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Ministry of Petroleum and Natural Gas
Government of India

Foreword

It is great pleasure for me to hand out first edition of Oil & Gas Technical Journal, which will be released henceforth annually by CHT.

The refining industry is currently passing through a very challenging phase due to crude oil price volatility and issue of sustainability in the long term arising from impending shift in demand pattern. Although, demand of transport liquid fuels may see some declining trend worldwide due to substitution by EVs, Green Hydrogen, gas and renewable, demand of petroleum fuels will continue to grow in India in near future due to rapid urbanisation and industrialisation. Therefore, refineries need to expand to meet the growing demand as well as be able to foresee the emerging technologies and act proactively to align with changing energy landscape. To remain competitive and be able to sustain pressure on margins, refinery also need to continue to invest in operational improvements, energy efficiency and integrate with petrochemicals and biorefining. Sustainable economic development requires more than simply “opening up” and waiting for new technologies to flow in. It demands continuous technological effort by domestic enterprises, along with supportive government policies.

India at COP 26 held in Glasgow made very significant announcement of achieving target of 500 GW renewable energy by 2030; 50 % of installed capacity of electricity from renewable sources and reduction of emission intensity by 45% by 2030 over 2005 level and net zero by 2070. India also aspires to be energy independent by the year 2047. Govt. has also announced the National Hydrogen Mission and biofuels policy with the ambition to boost growth of green hydrogen and biofuels in India to work towards being energy independent.

As a prelude to the above pronouncements, India announced the first part of the National Green Hydrogen policy on 17th February,2022. The policy is pathbreaking and paves the way for meeting the target of production of 5 million tonnes of Green hydrogen by 2030 and the related development of renewable energy capacity.

Govt has taken several steps to incentivize promotion of Green fuels. Govt. has targeted blending of 20% ethanol in Petrol by 2025 and 5% biodiesel in diesel by 2030. In order to augment availability of biofuels, Govt. is promoting 2G ethanol as well as setting up of 5000 plants for production of 15 TMT of CBG.

In today’s world, knowledge is treated as the key to success. Knowledge might be power, but it is much more powerful when it is shared. Information is really just the data or details of something, but knowledge taps into the experience and context of somebody who has understood and used that data. Some people believe that it is good to share as much information as possible in scientific research, business and the academic world. Others believe that some information is too important or too valuable to be shared freely and it is better to keep the information confidential. Some organizations try to conceal information because they believe they have invested in resources to research in a specific direction and they should receive the advantage of their investment.

In reference to modern data sharing, open science, open data and open access movement are also steadily growing in recognition. Most people would probably agree without hesitation that data sharing and the communication of scientific findings, technical expertise and knowledge has brought humanity where it is now, and still is one of the cornerstones of modern civilization. Thus, the publication of scientific data is an essential necessity.

With the objective to boost productivity, cut down on repeat mistakes, and to build on other experience, this is a humble beginning to get the latest technological advancements in the refining and Petrochemicals field and make it accessible to others.

This edition has been possible due to overwhelming response and contribution by the individuals and organisations. I hope this journal will help all stakeholders connected with energy sector both in public and private sector to remain abreast with the latest technological developments and formulate their strategies and action plans.

(Alok Sharma)
Executive Director

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Petrochemicals

1.1 Propylene Derivative Petrochemical Project Commissioning Experience

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BPCL Kochi Refinery

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1.1.1 Abstract

Considering disruption in alternate energy sources, advent of electric vehicles and change in consumer mobility pattern, a substantial reduction in fuels demand growth rate is expected. In order to overcome this predicted threat, fulfil the BPCL aspirations & de-risk its business, BPCL group refineries had undertaken visioning exercises and identified key focus area towards production of Petrochemicals producing both Commodity and Niche derivatives.

BPCL group refinery Kochi Refinery (KR) commissioned a Petro FCC (as a part of Integrated Refinery Expansion Project) to produce 500 KTA of Propylene which needs to be valorized to Petro chemicals. PDPP was envisaged to utilize 250 KTA of Propylene to produce niche petrochemicals Acrylic acid, Oxo alcohol and Acrylates.

PDPP project was mechanically completed and commissioning activities were in progress.. However, the covid pandemic disruption affected the project in a major way and affected the travel of foreign licensors to project site for supervising the commissioning activities. BPCL had to adopt innovative processes to engage the process licensors, who agreed to provide round the clock remote support if BPCL shares the DCS screens. BPCL established remote devices such as helmet mounted cameras, intrinsically safe mobile phones, and web interface for DCS screen sharing with dedicated Wi-Fi system. The aforesaid innovative approach with the support of Schneider electric, resulted in safe commissioning of all the three units of PDPP complex.

1.1.2 Introduction

BPCL group refineries have an installed crude processing capacity of 38.3 MMTPA post implementation of approved projects. Prior to entry into the field of petrochemicals, BPCL group refineries configuration was predominantly skewed towards transportation fuels. However considering disruption in alternate energy sources, advent of electric vehicles and change in consumer mobility pattern, a substantial reduction in the growth rate of fuels demand is expected in the future. In order to overcome this predicted threat, fulfil the BPCL aspirations & de-risk its business, BPCL group refineries had undertaken visioning exercises and identified key focus area as diversification into Petrochemicals, in future.

World over petrochemicals consumption is benchmarked in terms of per capita consumption of polymer. India's per capita polymer consumption of ~ 8.0 – 10 kg, is far below the world average of about 35 kg, USA's 90 kg and China's 46 kg giving enough indication of potential growth of Petrochemical industry. Also, a committee constituted by Ministry on India's Petro Chemical Vision 2030 envisages investments to the order of USD 40 – 60 billion to meet growing Petro chemicals demand in India. Based on relatively robust growth rates and current low levels of consumption, petrochemicals would provide an alternate hedge for Indian Refineries. Hence as a strategy BPCL group refinery future expansions are oriented towards production of Petrochemicals producing both Commodity and Niche derivatives.

1.1.3 Propylene Derivatives Petrochemical Project (PDPP)

Prior to PDPP, BPCL group refineries produced Benzene, Toluene & Poly Propylene Feed Stock (as petrochemicals) at its Mumbai & Kochi refineries with a typical production of about 243 kilo tons per annum (KTA). BPCL group refinery Kochi Refinery (KR) commissioned a Petro FCC (as a part of Integrated Refinery Expansion Project) to produce 500 KTA of Propylene which needs to be valorized to Petro chemicals. PDPP was envisaged to utilize 250 KTA of Propylene to produce niche petrochemicals Acrylic acid, Oxo alcohol and Acrylates as under:

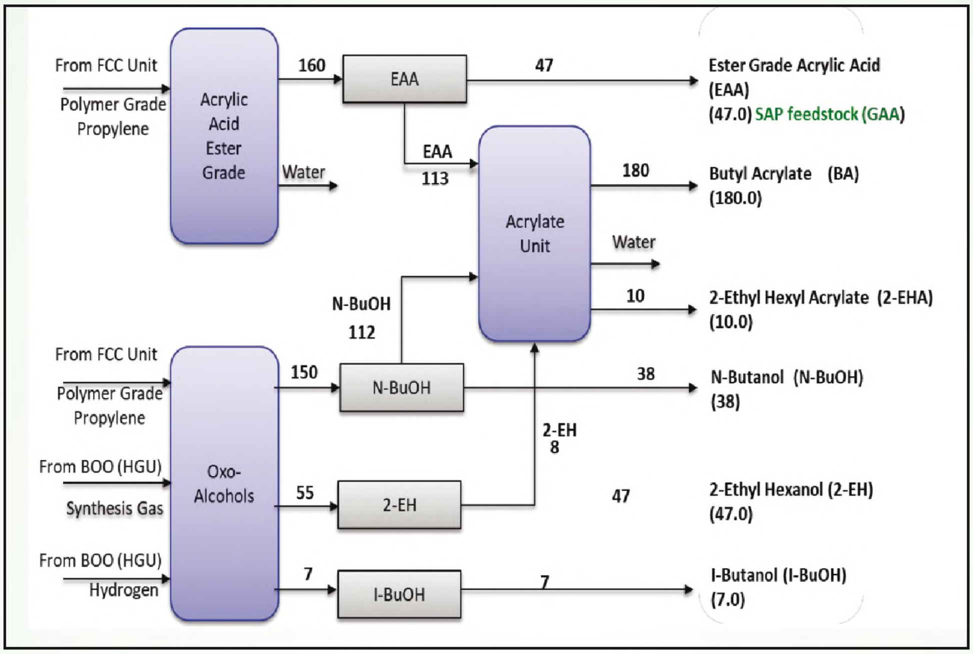
Product	Saleable Annual Quantity (KTA)
Acrylic acid	47
Butyl Acrylate	180
2 Ethyl Hexyl Acrylate	10
Normal Butanol	38
2 Ethyl Hexanol	47
Iso Butanol	7

The typical end uses of PDPP petrochemical products are as below:

Products	Typical End Use
Acrylic Acid	Detergents, pulp & paper, textiles, surface coatings and water treatment
Butyl Acrylate	Paints and coatings, Resins, Adhesives, Dispersions, Printing inks, Sealants, Pressure sensitive tapes
2-Ethyl Hexyl Acrylate	
N-Butanol	Plasticizers, Solvent, Paints and Coatings, Adhesives
I-Butanol	
2-Ethyl Hexanol	

1.1.4 Project Details

PDPP was implemented at a project cost of approx. Rs. 6200 crore. Technology was



sourced from reputed international licensors after a detailed two stage search process consisting of Expression of Interest (EOI) followed by tendering activity.

Engineers India Ltd (EIL) were appointed as the Project Management Consultant (PMC). Environmental clearance was accorded to the project by Ministry of Environment (MoEF) on 15 May, 2015. Synthesis gas and Hydrogen feedstock required for the project is being supplied on Build Own Operate (BOO) basis by Prod Air products India Ltd.

Acrylic acid and Acrylates unit are the units being set up first time in the country. Oxo alcohol, capacity is world scale catering to internal Acrylates consumption and merchant sales. The block diagram of the complex is shown below (qty in 1000 tons).

Technology characteristics:

- Closely guarded technology.
- Limited number of producers/technology licensors
- High capital investment for relatively smaller capacity.
- Limited number of operating plants for some technologies.

Challenges encountered during implementation:

- Unfamiliar nature of Niche/Specialty petrochemical project for BPCL and EIL (PMC) - First such project in India.
- Process related aspects related to polymerization tendency.

Procurement related:

- Long lead time for delivery of critical items like Acrylic Acid Reactor, Refrigeration System, and Incinerator etc.
- Limited number of vendors.
- Specialized nature/metallurgy of equipment.

1.15 Alternative to conventional way of commissioning

PDPP project was mechanically complete and commissioning activities were in progress during the Feb-Mar 2020 period. However the Covid pandemic disruption affected the project in a major way. Many commissioning experts (Foreign nationals) from the side of Process licensors and equipment vendors had been mobilized at site during February and March 2020 and were engaged in commissioning activities of equipment and units. During March 2020, when lockdown was declared, borders closed and only staff identified as essential were allowed to travel and work on-site, others worked remotely, where ever possible. This sudden change necessitated relook at work-practices concerning working conditions, employee engagement & training, efficiency enhancement and communication, without compromising on safety. Most of the site mobilized licensors left the site during second half of March 2020 owing to the spread of COVID 19 pandemic across the globe. After several follow ups with ministry, permissions were obtained to allow experts at site for essential activities. However, Licensor were not in a position to travel to site under the Covid situation. Many of the experts had informed that they may be able to travel earliest by the beginning of September 2020, hoping that the epidemic spread situation will improve. In case it materializes, the experts would have to undergo quarantine as per the COVID SOP established at work site and within the country. However due to a surge in Covid infection cases (second wave), the Licensors deferred travel plans again due to their Govt. / organization directives. The Licensor agreed to provide round the clock remote support, if BPCL agrees to share DCS console screen and video footage of plant activities with helmet mounted cameras. The "New Normal" conditions also made categorization of activities by rendering higher priority to core activities necessary for bringing the new units online safely.

With the assistance of Schneider electric, a Secure Gateway was established in the communication server system that acts as a conduit between users in remote locations and In Touch applications running on a communication protocol host in the data center. The secure gateway is installed in a protection zone to route all In Touch network data through a SSL based connection. This server arrangement enabled the commissioning team to avail remote support from licensor 24X7. Being first of its kind in India, BPCL has successfully commissioned PDPP complex by adopting this innovative technology that consists of remote devices such as helmet mounted cameras (see Image 1 below), intrinsically safe mobile phones, and web interface for DCS screen sharing, social media services, virtual meeting interfaces, secure gateway and dedicated Wi-Fi system for availing Licensor support.

Image 1:- Use of helmet mounted 'REAL WEAR' device for on the spot two way communication in Acrylic acid unit

Image 2:- Use of helmet mounted 'REAL WEAR' device for on the spot two way communication in Acrylates unit.

Image 3:- Use of helmet mounted 'REAL WEAR' device for on the spot two way communication in Oxo alcohol unit.

Image 4:- Use of helmet mounted 'REAL WEAR' device for on the spot two way communication in Offsites and utilities unit

1.1.6 Innovations adopted in PDPP complex

During the commissioning of PDPP project, BPCL-KR developed innovative schemes to sustain the plant operation with better safety by integrating package items installed in the units of PDPP.

Some of the innovative schemes developed are:

- Integration of chilled water lines from one unit's tank farm to other unit's tank farm for cooling of tank inventories.
- Developed schemes to run package item equipment individually (Incinerator) which resulted in reduced start up time.
- Innovative schemes, by which other units in PDPP can send their effluents without any hindrance irrespective of the unit run condition/shutdown condition.
- Developed schemes for better effluent management. Ex: installation of filter cleaning area and filter cleaning effluent pits. Installation of pumps at underground vessel sump pits. Etc.

1.1.7 Conclusion:

The onset of COVID 19 pandemic can be termed as a 'silver lining' which has enabled opening up a new and hitherto unexplored concepts, thereby leading to a digital transformation in commissioning activities of this petrochemical project. It has highlighted the importance of moving towards digitalization. BPCL is adopting new approaches and techniques are being brainstormed to create data-driven (AI enabled) and self-learning systems, concerning safety and efficiency enhancement. The success of this digitally transformation allowed BPCL to commission first of its kind niche petrochemical project. This innovative experience of BPCL can be taken as a model for other sister companies venturing into challenging projects to enable growth and increase investor value.

* * *

1.2 Indian Insight on Crude Oil-to-Chemicals (COTC): Future of Refining

Author: Ekta Powar, Process Manager, Indian Oil Corporation Limited

Ms. Ekta Powar is working as a Process Manager at Panipat Naphtha Cracker in IndianOil Corporation Limited. She is looking after monitoring of MEG, glycols producing unit, Effluent Treatment Plant (ETP), N2-O_2 BOO plant and MEG Revamp project. She has also worked as production engineer in Naphtha Cracker Unit, planning and coordination department and NCU/ AU unit monitoring

1.2.1 Abstract

With the swelling crude oil prices, flattening demands and plunging margins of transportation fuels, the likelihood of sustaining a standalone refinery operation seems very difficult in upcoming future. Demand of petrochemicals and downstream high value chemicals is continuously increasing globally. In this scenario, possibility to fulfill the increasing market demand by producing petrochemicals from crude oil appears to be a very promising strategy. In recent times, refineries are exploring ways to integrate petrochemical complexes with the refineries to realize striking margins in this sector. Further downward integration of petrochemicals to downstream chemicals adds even more worth to the value chain. This paper intends to provide an insight on how Crude oil to Chemicals (COTC) fits into the landscape of Refinery and Petrochemical integrations, its comparison with traditional refining configuration, technologies available for COTC and its strategic role in preparedness of the refineries for battling with ongoing and upcoming challenges in refining sector.

1.2.2 Introduction

During the last century, crude oil has played a vital role as primary source of energy in transportation, energy and manufacturing sector. Oil refineries play a significant role in providing the usable products for these applications by converting crude oil to products via various processes.

In refineries, share of petroleum derived transportation fuels i.e. gasoline, diesel, and fuel oil accounts for over 60% of the products manufactured [1]. In current times, refinery margins are continuously shrinking due to plateauing demand for transportation fuels and perennially changing environmental regulations on these fuels. Refineries are forced to explore ways to remain profitable in the near future by improving the yield of high-value products, reducing input costs with measures like expanding crude oil basket and exploring opportunities in downward integration to produce petrochemical and higher-margin chemicals in place of transportation fuels.

Crude Oil-to-Chemicals (COTC) is a powerful industry driver and a strong area of interest for all integrated refineries and chemicals producers in Asia/Pacific, China, the Middle East and Eastern Europe. COTC technology implementation becomes even more important considering the facts based on the forecasts which predict a slowing of transportation fuels growth approaching 2040 with market being adequately supplied with hybrids and Electric Vehicles, while the growth in chemicals is expected to go up considering the population and middle class wealth continues will rise increasing in demand for packaging, updating lifestyle and even in automobile sector In recent times, petrochemical products have become an integral part of modern societies with products like plastics, fertilisers, packaging, clothing, digital devices, medical equipment, detergents, vehicle tires etc. Petrochemical products are also used as part of the modern energy system in wind turbine blades, solar panels, battery cells, insulation for buildings, and automobile parts.

1.2.3 Challenges of a standalone Refinery

In refineries, crude oil is processed through these three processes namely, a) Separation Process; b) Conversion Process and c) Treatment Process.

In separation process, crude oil is separated into useful products such as liquefied petroleum gas (LPG), Naphtha, Motor Spirit (MS), High Speed Diesel (HSD), Aviation Turbine fuel (ATF), Fuel oil(FO), Bitumen and pet-coke. In conversion process, heavy hydrocarbon molecules are converted to lighter molecules adding value to product chain. In final stage of treatment, products from conversion stage are further treated to make them usable as final products complying with desired specifications and environmental guidelines.

Products from a refinery, their share and end use are illustrated in figure-1 below.

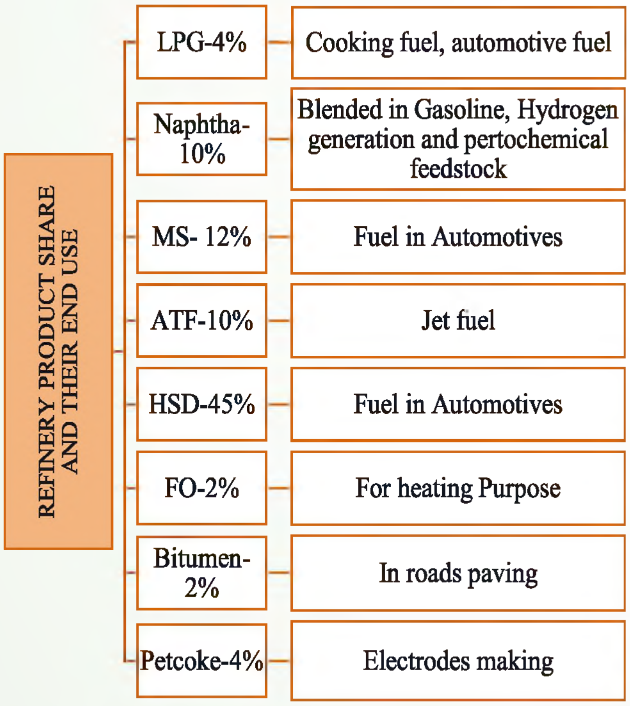


Figure 1: Refinery products share and their end use

In a traditional way of operating the refinery business, refiners are going to face an array of challenges related to operations, environmental concerns and sales of the products. Share of the average oil barrel dedicated to transportation fuel will peak at 58% in 2025 and begin to plateau after 2030[3]. Primary reasons for flattening the petroleum products demand will be penetration of electric vehicles in the market because of its cost effectiveness and being better for the environment. As per the forecast for next 25 years, there will be an increased uptake of alternative drive technologies like hydrogen, biofuels etc. for commercial vehicles which will cause a drop in demand for transportation fuels. With this decline in demand, refiners will face the challenges in operating the refineries in an economic manner. Figure-2 below illustrates the plateauing of demand in from 2035 onwards for conventional fuels.

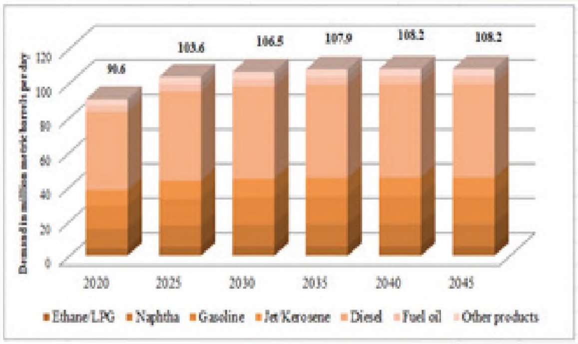


Figure 2: Demand forecast of conventional refinery fuels

With passing time, environmental regulations on transportation fuels are perennially becoming stringent and in order to meet these regulations, refineries are incurring extremely high expenditures for adding treatment facilities like hydro treatments for producing cleaner fuels. These treatment units involve substantial capital and operating cost for refineries. The cost of compliance acts as a deterrent for refinery margins and poses hurdle in the path of refineries planning for capacity expansions.

Also, with stringent environmental regulations in place, much cleaner gaseous fuels are replacing liquid feeds in refinery units as fuel/ feed. Also, Naphtha stream blending in gasoline and use as a feed in hydrogen generation unit is restricted because of its high sulphur content, making Naphtha a surplus stream from refinery. Due to this, Naphtha is exported at low prices to sustain refinery operation. On the other hand, Naphtha is an ideal feedstock for petrochemical process. Paraffinic/straight chain naphtha is a suitable feed to Naphtha Cracker Unit (NCU) and Aromatic Naphtha is apt for Para-Xylene (PX)/Para-Terephthalic Acid (PTA) Complex as a feed. Naphtha supply to petrochemical complex results in olefin and aromatics production, which are precursor to petrochemicals production.

1.2.4 Integration of Petrochemicals with Refinery

Integration of a refinery and petrochemical complex implies identifying synergies and optimising them for operational and economic gains by exchanging feedstocks, by-products, and utilities between both the facilities. The integrated complex provides an opportunity for optimal molecule and resources management for better bottom-line for the company. Refineries aim to maximize fuels as final products and, in the process, opportunities for extracting higher value is underutilised. For example, naphtha streams in a refinery are reformed to yield reformate which is used in gasoline as a blend, and propylene produced in the FCC is used to produce alkylate that again is used as blend in the gasoline pool or propylene is blended in LPG as a fuel. Preferably, reformate is an appropriate feed to produce aromatics, and the propylene can be further processed to produce high-value polypropylene. We illustrate a typical stream sharing between refinery and petrochemical complex below in figure-3.

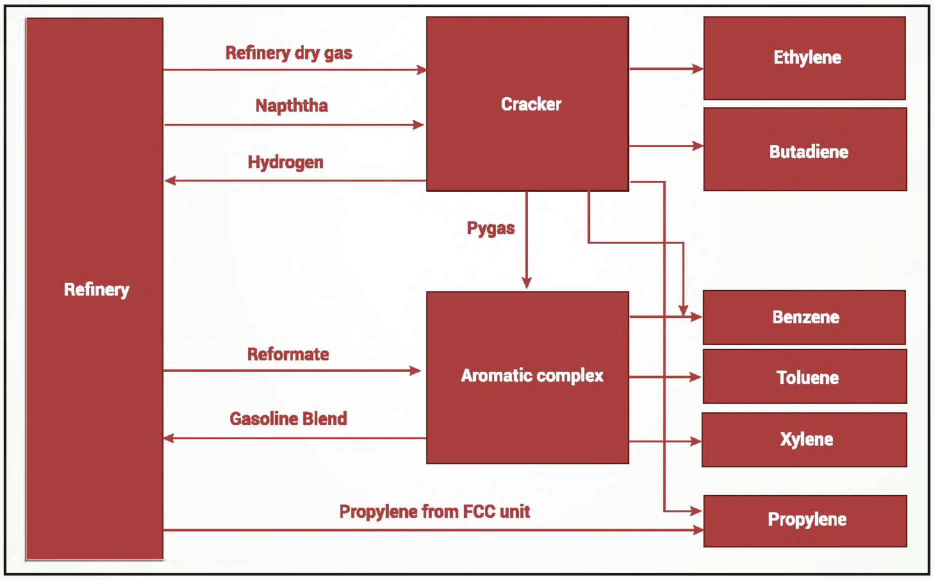


Fig. 3 Typical Refinery and Petrochemical Integration Block Flow Diagram

Some of the stream sharing options for an integrated refinery and petrochemical complex adds to the bottom-line and provide flexibility in the business.

1) Hydrogen sharing between the refinery, cracker and aromatics increases flexibility.
2) Recovery of ethylene and propylene from FCC/Coker off gas in Ethylene Recovery Unit (ERU).
3) Recovery of 1-3 butadiene/butenes-1/butane-2 from C4 Mix stream, recycling to the cracker, or adding to LPG after hydrogenation.
4) Pyrolysis gasoline up-gradation to elude negative value products generation (Negative value products are those whose value is lower than the Naphtha feed to cracker). Some options include:

- Recovery of di-cyclopentadiene (DCPD) from C5 di-olefins. Alternately, C5 stream can be hydrogenated and recycled to the cracker or blended to the gasoline pool as an octane booster.
- Recovery of benzene from pyrolysis

gasoline that contains over 30 wt% benzene by extractive distillation technology.

- C7-C8 stream also acts as an excellent octane booster for gasoline pool. Alternatively, C7–C8 cut can also be routed to PX-PTA for para-xylene (PX) yield enhancement.
- The C9+ cut can be absorbed in the diesel pool.

5) Pyrolysis fuel oil with low viscosity can be blended with refinery fuel oil pool or can be used as a feed for Carbon Black Feed Stock (CBFS) recovery.

6) Initiatives like INDMAX, a flagship venture by IOCL R&D helps refiners to produce higher yields of ethylene, propylene and LPG along with high octane gasoline from various resid/non-resid feedstocks. Robust and high performing design of INDMAX unit has proven it's commercially viability with three already commissioned and successfully running units. Four other units of 2-3 MMTPA capacity are at various stage of design in different Indian refineries.

INDMAX technology employs catalyst system having higher metal tolerance, higher selectivity towards light olefins and lower dry gas yield.

Typical light olefins yield on wt% of feed is shown below:

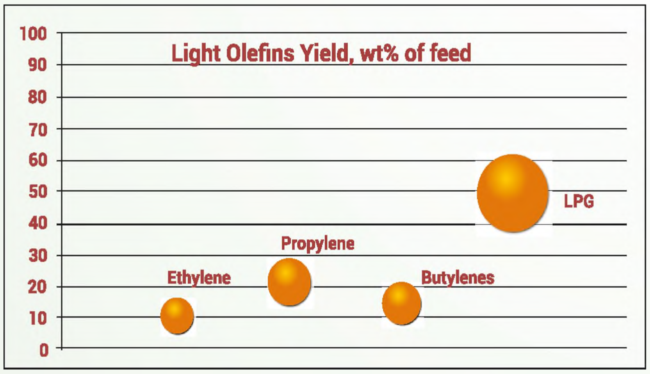


Fig. 4 INDMAX Unit Typical light olefins yield on wt% of feed [4]

In the non-integrated scenario, refineries are exporting naphtha to other autonomous steam crackers and aromatic complexes. However, several benefits can be accrued when refinery and petrochemical complexes are integrated at a single site, allowing exchange of return streams/intermediates and taking benefits of the synergies.

The advantages of a synergic integrated complex are listed below:

- Capital cost, operating cost and resource optimization and increasing profitability attributed to:
  - » Shared infrastructure and utilities.
  - » Lower transportation costs.
  - » Minimization of fixed overheads.
- Surplus feedstocks availability for petrochemicals.
- Very low transportation cost of feedstock/ intermediates to/from petrochemicals.
- Dampened effect of demand/price fluctuations of type of product on profitability by compensating with other products margins.
- Olefins command significant price advantage over transportation fuels.
- More options exist to for streams routing to respond to market demands.
- Value enhancement from integrating intermediate/ return streams.

Path forward for Petrochemical Industry in India

Petrochemical industry plays a pivotal role in the country's economy. The sector serves as the backbone for the development of various other key sectors, such as agriculture, infrastructure, health care, automobile, textiles and consumer durables. It is one of the fastest growing sectors, with demand growing at a CAGR of 8%-plus over the last five years [5]. The penetration level of petrochemicals in India is, however, far lower than the global average. As per a report published by FICCI in year 2014-15, India's per capita polymer consumption is 11 kg against the world average of 28 Kg/capita showing significant headroom for growth in the country.

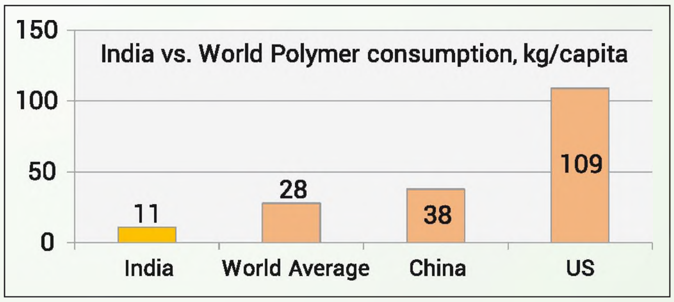


Fig 5: India's per capita polymer consumption comparison, kg/person

India is developing to be one of the fastest growing economies in the world. India is the fourth largest refiner in the world, with the capacity of 250 MMTPA of crude processing. Country's refining capacity aims to serve national demand of petroleum products and to supply petroleum products to neighbouring Asian countries.

In India, a large population and comparatively low per capita consumption of polymers shows the capacity of high growth margin for the petrochemical products. In today's changing scenario, chemicals and petrochemicals also have a vital role to play in economic growth for the areas like agriculture, infrastructure, health care, textiles and consumables. Petrochemical products cover the entire range of consumables and durables, starting from fabrics, housing, construction, furnishings, automobiles parts, household items, toys, cultivation, horticulture, irrigation system and packaging to medical supplies.

Some relevant projections for the Indian refining and petrochemicals sector are [6]:

- Domestic refining capacity is projected to reach up to 553 MMTPA by 2040 to meet domestic growing demand from current capacity of 249 MMTPA.
- Petrochemical market in India stands at 42.50 MMTPA presently and is estimated to reach up to 49.62 MMTPA by 2025.
- Additional propylene capacity of 5 MMTPA of polypropylene (PP) capacity is expected to be added by 2025.
- Around 4 MMTPA of high-density polyethylene

Source: maps of India

(HDPE) and low-linear-density polyethylene (LLDPE) capacity is forecast to be added by 2025.

- By 2025, India is forecasted to have a shortfall of Purified Terephthalic Acid (PTA) and Para-Xylene (PX) of 1.8 MMTPA and 0.6 MMTPA, respectively.

Considering the facts above, pathway to India's future towards petrochemical business holds tremendous potential of growth.

In last two years, Covid-19 had hampered the growth momentum of the petrochemical market in India, disrupting the supply chain along with weakening the demand. However, the level of impact and the recovery trajectory have been different across the petrochemical value chain. The supply of petrochemical was majorly been affected owing to labor shortage, logistical challenges, low utilization rates, and the reduction in operational expenses.

The petrochemical market witnessed a notable change in its consumption pattern amid the pandemic. Industries, such as the automotive, construction, electronics, textiles, and rigid packaging experienced a sudden slump in demand. On the other hand, the demand for petrochemicals from flexible packaging, personal care, and healthcare had risen sharply. The pandemic brought about various changes in the India petrochemical market, including digitization, increased consolidation activities, and a focus on scenario-based planning.

Chemical industries were temporarily hampered due to first and second wave of Covid-19 due to disruption of supply chain along with weakening the demand. On the positive note, chemical industry has witnessed a strong recovery since the beginning of 2021, with demand increasing from the major end markets such as construction and health & safety. This was driven partly by a rebound in US GDP, which will likely grow between 6.0% and 6.5% during 2021 after declining by 3.5% in 2020 [5].

