & \text{Net Cost of Oil} \end{aligned} \quad (76)$$

$$\text{Net Cost of Oil} = \text{Total Expenses} - \text{Subsidy} \quad (77)$$

The total expenses here refer to the sum of adjusted oil production costs, Oil transportation cost via pipeline and trucking, adjusted carbon tax, royalties, regulatory fines, export tariffs.

The government subsidy is not an expense, but a gain / savings which is subtracted from the total expenses to compute the net cost of oil.

Since netback value of only the oil fraction is computed, the price of gas is excluded and revenue allocation is made only on the oil fraction, i.e.,

$$\begin{aligned} \text{Adj. Oil Revenue Allocation} = \\ \frac{\text{Oil Revenue After competitor \& Strike}}{\text{Total Adjusted Revenue}} \end{aligned} \quad (78)$$

$$\text{Adj. Oil Revenue Allocation} = \frac{13,160,000}{13,560,000} \quad (79)$$

$$\text{Adj. Oil Revenue Allocation} = 0.9705 \quad (80)$$

Therefore, computing all the various expenses that add up to the total expense, based on only the oil fraction for netback value,

$$\text{Oil Prod Cost} = 1,500,000 \$ \quad (81)$$

$$\text{Pipeline Oil Transport Cost} = 720,000 \$ \quad (82)$$

$$\text{Oil Truck Transport Cost} = 360,000 \$ \quad (83)$$

$$\text{Adj. Carbon Tax} = 62,010 \times 0.9705 \quad (84)$$

$$\text{Adj. Carbon Tax} = 60,181 \$ \quad (85)$$

$$\text{Adj. Royalties} = 0.1 \times 13,160,000 \quad (86)$$

$$\text{Adj. Royalties} = 1,316,000 \$ \quad (87)$$

$$\text{Adj. Regulatory Fine} = 0.9705 \times 30,000 \quad (88)$$

$$\text{Adj. Regulatory Fine} = 29,115 \$ \quad (89)$$

$$\text{Export Tariffs} = 375,000 \$ \quad (90)$$

$$\text{Govt Subsidy} = 600,000 \$ \quad (91)$$

Therefore, the total expenses / net cost of oil to compute the netback value is,

$$\begin{aligned} \text{Net Cost of Oil} = & 1,500,000 + 720,000 + 360,000 + \\ & 60,181 + 1,316,000 + 29,115 + 375,000 - 600,000 \end{aligned} \quad (92)$$

$$\text{Oil Net Cost} = 3,760,296 \$ \quad (93)$$

Therefore, the Netback value of Oil is,

$$\text{Netback Value} = 13,160,000 - 3,760,296 \quad (94)$$

$$\text{Netback Value} = 9,399,704 \$ \quad (95)$$

Based on the netback value of oil, the netback price is computed as,

$$\text{Netback Price} \left[ \frac{\$}{\text{bbl}} \right] = \frac{\text{Netback Value}}{\text{Revised Oil Production}} \quad (96)$$

$$\text{Netback Price} \left[ \frac{\$}{\text{bbl}} \right] = \frac{9,399,704 \$}{200,000} = 47 \$/\text{bbl} \quad (97)$$

The total cost to process one barrel of crude oil in the gas oil separation unit is,

$$\begin{aligned} \text{Net cost per bbl} = & \text{Revised Oil price} - \\ & \text{Netback price of oil} \end{aligned} \quad (98)$$

$$\text{Net cost per bbl} = 65.80 - 47 = 18.80 \$ \quad (99)$$

From the computations, it is seen that for every 70 \$/bbl of crude oil, it costs 18.80 \$ to process the oil prior to sale. This gives a netback profitability of 47 \$/bbl.

### Price Breakup of Net Cost per Barrel

To analyze what constitutes the net cost per barrel of oil, a breakup of the various expenses is made.

$$\text{Royalties} = 0.1 \times 65.80 = 6.58 \text{ \$/bbl} \quad (100)$$

$$\text{Oil Prod Costs} = \frac{150,000}{200,000} = 7.50 \text{ \$/bbl} \quad (101)$$

$$\text{Pipeline Transport} = \frac{720,000}{200,000} = 3.60 \frac{\$}{\text{bbl}} \quad (102)$$

$$\text{Trucking Transport} = \frac{360,000}{200,000} = 1.80 \frac{\$}{\text{bbl}} \quad (103)$$

$$\text{Export Tariff} = \frac{375,000}{200,000} = 1.88 \frac{\$}{\text{bbl}} \quad (104)$$

$$\text{Regulatory Fines} = \frac{29,115}{200,000} = 0.15 \frac{\$}{\text{bbl}} \quad (105)$$

$$\text{Carbon Tax} = \frac{60,181}{200,000} = 0.30 \frac{\$}{\text{bbl}} \quad (106)$$