1.2.5 Future of Refining: Crude Oil to Chemicals (COTC)

Currently in most refineries, petrochemicals are manufactured as side streams, keeping a primary focus on transportation fuel production. Crude oil-to-chemicals (COTC) is the technology to directly convert crude oil to high-value chemical products instead of conventional fuels. It enables the production of chemical feedstock up to 70% to 80% of the barrel against ~10-15% in a typical refinery complex [6].

Petrochemicals products are expected to be the largest driver of global oil demand growth, exceeding the demand of gasoline/diesel 2030 onwards. The global chemicals market is growing at a fast pace, with chemicals demand rise forecast of 3-3.5% by 2025-30 compared to 1-1.5% for crude oil. In view of this, integrating petrochemical complex with refineries will be essential to match the gap between local demand and supply of the products. In this scenario, non-integrated refineries will be more susceptible to demand risks. Fig-6 below explains the level of integration in refinery and petrochemical complexes.

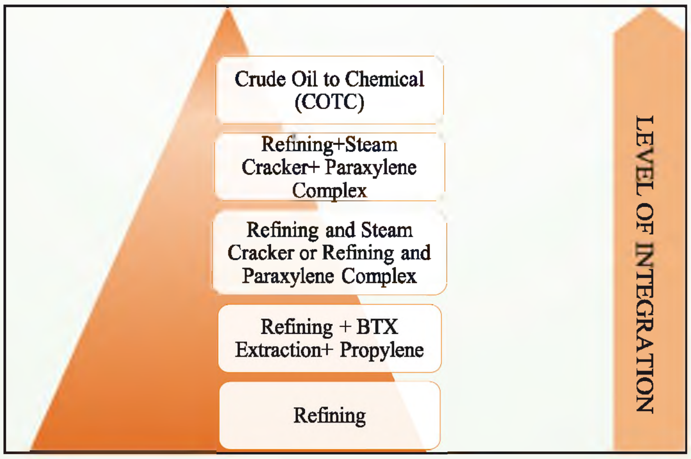


Fig 6: Typical Refinery and petrochemical integration block diagram

Crude oil to chemicals adds more value towards downstream chemicals value chains for propylene, ethylene and pyrolysis gasoline. These include cumene/phenol/Isopropyl Alcohol (IPA), propylene oxide (PO)/propylene glycol/polyol and styrene (as a co-product of PO). A substantial demand and growth rate exists for these downstream specialty petrochemicals to support an investment in India. Such strategic shifts have been found to increase margins, while also raising integration, complexity, and output volumes at a disruptive scale. A typical configuration of COTC plant is shown below in fig-7.

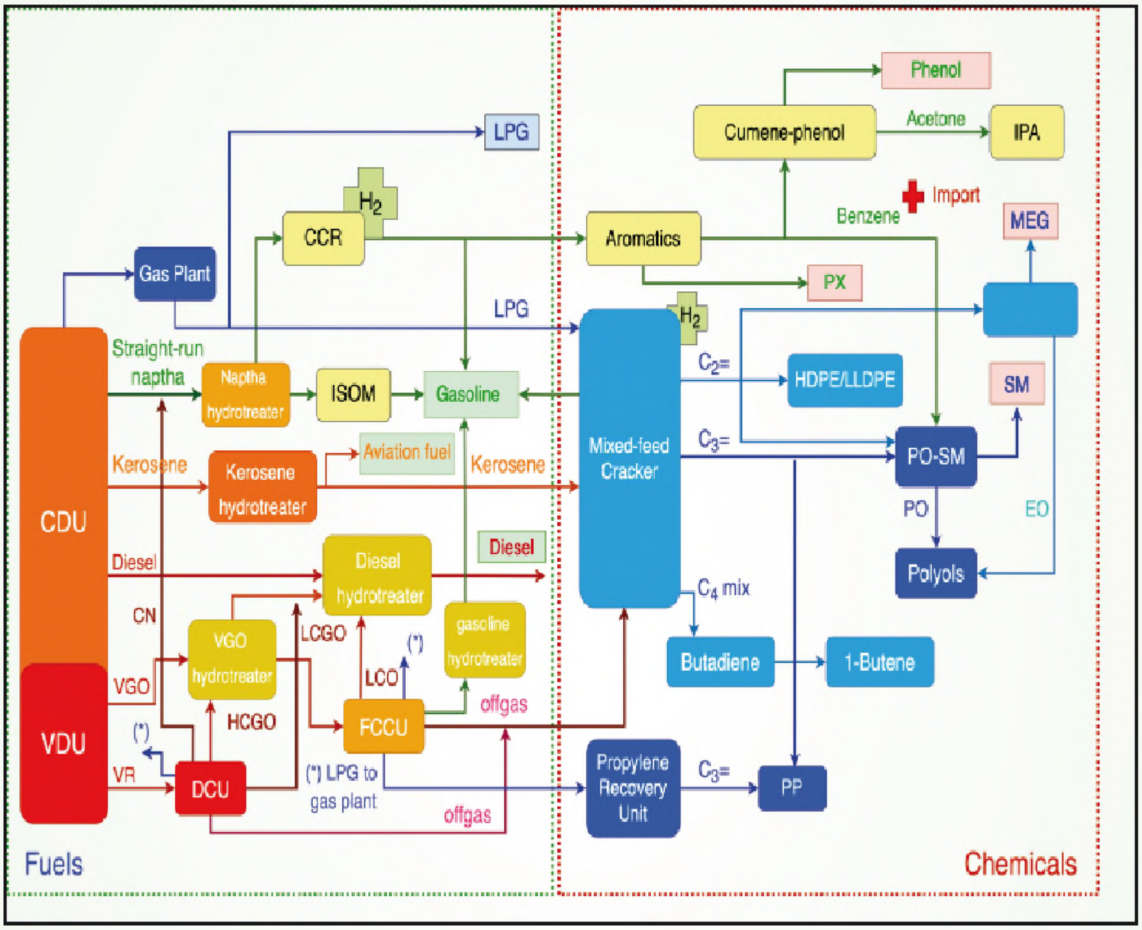


Fig 7: Configuration of a typical COTC plant

COTC continues to garner the attention of integrated refineries and chemicals producers in Asia Pacific, China, the Middle East and Eastern Europe. However, despite its growing popularity, only a few well-equipped integrated oil companies globally are looking to deploy this technology to make inroads in the petrochemical industry. These include some large companies in the U.S., Middle East and China. Major COTC players are tabulated below in Table-1. By expanding the usage of crude oil in the chemical industry, COTC is expected to change and possibly disrupt the market landscape by 2025-2030. National and independent oil companies are expected to invest further in this segment as COTC adoption grows [7].

Global Crude Oil to Chemicals Plants						
Project	**Refinery capacity (MMTPA)**	**Para-Xylene Capacity**	**Cracker Capacity**	**Estimated Conversion of chemical/ bbl of oil (%)**	**Investment ($ Billion)**	**Start of operation**
Hengli Petrochemical	20	4.3	1.5	42	11.4	2018
Zhejian Petroleum and Chemical (ZPC) Phase-I	20	4	1.4	45	12	2019
Hengyi (Brunei) PMB Refinery-Petrochem	8	1.5	0.5	>40	3.45	2019
Zhejian Petroleum and Chemical (ZPC) Phase-2	20	4.8	1.2	50	12	2021
Shenghong refinery and Integrated Petrochem	16	2.8	1.1	60	11	2021
Amanco/SABIC Jv	20	-	3	45	20	2025

Table-1: Major COTC Plants across the globe [7]

1.2.6 Case Study: COTC vs Non-integrated complexes

A case study is prepared to draw a comparison between COTC configuration vs non-integrated complex. In this case study, following three cases are studied and compared based on their economic value addition to the company based on Nov'21 feed and product prices. (Source: spglobal).

Case-1: Standalone Refinery

Case-1 represents a standalone refinery with 15 MMTPA of crude processing capacity targeting mainly on production of fuels. This refinery is equipped with traditional refining units like CDU/VDU, NHT, FCCU, CCR, isomerization, VGO hydrotreater and Delayed Coker Unit.

This configuration is aims at maximizing diesel and gasoline from the refinery and propylene produced from FCC is routed to LPG pool.

Case-2: Integrated Refinery with steam cracker and aromatics complex

In this case, an integrated refinery and petrochemical complex with 15 MMTPA of crude capacity equipped with all refining units as case-1 and also integrated with aromatics and steam cracker complex.

Combination of feed stock to cracker is considered as:

- Straight run Naphtha and kerosene.
- Off gases from FCC and coker (Rich in olefins and ethane/propane).
- FCC propylene.

The proposed configuration is equipped with these downstream units/facilities:

- Polypropylene Unit to produce PP.
- Dedicated HDPE unit.
- Swing unit to produce HDPE and LLDPE.
- Butene-1 unit for internal requirement of co-monomer in PE plants.
- Benzene Extraction Unit for Benzene production from Pyrolysis Gasoline Stream.
- Hydrogenated C5 and C6 raffinate cut is recycled back to the cracker.
- The C7-C8 stream is routed to the gasoline pool and C9+ stream is routed to diesel.

Case-3: Integrated Refinery and Petrochemical Complex along with downstream chemicals (COTC)

Case-3 represents an integrated refinery and petrochemical complex same as Case-2 and further integrates it with downstream high value chemicals units like Isopropyl Alcohol

Table-2 below represents the comparison of unit configuration of cases taken in the case study.

Unit Configuration			
	Case-1	**Case-2**	**Case-3**
CDU/VDU	√	√	√
NHT	√	√	√
FCCU	√	√	√
CCR	√	√	√
Isomerization	√	√	√
VGO-HDT	√	√	√
FCCU	√	√	√
Kerosene Treater	√	√	√
DCU	√	√	√
ERU		√	√
Aromatics complex		√	√
Mixed feed cracker		√	√
PP		√	√
HDPE/LLDPE (SWING)		√	√
HDPE		√	√
MEG		√	√
Propylene oxide (PO)/Styrene Monomer (SM)			√
Polyols			√
IPA			√
Cumene			√
Phenol			√
Butadiene		√	√
Butene-1		√	√

Table 2: Unit configuration of cases into comparison

Based on unit configuration, cases are compared based on their product pattern, share of fuel products, share of petrochemical products and their value addition to the bottom-line of the complex. These details are given below Table-3.

Table 3: Product Patten and Economic Analysis of Cases				
	UoM	**Case-1**	**Case-2**	**Case-3**
Crude t'put	MMTPA	15	15	15
LPG	KTPA	600	480	480
Naphtha	KTPA	1500	0	0
Gasoline	KTPA	1800	1800	1800
ATF	KTPA	1500	1500	1480
Diesel	KTPA	6750	6000	6000
Total fuel %		81%	65%	65%
PP	KTPA	--	600	400
HDPE	KTPA	--	300	300
LLDPE/HDPE	KTPA	--	350	350
MEG	KTPA	--	300	300
Butadiene	KTPA	--	200	160
Butene-I	KTPA	--	20	60
PTA	KTPA	--	580	420
Benzene	KTPA	--	20	10
Styrene	KTPA	--	0	50
Phenol	KTPA	--	0	100
Cumene	KTPA	--	0	60
IPA	KTPA	--	0	100
Polyols	KTPA	--	0	80
Petrochemicals%	%	0%	16%	16%
GRM	**Rs./barrel of crude**	**603**	**1024**	**1126**

*Based on Nov'21 prices. Source: sp global

Table-3: Product pattern and economic analysis of cases

From the table-3 above, it is clear that case 3-COTC technology garners more gross margins of Rs. 1126/bbl of crude processed as against Standalone refinery setup (Rs. 603/bbl of crude) and Integrated Refinery & Petrochemical Complex (Rs. 1024/bbl of crude). Integration to downstream high value chemicals adds value to the system and makes it more robust and resistant to fluctuations in demand. Crude-to-chemicals conversion to be more profitable, avenues may be explored for competitive crude pricing, export-oriented product pricing, and residue upgrade investments for heavier crude processing, among others.

Further, there are developments in olefin producing technology by selecting most appropriate feed of n-paraffins rich naphtha. In C4-C10 cut, n-paraffin feed is separated and used as a feed to steam cracker which gives higher olefins yield, longer run length of cracker furnaces, and reduced coking and lesser low value products yield. In order to move further in this direction and reducing petroleum production from the complex, design may be adopted to crack kerosene cut (C10-C14) in steam crackers with appropriate design.

On the other hand, there are a few risks associated with COTC technology which may decide for owners for taking decision on implementation of this technology:

- COTC being a cost intensive technology needs a considerable investment for chemical units' installation. Return on investment on these units will depend on region, local demand pattern.
- In major COTC players, China has the biggest capacity installation in the form of two large projects - Hengli Petrochemicals (42% conversion per barrel of oil) and Zhejiang Petroleum and Chemical (COTC phase 1, achieved 45% conversion per barrel of oil). Considering this, there is a risk of oversupply of petrochemicals and high value chemicals in the market of the Asia-Pacific region.

1.2.7 Conclusions

The paper presented a study of merits of Crude Oil to Chemicals technology over non-integrated complexes. In forecasted challenging times, COTC will emerge as vital technology to tackle the market dynamics, price fluctuations to remain profitable. COTC plants produce a large volume of chemicals, thereby disrupting the supply demand dynamics of end-product chemicals; end-product market dynamics are likely to play a major role in assessing the feasibility of the COTC plant. The large-scale adoption of COTC provides opportunities for operational integration in refineries to align themselves with the emerging trend of expanding business portfolios into petrochemicals. However, the type and level of integration are principally driven by feedstock availability and pricing that varies from region to region. For India, which depends on crude oil feedstock import (>90%) and with limited availability of natural gas, implementing crude-to-chemicals technology will be governed by capital efficiency of the project and demand for the petrochemicals project in the local region.

1.2.8 References

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* * *

1.3 Refineries of the Future Producing Petrochemicals

Authors: Prateek Gupta, Configuration Specialist & Mr Stan Carp, Senior Manager
Honeywell UOP

Mr. Prateek Gupta is Configuration Specialist and at present working with IPS- Configuration and Process Consultancy, Petrochemical and Refining Technologies (PRT), Honeywell UOP. He has over 15 Years of international experience. Expert on providing strategic direction to clients on proper configuration of refinery and petrochemical complex, Crude Oil to Chemicals via different pathways, Techno-economic evaluation. He is Certified Six Sigma Green Belt Expert.

Mr Stan Carp is working as Senior Manager, Configuration and Process Consultancy with UOP Honeywell. He is also Certified Six Sigma Green Belt Expert

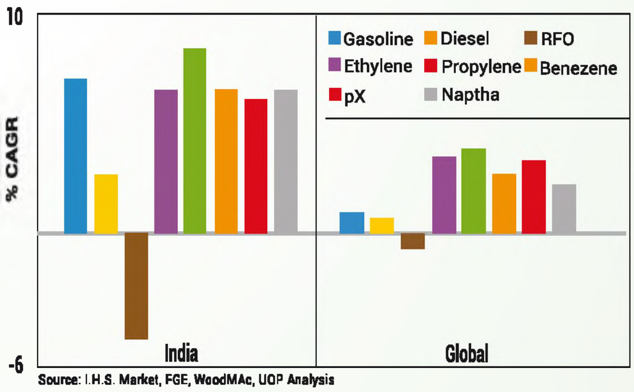
Domestic transportation fuel demand in India by 2025 is expected to grow by 50% for gasoline and 17% for diesel compared to 2019. Indian refiners currently export 17% of overall fuels production; most of the exported fuel is diesel. Reduced global demand for diesel will put downward pressure on these exports. Contributing to the excess diesel is the reduced demand for kerosene as a fuel. Since the government has been providing LPG to replace kerosene for consumers, refiners have been moving kerosene production into diesel.

Additionally, export fuel markets that have historically been supplied by India are now building their own refineries. With more regions supplying their own fuels, Indian refiners planning to export to those markets will be forced to adjust accordingly. With uncertainty in product demand and global trade dynamics, Indian refiners are under increasing pressure to chart their path forward for growth and continued competitiveness.

While global fuels demand is softening, global petrochemical demand is projected to grow nearly 1.5 times GDP, with compound annual growth rates (CAGRs) of 3-4% from 2018-2028. Similarly, for India, petrochemical demand is anticipated to grow with CAGRs up to 7.0% from 2018-2028. See Figure 1. Consumer demand for more packaging, plastics and synthetic fabrics is driving this demand growth both worldwide and in India. To take advantage of this opportunity, many in the industry are turning to petrochemical integration, an adjacent market with strong growth potential and substantially higher margins.

1.3.1 Demand Growth Forecast

Demand growth forecast (2018-28)



Source: I.H.S. Market, FGE, WoodMAc, UOP Analysis

Figure 1

In addition to projected growth in petrochemical demand, new technologies are enabling both massive increases in economies of scale and lower cost of production. World-scale refineries employing these new technologies are being built in regions with growing fuels demand, off-setting imports, and extending into petrochemicals to improve their internal rate of return (IRR). These new, world-scale integrated plants will be considerably more resilient to shrinking gasoline and diesel margins.

They will be able to service their debt and remain more competitive than much of the installed base.

Indian refiners that diversify into petrochemicals while satisfying local demand for fuels, will continue to run at capacity and will benefit from improved profitability.

Creating a Refinery of the Future

The key to unlocking these opportunities in petrochemicals lies in stepwise investments in new process technology with advanced molecular management that may include:

- Light olefin cracking to increase FCC propylene production.
- Bottom of the barrel conversion with slurry hydrocracking technology to upgrade heavy oil to fuels or intermediates for petrochemicals.
- Extension into an aromatics complex for para-xylene.
- Distillate hydrocracking to enable world-scale para-xylene production.
- Propane dehydrogenation to allow world-scale production of propylene.
- Steam cracking to extend into ethylene.

An integration case study has been developed to illustrate a potential pathway that profitably transforms an existing refinery into a Refinery of the Future. The study analyzes a base case with a product slate that is predominantly fuels, and six additional cases that incrementally increase production of petrochemicals at each step. If an existing refiner were to use this investment pathway to move from fuels to petrochemicals, the impact on flexibility, competitiveness, and profit margin could be immensely beneficial. Analysis of each step as a separate case allows for the economic benefits to be quantified.

The Base Case refinery is configured for processing 20,000 kMTA of Arab Light, producing gasoline and diesel fuels. The configuration includes a FCC as the main VGO conversion unit and a Delayed Coking unit for vacuum residue conversion. See Figure 2. The refinery is configured to produce BS-VI compliant fuels. The overall product slate is 35 wt% gasoline, 42 wt% distillate and 8 wt% LPG on a crude basis. See Table 1 for production profile and key economic performance indicators for this case and subsequent cases.

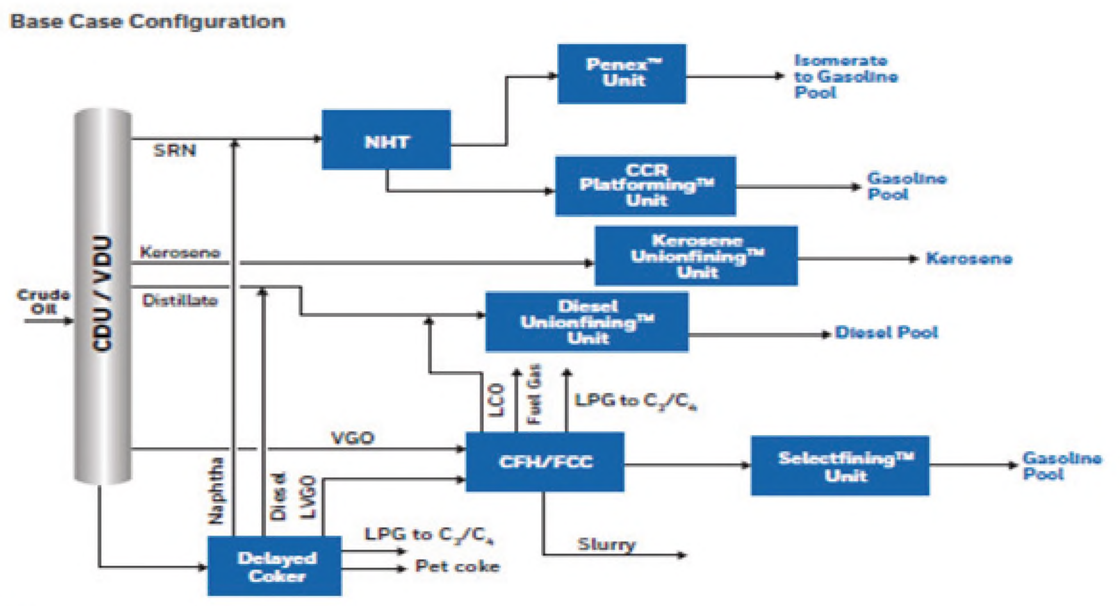


Figure 2

Case 1 adds the Total Petrochemicals/UOP Olefin Cracking Process (OCP) with propylene recovery to the existing FCC unit, reducing gasoline production and allowing the refiner to begin producing ethylene and propylene. Integration of OCP with the FCC unit enables refiners to overcome existing constraints that may prevent additional propylene production. Olefin production from the facility is 5 wt% on a crude basis, resulting in a net cash margin (NCM) increase of $4/BBL and an incremental internal rate of return (IRR) of 19% relative to the base case. See Figure 3.

Case 2 replaces the Delayed Coking unit with a Slurry Hydrocracking unit, in this case UOP Uniflex™ MC™ technology, which is based on hydrogen addition rather than carbon rejection. 98% of the vacuum residue is now converted to distillate, naphtha and LPG. The low-value unconverted product is only 2% of the unit's production. The Uniflex MC process increases residue conversion to higher value products, enabling the refiner to increase profit margin and set the foundation to maximize petrochemical production with subsequent investments. Diesel production is increased by 27% over Case 1. Upgrading the vacuum residue from $61/MT to diesel at $700/MT, is the clear economic driver. Case 2 results in a NCM increase of $3/BBL and an incremental IRR of 18% compared to Case 1.

Case 3 is major step into petrochemicals that integrates an aromatics complex into the refinery, enabling the refiner to enter into the para-xylene market. Reformate for gasoline blending is diverted to the aromatics complex, reducing production of gasoline and resulting in 1,600 kMTA of para-xylene production. Gasoline production is decreased by 30% compared to Case 2, while the refinery continues to produce a BS-VI compliant gasoline product. Increasing overall petrochemical production to 17 wt% on crude results in a NCM increase of $3/BBL and an incremental IRR of 22% relative to Case 2.

Production Profile & Economic Performance

Case Number	Base	1	2	3	4	5	6
Product, wt% Crude Processes							
Gasoline	35	34	31	22	35	36	25
Distilate	43	43	52	47	16	15	18
LPG	8	3	3	4	9	7	0
PetCoke or Pitch	5	5	1	1	1	1	1
Fuels & Loss	10	10	8	10	11	12	9
Aromatics	0	0	0	11	21	22	23
Others	0	5	5	5	5	8	24
Total Products	100	100	100	100	100	100	100
Total Petrochemicals	0	5	5	17	27	29	47
Economic Performannce Relative to Previous Case							
Net Cash Margin (NCM), SMM/year	Base	-619	+384	+424	+46	+266	+1555
Net Cash Margin (NCM), $/BBL	Base	+4	+3	+3	+1	+2	+11
Incremental IRR, %	Base	19.1	17.7	22.4	5.0	15.9	13.4

Table 1

Case 4 the Kerosene and Diesel Unionfining units are replaced with maximum conversion Unicracking units designed to produce naphtha. This enables elimination of kerosene, reduction of diesel and maximum production of heavy naphtha for para-xylene, moving the refinery into world-scale production of para-xylene. These two Unicracking technologies could be implemented stepwise with the low-cost kerosene hydrocracking option added first, followed by the diesel hydrocracking option. Employing two naphtha mode hydrocrackers enables para-xylene production to double compared to Case 3, resulting in 3,000 kMTA of para-xylene. Distillate production is reduced by 65% compared to Case 3 and overall petrochemical production increases to 27 wt% on a crude basis. Combining Cases 3 and 4 in one step enable maximum para-xylene production and result in an incremental IRR of 17% relative to Case 2. Further paraxylene production could be achieved with the UOP Toluene Methylation Process. Toluene methylation increases para-xylene by almost 50% from the same amount of reformate, and benzene production is eliminated.

Case 5 integrates a world-scale 500 kMTA UOP Oleflex™ Process Unit (propane dehydrogenation) into the refinery to further increase production of propylene from refinery produced propane. The previous cases have increased the production of LPG (5 times relative to the base case) enabling implementation of a world-scale Oleflex unit fed entirely on refinery produced propane. Recovery of the Oleflex propylene is integrated into the FCC/OCP propylene recovery system to reduce capital and improve efficiency. This additional investment increases overall petrochemical production to 29 wt% on a crude basis, and results in a NCM increase of $2/BBL and incremental IRR of 16% relative to Case 4.

Case 6 is another key step into petrochemicals that integrates a steam cracker with the refinery and aromatics complex, enabling the refiner to enter the polyethylene market. Light cracked naphtha, light straight run naphtha, LPG, and off-gases are fed to the 1,500 kMTA steam cracker. Gasoline production is decreased by 30% compared to Case 5, while the refinery continues to produce a BS-VI compliant gasoline product. This configuration increases overall petrochemical production to 47 wt% on crude basis, and results in a NCM increase of $11/BBL and an incremental IRR of 13% relative to Case 5. See Figure 4.

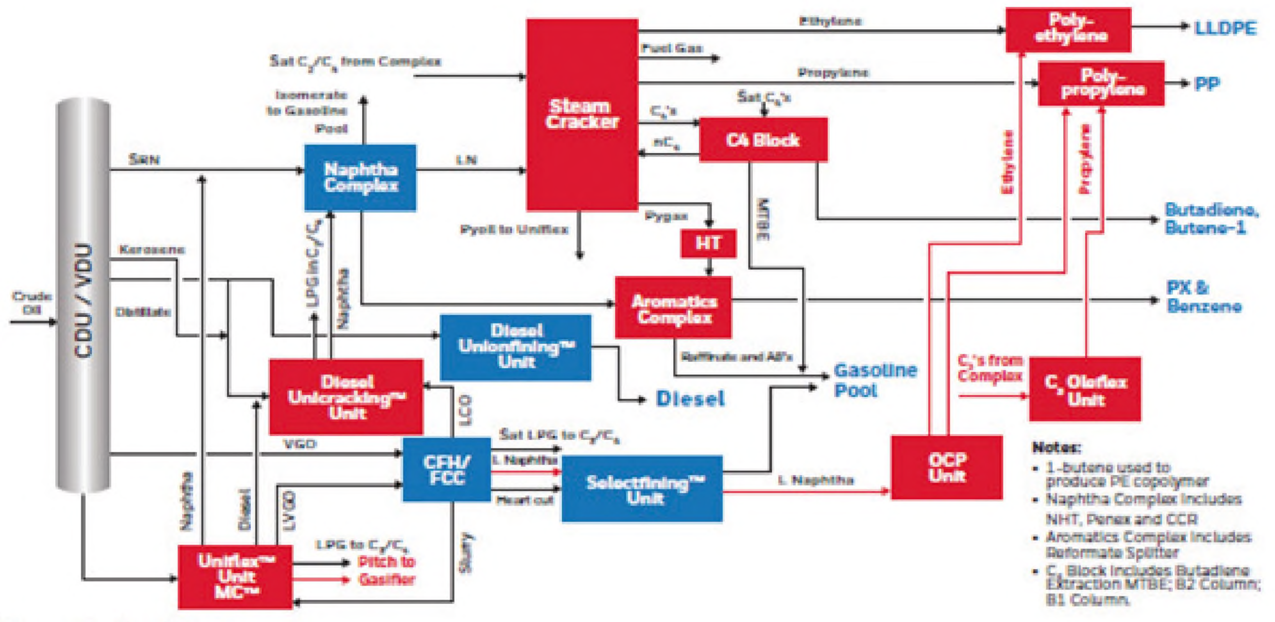


Figure 3 - Final Configuration

This study demonstrates a potential investment pathway that, over time, transforms existing assets into a Refinery of the Future. While each refiner will require a solution as unique as their refinery, the study demonstrates a strategy that is being successfully implemented for existing refineries. Many overseas refineries are embracing the petrochemical integration model and they are employing these advanced molecular management technologies. As an example, a refinery currently producing fuels, with a capacity of 100 kBPD, has begun engineering for the first phase of investments that will allow the refiner to improve margins by producing 35 wt% petrochemicals while continuing to make 43 wt% fuels. A number of UOP technologies, including the Uniflex MC process technology for maximum bottom of barrel conversion and Unicracking process technology for maximum conversion of VGO and distillate to naphtha, will form the core of this integrated refinery. UOP also identified a pathway to a maximum petrochemical operation producing 66 wt% petrochemicals and minimal fuels. Overseas refineries are being transformed into Refineries of the Future and Indian refineries can replicate this integration model as well.

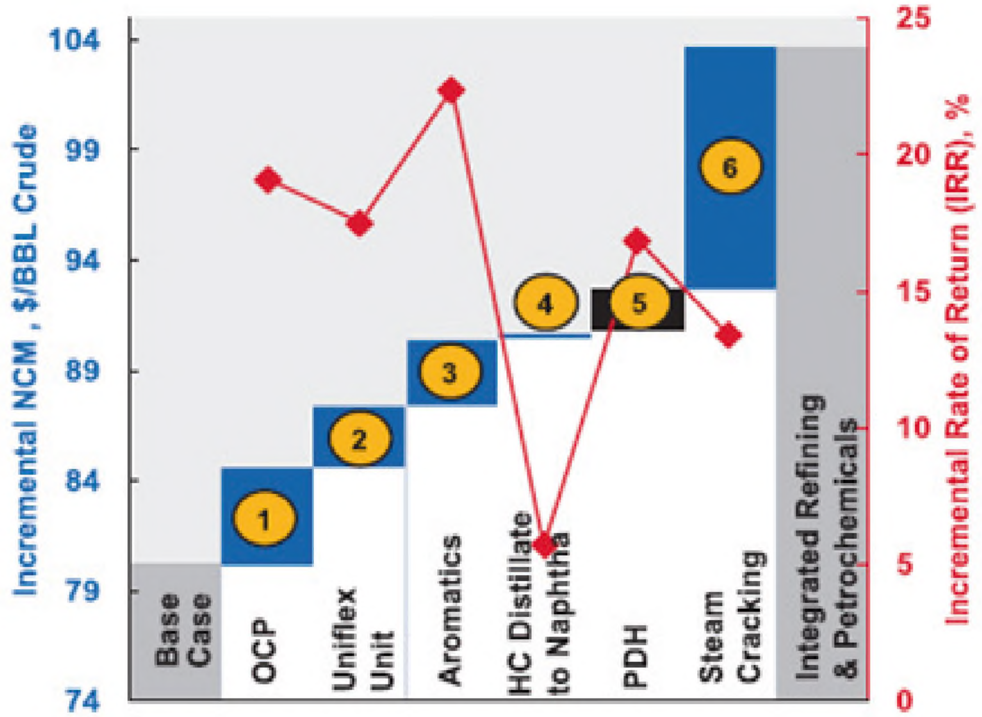


Figure 4 - Summary of Economic Results

*The economic results are for exemplary purpose only. Result may vary depending on the final configuration

1.3.2 Summary

As fuels demand declines and global competition increases, diversifying into petrochemicals will enable Indian refiners to maintain crude capacity and improve margins. For grassroots projects and existing refinery upgrades, a high-value integration strategy will create additional value. Crude capacity is maintained while moving into higher value petrochemicals, and on-specification gasoline and distillate will be co-produced, but at a reduced rate.

Petrochemical integration is complex and capital-intensive, requiring a strategy that is definitively quantified to maximize value at each step. Optimization, not maximization, is the key. Optimization means better molecule management and improved configurations. UOP's E6 model enables comparison of configurations against efficient benchmarks to ensure the best possible investment while meeting project objectives.