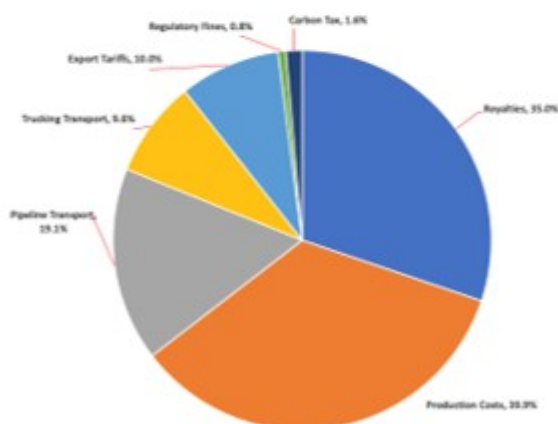
$$\text{Govt Subsidy Gains} = \frac{600,000}{200,000} = 3.00 \frac{\$}{\text{bbl}} \quad (107)$$

$$\text{Net Cost/barrel} = [6.58 + 7.5 + 3.60 + 1.80 + 1.88 + 0.15 + 0.30] - 3.00 = 18.80 \frac{\$}{\text{bbl}} \quad (108)$$

Making a Pie chart of the above data, to understand what contribute the highest to the net cost of processing per barrel,

**Table 3. Breakup of Net Cost per barrel**

Expense	\$/ bbl	% Contribution
Royalties	6.58	6.58/18.80 = 35%
Production Costs	7.50	7.50/18.80 = 39.9%
Pipeline Transport	3.60	3.60/18.80 = 19.1%
Trucking Transport	1.80	1.8/18.80 = 9.6%
Export Tariffs	1.88	1.88/18.80 = 10%
Regulatory Fines	0.15	0.15/18.80 = 0.8%
Carbon Tax	0.30	0.30/18.80 = 1.6%



**Figure 1. Breakup of Net Cost per barrel**

### Analysis

From the pie chart,

1. Production costs and royalties contribute the most to process per barrel of oil.
2. To reduce the production cost, efforts can be made to improve the operating efficiency of the gas-oil separation unit. This can be through better maintenance, optimizing process parameters, operator training and / or replacing worn out equipment.
3. To reduce royalties, the company can lobby/launch re-negotiations with the government.
4. It can be observed that the oil production costs increased from 5 \$/bbl to 7.50 \$/bbl when a factory strike occurred, Production volumes also fell from 300,000 bbls to 288,000 bbls. This is because production costs don't change much over short timelines, giving fixed production costs. With any loss of production, the same fixed costs have to be spread across fewer barrels.
5. The factory strike does not directly affect the total expenses, because its influence is only in loss of production and revenue.

### References

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### Author



Vijay Sarathy holds a Master's Degree in Chemical Engineering from Birla Institute of Technology & Science (BITS), Pilani, India and is a Chartered Engineer from the Institution of Chemical Engineers, UK. His expertise over 10 years of professional experience covers Front End Engineering, Process Dynamic Simulation and Subsea/Onshore pipeline flow assurance in the Oil and Gas industry. Vijay has worked as an Upstream Process Engineer with major conglomerates of General Electric, ENI Saipem and Shell.