The studies in this paper identified a potential diversification pathway to petrochemicals through a series of economically viable investments. Each step of this plan resulted in a high-quality investment with case-by-case incremental IRR's up to 20%. Following this plan, a refiner can unlock new value from crude oil, potentially improving net cash margin by over $20 /BBL.

Each existing refinery and new complex will require a tailored configuration that embodies the technologies and concepts discussed in this paper. As one of the only companies that incorporates process technology and configuration expertise, Honeywell UOP fully integrates complexes, achieves optimal molecular management and maximizes the value of a barrel of crude. Partnering with Honeywell UOP provides refiners with integrated services and solutions for a connected plant to accomplish today's complex operating goals, enabling maximum asset utilization and improved reliability. With the right retrofit technology and domain expertise, the Refinery of the Future is now within reach.

◆

Part-2

Innovations in Refining

2.1 De-bottlenecking of Crude and Vacuum Distillation Unit to improve productivity

Authors: Dr. Ashwani Malhotra and Mr. Ameya Dhok, Engineers India Limited, New Delhi

Dr. Ashwani Malhotra is serving as Chief General Manager in Engineers India Ltd. He has 35 years of experience in the process design and engineering of refineries (including Crude & Vacuum Distillation unit) and onshore/offshore oil and gas facilities and in the Equipment and R&D divisions of EIL. He also has experience in application of IIOT in Refinery.

Mr, Ameya Dhok works as Senior Manager with Engineers India Ltd. He has experience in Process simulation & optimization for refinery unit design like Crude distillation, Delayed Coker, and Naphtha splitter units. His area of interest includes Process engineering and exploring energy improvement measures.

2.1.1 Abstract

The refinery process unit needs to perform efficiently to have the maximum profitability and productivity. One of the main reasons for process units to perform inefficiently can be attributable due to variation in feed stream properties. In a typical refinery, the actual crude basket can be quite exhaustive from the design cases. Hence any change in crude composition can have significant impact on the yield and hence energy utilization. The problem is commonly encountered in crude units wherein the design and actual crude assay differs especially for lighter crude wherein the light ends vary significantly leading to debottlenecking of light end processing section. In this paper, a typical case study is discussed wherein the unit is revamped to address the above issue and also target for an energy efficient unit design. As the crude being processed is lighter, the yield from Crude Column is higher. This leads to higher Crude heater duty. In order to avoid modification in Crude heater and utilize margin in vacuum heater a new exchanger service (Crude/RCO) was added in preheat. The critical aspect in debottlenecking with hardware constraint is to achieve the target with minimum modifications and within stipulated turnaround time. A careful and systematic approach needs to be adhered to have an optimum design. The key highlights of the design include optimized light end data to match the existing overhead circuit limitation, maximizing the preheat with minimum modifications, upgrading to high-capacity tray in stabilizer section to accommodate the increased light end load, hybrid vacuum system for vacuum column operation to have reduced OPEX and thereby making the unit more energy efficient.

2.1.2 Introduction

The processing of crude oil in crude unit is an important aspect and is key to functioning of the refinery profitability as it provides feedstock to downstream unit. The separation of crude oil into the desired streams primarily depends on the crude oil characteristics. Typically, crude oil is characterized by following properties:

- API Gravity
- Sulfur content
- Total Acid Number (TAN)

The crude oil assay characterization is critical while designing crude unit. This becomes more important when it comes to revamping an existing crude unit. The approach is to carry out a test run with the intended design crude in existing unit, this helps in identifying the key bottlenecks/constraints in existing design.

A typical crude unit consists of crude section followed by vacuum section. The crude oil is firstly heated in preheat train exchanger network wherein the heat is made available through the hot stream from crude and vacuum column. After preheat the temperature of desalted crude is increased to the desired level in crude heater before it enters the distillation column (refer Figure-1) where it is separated into desired cuts depending upon its boiling range. The crude column bottoms, reduced crude oil (RCO) is further heated in vacuum heater and enters the vacuum column operating under vacuum condition and separated into desired cuts (refer Figure-2).

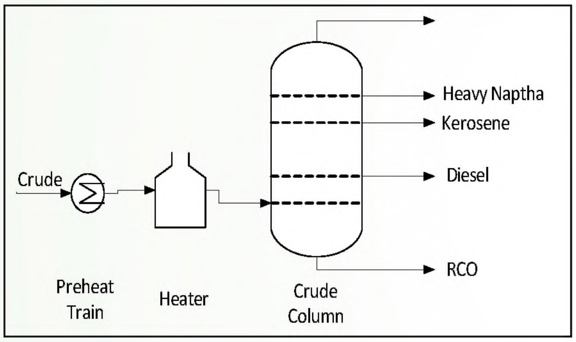


Figure 1

This paper focuses on design optimization for revamp of existing crude unit to process crude which is lighter than existing design. Further the implementation of revamp within the stipulated time frame of turnaround is challenging. With the existing hardware limitation and new crude assay, the design is to be optimized to

- Minimize the changes in existing unit with limitations in crude heater.
- Design objective to be met i.e. revamp design to be able to process lighter crude.
- Reduce the energy dependency and make the design more energy efficient.

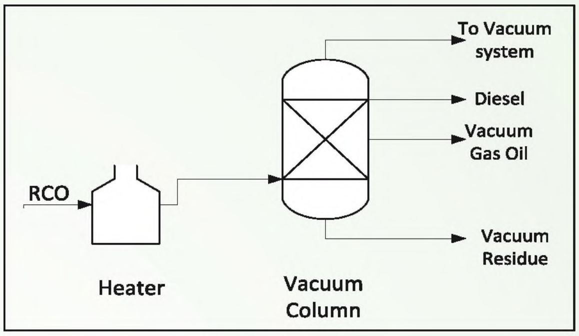


Figure 2

2.1.3 Methodology

Revamp of any process units is primarily with objective of capacity enhancement and/or yield and product quality improvement to be implemented within shutdown period. The recent trend in revamp projects is to aim for energy improvement also as an integral part of the objective. The activities in revamping and de-bottlenecking are far more complex which results in complex engineering scope requirements and hence execution challenges and significant performance issues. Revamp or de-bottlenecking projects require special consideration to the issues that are normally not present for grassroots designs. The major considerations are discussed in detail in following sections.

Light end processing section

The key aspect in design of crude unit, especially the light end section depends on the lighter hydrocarbon composition. The load to crude column overhead circuit increases linearly with increase in light end composition especially methane and ethane which governs the fuel loss. Thus, it becomes imperative to finalize the light ends to be considered in design.

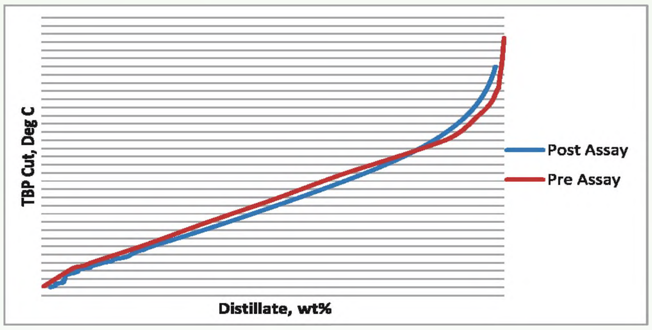


Figure 3

As a case study, comparison of TBP curve (Figure-3) for pre and post crude assay shows that the revamp crude has higher lighter content than existing. The TBP cut range (IBP -125) stream content increased by 25%. Due to this substantial increase in light end following constraints were identified.

- Increase in existing overhead circuit pressure drop leading to fuel gas generation.
- Stabilizer column limitation.

To address the above key issues to be taken care in design with the objective to implement the changes in short shutdown period, thorough analysis was done and scheme was finalized.

Table 1:

Option	Modification	Pressure drop acceptable	Fuel loss
I	Additional shell for overhead condenser	Yes	No
II	Single shell operating + lateral air cooler piping replacement	No	Yes

To minimize the modification in the overhead circuit i.e. replacing overhead main header and lateral lines and minimizing the losses of fuel, the option of considering an additional parallel shell to existing overhead condenser was envisaged (refer Figure 4). This modification was finalized as the existing layout allowed for easy placement of this additional shell. From table 1 above, providing additional shell in overhead condenser leads to total condensation and the pressure drop is within acceptable pressure drop limits.

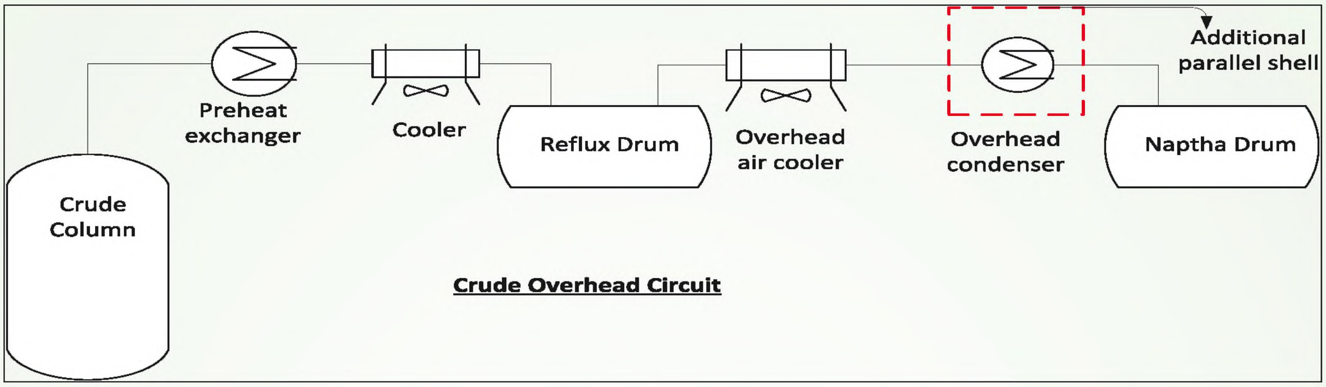


Figure 4

The increased light end had an impact on the stabilizer column which separates the LPG and Naptha cut. Due to the increased load in existing column, LPG specifications could not be met due to increased vapor liquid traffic in existing column. This problem was suitably mitigated by replacing the existing conventional valve trays with high capacity trays. With this revamp the additional load could be handled and the product streams met target specifications.

Pinch Analysis

The preheat train configuration is optimized using the Pinch technology which is based on the first principles for identifying the minimum energy requirement point. The key input to pinch analysis is the hot and cold stream conditions i.e. flow rate and temperature levels. The outcome is that the cold stream outlet temperatures are maximized with minimum exchangers.

The revamp objective was to maximize the preheat temperature as the existing crude heater was limiting. To achieve the target of maximizing the preheat temperature with minimal changes, potential strategic locations were identified in the existing preheat network (refer figure 5) so that existing network is utilized without any changes. Two preheat exchangers were added at the start and just before the heater inlet (refer figure 6).

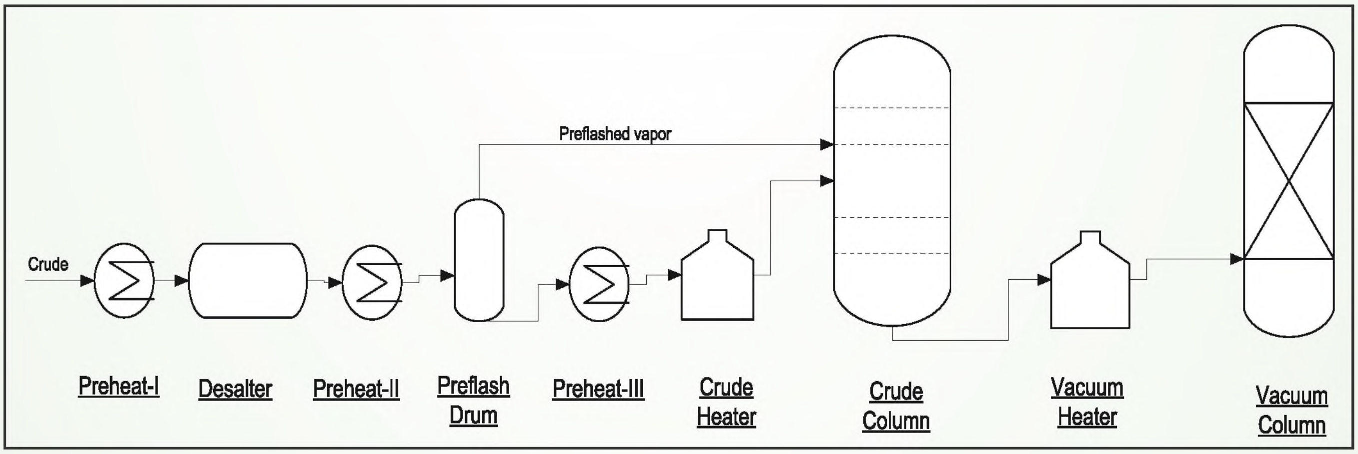


Figure 5

The crude column bottom stream (RCO) was utilized in the preheat exchanger located upstream of crude heater. This leads to increase in preheat temperature thereby reducing crude heater duty and avoiding major changes in crude heater. The RCO was again heated in vacuum heater which was within the design margin limit.

The crude received at battery limit is heated to an optimum value before it enters the existing preheat exchanger (wherein the heat is provided by crude column overhead stream) so as to minimize corrosion issue in overhead circuit.

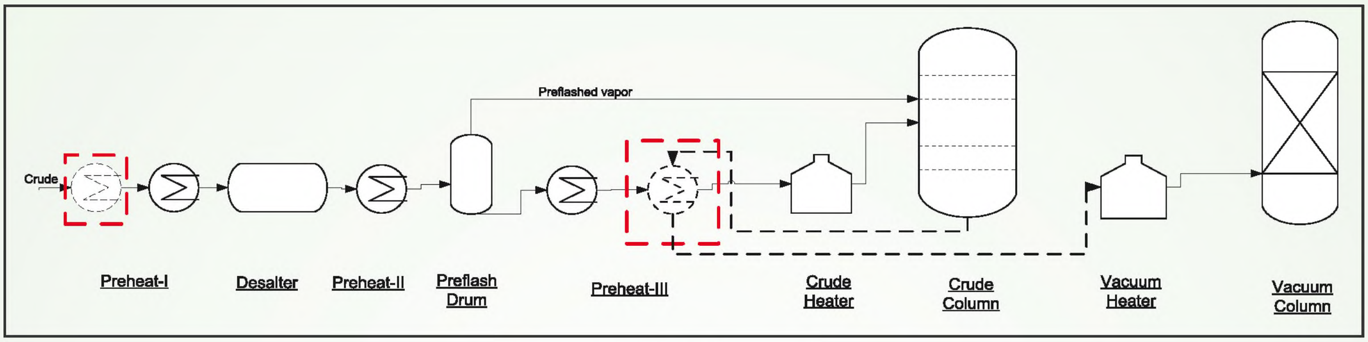


Figure 6

From table 2 below it is evident that utilizing the existing design margin minimizes the changes required.

Table 2

Sr. No.	Parameter	Pre-Revamp	Post-Revamp
1.	Preheat Temperature	X	X + 12 C
2.	Crude Heater Duty	X*	0.95 X

* Actual plant lower duty envisaged

Hybrid Vacuum system

The vacuum column operation is critical w.r.t. to desired specification of vacuum column products and so is the design configuration of it. The vacuum is maintained using ejector system which utilizes substantial quantity of energy in the form of steam. The hybrid vacuum system comprises of utilizing both ejector and Liquid ring vacuum pump (LRVP) to maintain the desired level of vacuum.

For revamp scenarios the last stage of the ejector can be replaced with LRVP (Liquid ring vacuum pump). For a typical case, Comparison shows that the OPEX for hybrid system is low compared to conventional all ejector system.

Table 3

Utility	Last stage Ejector system	Hybrid System
OPEX	X	0.25 X

(Basis: In house/ vendor data)

2.1.4 Conclusion

The crude and vacuum distillation unit being first primary processing unit requires thorough review for different crude processing. Also, it has the highest processing capacity in a refinery and it is highly energy intensive process and therefore, even a small reduction in Energy requirements in this unit leads to substantial saving for the Refiner.

The methodologies adopted shows that implementing changes in revamp during the stipulated shutdown period can be met after careful analysis of the constraints. To address the issue of handling increased light ends the modifications suggested are optimized w.r.t. implementation and fuel loss (in form of gas generated at low pressure). This fuel loss would require additional power to compress the gas further for sending to fuel gas system. Further the use of RCO in preheat addressed the issue of existing crude heater firing limitation which avoided major heater modifications. It is also observed that envisaging hybrid system by replacing the last stage ejector with LRVP in vacuum overhead system reduces the energy dependency. A typical case study shows that implementation of LRVP reduces the operating cost (OPEX) with viable payback period thereby making it a more realistic approach for energy efficient design.

* * *

2.2 Reconfiguration of Naphtha Splitters Using Divided Wall Column Technology

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2.2.1 Introduction

BPCL Mumbai Refinery is a pioneer in oil & gas industry, especially in the field of energy conservation and environment protection by means of innovative approaches. Naphtha management is crucial for improving the overall Gross Refining Margin (GRM) of any refinery. Naphtha can be managed by effective separation and upgradation and optimizing the blending strategies, which in turn minimizes the overall Naphtha production.

Mumbai Refinery (MR) consists of 2 Crude Distillation Units, namely CDU-3 and CDU-4. MR was having three Naphtha Splitters namely Reformer Feed Preparation Unit (RFU) Splitter I, RFU Splitter II and Isomerization Unit (ISOM) Naphtha Splitter, to split 6000 tons/day of Stabilized Naphtha from the Crude Distillation Units into light and heavy components. RFU Splitter I & II were operating in series configuration wherein Splitter I bottoms were fed to Splitter II. Along with its scheduled turnaround for maintenance and inspection activities, RFU had also undergone a revamp in the month of Sept-Oct 2021 for enhancing its feed processing capacity from 4300 tons/day to 6000 tons/day, by means of modification of column internals. Post revamp, MR is able to operate RFU Splitter I & II in parallel configuration, thereby shutting down ISOM Naphtha Splitter, which is an epitome of energy conservation by means of innovation.

2.2.2 Background

Straight Run Naphtha from Stabilizer bottoms of both CDU-3 and CDU-4 is being received in Naphtha Splitters. The quantity and quality of naphtha depends upon the type of crude. Typically, Naphtha generated from Bombay High (BH) crude contains high amount of Benzene; whereas Naphtha generated from Middle East crudes contains relatively lower Benzene. For upgradation purpose, Naphtha has to be separated into ISOM feed (C5 and C6 with low Benzene content) and CCR feed (C7+).

In the pre-revamp scenario, RFU, with series configuration of the two Splitters, was processing 4300 tons/day of Stabilized Naphtha and ISOM Naphtha Splitter was processing 1700 tons/day of Stabilized Naphtha. Details of these columns (pre-revamp) are provided in Table 1:

Table 1: Details of Naphtha Splitters (Pre-revamp)

Sl. No.	Equipment Description	Outer Diameter, m	Height, m	Internals
1	RFU Splitter I	3.0	21.75	60 Nos. of Valve trays with tray spacing of 610 mm
2	RFU Splitter II	3.4	21.75	3 beds (Total 48 layers) of structured packings
3	ISOM Naphtha Splitter	2.6	43.90	3 beds (Total 51 layers) of structured packings

In the pre-revamp scenario of RFU, Top cuts (C5-85oC) from RFU Splitter I as well as ISOM Naphtha Splitter were getting routed to Naphtha Hydrotreating Unit (NHT), where it was getting hydrotreated to get ISOM feed. Bottom cut from Splitter I was getting fed to Splitter II. Mid cut from Splitter I, Top cut from Splitter II and Mid Cut from ISOM Naphtha Splitter were getting routed to Naphtha product pool. Bottom cuts (95-135oC) from RFU Splitter II as well as ISOM Naphtha Splitter were getting routed to Naphtha Hydrotreating Unit (NHT), where it was getting hydrotreated to get CCR feed. Pre-revamp configuration RFU is indicated in Figure 1.

With an objective to improve the performance of these Splitters, our Corporate R&D Centre had done a detailed analysis of Naphtha operations in MR, in detail. Based on the analysis of feed and products data, it was found that:

- Existing configuration was outdated and requires upgradation as per changes in refinery configuration.
- Separation efficiency was low and overall energy consumption was high.
- ISOM feed was having low amount of C6 components, which are active reactants in ISOM Unit for RON improvement.

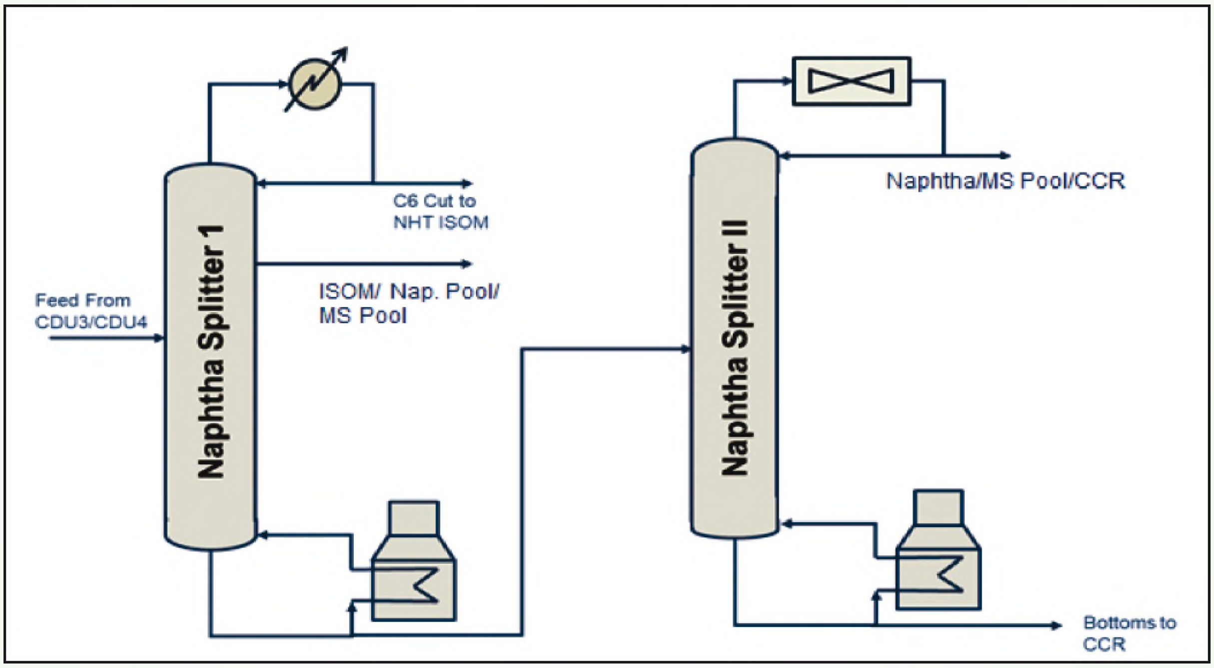

Figure 1: Pre-revamp Configuration of RFU Splitters

In order to address the above issues, different schemes were configured and simulated using Aspen Plus. Stream properties (quality and quantity) as well as energy consumption of each configuration was compared with existing configuration. Based on economical and operational benefits, one of these configurations was finalized and proposed for implementation. The selected configuration was to convert RFU Splitter II into a Divided Wall Column (DWC) so that RFU Splitter I & II can be operated in parallel and ISOM Naphtha Splitter can be shut down.

2.2.3 Objectives of RFU Revamp

The main objectives of RFU Revamp were as follows:

- Increase RFU feed processing capacity from 4300 MTPD to 6000 MTPD by operating Splitter I & II in parallel configuration so that ISOM Naphtha Splitter can be shut down. Feed distribution to both the Splitters shall be optimized suitably to minimize the quantum of modifications and maximize the product quality and yield.

- Maximize the quantity of Top cut along with minimization of Benzene, C6 Naphthenes & C7+ hydrocarbons in it. This stream will be fed to NHT-ISOM Unit.
- Minimize the quantity of Mid cut along with minimization of overlap of it with Top cut and Bottom Cut. This stream will be diverted to Naphtha storage.
- Maximize the quantity of Bottom cut along with maximization of Toluene in it. This stream will be fed to NHT-CCR Unit.

2.2.4 Post-Revamp Configuration of RFU

Post-revamp RFU Splitter I continues to operate as a conventional side cut column whereas Splitter II has got revamped into a middle Divided Wall Column. Post-Revamp Configuration of RFU is indicated in **Figure 2.**

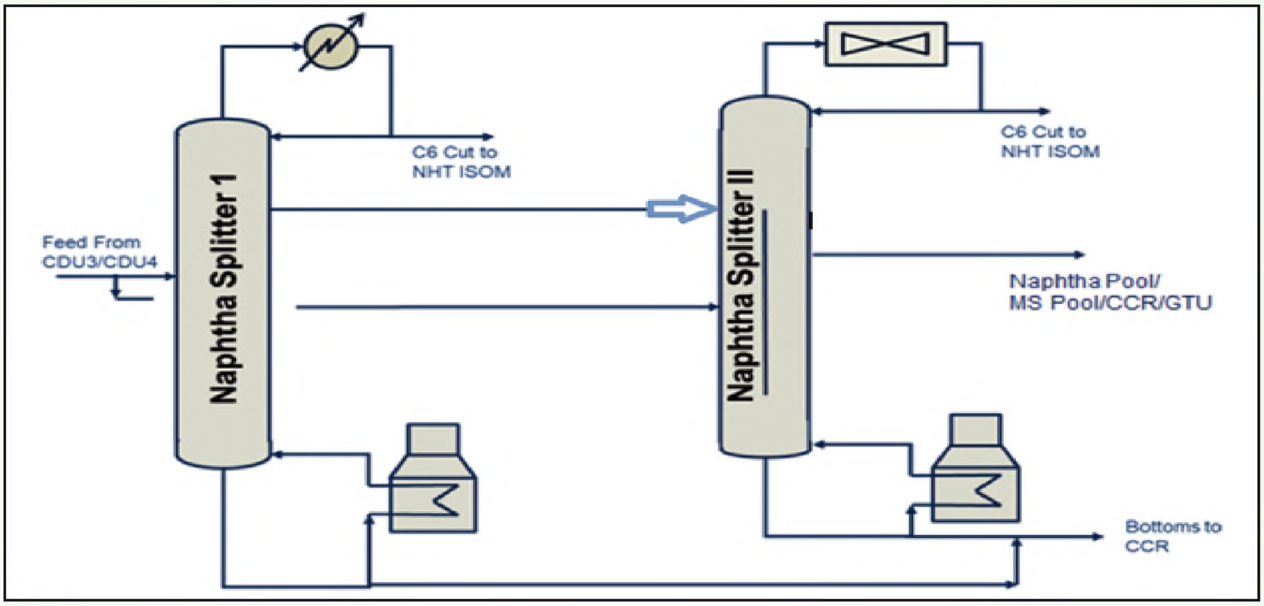

Figure 2: Post-revamp Configuration of RFU Splitters

With this configuration in place, RFU Splitter I & II are sufficient to split the entire quantity of Stabilized Naphtha from Crude Distillation Units.

2.2.5 Major Modifications done in Revamp

No modification was envisaged in Splitter I Reboiler & Splitter II Reboiler, which are fired heaters. 4 Nos. of new heat exchanger shells (by replacing existing 3 Nos. of heat exchanger shells) were got added in order to meet the revised cooling requirement of various process streams. Further, 7 Nos. of new pumps with LT motors (by replacing existing 5 Nos. pumps) were also got added. Major modifications done during the revamp are listed in Table 2.

Table 2: Details of Major Modifications done during RFU Revamp

Sl. No.	Equipment Category	Modifications Done
1	Splitter I	Packing of Top Bed (10 layers) completely replaced with 13 layers of new type of packing. Bed height reduced (from 12 layers to 8 layers) for middle bed. 26 layers of packings reused without any change in bottom bed.
2	Splitter II	All beds except bottom bed completely replaced with new structured packings and bed height reduced (from 27 layers to 13 layers) for bottom bed in stripping section of the column. A dividing wall was installed inside the column which runs between top and bottom beds. The dividing wall section runs approximately middle 1/3rd of the column.
3	New Heat Exchangers	MP Steam/RFU Feed Preheater (1 No.) Splitter I/II Top Cooler (1 Shell) Splitter I/II Mid Cut Cooler (2 Shells) Splitter I/II Bottom Cooler (1 Shell)
4	New Vessel	RFU Feed Preheater Condensate Pot
5	New Pumps	RFU Feed Pumps (2 No.s) Splitter I Reflux Pumps (2 No.s) Splitter I Mid Cut Pump (1 No.) Splitter II Mid Cut Pumps (2 No.s)

Rated capacity of RFU post-revamp is 6600 tons/day with turndown of 40% for Splitter I & Splitter II.

2.2.6 Product Specifications

Post-revamp product specifications are provided in **Table 3.**

Table 3: Post-revamp Product Specifications

Parameter	Top Product	Mid Cut	Bottom Product
IBP, oC	-	-	> 95
D86 5%V, oC	-	-	> 98
D86 95%V, oC	< 80	-	-
FBP, oC	< 85	-	-
Benzene, %w	< 4	-	-
C6 Naphthenes, %w	< 10	-	-
C7 Hydrocarbons, %w	< 3	-	-
Toluene, %w	-	< 2	-

2.2.7 Divided Wall Column Technology

The revamp of RFU is based on optimized DWC which maximizes the product yields. The added benefit of lower capital investment combined with lower operational cost have helped divided wall columns gain in popularity over conventional columns. When applied to sequential multi-component separation, DWC can separate the feed into two or more purified streams within single tower, thus eliminating the need of second tower. DWCs offer the following benefits:

- Suitable for separating multicomponent mixture into three or more high purity product streams in a single column.
- Ideal alternative for revamp of side cut columns when high purity is required from the three product streams.
- Lower footprint as equipment count is reduced by half.
- Equipment turnaround time and other miscellaneous expenditure are reduced.
- Operational and capital expenditure are reduced by approximately 20-50%.

Following were the salient features of RFU Revamp:

- Provision for MP steam preheating: Both the columns were limited in terms of fired heater duties. Besides providing high level of product recoveries, MP steam preheating provides flexibility to handle feeds from CDU-3 & CDU-4 at different feed temperatures.
- Integration between Splitter I & II: The side cut from Splitter I has a substantial overlap of C5 components. The side cut from Splitter I is fed to Splitter II on the feed side of dividing wall. This leads to a considerable reduction in overall side cut rate from the two columns.
- The new packings in both the columns are high efficiency packings which are capable of handling high vapor liquid traffic.
- Flexibility has been provided to operate Splitter I & II columns in series configuration as well.

Figure 3: New Dividing Wall inside Splitter II

2.2.8 Conclusion

With the latest advances in process simulators and design methods, DWCs have emerged as a viable technology over the course of the previous two decades. DWCs can also be integrated in existing refining technologies, thereby operating cost can be reduced. Naphtha management in refineries can be done by effective separation and upgradation strategies, which can minimize the overall Naphtha production. With RFU revamp, BPCL Mumbai Refinery is currently the proud owner of 2 divided wall columns i.e., a middle divided wall column in RFU and a top divided wall column, which is a Deisohexanizer, in ISOM Unit, with huge savings in terms of energy.

* * *

2.3 Commercial Demonstration of [HP]2 Catalyst: A multispecialty catalyst formulation for maximizing FCC products yield

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2.3.1 Introduction

Fluid catalytic cracking (FCC) is one of the most important conversion processes used in petroleum refineries and has existence of 75+ years. It is widely used to upgrade heavier cuts like vacuum gas oil and residues to more valuable petroleum products like gasoline and light olefins. It can readily adjust to changes in feed quality through modifications of catalyst and operating conditions. Catalysts and additives play important role with respect to activity and selectivity in FCC. FCC units typically produce around 4-6wt% propylene but can go as high as 12%, depending on feedstock type, operating conditions such as riser outlet temperature, reactor pressure, catalyst-to-oil ratio and the type of FCC catalysts/additives.