## Appendix A










NETBACK PRICING ANALYSIS FOR GAS OIL SEPARATION UNIT									
<b>Base Production &amp; Revenue</b>			<b>Carbon Tax</b>				<b>Adjusted Revenue (Post Competitor &amp; Strike)</b>		
Crude Oil Production Rate	10,000	bbl/d	CO <sub>2</sub> e / Mscf	53.00	kg CO <sub>2</sub> e / Mscf	Crude Oil Revenue	13,160,000	USD	
Natural Gas Production Rate	5.00	MMscfd	Carbon Tax	60.00	USD/ mton CO <sub>2</sub> e	Natural Gas Revenue	400,000	USD	
Timeline	30	days	Emissions from Equipment	3.00	%	Total Adjusted Revenue	13,560,000	USD	
Crude Oil Market Price	70	USD	Emissions from Flare Stack	10.00	%	Adjusted Royalties	1,316,000	USD	
Natural Gas Market Price	4.00	USD/Mscf	Flaring Rate	19,500	Mscf	Carbon Tax	62,010	USD	
Oil Production Volume	300,000	bbl/m	CO <sub>2</sub> e from Flaring	1,034	metric tons CO <sub>2</sub> e	Regulatory Fines	30,000	USD	
Gas Production Volume	150,000	Mscf/m	Carbon Tax Cost	62,010	USD	Export Tarrifs (Pre-Strike)	375,000	USD	
Oil Revenue over 30 days	21,000,000	USD	<b>Royalties</b>			Total Expenses	4,483,010	USD	
Gas Revenue over 30 days	600,000	USD	Royalties on Oil Revenue	10.00	%	Subsidy	600,000	USD	
Total Revenue over 30 days	21,600,000	USD	Royalties on Oil Revenue	2,100,000	USD	<b>Net Costs (Post Competitor &amp; Strike)</b>	<b>3,883,010</b>	USD	
<b>Production Costs</b>			<b>Regulatory Fines</b>				<b>Netback Price of Crude Oil</b>		
Oil Production Cost per bbl	5.00	USD/bbl	Permissible Flaring per day	0.30	MMscfd	Revenue Allocation of Oil [Adjusted]	0.9705	-	
Gas Production Cost per Mscf	0.50	USD/Mscf	Flaring Rate per day	0.50	MMscfd	Oil Production Costs	1,500,000	USD	
Oil Production Costs	1,500,000	USD	Excess Flaring	0.20	MMscfd	Pipeline Transport of Oil Costs	720,000	USD	
Gas Production Costs	75,000	USD	For 30 days of flaring	6.00	MMscf	Trucking Transport of Oil Costs	360,000	USD	
Total Production Cost	1,575,000	USD	Regulatory Fine due to Excess flaring	5,000	USD / MMscf	Carbon Tax [Adjusted]	60,181	USD	
<b>Pipeline &amp; Trucking Transportation Costs</b>			Regulatory Fine Cost	30,000	USD	Royalties [Adjusted]	1,316,000	USD	
Pipeline Oil Transport %	80.00	%	<b>Presence of New Competitor</b>				Regulatory Fines [Adjusted]	29,115	USD
Trucking Oil Transport %	20.00	%	Fall in Oil Price due to competitor	6.00	%	Export Tariffs	375,000	USD	
Pipeline Oil Transport Tariff	3.00	USD/bbl	Revised Crude Oil Price [Market Price]	65.80	USD/bbl	Government Subsidy	600,000	USD	
Trucking Oil Transport Tariff	6.00	USD/bbl	Revised Oil Revenues	19,740,000	USD	Net Costs of Oil	3,760,296	USD	
Pipeline Gas Transport Tariff	0.30	USD/Mscf	Revenue Loss	1,260,000	USD	Netback Value	9,399,704	USD	
Pipeline Oil Transport Cost	720,000	USD	<b>Factory Strike</b>				<b>Netback Price of Oil</b>	<b>47.00</b>	<b>USD/bbl</b>
Trucking Oil Transport Cost	360,000	USD	No of Days on Strike	10	days	<b>Net Cost per Barrel</b>	<b>18.80</b>	<b>USD</b>	
Pipeline Gas Transport Cost	45,000	USD	Loss of Production of Oil	100,000	bbl	<b>Breakup of Net Cost per Barrel</b>			
Total Transportation Costs	1,125,000	USD	Loss of Production of Gas	50,000	Mscf	Royalties	6.58	USD / bbl	
<b>Export Tariffs</b>			Revised Production - Oil	200,000	bbl/m	Production Costs	7.50	USD /bbl	
Export Tariff	5.00	USD/bbl	Revised Production - Gas	100,000	Mscf/m	Pipeline Transport	3.60	USD /bbl	
% of Exported Crude Oil	25.00	%	Revenue Loss - Oil	6,580,000	USD	Trucking Transport	1.80	USD /bbl	
Exported Oil Capacity	75,000	bbl	Revenue Loss - Gas	200,000	USD	Export Tariffs	1.88	USD /bbl	
Tariff Cost	375,000	USD	Total Revenue Loss due to Factory Strike	6,780,000	USD	Regulatory Fines	0.15	USD/bbl	
<b>Government Subsidy</b>									
Government Subsidy	2.00	USD/bbl							
Government Subsidy Cost	600,000	USD							

# TrayHeart

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