The major source of ethylene and propylene is the traditional steam naphtha cracker that supplies about 57% of global propylene as a by-product to ethylene production. The FCC unit is also an important source of propylene producing about 35% of world propylene as a by-product to gasoline production. The remaining 8% of world propylene is produced by 'on-purpose' processes such as propane dehydrogenation, olefin metathesis and methanol-to-propylene. But due to shift of naphtha crackers to ethane crackers, the gap for propylene has been on increasing trend. Most of the new steam crackers coming online are designed to use ethane as the primary feedstock, which typically produces less than 2% of propylene compared to ethylene production. Propylene demand has increased at an average rate of nearly 4-5% per year. In India, growth rate for propylene stood at 2.33% CAGR and polypropylene (PP) at 3.85% CAGR for 2020-21. Enhancement of propylene yield from FCC from maximum of 12wt% to 20wt% is one of the option to meet growing demand of propylene. Refiners are integrating the modern configuration with petrochemical complex and petrochemicals from current average of 7% will go upto 20%.

Propylene is perhaps the most versatile building block in the petrochemical industry, in terms of its variety of end-use products and its multitude of production sources. High demand for polypropylene (PP) has been a major driver for the rapid expansion in propylene production processes and many polypropylene units are added by refineries. Worldwide, approximately two-thirds of propylene is used to make PP.

HP Green R&D Centre (HPGRDC) has developed a novel catalyst formulation: [HP]2 (Hindustan Petroleum High Propylene) catalyst system for maximizing propylene yields. The catalyst formulation has been patented. The catalyst formulation acts as an additive in conventional FCC units. The catalyst system can be used in high severity FCC unit like HPCL patented [HP]2 FCC Technology, DCC (Deep Catalytic Cracking) or other high severity FCC for maximization of light olefins. To assess the performance of the [HP]2 catalyst field trials of the catalysts were carried out at HPCL's FCC units at 10% and 15% inventory change over and the commercial demonstration in one of India's DCC unit. FCC Performance of the catalyst formulations as a catalyst and additive is discussed here.

2.3.2 [HP]2 Catalyst for Light Olefins:

Catalysts and additives play vital role in FCC for enhancing light olefins. The proprietary tailor made catalyst system has cracking functionality to crack feed molecules to gasoline by use of macro-mesoporous and micro-porous functions and increase light olefins by modified shape selective pentasil zeolite. In [HP]2 catalyst there is upgradation of larges molecules by physical transport in macrospores (Lewis acid sites) and primary cracking mesoporous sites (medium acid sites) of alumina, which is surface modified to change the strength of the acid sites. The upgraded molecule diffuses into zeolite pores to give gasoline, which further cracks to light olefins in presence of modified shape selective ZSM-5 additive incorporated in the [HP]2 catalyst formulation. The large molecules in the feed prefer to be first precracked on the alumina surface. The feed molecules are 370+ boiling range consisting of saturates (C14-C34) and heavy aromatics (C14-C60) in the ranges of 40-60% and 35-45%, having pore diameter of 12-20Ao and 12-30Ao. These hydrocarbon molecules are too large to fit into the zeolite pores. The macropores provide free path to these molecules to transport and crack on mesoporous of active alumina having pore size of 12-100 Ao. The upgraded molecules viz: LCO range come in contact with Y zeolite pores having pore size of 7-8Ao and convert to gasoline range molecules using strong acid sites and the gasoline range olefins are converted to light olefins (LPG Olefins) through modified shape selective ZSM-5 having pore size of 5-6 Ao. It is important that the catalyst have the proper pore size distribution to enable large feed molecules to enter, crack into lighter products, and diffuse out before being over-cracked to coke and gas. Therefore, it is essential to design a catalyst with optimal porosity for effective kinetic conversion. The sequential cracking is depicted in Figure-1. Typical properties are given in Table-1. The modified ZSM-5 of the formulation is having metal function to increase the light olefins. The catalytic cracking of alkanes occurs via bimolecular and monomolecular reaction mechanisms. If the monomolecular mechanism is dominant, the yield of light olefins (e.g., ethylene and propylene) is more. Bimolecular reactions are hydrogen transfer reactions, which will saturate the olefins. Hydrogen transfer in FCC is a well-known phenomenon and reduces the gasoline range olefins. The cracking rates of gasoline olefins on ZSM-5 are higher than those of paraffins and therefore, an increase in hydrogen transfer reduces the effectiveness of ZSM-5 additives. The synergistic alumina and Y-zeolite cracking of feed molecules as explained will provide maximum activity and higher gasoline range olefins for cracking on modified ZSM-5. The ratio of monomolecular to bimolecular for the [HP]2 catalyst formulation is higher, indicating monomolecular reactions are dominant in [HP]2 catalyst formulation. The paraffin to olefin ratio, which is measure of hydrogen transfer reactions is almost 50% less in [HP]2 catalyst formulation, indicating the design of the catalyst is selective towards light olefins.

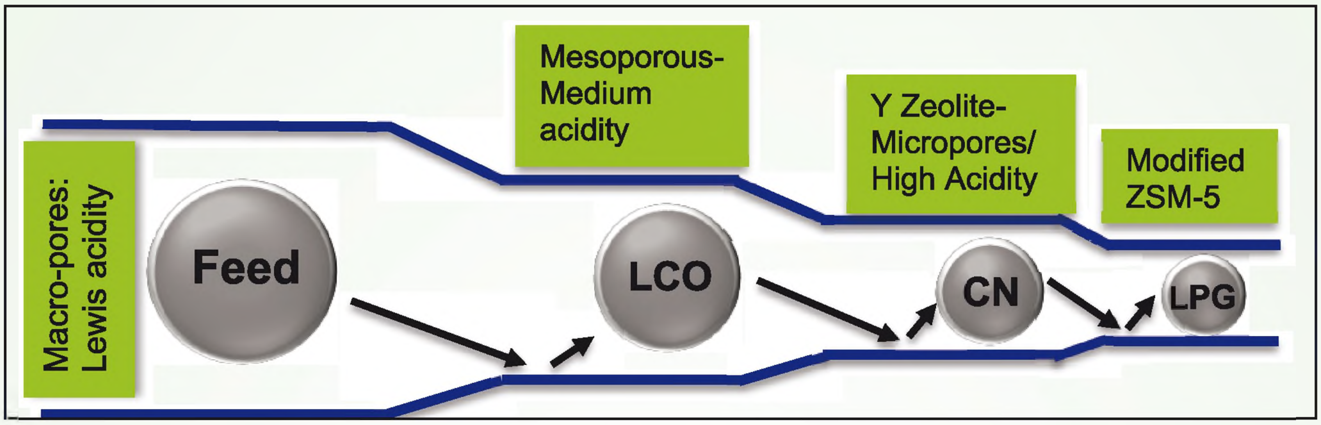

Figure 1: Sequential cracking of Hydrocarbon feed to light olefins using $[HP]_2$ catalyst

Table-1: [HP]2 Catalyst properties

Parameter	Values
Fresh surface area, m2/gm	150-250
PV, cc/gm	0.35-0.4
APS, micron	75-85
ABD, gm/cc	0.75-0.85
Attrition Index, wt%	<6

2.3.3 Field demonstration of [HP]2 catalyst:

The catalyst formulation also acts as an additive in conventional FCC units. Refinery trials were taken at three FCC units to assess the performance of the catalyst as an additive and commercial demonstration as a catalyst in one of India's DCC unit.

Field trial at FCCU-A:

Trial were conducted by 10% inventory changeover over the period of one and half month. Unit throughput was 100 m3/hr with ROT of 490oC, feed density of 0.88g/cc sulphur-0.3wt% and CCR-0.11wt% with unit cat/oil of 5.7wt/wt. Test run was conducted to see the performance of [HP]2 catalyst as an additive at 10% concentration. Performance of [HP]2 catalyst showed 0.6 wt% increase in LPG, 0.5wt% increase in propylene, increase in RON by 0.6 units and reduction in bottoms by 0.2wt%. Product yields are given in **Figure-2.**

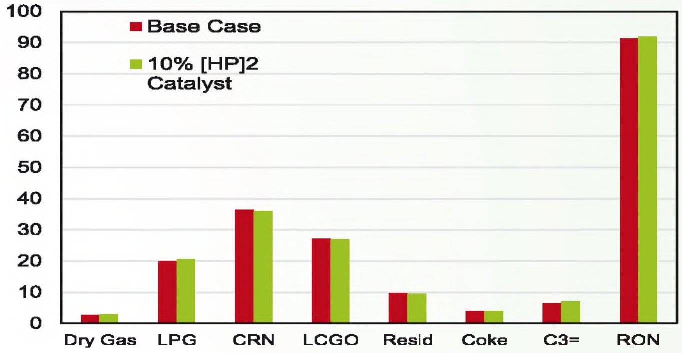

Figure-2: Product yields with 10% [HP]2 catalyst at FCCU-A

Field trial at FCCU-B:

Trial were conducted at FCCU-B by 15% inventory changeover over the period of one month. Unit throughput was 130 m3/hr with ROT of 524°C, feed density of 0.918g/cc sulphur-1.6wt% and CCR-0.62wt% with unit cat/oil of 7.1wt/wt. Monthly average yields of before and after addition of [HP]2 catalyst are given in Figure-3. Performance of [HP]2 catalyst showed 0.32wt% decrease in dry gas, 0.50wt% increase in LPG, 0.54 wt% increase in propylene, increase in LCO by 0.62wt% and reduction in bottoms by 1wt% w.r.t to base case.

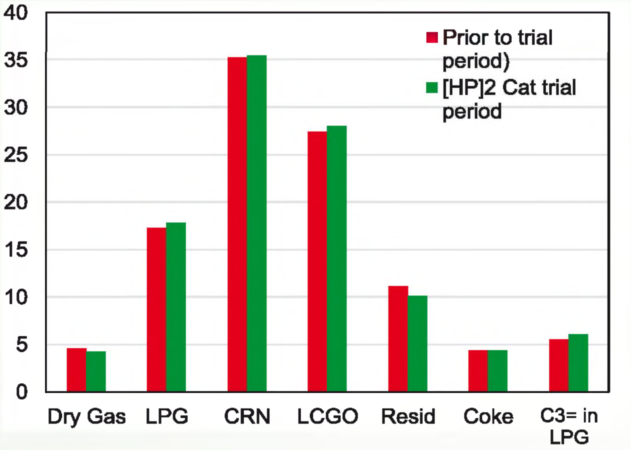

Figure-3: Monthly average product yields obtained at FCCU-B

In both FCC unit field trials, the C3= selectivity in LPG was seen to increase by 2.5 to 5 vol% from base value of 34-35 vol%. During, the trial period, there was no observation on incremental catalyst loss from the FCC units, due to the addition of [HP]2 catalyst. Hence, meeting catalyst compatibility with the existing base catalyst.

Field trial at FCCU-C:

Trial were conducted by 10% inventory changeover over the period of 2 months in resid FCC unit. Unit throughput was 176-179 m3/hr with ROT of 520-525°C, feed density of 0.9231g/cc, sulphur-1.6-2.2wt% and CCR-1.3-1.6wt% with unit cat/oil of 7.3-7.5wt/wt. Test run was conducted to see the performance of [HP]2 catalyst as an additive at 10% concentration. Performance of [HP]2 catalyst showed 0.42wt% increase in LPG, 0.31wt% increase in propylene, increase in RON by 0.2 units and reduction in bottoms by 0.25wt%. Product yields are given in **Figure-4.**

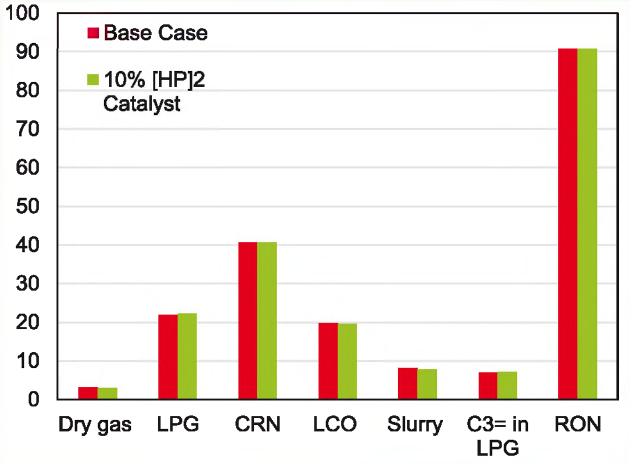

Figure-4: Product yields with 10% [HP]2 catalyst at FCCU-C

2.3.4 Commercial Demonstration in FCCU-D:

Commercial demonstration as a catalyst was conducted over the period of 4 months in one of India's DCC unit. Performance of [HP]2 catalyst showed 0.3wt% increase in propylene (17.7wt% achieved at 132% of design capacity) and also increase in propylene selectivity in LPG from 42.57% to 44.56%. The hydrogen transfer index for [HP]2 catalyst was 0.3 as compared to base value of 0.4 indicating propylene selectiveness of the catalyst.

2.3.5 Conclusion:

Based on the lab study and field trials at FCCU-A, B & C, [HP]2 catalyst can be used an additive in existing FCC units to maximize the product yields and selectivities and increase the RON barrels. In a high olefin FCC unit, the commercial demonstration has proven propylene increase by 0.3wt%. The demonstration/field trial has shown it can be used in conventional VGO FCC, resid FCC and high olefin FCC as an additive and catalyst.

* * *

2.4 HPCL's Pressure drop mitigation technique for Naphtha Hydrotreaters

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2.4.1 Introduction:

The total distillate production from Indian refineries is about 200 MMT per year. With the implementation of BS-VI norms, hydrotreaters play an important role in fulfilling the requirement and demands of BS-VI-compliant gasoline and diesel. Hydrotreaters help to remove hetero atoms like sulphur, etc., from diesel and naphtha fractions for providing on-spec products for marketing or for further processing in other secondary conversion units.

Hydrotreating Units are fixed bed reactors with single or multiple catalyst beds. While processing diesel or naphtha, the beds often receive solid materials along with the process fluid. These solid materials are often corroded materials from upstream of reactor, inorganic materials such as sediments and other organic gum forming compounds. In addition, any coke formed in the upstream unit operations, may also be carried along with the process stream and brought into the reactor. These solid materials deposit mainly on the top of first bed inside the reactor. Such solid deposits, as shown in Figure 1, can reduce the performance of the process unit by means of blocking the flow of process streams in the reactor that will lead to pressure drop increase across the catalyst bed, reducing the heat transfer and fouling the catalyst bed resulting in reducing the effectiveness of the catalyst bed. With the increase in pressure drop across the catalyst bed, the continuous operation of the unit becomes a challenge as the unit is designed to operate within the maximum allowable pressure drop. In addition, the pressure drop increase will increase the overall energy requirement in the process.

Figure 1: Solids Inside the Reactor

In refinery, processes such as Naphtha Hydrotreaters, Diesel Hydrotreaters and VGO hydrocrackers encounter increased pressure drop across the first bed due to such solid deposits. Though the pressure drop builds up gradually, any unplanned shut down in the unit suddenly increases the pressure drop across the first bed of catalyst. From there on the operation of the unit becomes a challenge and force the refiner to limit the unit throughput to maintain the pressure drop. This pressure drop gradually increases to a level where the continuous operation of the plant will become infeasible. This forces the refiner to shut down the unit to address the pressure drop issue before commencing the normal operation.

It is widely practiced in the refinery, that whenever such issue is encountered, the operator takes the unit shut down, skims the first bed catalyst along with solid deposits, make up with fresh catalyst and resumes the plant operation. This skimming process has shortcomings in terms of production loss, loss of active catalyst, additional cost due to make up catalyst, additional manhours for shut down, catalyst replacement & plant startup following all safety measures, etc. The other ways by which pressure drop issue is handled are by means of capital-intensive options such as Scale Catching internals, graded beds, etc.

2.4.2 HP-DUCER for Hydro-processing Units:

HPCL Green R&D Centre (HPGRDC) has developed a simple technique to address the pressure drop increase without disturbing the continuous operation of the plant. This technique is by means of adding the HPCL's proprietary product viz., HP-DUCER at certain intervals based on the severity of the problem and the type of solid deposits in the reactor. This product has been successfully demonstrated and commercialized in Diesel hydro-processing reactors.

2.4.3 HP-DUCER NHT:

HPGRDC has recently developed a new product viz., HP-DUCER NHT for addressing pressure drop issue in Naphtha Hydrotreaters (NHT). The solid deposits in NHT vary from corrosion products such as iron sulphides to coke from coker naphtha or solids from caustic wash, etc. The product, HP-DUCER NHT is versatile and robust to handle all types of solid deposits and also can be customized to suit the unit requirements.

HP-DUCER-NHT dislodges the solids from the catalyst bed thereby reducing the pressure drop across the Naphtha Hydrotreating reactor. The working principle is depicted in Fig.2. The use of the HP-DUCER-NHT is an economical approach for maintaining the continuous operation of the unit without shutting down the unit. The product is a novel material with great business potential in the downstream as well as upstream industries. In this article, the development of HP-DUCER from lab-scale to the demonstration in NHT reactor has been described.

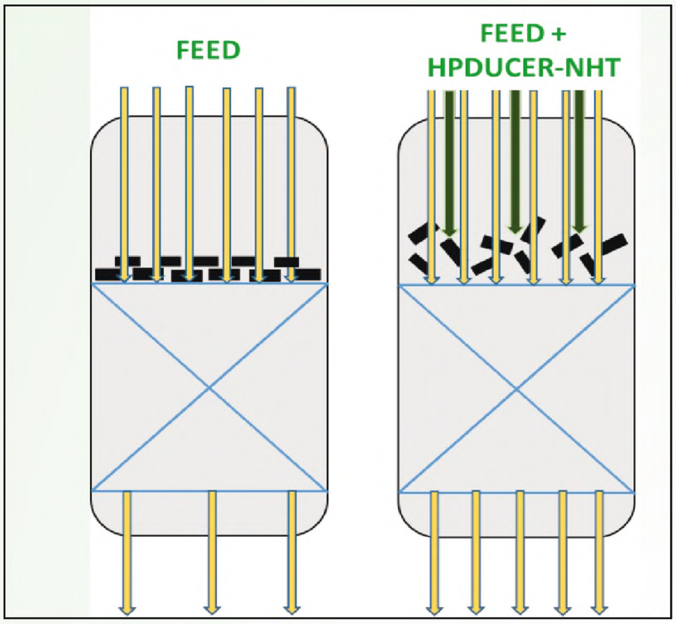

Figure 2: HP-DUCER NHT

2.4.4 Research & Development:

Several product formulations have been synthesized at lab scale and tested in various stages to understand the underlying chemistry and narrow down properties required for different kinds of solid deposits that the product is supposed to encounter in the severe reactor conditions. HP-DUCER NHT was tested for its efficacy in batch scale and pilot scale to finalize the product formulation and dosage optimization. It is ensured at the development stage that HP-DUCER NHT has no effect on catalyst performance and the product properties.

2.4.5 Case Study:

One of HPCL's refineries has the issue of pressure drop increase in the NHT unit. The unit has been operating at less than 1 barg pressure drop until a shut down was carried out. Post unit start up, the pressure drop started increasing and reached above 2 barg. The unit throughput had to be reduced to maintain the pressure drop.

The dosage system has been developed at refinery site and 10 MT of HP-DUCER NHT has been produced for commercial use. Based on the unit performance, feed and product analysis, the dosage rate has been established to reduce the pressure drop in the NHT reactor.

The product was slowly dosed to alleviate the pressure drop and dislodge the solid deposits on the catalyst bed. Initial response confirmed the functionality of the product. Subsequently, the unit responded positively to the minimal dosage rates.

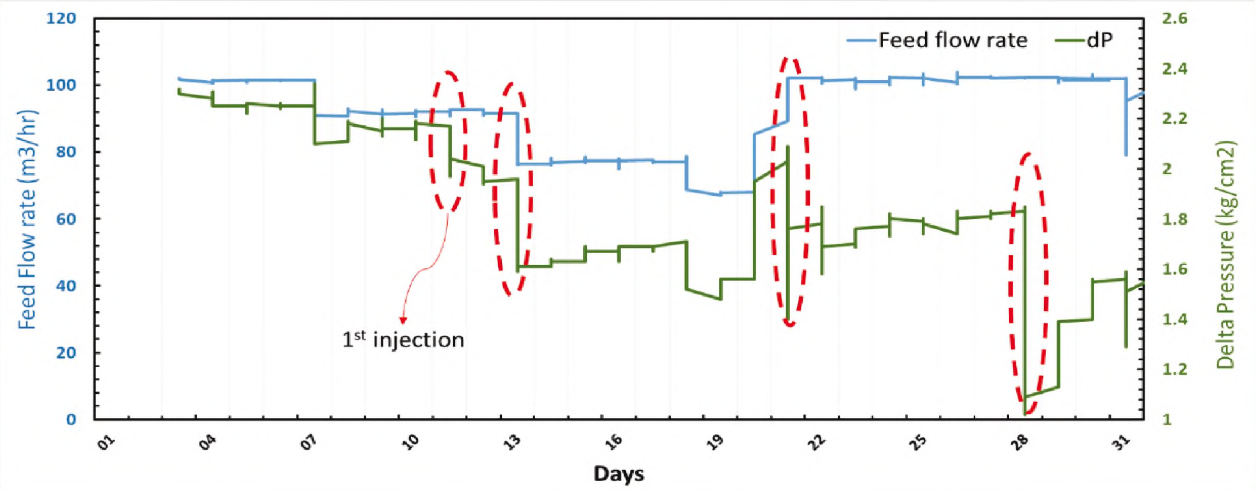

Figure 3: Field data for HPDUCER-NHT performance in NHT-CCR

Figure 3 shows the field data of the Feed flow rate & Delta pressure across the reactor.

The red envelopes indicate the injections of HP-DUCER-NHT at different intervals. With the first injection of HP-DUCER-NHT, the pressure drop of the reactor was reduced below 2 kg/cm2. Subsequent dosage resulted in reduction in pressure drop down to 1 kg/cm2. In about 10 days, the flowrates have been brought back to the desired levels with reactor operating at lower pressure drop.

2.4.6 Conclusions:

Pressure drop increase in hydro-processing fixed bed reactors is a common scenario. The conventional way of skimming or capital-intensive internals are expensive. HPCL's HP-DUCER NHT offers an economical and flexible technique to overcome this problem. The technique is highly safer, requires minimal operational intervention and provide the option to the operator to postpone the unit shut down as long as the catalyst is active. This can provide enough window to the refiner to plan for the next shutdown for maintenance or catalyst replacement activities. From the commercial experience, it is established that HP-DUCER-NHT is a perfect solution for reducing the pressure drop while sustaining the throughput, maintaining the catalyst life cycle and increasing the service factor of the unit.

* * *

2.5 Potential Technologies for Benzene Recovery from FCC Gasoline

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Dr. Kirtika Kohli,is Scientist CSIR-Indian Institute of Petroleum. Her professional interest include Extraction-based technologies, Desulfurization and dearomatisation, Separation of value-added chemicals from coal and bio-mass, crude oils to chemicals, Heavy crude oil and vacuum residue upgradation using slurry bed hydro-cracking process, Deasphalting and de-waxing of heavy crude oils thermo-chemical conversions of renewable and non-renewable materials via catalytic process Microwave-assisted pyrolysis of plastics, biomass, and co-pyrolysis of biomass and plastics, Catalytic CO_2 conversion to value-added chemicals. Two U S Granted Patents; Slurry phase catalyst for residue hydro-cracking and Waste Plastic as a hydrogen donor for residue upgradation

The declining demand for transportation fuels (mainly gasoline) made refiners to focus on upgrading and integrating their refinery operations towards high-value petrochemicals production. In 2016, the petrochemical feedstocks were reported to be 12% of global crude oil demand, and this demand is forecast to reach 18 million barrels per day in the year 2030 . Among the petrochemicals, light olefins and naphtha-based aromatics are the largest volume basic or intermediate chemicals with a global production capacity of 240 and 85 million tons, respectively, in 2016 . The global production capacity of aromatics is expected to reach 133 million tons by 2030.

Aromatic hydrocarbons (especially benzene, toluene, and xylene, BTX) play a pivotal role in the petrochemical and chemical industries. Benzene is extensively utilized as a precursor/intermediate to produce various industrial chemicals. Benzene (approx. 80%) is mainly used to produce ethylbenzene, cyclohexane, and cumene. Ethylbenzene, a precursor to styrene, is the most widely produced derivative and it is further used to generate polymers and plastics. Cyclohexane is used in the manufacture of nylon. Cumene is mainly converted to phenol for making adhesives and phenolic resins. Benzene is also utilized to produce lubricants, rubbers, detergents, dyes, explosives, drugs, and pesticides. In addition, due to health and environmental concerns, there has been an increasing pressure on refiners to reduce the amount of benzene and other hazardous air pollutants in the gasoline pool. In 2011, under Mobile Source Air Toxics (MSAT) II regulations, Environmental Protection Agency (EPA) the United States restricted the annual average benzene level in gasoline to 0.62% vol .

In general, hydrogenated pyrolysis gasoline, reformate, and catalytically cracked gasoline feedstocks are the major contributors of benzene in the refinery gasoline pool. Because of the increasing demand for petrochemical products, refiners need to develop technologies using alternative feedstocks.

World Energy Outlook; International Energy Agency (IEA), November 2017, Paris.

2.5.1 Fluid Catalytically Cracked (FCC) Gasoline as an Alternative Feedstock for Benzene Production

In a typical refinery, FCC gasoline comprises approximately 10-20% of the gasoline pool. Because of the increasing demand for light olefins (ethylene and propylene) for the polymer industry, FCCs are predicted to operate with higher severities, mainly using heavier feedstocks (gas oil and residues). High severity FCC operation results in increase in production of both olefins as well as aromatics. For instance, propylene yields can be enhanced from 2-5% (conventional FCC) to 16–27%. In addition, the aromatic content of cracked naphtha can reach 50-70%. However, it also contains a significant amount of olefins and thiophenic sulfur.

An FCC gasoline (full range) contains 1000–2000 ppm sulfur and ~15-30% vol. aromatics (up to 2% vol. benzene). On the contrary, a narrow C6 fraction (from FCC gasoline) consists of ~11–19 wt% benzene and ~500 ppm sulfur. Therefore, it is essential to develop technologies to efficiently recover high-value chemicals like BTX from FCC gasoline. Also, technologies are required to make it market-ready (with low sulfur and benzene content).

The recovery of benzene from FCC gasoline is comparatively less straightforward. The effect of feedstock properties and reaction process conditions for the desired product formation is a challenging task in an FCC unit. Compared to reformates and hydrogenated pyrolysis gasoline, cracked gasoline (unprocessed, from FCC or thermal crackers) contains olefins and impurities such as metals, oxygenates, organic peroxides, chlorides, nitrogen, and sulfur compounds. Because of the complex nature of cracked gasoline (unprocessed), it is challenging to develop an economically feasible and reliable benzene recovery process. It has not been practiced in the industry so far.

Globally, the processes reported are related to either recovering aromatics or decreasing aromatics from the petroleum feedstocks such as pyrolysis gasoline, reformate, or cracked gasoline fractions. As per the author's knowledge, there is no technology in operation worldwide that can serve the dual purpose of producing benzene lean streams from a cracked petroleum feedstock like FCC naphtha and simultaneously recovering high purity benzene. The most widely used hydroprocessing route reduces benzene from olefinic feedstocks such as cracked gasoline. This helps in saturating the olefins, thus lowering the octane of the cracked gasoline fraction. Olefins present in the cracked gasoline fraction contribute substantially to the octane in the gasoline pool. Therefore, while using hydroprocessing route for reducing benzene, results in saturating the olefins as well and hence lowering the octane of the cracked gasoline fraction.

In hydrocarbon industries, the extraction of aromatic hydrocarbons (mainly BTX) is currently performed by liquid-liquid extraction (LLE) or extractive distillation (ED) processes, using solvents such as N-methyl-2-pyrrolidone (NMP), sulfolane, N-formyl-morpholine (NFM), etc. Patents such as US 3,591,490 , US 3,723,256 , US 5,022,981 , US 7,501,549 describe the processes for the recovery of ethyl benzene and xylenes, BTX from feedstocks like hydrogenated pyrolysis gasoline, hydrotreated pyrolysis naphtha C6-C8 cut, C6-C9 feed stream, and FCC naphtha, respectively. Another patented process, US 8,143,466 disclosed a method for removing benzene from coker naphtha, coker pentane/hexane, reformate FCC gasoline, FCC naphtha, coal oven naphtha, pyrolysis gasoline, straight-run gasoline, and mixtures containing two or more of these streams. According to this process, benzene present in feedstocks is catalytically alkylated with alcohol and ethers to higher aromatics. Therefore, the benzene removal is affected by the alkylation of the benzene rich feedstock. These claimed and proven technologies had the disadvantages such as higher capital and operating expenditures, significantly lower

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[2] Long-term sustainability in commodity petrochemicals; An outlook for olefins and aromatics, presented at Asia Petrochemical Industry Conference (APIC), May 2017, Sapporo, Japan.

[3] Gasoline mobile source air toxics. United States Environmental Protection Agency (EPA) https://www.epa.gov/

benzene recovery, and loss of octane barrels due to loss of high-octane olefinic compounds. In addition, technologies related to extracting benzene from FCC light naphtha were not proven commercially. The reason is the rapid degradation of solvent by polymerization in the presence of reactive species such as olefins and di-olefins and impurities like sulfur, nitrogen, oxygenates, and chlorides.

In view of these challenges and requirements for the future petrochemical industries, CSIR-IIP has developed extractive distillation processes for the recovery low molecular weight aromatics like Benzene and Toluene from FCC naphtha. The details of CSIR-IIP's two patented technologies for the above purpose are described in the following sections. Both the processes are based on the principle of extractive distillation using NMP solvent system and neither of the processes requires any prior feed pre-treatment like selective hydrogenation (for di-olefin or sulfur removal) or any other impurity removal procedure. A C6 rich narrow boiling range cut of full range FCC naphtha is used for both the processes with the objective of producing benzene lean (< 0.4 wt% Bz.) dearomatized naphtha and high purity benzene (purity > 97% in the aromatics rich product).

2.5.2 CSIR-IIP's NMP based Extractive Distillation Technologies

1. Aq. NMP based Process

CSIR-IIP in collaboration with RIL developed an Aq. NMP based extractive distillation (ED) process scheme to produce benzene lean gasoline along with recovery of high purity benzene from unprocessed cracked gasoline fraction. The process has been granted Patents in India and 7 other countries including The United State of America **(US 8,722,952 B2 and IN 294311)**. The developed process is reliable to catalytically cracked gasoline fraction with a boiling range 40-90°C and containing a mixture of olefins, diolefins, naphthenes, paraffins, iso-paraffins, benzene along with impurities such as metals, chlorides, sulfur, oxygenates, nitrogen, and organic peroxides. An aromatic selective solvent (NMP) system and a co-solvent (water) have been used as a solvent mixture for the ED process. In the process configuration, four major columns are used, and their details are:

1. Extractive Distillation Column (EDC) is the heart of the process and comprises a mechanism wherein the feedstock enters the middle section and solvent system enters the top section below the reflux entry point. ED re-boiler temperature is maintained in the range of 140 to 185°C. From the top of ED column, benzene lean gasoline (raffinate) and from the bottom, benzene loaded solvent phase (extract) is recovered.
2. Solvent Recovery Column (SRC) column is used to separate solvent from the extract phase to obtain hydrocarbon free solvent system which is recycled and benzene with purity > 97 wt%.
3. Extract Section Stripper (ESS) is utilized to remove benzene/aromatics dissolved in the water from the SRC overhead decanter, and the stripped water is used for washing raffinate phase.
4. Raffinate Section Stripper (RSS) is used to remove the non-aromatic hydrocarbons dissolved in water from the ED overhead decanter. Hydrocarbon free water from the RSS bottom is made to enter the steam generator for introducing as stripping steam in the SRC.

Benzene recovery in the final extract product is > 99% of the feedstock benzene with a purity > 97 wt%. On the contrary, the benzene content in the raffinate (US Grade Gasoline) is < 0.4 wt%. The total hot and cold utility requirement (for 70 tph feedstock throughput) is about 24 MMKCal/hr and 26 MMKCal/hr, respectively.

2. Pure NMP based Process

Most recently, CSIR-IIP has developed and patented an energy-efficient and cost-effective extractive distillation technology using pure NMP for the same purpose of recovering high purity benzene from C6 rich FCC Naphtha. The process has been granted patents in India and The United States of America (US 10,105,620 B2 and IN 342248). Case studies and examples highlighted in the patent indicate that it has lesser utility requirements along with better product yields and purity as compared to the Aq. NMP based process for the same feedstock and product requirements. This process is a vacuum based two-stage extractive distillation process using NMP (without any co-solvent) which produces benzene lean gasoline (benzene < 0.4 wt %) and high purity (> 98 wt %) benzene from C6 rich cracked gasoline/ naphtha fractions (preferably having a boiling range of 40-90°C). The advantages of the process are:

- It is a two-stage vacuum based extractive distillation process to produce US Grade Gasoline (having benzene < 0.4 wt %) and high purity benzene (> 98 wt %) using pure NMP, which is a thermally and chemically stable solvent system for impurity laden feedstocks such as FCC naphtha.
- The process does not require any feed purification step or selective hydrogenation (to reduce chemically reactive di-olefins and sulfur compounds).
- Increase in desired product (benzene) yields and purity as compared to using Aq. NMP based system.
- Improvement in purity of benzene shall help decrease the cost of secondary operations (where benzene is used as a precursor or intermediate chemical).
- Reduction in hot and cold utility requirements by > 33 and 31 %, respectively as compared to the Aq. NMP based process.
- There is a considerable reduction in capital investment by eliminating extract and raffinate sections stripers, and associated machinery.

The process configuration for the improved process is shown in Figure 1.

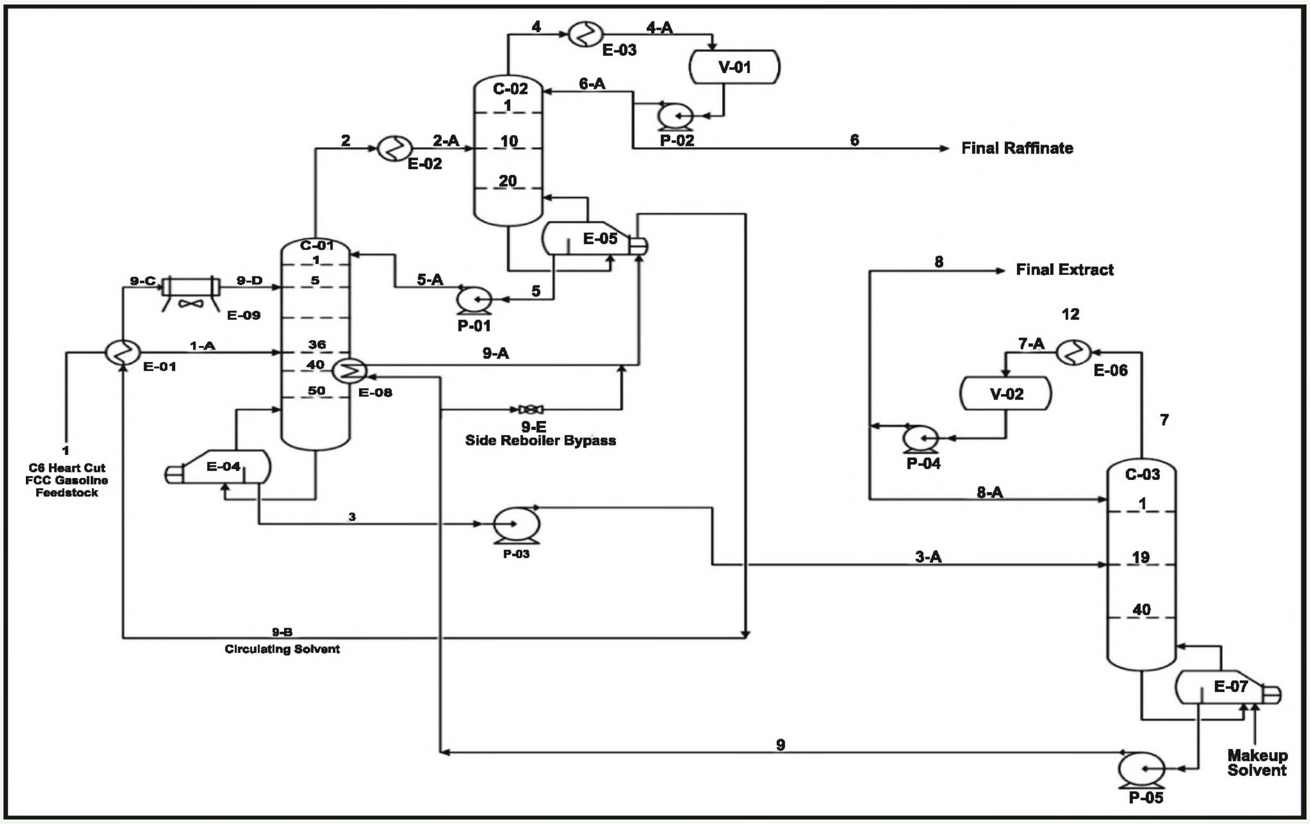

Figure 1. Process configuration for the two-stage vacuum-based extractive distillation for the simultaneous production of US Grade Gasoline and high purity benzene from cracked gasoline fraction 10.

2.5.3 Process Description

A two-stage vacuum-based ED operation is used for this process. A single solvent system having pure NMP is utilized. The solvent to feedstock weight ratio in the main ED column (C-01) is maintained in the range of 3-4 and the reboiler temperature is in the range of 175-185°C. Referring to Figure 1.

- The feedstock i.e., catalytically cracked gasoline fraction (boiling range 40-90°C) enters through line 1-A (below the middle portion of a multi-stage ED column C-01), the feedstock is pre-heated in a pre-heater E-01, and a circulating solvent is used as a hot stream 9-B for the pre-heater.
- The overhead product from ED column C-01 is passed through line 2 and condensed in the cooler E-02 to about 70°C. Further, the mixed vapor-liquid overhead steam 2-A is fed to a second ED column C-02 (middle section). C-02 is a refluxed ED column, and sufficient reflux in C-02 minimizes any solvent carryover to the top product section.
- ED column C-02 top product is rich in olefins and non-aromatic hydrocarbons is passed through line 4, condensed in cooler E-03, and is collected in the drum V-01. A portion of the condensed hydrocarbon from V-01 can be returned to the ED column C-02 as reflux (via line 6-A), While benzene lean gasoline product can be sent to gasoline storage and other processing units through line 6. The bottom product from C-02 is recycled back to the top of C-01 as a reflux stream.
- Using vacuum, both sequential ED columns C-01 and C-02 are maintained at a pressure below atmospheric pressure (0.59-0.39 kg/cm2g).
- The solvent from the benzene rich extract phase (bottom stream 3 from ED column C-01) is separated in a Solvent Recovery Column (SRC) (C-03). Benzene of high purity can be routed to storage through line 8.
- Circulating solvent (70-90°C) after exchanging heat is fed to ED column C-01.
- E-04, E-05, and E-07 are the re-boilers of columns C-01, C-02, and C-03, respectively.

The major process outcomes are:

- The total heating duty (17.63 MMKCal/hr) and cooling duty (19.45 MMKCal/hr) requirements are significantly reduced compared to the heating duty (23.76 MMKCal/hr) and cooling duty (25.73 MMKCal/hr) requirement of the Aq. NMP based system for the same feed throughput composition. The benzene purity in the extract product and the raffinate yield also increases slightly.
- Another interesting observation is when both ED columns C-01 and C-02 are operated in vacuum at -0.285 kg/cm2g and -0.489 kg/cm2g pressures, respectively, in the presence of a side re-boiler in C-01, the total heating duty and cooling duty requirements can be further decreased (14.16 and 15.99 MMKCal/hr, respectively) due to the utilization of heat from the hot circulating solvent. A substantial amount of heat i.e., 3.5 MMKCal/hr present in the hot circulating solvent, is used in a side reboiler E-08 (attached with main ED column C-01) which not only decreases the column's heat load but also the cooling load of the circulating solvent cooler.

Thus, the pure NMP based process indicates a better performance in terms of product yield and purities. It has a lesser energy/utility requirement in comparison with Aq. NMP based system (reduction in heating up to ~33% and reduction in cooling duties up to ~31%) for the same feedstock and processing objective.

2.5.4 Way Ahead

Both the above-described processes have immense applicability in valorizing unconventional cracked hydrocarbon streams like FCC naphtha by recovering high value aromatics like Benzene and Toluene, especially now that the focus is more on production of petrochemicals rather than fuel. Increase in severity of FCC units across the world are being for maximizing production of olefin and aromatics will eventually lead to adoption of solvent extraction-based technologies as described above. The described processes also have the potential to be extended to recovery of light aromatics from other unconventional feedstocks such as reformed bio-derived naphtha or waste plastic derived naphtha.

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Part-3

Energy Efficiency Improvement

3.1 Maximize Fired Heater Efficiency

(A blueprint for saving energy and reducing carbon footprint)

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Mr Kapil B Batra holds a Bachelor's degree in Chemical Engineering, working as Deputy Manager with Engineers India Ltd. He has over 8 years of work experience in thermal design of fired heaters, process design and field operation. Developing tools for increasing productivity and reliability though digitization. Published technical papers in reputed journals including Hydrocarbon Processing

India has set an ambitious target of significantly reducing its carbon footprint. At the same time, India is also targeting to double its oil refining capacity. A lot of impetus is on developing options to capture CO_2 and integrating renewable power into refinery, but these options tend to be much more expensive than the current energy sources. Hence, making the most of energy that we currently use is even more important. Fired heaters are one of the major energy consumers in any refinery or petrochemical plant. They can account for as much as 70% of CO_2 emissions through burning of hydrocarbon fuels. Hence it makes perfect sense to target fired heaters for meeting emission reduction targets through reduced fuel consumption.

Modern day Fired heaters can generally be designed for as high as 93% efficiencies using state of the art technologies, and further reduction in emission can be achieved by using fuels with less carbon content. The following four sections covering the entire life cycle of fired heaters i.e. Design, Revamp, Operations, and Adoption of latest technologies, provides a framework on building and operating fired heaters at their peak efficiencies.

3.1.1 Design & Conceptualization

In process fired heaters, fuel oil, fuel gas or a combination of both are used to heat the process fluids, such as crude oil, residues and gas oils and convert them to fuels used for transportation and other products. In the nascent stage of design itself, correct requirement and specifications needs to be considered for conceptualization of fired heater which will result in reliable and energy-efficient operation of processes. Critical parameters such as Design Considerations, Waste Heat Recovery System, Heat Integration and Fuel selection that need careful consideration during conceptualization and design of fired heater, are discussed below:

Design Considerations

Design Margin: Efficient fired heater design commences with the optimization of the heating requirements of process fluid. Additional design margins are typically added as an indemnity to meet or exceed the guarantees provided. However, this can also result in inefficient heater design and higher fuel consumption for the actual operating scenario. Excessive margins can also cause glitches in design & operation of heaters and burners to meet emissions at turndown (Arch temperature lower than 705°C leads to high CO and VOC emissions). When excessive heater overdesign is observed, particularly with wide range of variation in duties for different cases of operation, it should be discussed with the end user/owner and the process licensor to ensure that they are aware of the limitations.

Type of Configuration: There are extensive design variations of furnace depending on their functions, heating service, duty, combustion air delivery and heat recovery systems adopted. The preferred type of design configuration is cylindrical or box-shaped enclosure lined with coils carrying process fluid introducing from convection section and exiting from radiant section, since it utilizes the combustion energy from flue gas achieving higher thermal efficiency and lower fuel consumption (lower operating costs) as compared with the stand-alone convection or radiation type furnaces.

Excess Air: An important parameter for design consideration in fired heater is at an optimum excess air level. Operation below recommended excess air limits could result in higher unburned combustibles, flame instability, and uncontrolled flame patterns, at the same time, operation at higher than design excess air will increase carbon emissions as well as reduce the efficiency of the fired heater. Refer Figure 1.0 for the effect of excess air on emissions and efficiency.

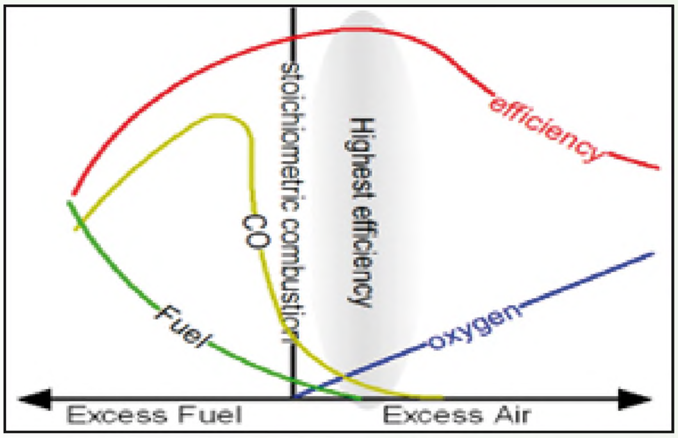


Figure -1

Draft: Draft is Negative pressure (vacuum) of the air and / or flue gas measured at any point in the heater. Stack & flue gas systems are designed such that draft at heater arch is kept at 0.1-inch WC (2.54 mmWC). Excessively high draft increases the air delivery of the combustion air fan, which although facilitates complete combustion, but raises stack temperature, resulting in reduced efficiency. Low draft reduces the combustion air delivery of the burner and can cause smoke. Hence, automated draft control needs to be included in the process fired heater system design for better control of excess air and draft.

Waste Heat Recovery Schemes:

Efficiency of the fired heater signifies the amount of fuel required to produce certain amount of heat; hence it will call for maximum possible heat extraction from the combustion gas or flue gas for getting higher fuel efficiency of a fired heater. Most of the heaters employ designs with various types of heat recovery schemes from flue gases which are worldwide prevalent now-a-days. Refer Table 1.0 for features and limitations of various types of waste heat recovery schemes.

Despite few limitations, waste heat recovery equipment are widely adopted since they increase fuel efficiency of the heaters to the maximum in order to reduce fuel consumption as well as carbon footprint, along with other detrimental emissions such as SOx, NOx etc.

Steam air pre-heaters (SAPH) are generally installed with cast air-preheaters to preheat the combustion air in order to maintain minimum tube metal temperature, also leading to additional increase in heater efficiency.

Figure 2.0 is a good example of the effect on fuel efficiency, fuel consumption, and CO_2 emission with different heat recovery schemes based on one of the crude heaters of an executed project. A significant reduction in CO_2 emissions and increase in fuel efficiency can be noticed with increasing heat recovery potential.

Table 1.0: Types of Flue gas Waste Heat recovery Schemes

Type	Details
Cast Air Preheater (CAPH)	Assembly of rectangular cast tubes with integral fins
	Increase furnace efficiency by cooling flue gases typically up to 150°C
	Prone to sulfur acid corrosion, heat recovery potential depends on the flue gas acid dew point
Glass Air Preheater (GAPH)	Glass tubes resistant to cold end corrosion
	Flue gas exit temperature can be kept ~ 20-25°C above flue gas acid dew point
	Target efficiency >90% with both cast & glass APH
Top mounted Air Preheater	Used in case heat recovery potential in the existing furnace is low or space constraint
	Tube bundles are installed on convection top of heater to heat combustion air from flue gases
Steam Generator/ Steam Superheater (SG/SSH)	Flue gas residual heat recovered by generating or heating steam in the heater convection section
	Complete steam generation system in a convection section of an all-radiant process heater can result in ~90% fuel efficiency

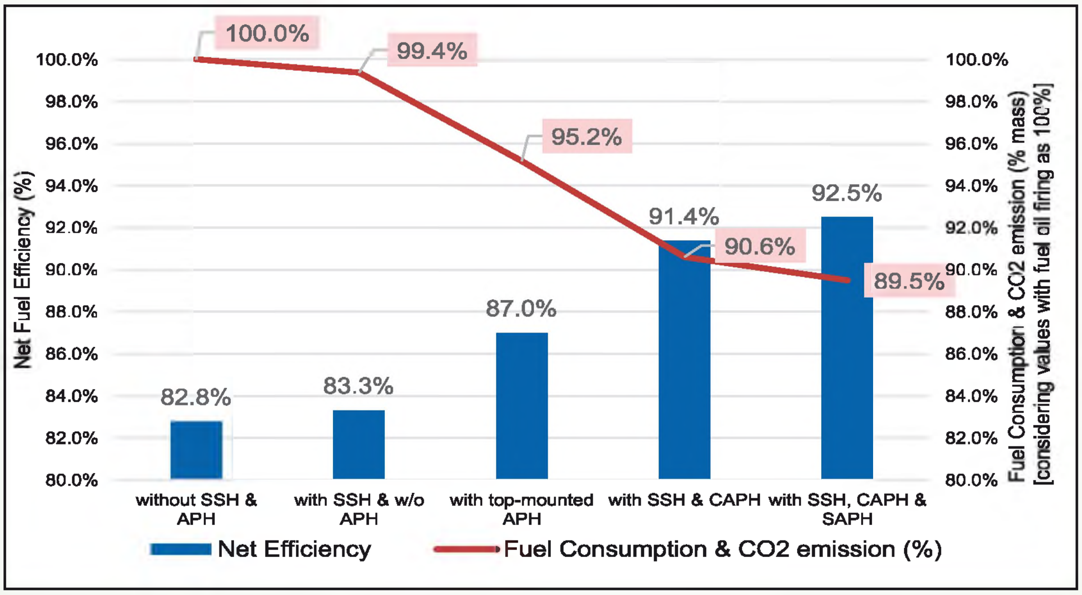


Figure 2.0: Impact of Fuel Efficiency on Fuel Consumption & CO_2 Emission with various Heat Recovery Schemes

Heat Integration:

Energy integration of fired heater into the process helps to target minimum fuel and optimum air preheat temperature prior to the detailed design which eventually reduces the carbon footprint. Few approaches for heat integration are:

- Multiple lower duty heaters can be combined into a single balanced draft heater system wherein collective flue gases from the convection section of the heaters are routed to a single air preheater and the preheated combustion air is also fed to all the furnaces thereby increasing overall fuel efficiency of the combined system.
- In case of an all-radiant heater along with other radiant-convection fired heater in a single unit, high temperature flue gases from the all-radiant heater can be routed below the convection of other heater for further heat recovery. Thus, overall firing for both of the heater shall be lower resulting in saving significant amount of fuel and reducing overall emission along with carbon foot print.
- In certain cases, more than one process streams in a unit can be simultaneously heated in a single heater. This type of integration will reduce the required number of fired heaters compared with each process integrated individually with standalone fired heater. Several utility heating can also be considered in a single furnace. With the heat integration approach, operating cost and carbon footprint will reduce along with capital expenditure.

Feasibility & scope of any heat integration should be ascertained in the initial stage of conceptualization and should be carefully considered for detailed design of the fired heater system.

Fuel Selection:

Selection of fuel weighs heavily while designing a fired heater primarily due to the two main important aspects viz. fuel efficiency and flue gas emissions. Contaminants in the fuel result in emission of harmful pollutants as well as Green House Gases (GHG) into the environment. Typically, liquid fuel or fuel oil contains much more sulphur and carbon than gaseous fuel leading to less energy content and high amount of undesirable pollutant emissions. Achievable fuel efficiency with fuel oil is also lower than that of fuel gas due to high flue gas acid dew point of flue gases. Primarily, for these reasons liquid fuel firing has become successively less in use other than in older refineries. Firing fuel gas and natural gas is a recent trend adopted in refineries and petrochemical plants.

Impact on fuel efficiency and CO_2 emission has been analysed for a balanced draft (BD) heater in Figure 3.0. With standard excess air levels as per API-560, it is observed that CO_2 emission rate can be decreased drastically by ~30% with fuel gas or RLNG firing along with increasing fuel efficiency.

Refiners are also interested in the new trend of concepts for assessing hydrogen gas as a fuel. It can also be observed from Figure 3.0 that hydrogen rich gas (being less in carbon content) helps to reduce carbon dioxide emissions significantly by ~70%, thereby also reducing carbon footprints. Hydrogen rich gas containing ~89% Hydrogen has been considered here for assessment.

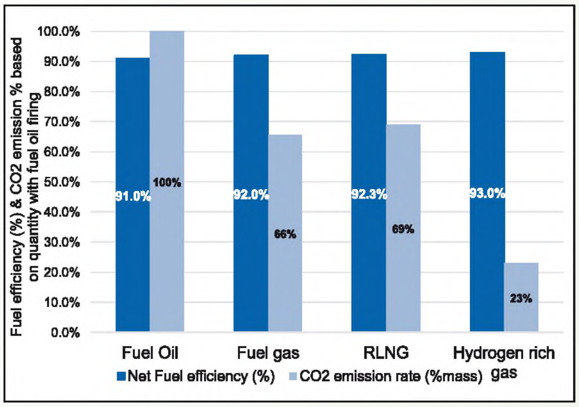


Figure 3.0: Net Fuel efficiency (%) & CO_2 Emission for firing various Fuels in a Balanced Draft (BD) heater

3.1.2 Revamp or Retrofitting

Revamp or retrofitting of a heater entails significant potential with respect to fuel saving & carbon footprint reduction. In the event of facing major challenges due to the fact that fired heaters are one of the prime contributors of the global emission of carbon, refineries, petrochemicals and many process industries are in overwhelming pressure to reduce emissions from their existing fired heaters.

However, there should be some concrete reasons, why the industries shall revamp the fired heaters. Some of the key motives are recognized as follows:

- Increasing fired heater capacity
- Decreasing fired heater severity
- Improving thermal efficiency
- Improving run lengths
- Reducing emissions
- Reducing utility consumption

Parameter	Impact on Efficiency
19°C reduction in Stack Flue Gas Temperature	Increases by 1%
25°C increase in Air Temperature	Increases by 1%
10% increase in Excess Air	Decreases by 1%

Majority of the above can be resolved simultaneously by revamping the heater in one go, enabling enhancement of heater design duty whenever it is required to add to an existing unit capacity. In this way, heater can operate less severely than the scenario while not being revamped and eventually improve life & run length of the heater.

By optimizing the required modifications, existing heater can be revamped to achieve maximum possible efficiency and maximum fuel savings that can compensate the modification costs within a lucrative timespan along with helping to reduce carbon footprints.

It may be noted that for a 120,000-bbl/d (BPSD) refinery in India, even 1% improvement in Fuel efficiency translates into energy savings of almost INR 7 Crore /yr.

3.1.3 Methodology for Performance Improvement & Revamp Studies:

Plant Data Collection: This is the foremost step to understand the inherent and practical conditions of the fired heater intended for revamp. Process data and other existing data requirements are gathered from site along with site observations of furnace including burner performance. Operating personnel's feedback on furnace operations hold substantial importance so that these can be considered and addressed for performance analysis of the heater.

Evaluation of Current Performance: Targeted furnace is simulated based on the operating data collected using furnace rating tools employing feedback / experience of other cases to arrive at the most realistic model. With the basis of the simulated model, current performance parameters including extent of fouling/ derating are established which are further used in the next level of evaluation.

Evaluation of Performance at Desired Load/ Efficiency: This step is imperative to predict heater performance after revamp and also identify the extent of modifications required to achieve desired target. Accordingly, assessment of furnace for revamp conditions are done and performance parameters are established for the revamp conditions. Detailed check of Heater components / auxiliaries is carried out to identify the required modifications for each components/ equipment associated with the heater system.

Feasible Options: Subsequent to the above evaluation steps, various alternatives are studied to target the objective of revamping. As required, interactions with equipment suppliers are carried out for adequacy checks of different equipment such as burners, fans, damper, air preheaters etc. within existing constraints. After detailed feasibility analysis, list of modifications for each alternative can be worked out along with cost benefit analysis for final selection of the desirable option with the end user/owner.

3.1.4 Options for Fired Heater Revamp and case studies:

For revamp, multiple options are available to increase heater efficiency such as:

A. Augmentation of convection surface area

Convection section heat transfer duty can be boosted by addition of convective heat-transfer surface. Additional rows of tubes can be installed in the convection section of most heaters without making any major changes since most of the heaters generally have a provision for addition of few future rows. If space for adding tubes has not been provided, convection section may be extended into the breeching to make space.

B. Installation or addition of a new air preheater in an existing fired heater

Installation of outboard air preheating system into an existing fired heater is the most effective way of increasing fired heater efficiency as already discussed above.

Upgrading natural draft heater to a balanced draft heater with the addition of an air preheating system results in significant hike in heater efficiency and carbon footprint reduction. In this case, existing heater can be re-simulated with air preheater to establish revised operating conditions and plot area evaluation. Minimum modifications are required to be done in the existing heater system which can reduce the shutdown time significantly. The balanced draft system also calls for forced draft fans which facilitates good mixing and uniform distribution of combustion air and forced draft burners that use higher air pressure drop favorable for good combustion.

The impact of installing air preheater for achieving maximum efficiency has been shown in Figure 2.0. Similar benefits are expected to be achieved for an existing heater revamp also, if other factors or deterioration of the existing structure & components are not considered or as insignificant.

C. Switchover of firing from fuel oil/ fuel gas to natural gas

The primary benefit of converting a Fuel oil/ gas fired heater to natural gas is to gain a more cost-effective, cleaner, more efficient, and reliable source of heat. This is a clean energy approach considering stringent environmental stipulations across the globe due to the following reasons:

- Eliminating SOx Emission
- Increased Fuel Efficiency
- Better Control & Flexibility in Operation
- Enhanced Life of Furnace & Heat Transfer Areas

Case Study #1: Emission Reduction & Performance Improvement by switchover to NG / RLNG firing

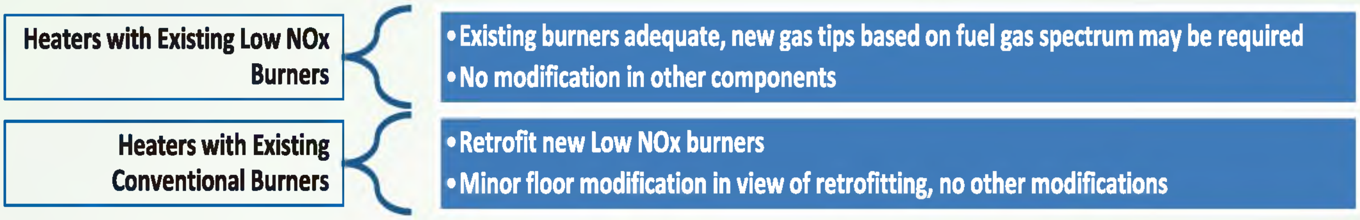
This is a case study with reference to detailed study conducted for fired heaters firing conversion to RLNG for the entire refinery complex. Results of the analysis carried out are summarized below:

a) Existing heaters are adequate with NG/RLNG without modification in the heat transfer surfaces. The flue gas temperature profile across the heater is marginally higher which increases heat pick-up in the convection section.

b) Marginal increase in flue gas & combustion air quantity w.r.t fuel gas firing and reduction in quantities w.r.t fuel oil firing are estimated. In case of marginal increase get easily compensated with the auxiliary design margins. Hence, no modification in stack, fan etc. unless operational issues are foreseen.

c) Resulted in reduction in carbon footprint by ~35% w.r.t fuel oil firing.

d) Burners:



Heaters with Existing Low NOx Burners

- Existing burners adequate, new gas tips based on fuel gas spectrum may be required
- No modification in other components

Heaters with Existing Conventional Burners

- Retrofit new Low NOx burners
- Minor floor modification in view of retrofitting, no other modifications

Figure 4.0: Modifications envisaged for burners

Case Study #2: Capacity Augmentation Along with Efficiency Improvement:

Adequacy study performed for higher loads as part of capacity enhancement project of VDU, for existing:

- Heater system
- Transfer line &
- Associated fuel skid

It was inferred from the site data that fouling in convection section was possible leading to high convection exit temperature along with cold end corrosion problems due to lower flue gas APH outlet temperature. It was also observed that Stack damper was in open condition which suggested limitation in ID fan capacity. In view of these concerns, following modifications & conclusions had been arrived.

Performance parameters	Current Operating (~80% load)	Revamp Condition
Absorbed Duty- HC(Gcal/h)	28	33.5
Temp, In/out, °C	285/404	278/402
BWT, °C	690/825/754	815
Flue Gas exit temperature, °C	377/142	345/160
Stack Temp, °C	230	160
Fuel Efficiency, %	~86	89

Table 3.0: Performance Evaluation for Revamp Case Study #2

Major achievements & minor modifications

- Capacity enhancement with only addition of two future rows above existing hydrocarbon coils in convection sector of heater
- Heater process fluid inlet terminal modification
- FD and ID fans' replacement
- Recommended air bypass in case of lower flue gas temperature than as estimated in revamp findings

With these minimum modifications, 89% fuel efficiency has been estimated post revamp which is more than the operating scenario even with several limitations. It also reduced the fuel consumption cost and carbon footprint substantially. It is also specifically highlighted that no modification in fuel circuit & transfer line and radiant heat transfer had envisaged herein leading to minimum shut-down time.

3.1.5 Efficient Fired Heater Operating Strategy

The main objective of an efficient heater operating strategy must be to achieve the target coil out temperature (COT) safely while also reducing the energy, emissions and maintenance costs. While doing so, the heater should demonstrate stable and robust performance. All of this requires the heater to be operated very close to the constraints.

The energy required for heating process coils in Fired Heaters is provided by the combustion of fuels, mostly hydrocarbons; and the efficiency of this combustion process greatly determines the overall efficiency of the fired heater. Since, it is impossible to operate safely at stoichiometric oxygen level, fired heaters are always operated with minimum excess air. Fired Heaters efficiency, emissions and safety will strongly depend on the amount of excess air volume used for combustion.

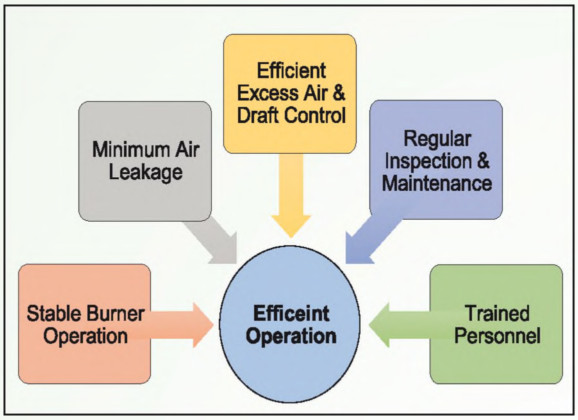


Figure 5.0: Strategies for Efficient Heater Operation

Minimizing excess air improves fuel efficiency by reducing the energy consumed to heat the additional air. Other factors affecting the heater efficiency are draft control, tramp air, burner operation/flame patterns, convection section tube efficacy etc. Fired heaters operate under extreme conditions, and hence regular inspection and asset management should also form a big part of any strategy in ensuring a reliable and efficient fired heater operation.

Excess Air & Draft Control

The amount of excess air used in combustion process majorly defines fired heater's efficiency, emissions and safety. Minimizing the excess air will improve fuel efficiency by reducing the energy consumed to heat the additional air. Figure 7.0 illustrates the relationship between excess air, stack temperature and fuel efficiency. Typically, presence of carbon monoxide (CO) indicates that the fuel is not completely burnt, hence it is important to target oxygen levels that does result in no CO in the stack. The optimum amount of excess air varies from one burner type to another. It also depends on the fuel type & heater condition. For new heaters, minimum excess air level should be specified by the burner vendor and be verified during burner testing.

In most fired heaters, draft is measured at the arch or top of the radiant firebox. In natural draft heaters, this negative pressure creates the driving force for air to flow into the burners. Fired heaters are also maintained under slight negative pressure to ensure that flames stay within the firebox. However, it is important to minimize the arch level draft as too much draft can lead to increased "Tramp Air ingress" i.e. air passing through any non-burner openings such as peep doors, header boxes, tube penetrations etc. into the heater.

Figure 6.0: Tramp air through tube penetration

Tramp air does not take part in combustion and instead absorbs the heat that should be transferred to the heater tubes. Tramp air can also skew O2 readings resulting in inadvertent sub-stoichiometric burner operation. However, while controlling draft, one must be careful as too little draft can restrict the airflow through burners (for natural draft heaters), causing flame instability, flame impingement, and even the formation of CO. Figure 8.0 demonstrates a step-by-step procedure to effectively control excess air and draft in a balanced draft heater.

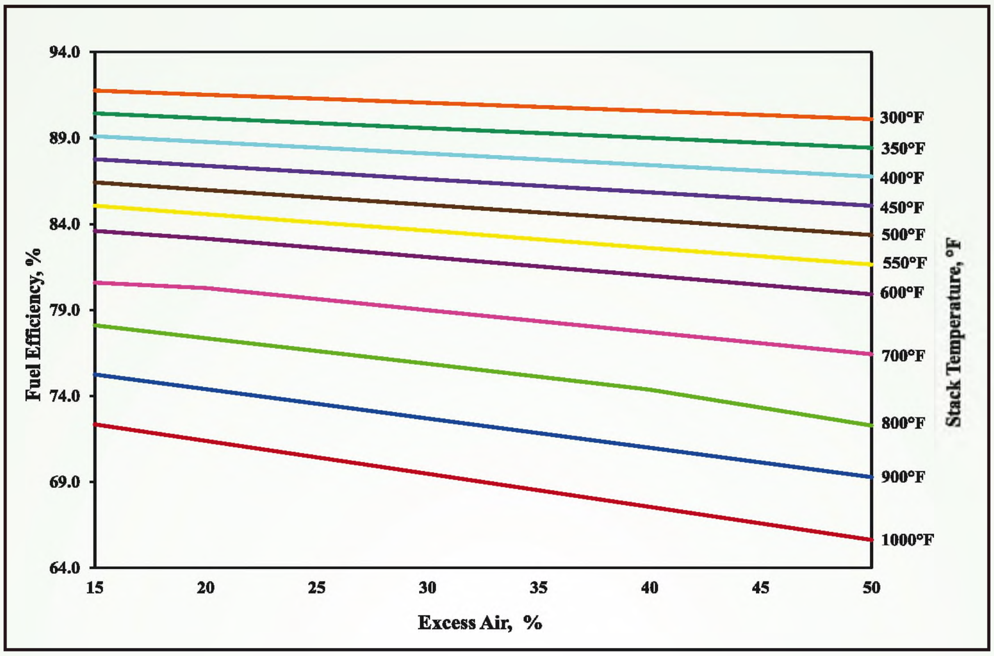


Figure 7.0: Fired Heater Efficiency vs. Excess Air

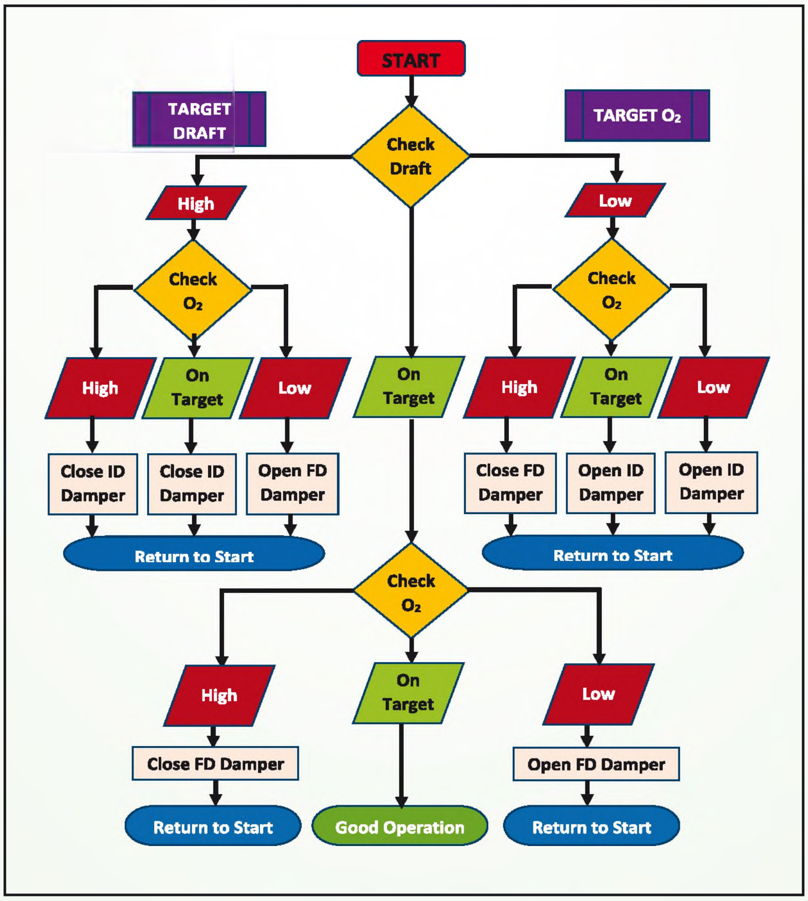


Figure 8.0: Balanced Draft Heater excess air and draft control

Burner Operation/Flame Stability

Burner is the heart of a fired heater equipment. Fired heaters are fitted with multiple burners and type of burner is based on the fuel burned, air supply and emission requirements. A good burner operation is indicated by clear firebox, no smoke, and flames that are compact, steady and well-formed. It is important to often visually inspect burner flames for characteristics such as shape, size and color. Long and lazy burner flames are an indication of poor air to fuel mixing. Such abnormal flame conditions can lead to inefficient operation consuming far more fuel than necessary. It also increases the chances of flame impingement on process tubes, resulting in higher TMTs and coking. Table 4.0 lists possible solutions for common problems with burner operations.

Table 4.0: Common Burner Problems & Possible Solutions

Problem	Cause	Solution
Erratic Flames/Tilting/ Leaning Flames	Lack of combustion air	Reduce firing & adjust air register/ stack damper
	Incorrect burner tip location	Correct burner tip location
	Furnace Currents	CFD modelling to identify & correct flue gas pattern
Gas flame too long	Excessive firing.	Reduce firing rates.
	Too little primary air (premix only).	Increase primary air; decrease secondary air.
	Worn/damaged burner tip.	Replace tip
Gas flame too short	Tip drilling angle incorrect.	Consult burner manufacturer.
	Too much primary air (premix only).	Increase secondary air, decrease primary air.
	Tip drilling angle incorrect.	Consult burner manufacturer.
Flame instability. Flame liftoff.	Lack of oxygen/draft—flooding/ bogging situation.	Lower the firing rates. Adjust stack damper or burner register as needed. When combustion is stable increase air before increasing fuel.
	High fuel pressure.	Check/adjust fuel pressure. Clean tips.
	Incorrect fuel composition.	Check/correct fuel composition.

3.1.6 Reliability & Asset Management

Fired Heater operate under extreme conditions. It is important that the components such as burners, sight ports, tubes etc. are maintained in peak condition. Proper asset management can greatly improve reliability and performance, resulting in cost reduction and a decreased risk of unplanned asset failures. An effective asset management program involves understanding the conditions of firebox while it is in operation. This involves monitoring critical operating parameters such as bridge-wall temperature (BWTs), tube metal temperatures (TMTs), coil outlet temperatures (COTs), flue gas composition etc. Regular visual inspection concerning flame patterns and condition of firebox also plays a major role. Next step involves setting up integrity operating windows (IOWs) which require determining the operating limits under which fired heater is to be operated. This requires effective data collection. The collected data must be analyzed to identify potential failures & reduce operating risks through preventive maintenance.

Fired Heaters must be inspected thoroughly during shutdown and actions must be taken to replace/repair the damaged components. Standards such as API 530 Annexure A, API

573 and API 579-1 provides the necessary knowledge for assessing the fitness and remaining life of fired heaters. Standards such as API 580 and 581 can also provide understanding the scenarios for failure. It is essential that a reliability strategy is developed that addresses the major concerns and potential risks identified in the assessment. Table 5.0 provides a sample reliability management strategy.

Reliability	Performance
Regular IR Surveys	Clean preheat exchangers when fouled
UT surveys during shutdowns	Train operators annually on burner operation
Burner maintenance during shutdown	
Selecting optimum metallurgy based on process composition	Using advanced analytics and digitization tools for operation improvement
Developing effective maintenance philosophy during shutdown.	

Table 5.0: Sample Reliability Management Strategy

3.1.7 Emerging Technologies in Fired Heaters

With the increasing focus on reducing carbon emissions, the latest developments in fired heater technologies are focused on increasing the heater efficiency, thereby reducing emissions. These technologies also help improve safety and reliability of fired heaters resulting in reduced unscheduled production downtime. The myriad developments in technologies range from advanced analyzers, smart combustion systems, and model based process (MPC) control system, new generation air-preheaters, and latest advancements such as digital twins. The technologies utilize the latest trends in automation, data analytics and processors leading to overall improvement in performance & asset management. Let us take look at some of these advancements in brief:

Digital Twins:

A digital twin is a virtual copy of an actual operating furnace. It is mostly built using the first principle model and a physical furnace feeds input data into the model utilizing the installed sensors. The pre build model then uses this data, modifies the model, and generates an accurate digital representation of the operating furnace. Also, a digital twin has full knowledge of the furnace's historical performances, and thus it mirrors the actual furnace operation throughout its lifecycle.

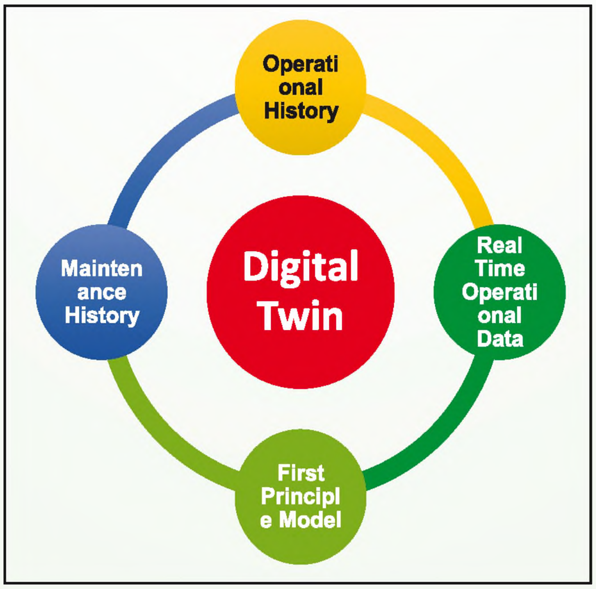


Figure 9.0: Industrial Furnace as Digital Twin

A digital twin can be utilized for various scenarios "what-if" scenarios, assessing the outcomes and impact without the risk of damaging the physical entity. For example, a digital twin can be used to set the correct air-fuel ratio taking into account the burner properties, fuel composition, and particular operating conditions instead of the trial-and-error method that is often used by operators.

A digital twin tracks the fired heater asset operation over-time and this information can be used for predictive maintenance, reducing unscheduled downtime. Hence, an efficiently utilized digital twin can produce returns on energy efficiency, reduced emissions and increased asset life span.

New Generation Air Preheaters

Fired heaters can generally be designed for efficiencies as high as 93%. Conventional, fired heaters are designed with metal air preheaters for a minimum flue gas exit temperature of ~140-150°C in order to prevent acid dew-point corrosion and subsequent high maintenance cost. The exiting flue gases still release ~7% of available energy to atmosphere. Modern air preheaters are designed to maximize the heat recovery from flue gases released to atmosphere.

Recent developments include use of a **"Plate type heat exchangers"** instead of cast air-preheaters. Plate type air-preheaters are typically used with very clean fuels having H2S content as low as 5 ppmv. Plate APH system offer very high heat transfer co-efficient, providing superior heat transfer and occupy less space compared to cast APH system.

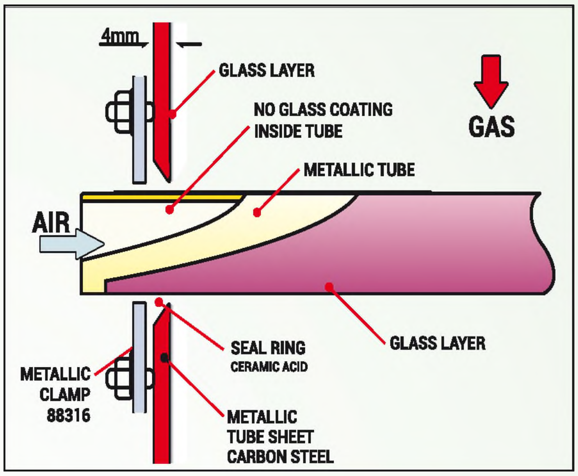


Figure 10.0: Typical Glass enamelled tube

Some advanced plate type air preheaters **use glass coating** in the lower sections which is prone to acid dew point condensation. Glass enameled tube APH are also recent alternatives of GAPH wherein the carbon steel tubes are typically designed with 2-3 coats of an acid resistant glass enameling /ceramic coating. The tubes are also less prone to breakages compared to use of complete glass tubes as in GAPH.

Another advancement is the use of **polymer tube bundles** in the lower sections of cast air preheaters. The polymeric tubes are resistant to acid corrosion. It can also be inferred from figure 11.0 that the corrosiveness of flue gas is reduced as the temperature of the flue gas is reduced beyond the acid dew point. Hence, such air-preheaters offer immense potential to exploit and recover the available heat from the flue gases presently released to atmosphere, leading to increased efficiency and reduced emissions. The actual efficiency achievable will depend on the fuel specifications, service, operating conditions etc. and need to be evaluated with the suppliers.

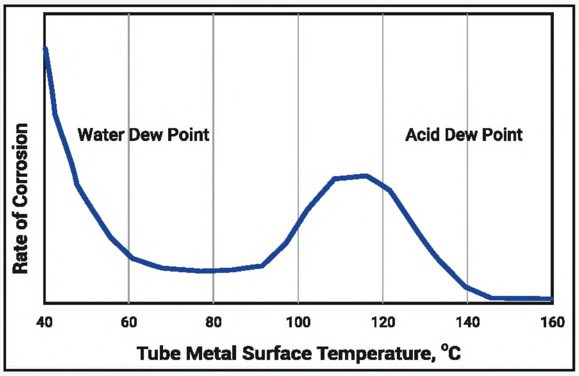


Figure 11.0: Rate of Corrosion vs. Surface TMT

Smart Combustion Systems:

Generally, oxygen measurements are taken at radiant arch, as it is a cost-effective way to ensure there is enough oxygen within the firebox. However, this location is prone to issues such as tramp air ingress which can skew the measurements. Also, it represents the overall situation within the firebox and does not represent the condition of individual burner. Hence, it is difficult to get an accurate assessment by measuring at one location. Ensuring sufficient oxygen for individual burner is more prominent during turndown conditions. The new combustion control system is targeted to provide the operator with details on each individual burner, by utilizing advanced instrumentation hardware and data analytics. This improves emission performance and enables single-digit NOX and near-zero CO emissions over the entire operating range of the heater. Also, the burner level insight improves safety of the combustion systems. Actual efficiency achievable based on fuel specifications, heater configuration, service etc. needs detailed evaluation with the suppliers for specific operating cases.

3.1.8 References

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3.2 Energy efficiency improvement through APC

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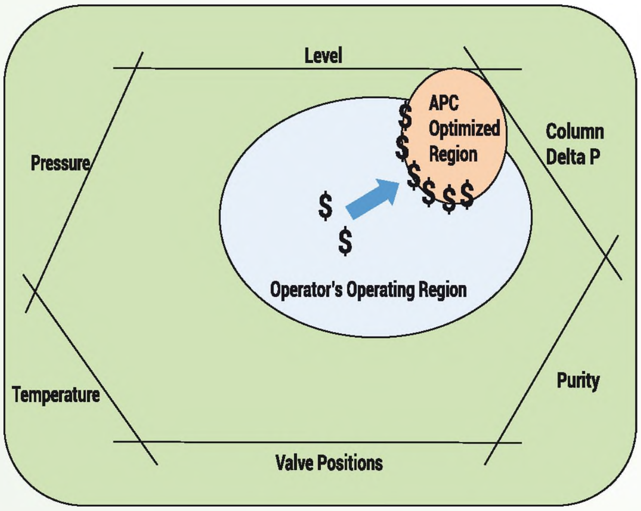
Abstract

Process Automation Systems (PAS) are widely known to be a crucial element in processing plants worldwide which includes oil refining, petrochemical, Chemicals and power generation industries. This paper describes the implementation of Advanced Process Control in BPCL Kochi Refinery which resulted in optimized process operation thereby improving the energy efficiency. APC has been implemented in 3 major secondary units of Kochi Refinery (BPCL) in 2021 viz, Vacuum Gas Oil Hydro Treatment Unit (VGO HDT), Delayed Coker Unit (DCU) and Petrochemical Fluidized Catalytic Cracking Unit (PFCCU).



3.2.1 Introduction

Energy efficiency in its simplest sense stands for efficient energy use. Decreasing energy use reduces energy costs and results in financial cost saving to consumers. Reducing energy consumption is seen as a solution to minimizing greenhouse gas emissions. According to the International Energy Agency (IEA), improved energy efficiency in buildings, industrial processes and transportation could reduce the world's energy needs in 2050 by one third, and help control global emissions of greenhouse gases.

Today against a backdrop of rising GHG emissions, oil and gas companies are viewed as crucial segment in mitigating it. Bharat Petroleum Corporation Limited (BPCL) being one of the major and integrated oil company in India continually strive to implement path breaking energy saving initiatives and has always been at the forefront in implementing projects which yield twin benefit of savings on energy cost and reduction of Carbon foot print.

Process Automation Systems (PAS) are widely known to be a crucial element in processing plants worldwide which includes Chemicals, petrochemical, oil refining and power generation industries. In today's VUCA (volatile, uncertain, complex and ambiguous) environment, industry leaders employ state of the art PAS to mitigate complexities with especially Advanced Process Control (APC) systems specifically leading to, higher efficiency, less operator interaction and increased profits.

This paper describes the implementation of Advanced Process Control in BPCL Kochi Refinery which resulted in optimized process operation thereby improving the energy efficiency. APC has been implemented in 3 major secondary units of Kochi Refinery (BPCL) in 2021 viz, Vacuum Gas Oil Hydro Treatment Unit (VGO HDT), Delayed Coker Unit (DCU) and Petro Fluidized Catalytic Cracking Unit (PFCCU).

3.2.2 Background

Advanced process control (APC) applications have become a norm for refining units in addition to basic regulatory control. Progressing along the path of regulatory control to advanced regulatory control (ARC) to conventional APC to multivariable predictive control (MVPC), MVPC technology has become the main workhorse of refinery process control and optimization.

BPCL-Kochi Refinery is located at Ambalamugal in Ernakulam Dist. in Kerala State. The company was incorporated in 1963 as Cochin Refineries Ltd. This Refinery had an initial refining capacity of 2.5 MMTPA was dedicated to the nation on 23rd September 1966. Cochin Refineries Ltd was then renamed as Kochi Refineries Ltd (KRL) in May 2000. Govt. of India had divested its entire holding in favor of Bharat Petroleum Corporation Ltd (BPCL) and later it was amalgamated with Bharat Petroleum Corporation Ltd in 2006. BPCL-KR, on the growth trajectory has completed a dream project "Integrated Refinery Expansion Project", marking a milestone on the organization's path to progress with refining capacity expansion to 15.5 MMTPA . The project envisages modernization of the refinery to produce auto fuels complying with BS VI specifications.

As part of Integrated Refinery Expansion Project (IREP), BPCL has setup a Crude/Vacuum Distillation Unit along with major secondary units i.e. DHDT, VGOHDT, DCU, PFCCU along with associated utilities and off-site facilities

Efficient ways of energy usage is a very crucial factor in profitability of any organization. BPCL management always have special focus on energy efficiency improvement. Knowing the potential of value addition on implementation of APC, the management was keen for implementing APC in these units and fully supportive of the initiative and provided all the resources.

History of APC in Kochi Refinery started way back in Nineties. The APC in Kochi Refinery has got the peculiarity that the implementation of APC in all the units have been completed by the in-house resources and without taking the help of any external implementation partners. The APC for Crude/Vacuum Distillation and DHDT was completed in previous years. The APC team taken the ambitious target of completing the APC implementation in the balance units in the current year itself. As being the tradition of Kochi Refinery, this also has been planned to execute utilizing own resources and the team was able to complete APC implementation in VGO HDT, DCU and PFCC units by Nov'21.

3.2.3 APC Controller Concept

There are 3 types of variables being considered in controller.

1. Manipulated Variables (MV): A manipulated variable is a setpoint or valve position moves to control the process. The controller will move these setpoints (or valves) in much the same way an operator would to meet the control targets that have been set. These variables are also called independent variables.
2. Feed Forward Variable (FF): A feed forward (disturbance) variable is variable which has an impact on the process but one which the controller cannot move. These referred to as feed forward variables. Disturbance variables are also independent variables.
3. Controlled Variable (CV): A controlled variable is a variable which changes in response to a change in a manipulated or disturbance variable. These variables are also called dependent variables. This is because their values are dependent on the values of the independent variables.

The relation between manipulated variables and controlled variables can be inferred (whether it's positively or negatively related) and called as the model gain. Each MV will be related to one or more CVs. The controller works in two steps:

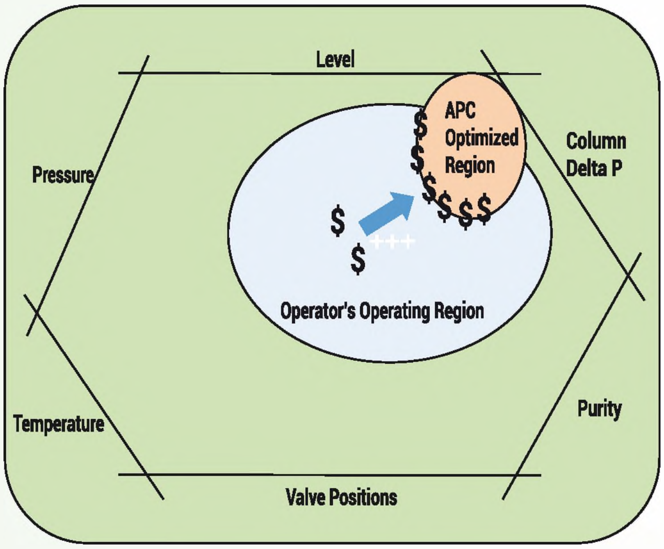
a) Controlling
b) Optimization

First objective of the controller is to keep all CVs within the given limits. Depending on the process requirements high and low limits for the CVs are to be set from the DCS (Distributed

Controlled System). To make CVs within limits, related MVs get adjusted by the controller only within the low and high limits set for the MVs.

Once all related controlled variables are within limits, MVs get adjusted to achieve optimization strategies like minimization or maximization. MVs are minimized or maximized based on controller's economic objectives. It is important to set the variable limits correctly based on actual requirements since if CV limits are infeasible or MVs are restricted, economic objectives shall not be met as in such situation MVs are adjusted only to control CVs within limits or minimize violation of CV limits.

Steady State Optimization



3.2.4 APC Implementation in BPCL KR

Typically APC implementation leads process unit profitability by

- Maximizing feed and products (maximum utilization of assets)
- Minimizing utilities (air, steam etc) consumption (For BPCL KR, 1% Change in Steam System Size equals ≈0.9 EII & 1 EII reduction is equivalent to cost savings of Rs. 31 Cr.)
- Pushing to the limit for most profitable constraints
- Reducing product quality variations (stretching toward max limits)
- Responding faster to specification changes or disturbances (adoption of change)

VGO-HDT Unit

VGOHDT is Vacuum Gasoil treating unit commissioned as a part of IREP and having capacity of 3.00 MMTPA. This unit is designed for hydro treating Vacuum Gas Oil (VGO) and mild hydrocracking of VGO to produce lighter products. APC was implemented in VGOHDT in Jun'21. The APC in VGOHDT unit consist of the following 4 sections.

a) VGOHDT Reactor Controller: This controller is mainly designed to maintain conversion as per demand and product sulphur within quality specification mandated. Good amount of amine consumption reduction also achieved.

b) VGOHDT Fractionator Controller: This controller is mainly designed to maximize Diesel and other products. Steam consumption reduction was also achieved.

c) VGOHDT Fractionator Heater Controller: This controller is mainly designed to minimize flue gas excess Oxygen and to maximize air preheat.

d) VGOHDT Reactor Heater Controller: This controller is mainly designed to minimize flue gas excess Oxygen and to maximize air preheat.

Delayed Coker Unit (DCU)

DCU is Delayed Coker unit commissioned as a part of IREP with a capacity of 3.80 MMTPA. This unit is designed for up gradation of Vacuum Residue to value added products i.e mainly Diesel. APC implemented in DCU in Nov'21. DCU consist of 2 controllers. (APC already implemented in DCU heaters)

a) DCU Fractionator Section: This controller is mainly designed to maximize Diesel and MS components. Operator intervention reduction also achieved in this controller.

b) DCU Gas Concentration Section: This controller is mainly designed to optimize Wet Gas Compressor performance. Steam consumption reduction also achieved.

Challenge Faced during DCU APC Implementation

DCU is a process which involve thermal cracking of vacuum residues. The process involve batch operation to separate coke by means of drum operation. This batch type operation is made continuous by providing a configuration of a pair of identical Coke Drums located at the combined process tubing coil outlets of a Coker Heater. The decoking cycle steps comprise the greatest number of required adjustments to the DCU process operation. Completing these steps within the scheduled time intervals is vital to fully utilize the throughput capacity of the DCU. During this process (Coke drum switch over process) which takes place at least once in 24 hrs plant get upset due to wide variation in process parameters. To bring this procedure under APC umbrella was a big challenge, which otherwise reduced APC uptime on daily basis whenever drum change over process initiated. BPCL KR Team APC successfully overcome this challenge by introducing separate mechanism " LOGIC 2" to address process upset during drum change over process.

All related MVs & CVs (LCGO Tray Level, LCGO draw off temp, HCGO draw off temp) pertaining to drum change over activity made faster by assigning different model gains. This logic is made in such way that it identifies drum switch over process initiation on its own looking at some related process parameters and also stops actions under LOGIC 2 automatically looking at some related process parameters.

LOGIC 2 made it possible to keep APC uptime higher by 4-5% during single train operation and by 8-10% during two trains operation on daily basis.

PFCCU

PFCCU is Petro Fluidized catalytic cracking unit came as a part of IREP with a capacity of 2.20 MMTPA. This unit is designed for converting unconverted vacuum gasoil in VGO Hydro treatment units to value added lighter products i.e MS and Propylene. APC implemented in PFCCU in Nov'21. PFCCU consist of 4 controllers.

a) PFCCU Reactor Regenerator: This controller is mainly designed to maximize value added products i.e Propylene and MS. Also steam consumption saving was addressed through this controller.

b) PFCCU Main Column: This controller is mainly designed to maximize diesel and to maximize feed preheat.

c) PFCCU Gas Concentration Unit: This controller is mainly designed to optimize Wet Gas Compressor performance. Steam consumption reduction also achieved.

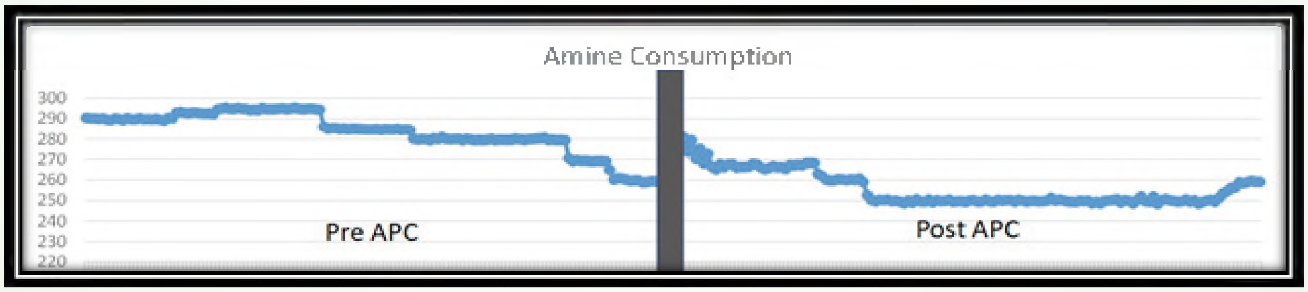
d) PFCCU Propylene Recovery Unit: This controller is mainly designed to focus on purity level of different grades of Propylene.

3.2.5 Post APC Implementation Benefits

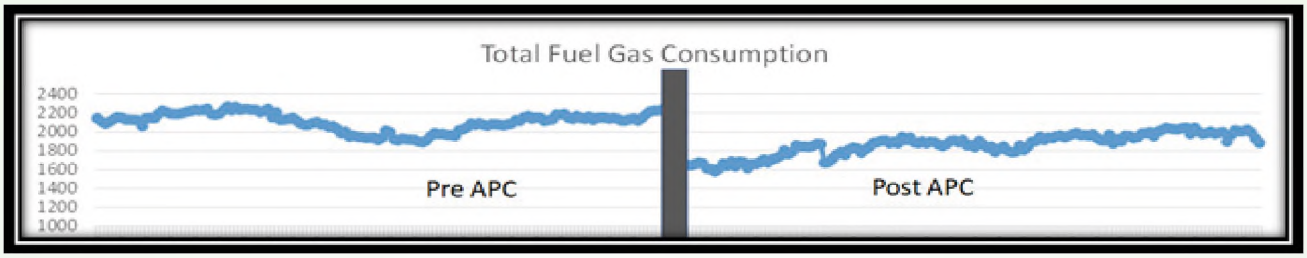
Given below some of the process parameters changes after implementation of APC

VGO-HDT:

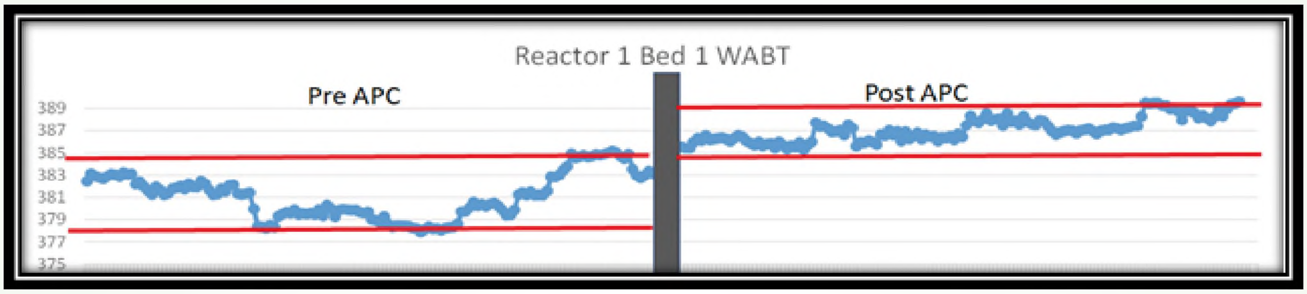
Amine flow decreased to 256 Mt/Hr (Post APC) from 279 Mt/Hr (Pre APC)



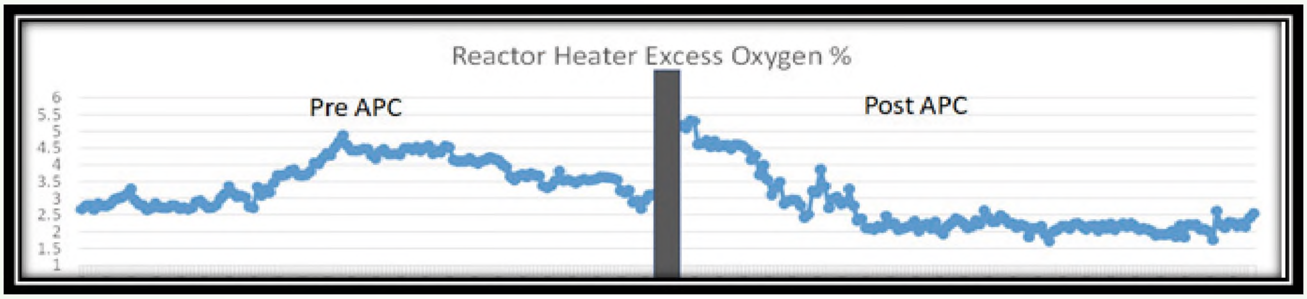
Total Fuel gas consumption decreased to 1866 Kg/Hr (Post APC) from 2126 Kg/Hr (Pre APC)



Reactor1 Bed1 WABT Standard Deviation decreased to 1.05 (Post APC) from 1.67 (Pre APC)



Reactor Heater excess Oxygen decreased to 2.6% (Post APC) from 3.5% (Pre APC)

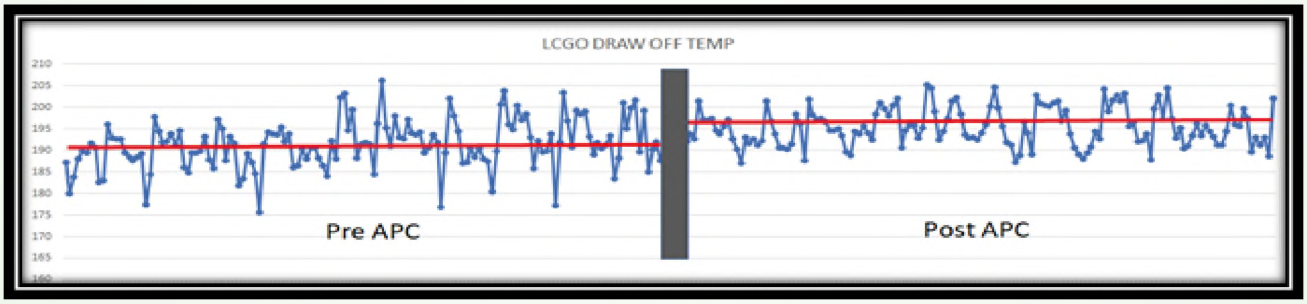


Thus VGO HDT total financial benefit estimated to be 14.51 Rs Cr/annum based on Amine consumption reduction and Fuel gas reduction. Apart from this financial benefit, fractionator diesel draw off flow is being regulated in a much effective way, looking at draw off temperature which resulted in manual intervention reduction.

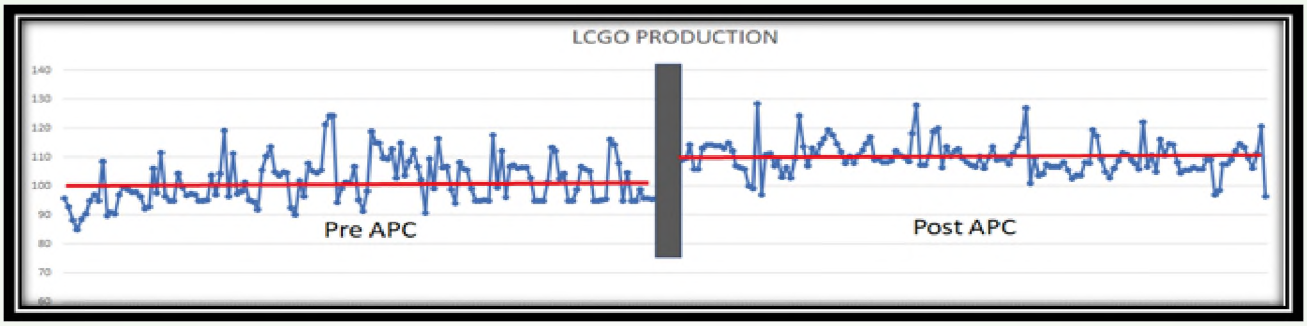
DCU:

Given below some of process parameters changes after implementation of APC in DCU.

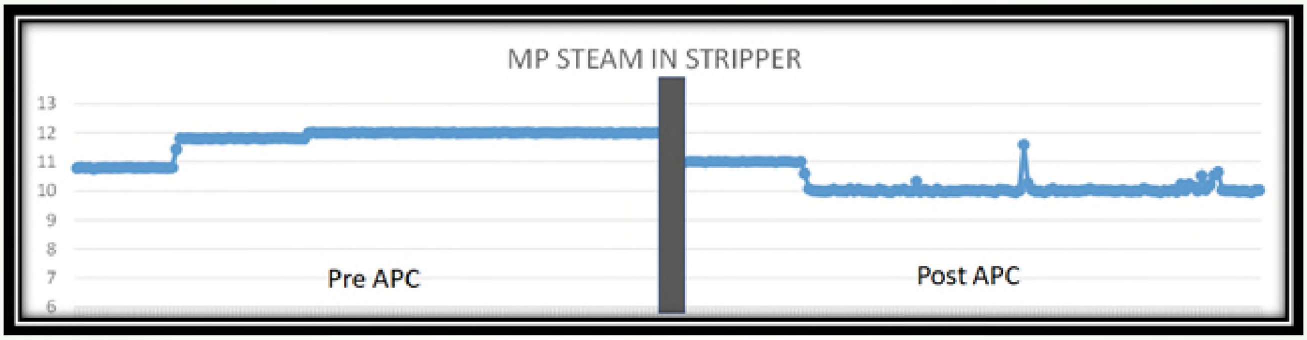
LCGO draw off temperature increased to 195 deg cel (Post APC) from 191 deg cel (Pre APC) and its Standard Deviation decreased to 5.2 (Post APC) from 6.2 (Pre APC)



LCGO production increased to 110 Mt/Hr (Post APC) from 100 Mt/Hr (Pre APC)



MP steam in Stripper reboiler decreased to 10.2 Mt/Hr (Post APC) from 11.8 Mt/Hr (Pre APC)

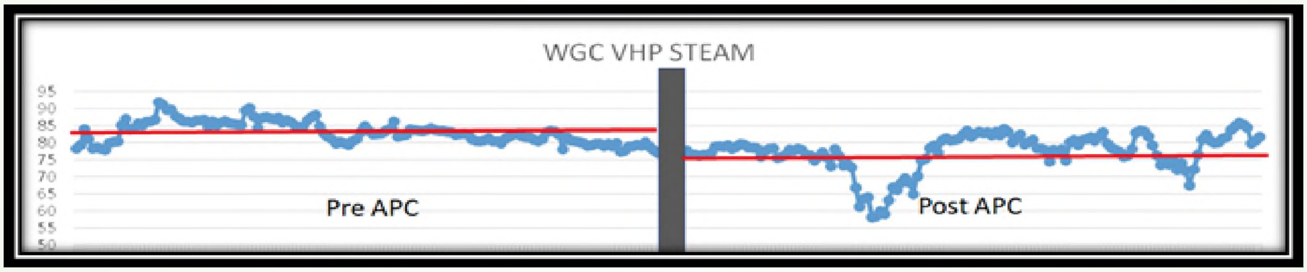


Thus DCU total financial benefit estimated to be 48.65 Rs Cr/annum based on majorly product yield variation (HSD component increase) along with steam and power reduction. Apart from this financial benefit, process upset during drum change over operation drastically came down because of APC implementation. Also WGC antisurge opening being regulated in much effective manner looking at deviation which has reduced manual intervention a lot.

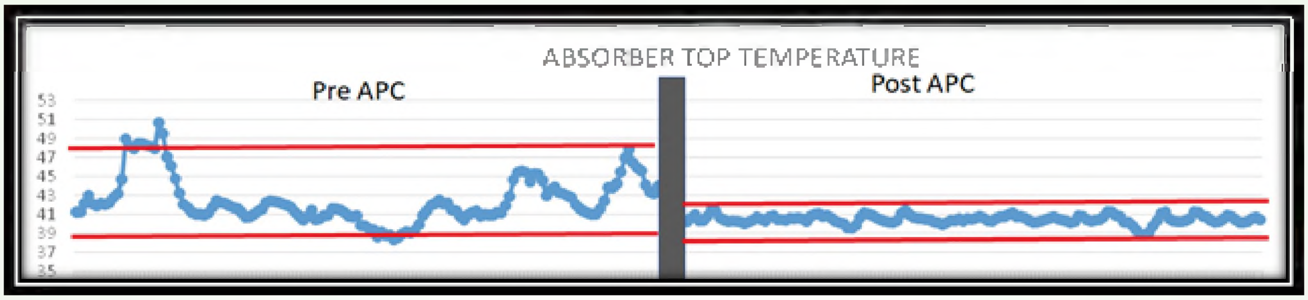
PFCCU:

Given below some of process parameters changes after implementation of APC in PFCCU.

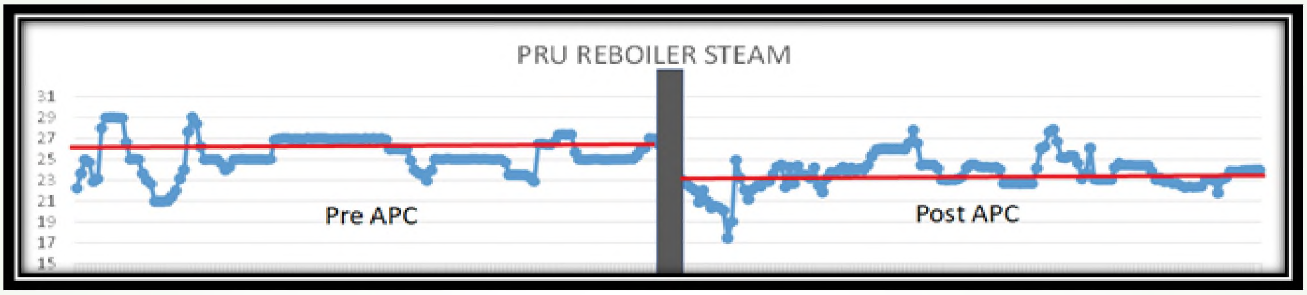
WGC VHP steam decreased to 75 Mt/Hr (Post APC) from 82 Mt/Hr (Pre APC)



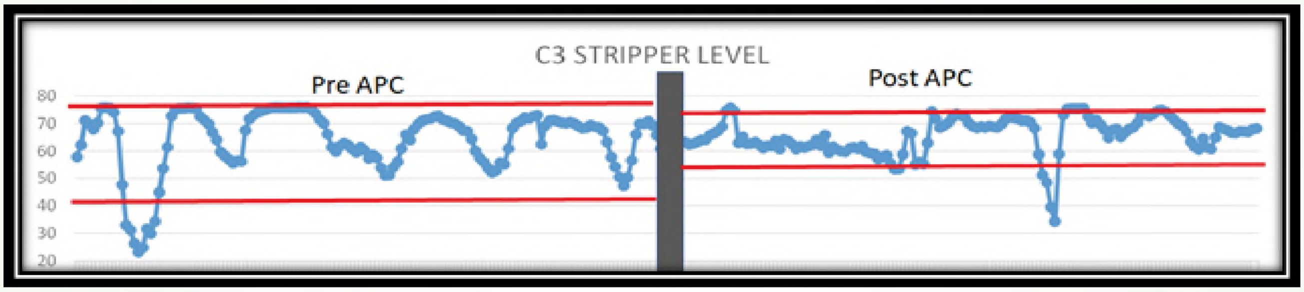
Absorber Top Temperature Standard Deviation decreased to 0.43 (Post APC) from 2.39 (Pre APC)



PRU REBOILER steam decreased to 23.4 Mt/Hr (Post APC) from 25.8 Mt/Hr (Pre APC)



C3 STRIPPER level Standard Deviation decreased to 6.95 (Post APC) from 10.70 (Pre APC)



Thus PFCC total financial benefit estimated to be 7.93 Rs Cr/annum based on majorly steam consumption reduction and propylene giveaway reduction. Apart from this financial benefit, Fractionator bottom level, LCO tray level and HCO tray level is controlled by manipulating LCO product flow which has streamlined level controlling in fractionator in much better way. Also WGC antisurge opening being regulated in much effective manner looking at deviation which has reduced manual intervention a lot.

3.2.6 Conclusion

APC is a great tool for energy optimization in a process plant. For decades, it has been contributing to the industry, bringing millions of dollars benefits all over the world. Advanced process control is an unbeatable combination of high level technical and business expertise for optimizing plant performance.

Overall improvement was seen in plant operational efficiency –¬ increase in target output, decrease in energy consumption, and stability of quality indicators. APC implementation resulted into both tangible (Product yield, steam consumption, power consumption, amine consumption etc) and intangible benefits (steady state operation, standard deviation reduction etc) in BPCL KR.

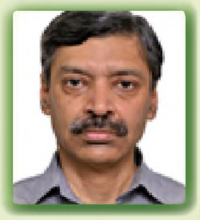
Team APC will continue their efforts towards conceptualizing and implementing means of energy efficiency improvements through way of APC to reap more benefits for organization.

APC Team Members

Mr. Jose V Karenthanam, Mr. Manoj Kumar M N, Mr. Biju M P, Mr. Rahul V. Kalbande, Mr. Jitendra Verma, Ms. Vandana S and Ms. Sonali Shetty of Bharat Petroleum Corporation Ltd, Kochi Refinery.

3.3 Energy Efficiency Improvement in Crude & Vacuum Distillation unit Targeting Emissions

Authors: Dr. Ashwani Malhotra & Mr. Ameya Dhok, Engineers India Limited, New Delhi



Dr. Ashwani Malhotra is serving as Chief General Manager in Engineers India Ltd. He has 35 years of experience in the process design and engineering of refineries (including Crude & Vacuum Distillation unit) and onshore/offshore oil and gas facilities in the Equipment and R&D divisions of EIL. He also has experience in application of IIOT in Refinery

Mr. Ameya Dhok works as Senior Manager with Engineers India Ltd. He has experience in Process simulation & optimization for refinery unit design like Crude distillation, Delayed Coker, and Naphtha splitter units. His area of interest includes Process engineering and exploring energy improvement measures.

3.3.1 Abstract

Petroleum refining is one of the largest energy consuming industrial sectors and is run on tight profit margins. Because of ever changing market scenarios, crude price dynamics, it becomes imperative to realize the optimum refining margins. Energy consumption is a major operating cost component in any refinery process unit. Hence reduction in fuel & loss offers great potential and incentive to improve unit performance as well as overall refinery profitability, thereby, **reducing harmful emissions**. Typical energy usage accounts for approximately 50% of refining operating costs. Crude & Vacuum Distillation Unit (CDU/VDU) the basic processing step in oil refinery is a highly energy-intensive process representing one of the most important areas for energy integration. Optimum design shall ensure minimization of OPEX by optimizing operating parameters with suitable provisions for operation flexibility thereby making the unit energy efficient. Options like Pinch technology for Heat exchanger network (HEN), increase in crude heater efficiency, optimizing operating parameters, use of Hybrid Vacuum system can be approached during design. A typical case study for optimization of operating parameters like column pressure shows that selecting optimum value leads to saving in OPEX. Hybrid Vacuum system (Ejector + LRVP) design can prove to be an energy efficient option for both grass root and retrofit designs w.r.t. utilities consumed mainly steam and power. For a typical case, the OPEX for hybrid system in case of revamp & grass root designs can be reduced by 10-25% with viable payback period.

3.3.2 Introduction

Crude distillation unit plays a pivotal role in Petroleum refineries as it provides feedstock to downstream secondary processing unit. The unit is highly energy intensive system which requires energy to separate various fractions of crude oil. Energy consumption in any processing unit constitutes a major operating cost. Typically about 2 % of crude oil input is consumed for the energy requirements of crude unit. Mitigation measures to minimize this energy requirement will result in substantial savings.

Grassroot design of CDU/VDU should be reliable in such a way that it gives flexibility to process desired range of crude basket. Unit is required to be designed such that it maximizes yield of high value products with minimum energy consumption, optimum product quality and flexibility provisions needed to process varying crudes. Approximately 50% of operating cost in refinery is due to energy requirement. Sincere efforts need to be inherited in design to lower the energy requirement. Lowering the energy requirements leads to reduction in emissions. Typically the utilities considered for energy consumption are

- Fuel oil / Fuel Gas
- Steam
- Power
- Cooling water

Crude oil is basically a mixture of hydrocarbon (HC) ranging from lighter HC (Methane, ethane) to heavier HC (having boiling point more than 600 deg C). Crude oil Distillation is simple separation of crude oil into desired fractions. A typical flow scheme of CDU/VDU is shown in Figure 1. Crude oil is preheated in a series of preheat exchangers to an optimum desalting temperature. After salt removal, the desalted crude is then pumped to preflash drum where the crude is flashed and the flashed vapors which are lighter volatile material is sent to crude column thereby reducing the fired heater firing demand.

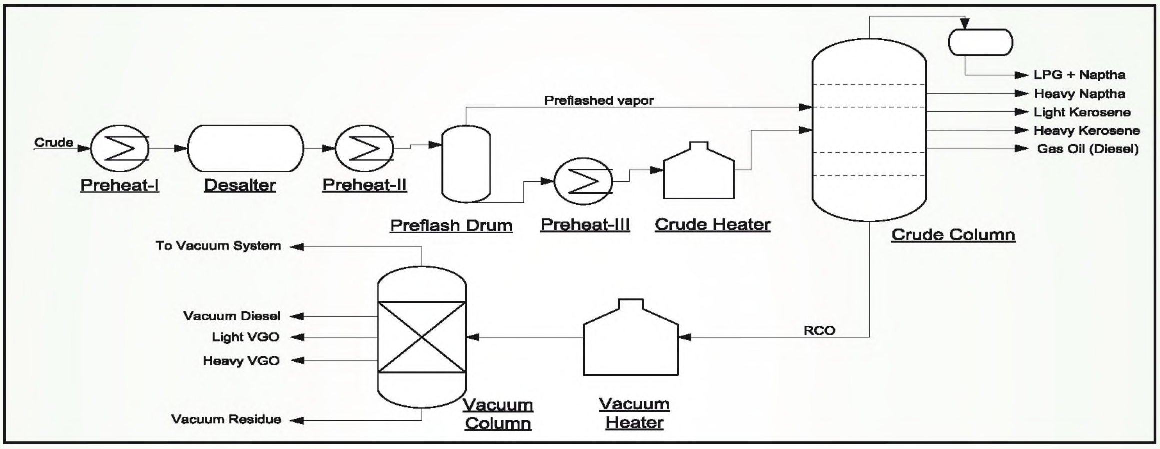


Figure 1

The preflashed crude flows through a series of heat exchangers, heated to an optimum temperature referred as COT (Coil Outlet Temperature) in crude heater and finally enters the Crude Column. In crude column products are separated based on their boiling range and desired specification. Unstabilised Naphtha from crude column overhead is sent to naphtha stabilizer where LPG and stabilized Naphtha are further separated. Typically Heavy naphtha, Kerosene, Gas oil (Diesel) is drawn as side cut through dedicated side strippers. The column has typically 2 to 3 pump arounds located across the column and depends upon the column configuration.

Reduced crude Oil (RCO) from crude column bottom is sent to vacuum heater and enters the column at desired temperature. The column has packed beds and operates under vacuum condition so that the temperature requirement for separation gets lowered i.e. it is based on the fundamental that boiling point and pressure are directly proportional and thus avoids thermal cracking to form coke at elevated temperatures. The RCO is separated into Vacuum Diesel, Vacuum Gas oil and Vacuum residue. The different product streams so obtained from crude & vacuum column are good heat source and can be suitably used in preheating crude in preheat network making the unit more energy efficient. In certain revamp scenarios the preflash drum is replaced by a prefractionator which lowers the load of downstream crude column thereby increasing the throughput.

In this paper, an overview on major design approaches for energy optimization shall be discussed focusing typical case studies for design optimization which shows substantial energy saving.

3.3.3 Methodology

The key aspect to have an energy efficient design is to choose the optimized parameter/equipment. The subsequent section would give an outline of the major design approaches for reducing the energy requirement thereby reducing the net emissions.

Heat exchanger network (HEN) Optimization

Pinch technology uses the first principles basis for identifying the minimum energy requirement point. It mainly depends upon the stream flow rate, temperature and heat available within. It basically optimizes the heat integration between hot and cold stream to have the maximum temperature of the cold stream with minimum heat transfer area and exchangers. The critical factors affecting the final preheat temperature needs to be taken care in the design.

Crude Heater Design

Typically in refinery, the heaters are mostly natural draft design with process fluid flowing through both the convection & radiant section and the efficiency is around 80% - 82%. Depending upon the existing heater configuration the heater duty can be increased to around 90% - 92% by modifying to balanced draft type heater by including an Air Preheater system (APH). The heater efficiency can also be increased by APH augmentation approach, inclusion of waste heat recovery section, increasing the radiant section area to increase the heat flux in existing heaters.

Optimization of operating parameters

The optimization of column operating parameters is case specific i.e. it depends upon the type of crude being processed, new or retrofit design, product specification & objective. This aspect of design shall be discussed in detailed as case study wherein substantial saving in OPEX is reflected.

Case Study: Approach to energy improvement

- **Optimizing Crude Column Pressure**

  A typical case study for carrying out optimization for fixing crude column pressure is done processing a blend of Arab light & Arab Heavy crude. The design objective is maximization of Diesel stream from the column. The crude column overhead circuit comprises of two drum system with heat recovery in overhead exchanger as shown in Figure 2 below.

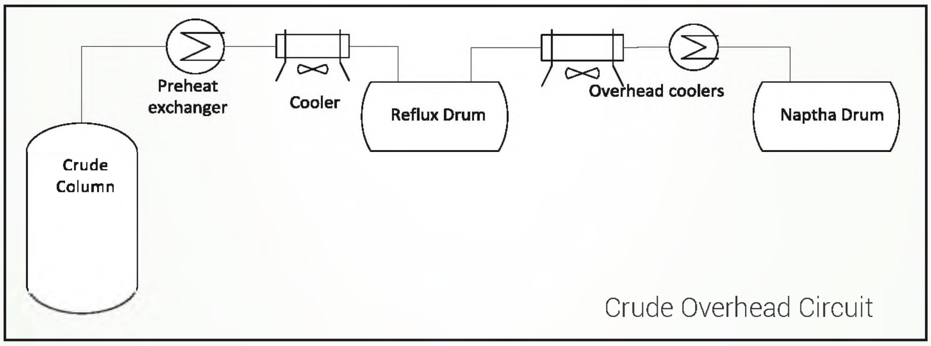


Figure 2

A comparison of major operating parameter data at different operating pressure are specified in Table 1 below.

Table 1

Parameter	Unit	Case-I	Case-II	Case-III
Column Top Pressure	Kg/cm2 a	2.1	2.9	3.2
Heater Duty	MMKcal/hr	Base	1.15 X Base	1.18 X Base
Fuel Gas generation		Yes	Nil	Nil

The crude heater outlet temperature requires increase with increase in pressure & there is fall in hot rundown stream temperature with decrease in operating pressure. However the fall in preheat (~ 5 – 7 deg C) would be compensated by increasing heater firing thus increasing the Fuel gas requirement in heater. As seen from Table 1, there is also fuel gas generation from overhead naphtha drum at lower operating pressure. This fuel gas generated will require additional facilities / equipment for further processing. This will lead to additional power requirement, thereby directionally increasing total energy requirement.

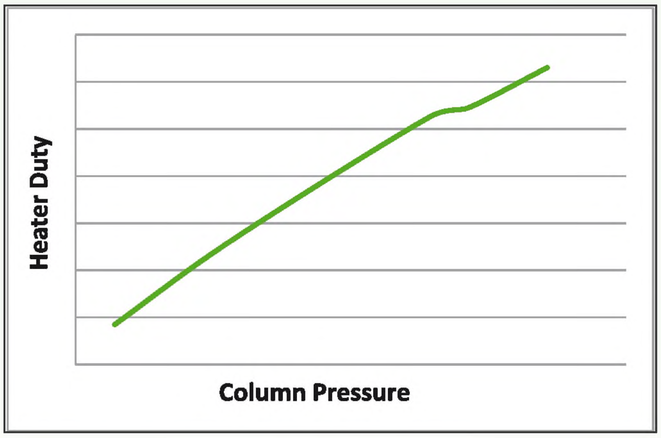


Figure 3

From figure 3, it is seen that the crude heater duty and crude column pressure are directly proportional to each other considering other parameters as same.

Hence from Table 1, above the optimum conditions can be inferred to that corresponding to case II.

- Vacuum column overhead configuration – New Design

Vacuum system configuration is also an important aspect in design for vacuum column operation. The vacuum system can be

- Conventional all ejector system
- Hybrid system (Ejector + LRVP)

Hybrid system can be highly energy efficient option during design. It can be implemented in new as well as revamp scenarios. A comparison study for OPEX is done for a hybrid vis a vis ejector system for a typical crude unit is given in table 2 below.

Table 2

Utility	Ejector system	Hybrid system
Steam Consumption	Base	0.85 X Base
Operating Cost (steam)	Base	0.83 X Base
Power Consumption	No	Yes
Total Operating Cost	Base	0.87 X Base

(Basis: In house/vendor data)

From above it is evident that hybrid system can be highly rewarding in terms of OPEX, thereby reducing the overall energy requirements.

- **Vacuum column overhead configuration – Revamp Design**

Depending on the tradeoff between the cost of steam vis a vis electricity, it may be economical to replace last ejector stage with a LRVP referred to as a Hybrid system. For a typical case, Comparison between utility data requirement for following case studies are given below.

Table 3

Utility	Ejector system	Hybrid System
Steam Consumption	Yes	No
Power Consumption	No	Yes
Operating Cost	Base	0.25 X Base

(Basis: In house/ vendor data)

Going further, the capital cost and payback period (using straight line method) evaluation is given below in Table 4.

Table 4

Parameter	Value
CAPEX Hybrid (Replacement of Last Stage)	Base
OPEX Hybrid (Annual saving for above as per Table 3)	1.25 X Base
Payback period (using straight line method)	0.8 (less than a year)

(Basis: In house/ vendor data)

As the payback period for hybrid system implementation is less than a year, it can be suggested to implement LRVP.

3.3.4 Conclusion

Every design aspect should be thoroughly analyzed and finalized accordingly which again depends upon unit design requirements & configuration. Every effort to make the design more energy efficient is the need of the hour. Energy use in general needs a thorough review to ensure that all appropriate costs are included.

The presented case studies demonstrate substantial energy saving in terms of OPEX. As seen from above, optimizing column pressure there is considerable saving in crude heater duty as a result fuel gas requirement will come down thereby making the design energy efficient. Further in case of gas generation at lower pressure there would be additional power requirement to compress the gas further. This case study demonstrates reduction in fuel firing which leads to reduction in emission. Further it is observed that implementation of LRVP in vacuum overhead system leads to significant energy saving. A typical case study shows that implementation of LRVP in case of grass root design as well as revamps scenario leads to saving in OPEX. in case of revamp scenarios, the payback period can be less than one year thereby making it a more realistic approach for energy efficient design. This case study demonstrates reduction in steam consumption which leads to reduction in fuel consumption in steam generation system and thereby reduction in emission.

* * *

Part-4

Alternate Energy, Carbon Sequestration & Environment

4.1 CO2 EOR as a Possible Carbon Sequestration Tool in a Matured Reservoir: Pilot Design based on simulation

Authors: Akhtar Uddin Ahmed, Pankaj Kumar, Ranjit Dutta and Saloma Yomdo, Oil India Limited

Mr Akhtar Uddin Ahmed is working as Dy. Chief Reservoir Engineer in Oil India Limited. His area of interest includes Reserves Estimation, Dynamic Simulation, EOR

Mr Saloma Yomdo Is working as Chief General Manager with Oil India Limited. He is an expert in the field of Reservoir simulation, field development studies, water flood management, mature fields revitalization, Enhanced Oil Recovery studies

4.1.1 Abstract

The role of Carbon Capture, Utilization and Storage (CCUS) in climate change mitigation has been a topic of debate for over two decades. India's energy demand has increased multi fold in recent decades and is likely to propel the nation to becoming one of the largest energy markets in the future, the transition towards a green economy remains the government's priority in line with various climate change agreements. This work is an endeavor to use CCUS as an effective CO_2 mitigation tool from the perspective of upstream oil and gas companies.

The current study summarizes the prospect of CO_2 flooding and subsequent CO_2 sequestration from an Indian mature oil field in Assam through laboratory study, reservoir modeling and pilot design studies.

It was confirmed through PVT laboratory studies that CO_2 injection can achieve the desired miscibility under reservoir conditions at its Minimum Miscibility Pressure (MMP). The core-flooding test showed the potential for significant incremental oil recovery by continuous CO_2 injection and the residual oil saturation after miscible CO_2 injection reached ~0.13PV.

A fine scale geological model was built for the entire reservoir and dynamic simulation work was performed on the geological model without upscaling. The history match of 53-year field production and pressure data in the whole reservoir was completed in a commercial simulator, and various development scenarios were investigated. Based on the results from CO_2 EOR simulation study, a pilot pattern area of ~ 60 acres with one injector and four producers have been identified. The CO_2 was injected into the reservoir at 67 metric ton per day for 5 years and cumulative injection volume is of the order of around 0.122 million metric ton. Then the well is proposed to be switched back to water injection afterward.

4.1.2 Introduction

The world, and India, can no longer reach Net Zero goals through emission reduction alone. Achieving Net Zero will require widespread adoption of mechanisms to remove carbon dioxide that is already in the air due to unavoidable emissions. Geological Carbon sequestration which includes Carbon Capture, Utilization, and Storage (CCUS) and Carbon

Capture and Storage (CCS) will play a vital role in achieving India's ambitious net zero goals, by 2070.

Both CCUS and CCS will need rapid technology breakthroughs to sequester carbon at large scale. While CCUS has been around since 1960's, it is still in experimental stage in India. At its current cost points (above $ 50/t - $ 100/t of CO_2 abated), carbon capture is too expensive for commercial scaling. CCS, on the other hand, is a very new development. The largest CCS plant in the world, recently commissioned in Iceland, will capture 4 kt CO_2/year for storage in basalt formations and is reported to cost anywhere between US $ 600 - 1,200/tonne of CO_2 for customers purchasing carbon offsets.

4.1.3 Importance of CCUS in Indian Context

Current global annual CO_2 emission is around 34.8 billion tons per year, of which India produces around 2.44 billion tons (as per 2020 data). With over 1.3 billion population, India is one of the fastest growing major economy in the world and it needs sustained sources of energy to fuel its growth and cater to the aspirations of its huge population. On the other hand, looking at the emission front, India, albeit with very less per capita emission, is the third largest CO_2 emitter in the world. As per the Nationally Determined Contributions (NDC) of Paris Agreement, India has ratified to decrease its emission intensity of GDP by 33- 35 percent by 2030 from 2005 level. In the recently concluded COP-26, India declared to be Net-Zero by year 2070. In this regards CCUS offers win-win proposition by curtailing atmospheric emissions as well as may potentially be utilized for enhanced oil recovery (EOR) from mature oil fields or for production of chemicals & fuels.

Carbon dioxide-enhanced oil recovery (CO_2-EOR) is a technology which has a dual benefit of oil production enhancement and at the same time sequestration of CO_2 into the Formation. CO_2-EOR has been applied successfully in the USA since the early 1970's. The area with the most extensive history of CO_2 -EOR is the Permian Basin in West Texas and eastern New Mexico where more than 50 CO_2 -EOR projects operate. The technology targets the residual oil in depleted oil reservoirs with the injection of CO_2 The oil recovery process can be immiscible or miscible, with the highest oil recovery expected in miscible displacements [3]. In a miscible process CO_2 enhances oil production by mixing with the residual oil as a solvent agent at pressures above the minimum miscibility pressure (MMP), which is the minimum pressure at which miscibility is achieved. The reduced viscosity and expansion of the new CO_2 -oil phase decreases flow resistance toward oil producing wells. The produced CO_2 is separated from the produced fluids, re-injected back into the reservoir and the process is repeated in a loop. However, not all the injected CO_2 is produced back to the surface, as several mechanisms such as capillarity, dissolution, and the geologic structure trap a significant percentage (as much as 50%) of the CO_2 injection stream within the reservoir.

Tertiary recovery methods may be employed after waterflood oil recovery declines. Among the methods commonly used in the United States is the miscible CO_2 EOR.

EOR flood was initiated in SACROC project in Permian Basin, West Texas. The utilization of anthropogenic CO_2 for enhanced oil recovery (EOR) becomes an industry trend, starting from USA to Middle East and now to India. Carbon Capture, Utilization and Storage (CCUS) can significantly extend the life-span of an oil field, and reduce the atmospheric emission of CO_2. Figure 1 below shows a strategical field EOR development plan, which typically contains the following phases:

Phase-1: In this phase, waterflood performance/primary recovery of all the available brown field is reviewed for identifying probable EOR candidates.

Phase-2: After candidate selection, a rapid EOR scoping study is recommended by analyzing the available field data and laboratory test data. A suitable EOR scheme is selected based on key rock and fluid properties like reservoir heterogeneity, API gravity, viscosity of crude, formation thickness, depth, permeability, temperature etc. Geomodeling work is initiated followed by a dynamic simulation study. Field development and optimization plan and IOR/ EOR scenarios will be proposed through simulation studies.

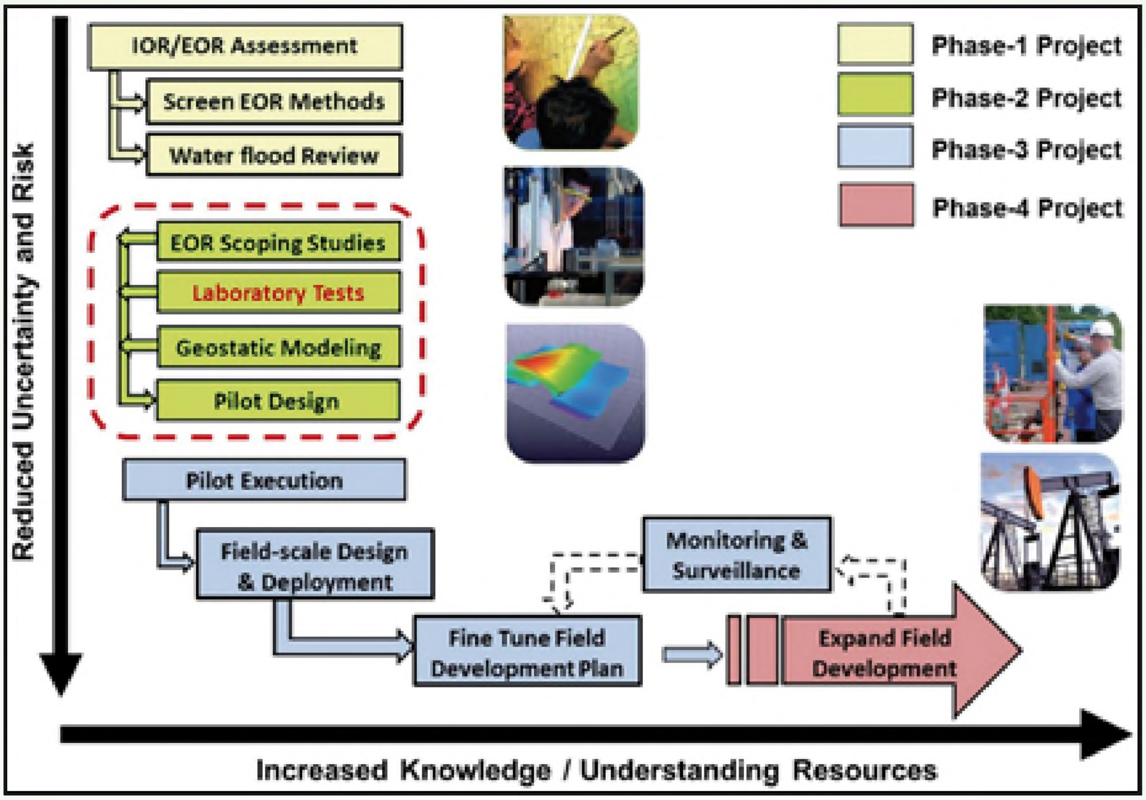


Figure 1: development stages of a typical EOR Project

Phase-3: After proving the technical and economic success through static/dynamic simulation work, the pilot design is completed with a field implementation plan. Surface facilities upgrading and subsurface monitoring and surveillance plan are designed and implemented. Then gas injection pilot test is executed by a multi-disciplinary team effort.

Phase-4: When the pilot test completes, the field data including production and pressure data will be interpreted. Reservoir model will be tuned continuously by feeding with more and more new pilot testing results. If the pilot test shows a technically and economically favorable result, the field-wise EOR injection will be deployed.

This paper mainly presents the results of CO_2 flooding in a matured reservoir through laboratory studies, reservoir modeling and dynamic simulation work.

4.1.4 Materials and Methodology

EOR Core-flood Tests

Core flood experiment was designed to verify the miscibility of CO_2 with live fluid in the reservoir rock, and the residual oil saturation after miscible flood (Sorm). The experiment was performed on a 24 inch long reservoir core (composite) which was established to initial water saturation level and conditioned with regard to its initial wettability by an aging process. The experiment was performed at 3,250 psi (228.5 Ksc) and 178°F (81°C).

A stack of eight (8) core samples selected from the same rock type, representing good quality sandstone, were placed in the core holder, forming a 2-ft composite. The composite was constructed using Huppler's ordering criterion (Huppler, 1969). The initial water saturation of this composite was 42.2% in average, which was carefully brought to irreducible water saturation using dead crude oil by core-flood and porous plate desaturation methods. The wettability of the core composite was restored dynamically by aging with dead crude oil for around 4 weeks time. Once the reservoir conditions equilibrated, the synthetic live oil displaced the dead oil, and a dispersion test (fully miscible) was performed to measure hydrocarbon pore volume (HCPV). The density of the effluent was measured downstream using an in-line densitometer.

It is to be noted that all the core flood experiments were conducted at reservoir conditions of 80°C and 3300 psi (232 Ksc), which is 300 psi (21 Ksc) above the pure CO_2-live oil MMP value. The net confining stress used in the coreflood was set as 3650 psi (257 Ksc), reflecting the average net overburden pressure encountered in the actual reservoir.

PVT Experiments

Multiple PVT experiments were conducted, including Constant Composition Expansion (CCE), Differential Liberation (DL) and Swelling Tests. Slim tube studies were conducted to determine the MMP between multiple injectants with recombined live oil. This study provided the minimum pressure at which the fluid is expected to develop multi-contact miscibility with pure CO_2 or CO_2 stream with impurities and helped to establish the suitability of miscible gas flooding and the reservoir operating pressure. Solubility swelling experiments were carried out on reservoir oil to study how the reservoir fluid reacted to gas injection. The saturation pressure of the reservoir fluid was determined by carrying out a full or partial Constant Composition Expansion (CCE) experiment.

Static and Dynamic Modelling

A fine scale geological model was constructed integrating geophysical, geological, petrophysical and engineering information using a commercial software. Review of well logs, core data and well test data is being carried out for facies and rock type determination. The reservoir static model is bounded by faults with 0.7 million cells (107 × 50 × 132). The simulation study was performed on the fine scale geological model without going through the upscaling process.

Well wise monthly pressure-production data for all the wells have been used as input for history matching in the commercial simulator from June 1967 to March 2020. Well wise oil rate, gas rate, water rate and the static pressure measurements have been used as history matching parameters. Some key parameters like relative permeability curves, vertical permeability and aquifer size are tuned to achieve the desired history match. Both static geological data, petrophysical and dynamic data analysis indicated the presence of three (3) major facies (sand, shaly sand, shale) and a lack of hydraulic connectivity in some regions between these facies. Reasonable rate and pressure matches were obtained on both well and field level.

Todd-Longstaff Model for Misicble Flood

The Todd-Longstaff (TL) concept was used to model the effects of miscible gas injection in the commercial simulator. TL model captures the key effects of gas injection in several aspects:

1. The injected gas and in situ oil are assumed to be first contact miscible above the MMP.
2. The value of represents the size of the dispersed zone in each grid block i.e. a small value indicates that the dispersed zone is negligible and a large value indicates that the dispersed zone is potentially larger than the grid block size. Typical values range from 0.3 to 0.7; in this simulation, the oil recovery is not significantly affected by the value of and a value of 0.5 is used.
3. The effects of mixing of oil and gas on viscosity are captured by a mixing equation. The mixture viscosity is a function of oil and gas viscosities and saturations.
4. The relative permeability values are entered for a hydrocarbon phase (krn (Sn)) and a water phase (krw). The oil and gas relative permeabilitys are then calculated as a weighted saturation function. In this simulation, the oil relative permeability curves from the history match case are used for hydrocarbon relative permeabilities, and the water relative permeabilities are kept the same.

4.1.5 Results and Discussion

Reservoir Fluid Analysis

Laboratory studies were carried out in order to obtain some critical input parameters for reservoir simulation study. CO_2 behaves like a fluid under reservoir with liquid like density and gas like viscosity under reservoir conditions in super critical state.

Review of 53 years production history have shown that the reservoir pressure has declined to a level of below 100 Ksc during the year of 1985-2008 (Figure 2). When the solution gas was liberated and left the reservoir oil, the gas production and GOR increased significantly. The free gas production during 53-year production history is just like an immiscible lean gas flood taking place in the reservoir for decades. Therefore, the reservoir fluid under the current reservoir conditions is completely different from the original live oil at 1960s.

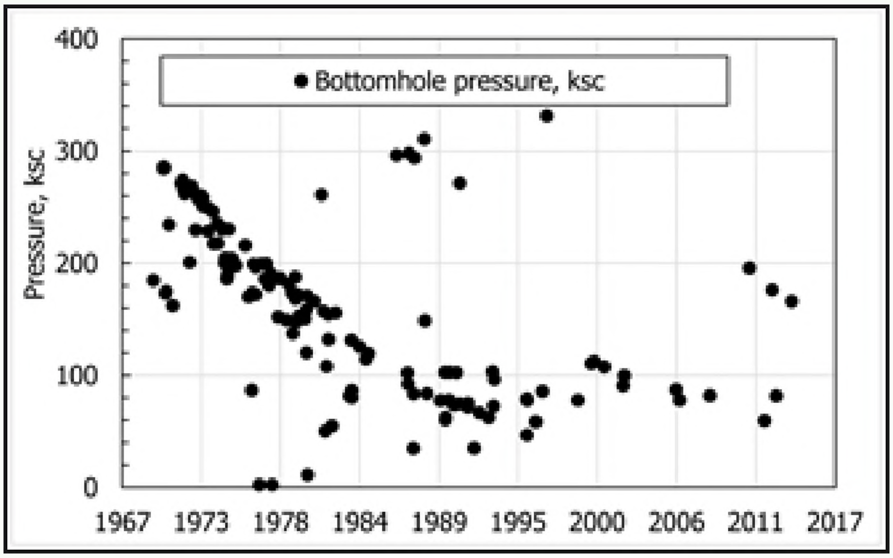


Figure 2: Recombined Live Oil Preparation and Validation

MMP Determination

Minimal miscibility pressure (MMP) is the single most important parameter in the design of a miscible gas EOR. The MMP of CO_2-live oil system in well N079 was determined using the classical slim tube displacement test. As shown in Figure 3, the MMP of pure CO_2-live oil is 211 ksc (3000 psi), which is achievable in the area of interest of N79 block.

The slim tube test using CO_2 with some impurities were also investigated. Gas composition containing 95% CO_2 and 5% impurity (4.5% C1+0.5% C2) showed the MMP of 211-232 ksc (i.e., 3000-3300 psi). The gas composition containing 90% CO_2 and 10% impurity (9.0%C1+1.0%C2) showed the MMP above 232 ksc (i.e., 3300 psi). These test result support the robustness of CO_2 miscibility due to the slightly trapped gas saturation near production wells in N079 reservoir.

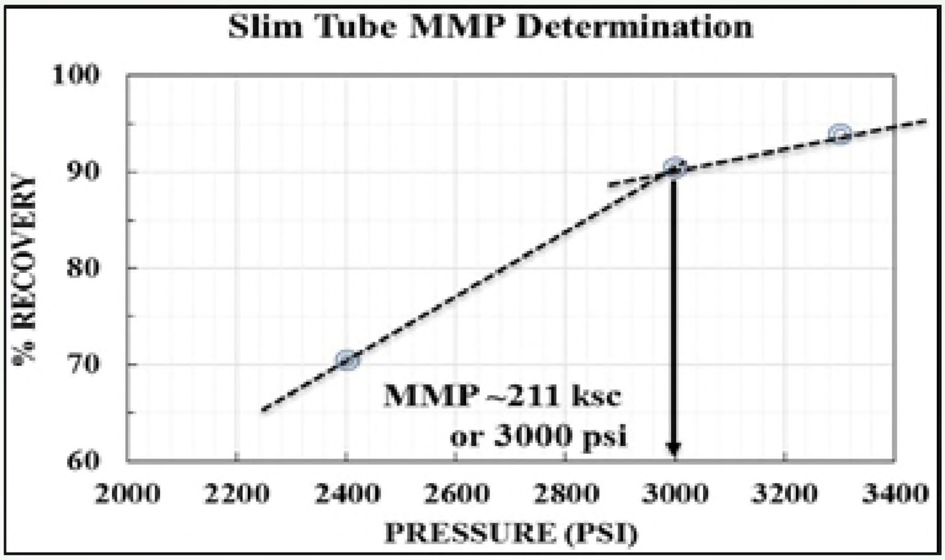


Figure 3: MMP determination through slim tube test.

Table 1: Summary of Live oil swelling test at 80 degC

Solvent (mole %)	Pressure		Density (g/cc)	Viscosity (cp=mPa.s)	FVF [1]	Solution Gas-Oil Ratio		Swelling [2]
	(psia)	(MPa)				(scf/STB)	(m3/m3)	
0.00	2052 Pb	14.15	0.7780	1.137	1.2288	371.23	66.12	1.0000
21.72	2500 Pb	17.24	0.7687	0.874	1.3597	622.80	110.92	1.0987
34.51	2870 Pb	19.79	0.7682	0.687	1.4472	842.02	149.96	1.1696
48.61	3442 Pb	23.73	0.7692	0.511	1.5955	1222.12	217.66	1.2907
60.38	4204 Pb	28.99	0.7715	0.405	1.8639	1834.33	326.70	1.4637

[1] Barrels (Cubic meters) of fluid at indicated pressure and temperature per barrel (cubic meter) of residual oil @ 60 F (288.7 K).

[2] Swelling is defined as the volume of fluid at saturation pressure divided by the volume of reservoir oil at initial saturation pressure

Pb - Bubblepoint Pressure

Pd - Dewpoint Pressure

- Tank conditions: 60 F (288.7 K) @ 13 psia (0.09 MPa); Standard conditions: 60 F (288.7 K) @ 14.696 psia (0.101325 MPa).

Swelling Test

Solubility swelling test were carried out on reservoir oil mixtures to study how the reservoir fluid will interact with the gas injection. The typical procedure applied to swelling tests is listed as follows:

- A swelling test starts with a known volume of reservoir oil at its saturation point in a PVT cell kept at the reservoir temperature (80°C).
- Certain percentage volume of CO_2 is transferred into the PVT cell. The gas and oil phase are well mixed.
- The pressure is increased, maintaining a constant temperature until all the CO_2 has been dissolved. When the last CO_2 gas bubble disappears, the new cell mixture (Oil + injected CO_2) is at its saturation point.
- The pressure and the swollen volume are recorded. Other key fluid properties, including fluid density and viscosity, FVF, swelling factor, GOR etc. are determined.
- More CO_2 is injected, and the pressure increased until all CO_2 is in solution in the oil. This process is repeated for a number of stages. The summary of the swelling test data is presented Table 1.

Coreflood Experiment

The key parameters of rock and fluid properties and core-flood results are summarized in Table 2 and 3.

Table 2: Fluid and rock properties of Core flood sample

COMPOSITE STACK PARAMETERS	
Sample Length (cm)	58.17
Sample Diameter (cm)	3.76
Average Pore Volume (cc)	130.82
Average Porosity (%)	20.29
Harmonic Air Permeability (mD)	28.8
FLUID PARAMETERS @ RESERVOIR CONDITIONS	
Reservoir Temp (°C)	80
Reservoir Pressure (Pore Pressure) (psi)	3300
Reservoir Brine Viscosity (cP)	0.45
Reservoir Oil Viscosity (cP)	1.14

Table 3: Coreflood results

Injection CO_2 Viscosity (cP)	0.05
COREFLOOD RECOVERY DATA	
Harmonic Water Permeability, kw (mD)	9.2
Live Oil Phase Permeability@ Swi (mD)	5.37
Initial Water Saturation - Swi (%PV)	42.2
Initial Oil Saturation –So (%PV)	57.8
Hydrocarbon Pore Volume: (cc)	75.6
Water Injection Rate (cc/min)	0.4
Residual Oil Saturation after waterflood – Sorw (%PV)	28.4
Oil Recovery after Waterflood (%OOIP)	50.9
Residual Oil Saturation - Sorm (%PV)	13.3
Incremental Oil Recovery by CO_2 (%OOIP)	26.2

After restoring the wettability and establishing initial oil saturation in the core composite, a waterflood was performed by injecting formation brine for five pore volume using injection rate of 0.4 cc/min. The oil recovery by water injection is 50.9% OOIP and residual oil saturation after the waterflood is around 0.284 PV. Figure 4 shows the pressure drop across the sample, injection rate, and oil recovery versus pore volume injected.

After the initial water flood, continuous injection of CO_2 started at a rate of around 0.4 cc/min, with the flow direction being the same as the preceding water flood. The incremental oil recovery was produced mainly in the first half pore volume of CO_2 injection. After ~ 8 pore volumes of CO_2 injection, the incremental oil recovery beyond water flood is 26.2% OOIP. At the end of CO_2 injection, the remaining oil saturation was 13.3% PV.

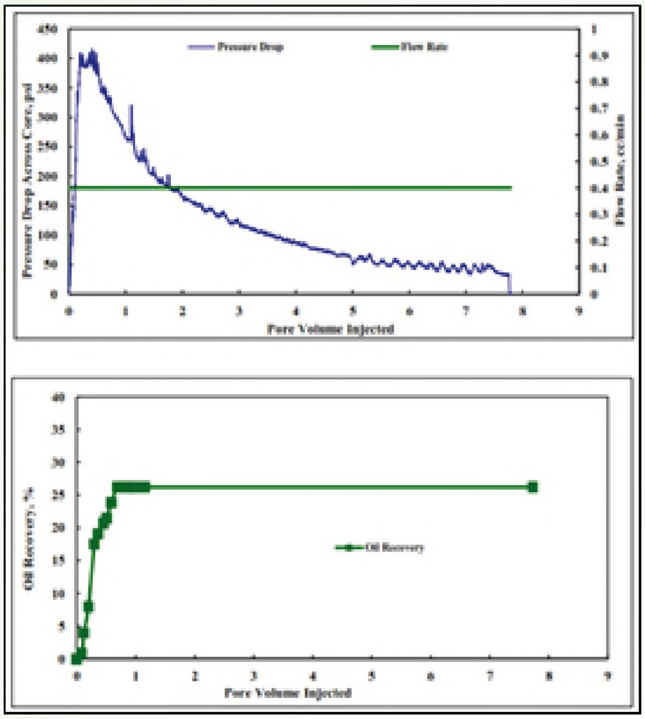


Figure 4: CO_2 EOR Flood Pressure drop Flow Rate and oil recovery

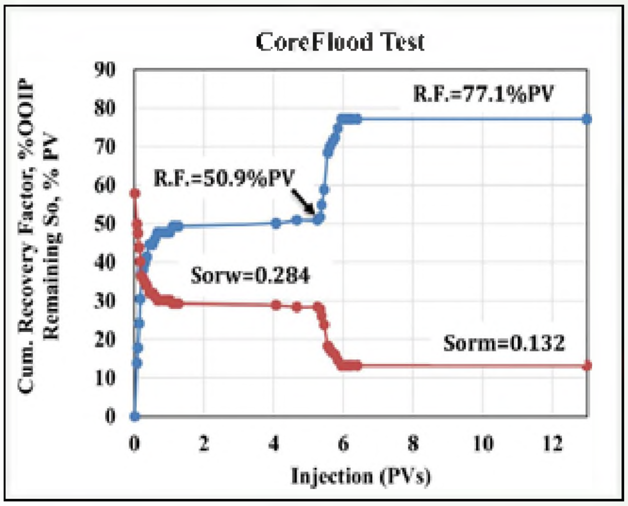


Figure 5: Coreflood Results

Simulation study

The main objectives of the simulation study were to

1. Carry out screening and identify suitable areas of leftover saturation for a CO_2 injection pilot
2. Optimize the pilot design through sensitivity in injection volume and associated CAPEX involvement
3. Assess incremental oil recoveries associated with pilot CO_2 injection.

A reasonable good history match is achieved for oil, water and gas rates, both at the field and well level along with pressure (Figure 6). By computing and visualizing an oil saturation index, the CO_2 pilot area was selected based on remaining oil saturation, sand thickness, heterogeneity and continuity of sand. The south-west part of the field had the highest remaining oil saturations with reasonable sand thickness and continuity. Furthermore, the sand package here was clearly overlain by a thick contiguous shale zone, providing containment. Two inverted 5-spot patterns have been investigated using simulation for implementation of CO_2 EOR (Figure 7). Both the pilot areas required drilling of an injector well at the center. Further, it has been observed during the study that Pattern 1 does not merit implementation as the incremental oil recovery is too low to justify high Capex involvement. Hence Pattern 2 (P2) has been finally selected for CO_2 EOR implementation.

The Pilot area is located in the far eastern part of the Country with only few sources of CO_2. CO_2 supply was likely to be sourced from nearby Digboi oil refinery. Due to scarcity of CO_2 source in the vicinity of the Pilot area and high CO_2 cost, injection schemes were investigated to have an optimized injection to production ratio. Alternating gas and water injection scheme is found to be the most profitable with improved CO_2 sweep as well as increased oil recovery. The Injection scheme for the selected pattern is given below in Table: 4

Another design consideration is the presence of free gas saturation and depletion. The history matched model indicated that the gas saturations were between 8-15% in the main zone of interest. The presence of free gas saturation in the reservoir introduced

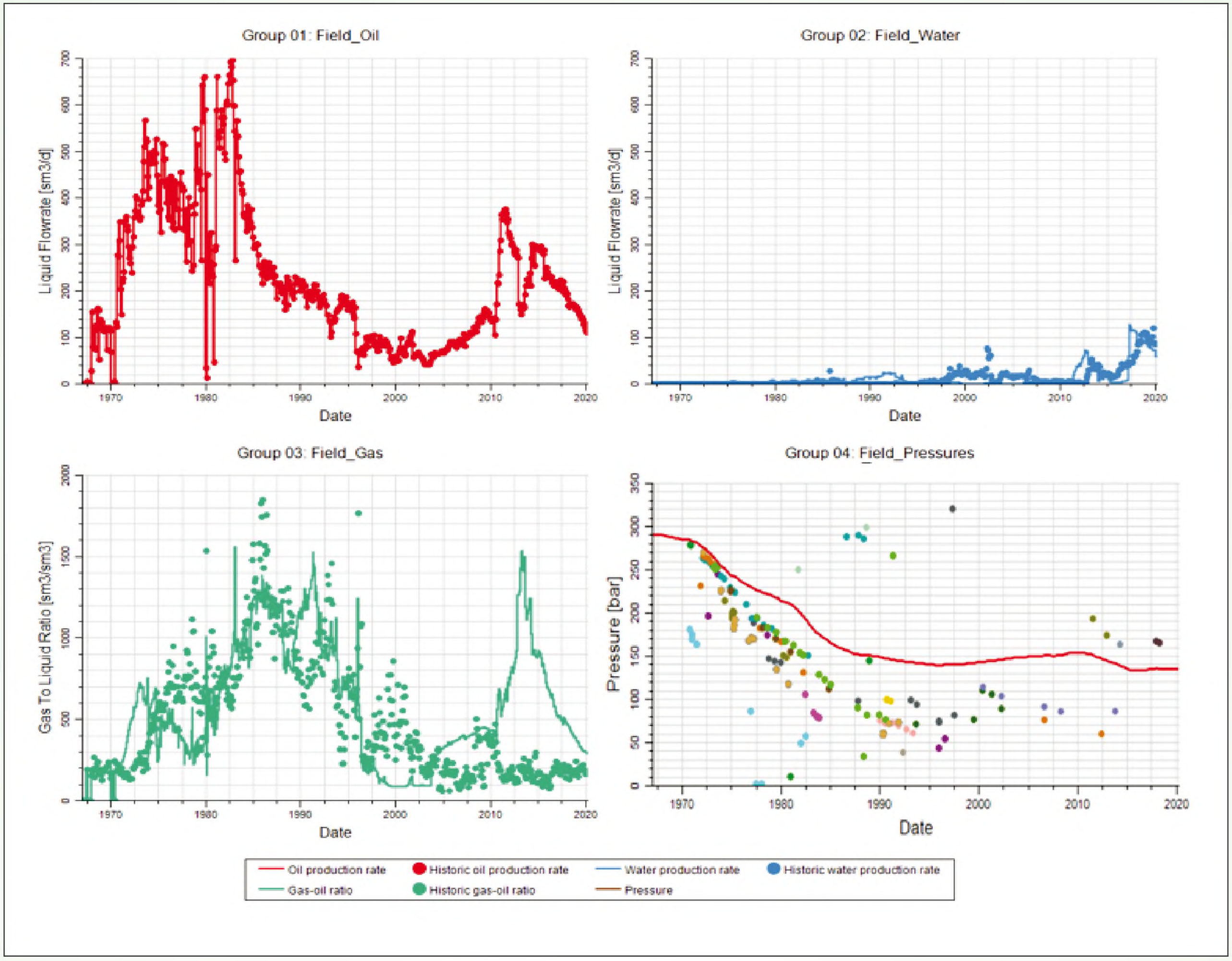


Figure 6: Field Level History Match

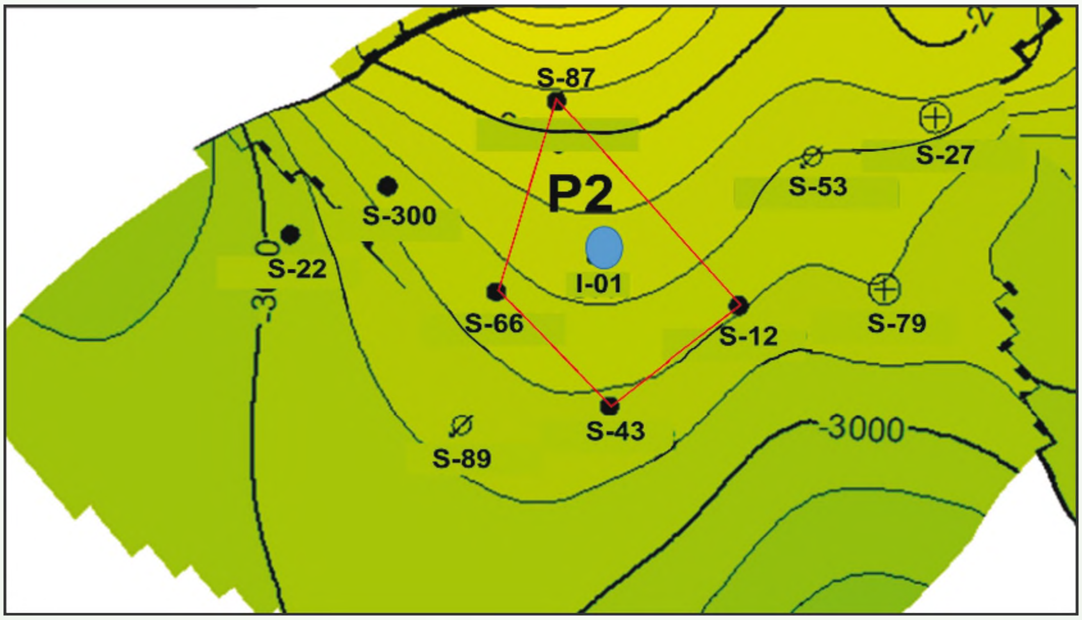


Figure 7: Identified Inverted 5 spot Pattern

an additional element of uncertainty. There were two possible options – to continue waterflooding the reservoir for several years to resaturate the free gas or to commence CO_2 flood with the presence of the free gas, effectively making the flood a mixed CO_2-hydrocarbon flood. It is felt that the current water flooding will continue for 5 years to increase the reservoir pressure and dissolve the free gas in the zone. Simulation work revealed that the presence of hydrocarbon gas saturations less than 10% had a minimal impact on CO_2 miscibility and did not have a significant effect on the flood effectiveness. This is supported by PVT studies indicating that the presence of hydrocarbon gas components does not significantly alter the miscibility of CO_2. It was recommended that field operations maintain a voidage replacement ratio of 1.1 till CO_2 flood commenced.

Table-4: Pilot Area 2 (Case-4) injection strategy

Water Injection		CO_2 Injection		Water Injection	
Surface Rate (m3/d)	Period	Surface Rate (sm3/d)	Period	Surface Rate (m3/d)	Period
200	5 years (2022-27)	38,000 (67 tons/d)	5 years (2027-32)	200	13 years (2032-45)

The optimum CO_2 injection rate in the selected pattern is about 67 tons per day. This translates to approximately 5% hydrocarbon pore volume injected annually. In total, it is estimated that nearly 1,20,000 tons of CO_2 will be captured and injected during the 5-year pilot phase.

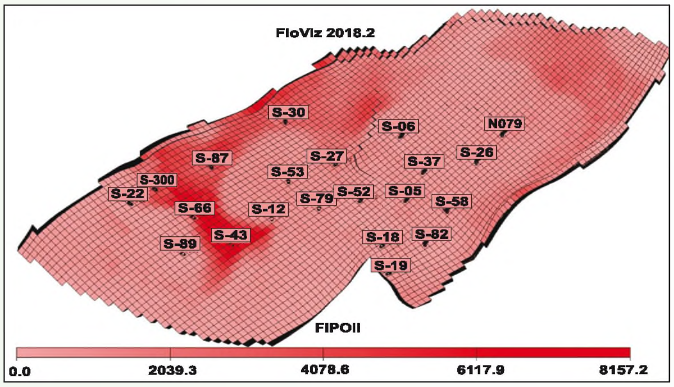


Figure 8: Remaining oil saturation after history match

When CO_2-EOR is performed, some of the CO_2 is retained in the reservoir. CO_2 injection into a reservoir can be implemented in miscible and immiscible conditions, and the distinction between the two is defined by the minimum miscibility pressure. If the conditions are miscible, CO_2 increases the oil mobility as it is dissolved in oil between the injector and the producer, and if the conditions are immiscible, there is no CO_2 dissolution in oil, which means that CO_2 flows much faster than oil toward the producers, causing lower oil recovery and higher production of previously injected CO_2.

As per the available literature around 90% of the purchased CO_2 is trapped in the geologic Formation (Melzer et.al, 2012). As TL model is used to simulate miscible gas injection, the exact value of CO_2 retention could not be calculated. However, since CO_2 injection is carried out near MMP, a considerable volume of CO_2 retention is expected.

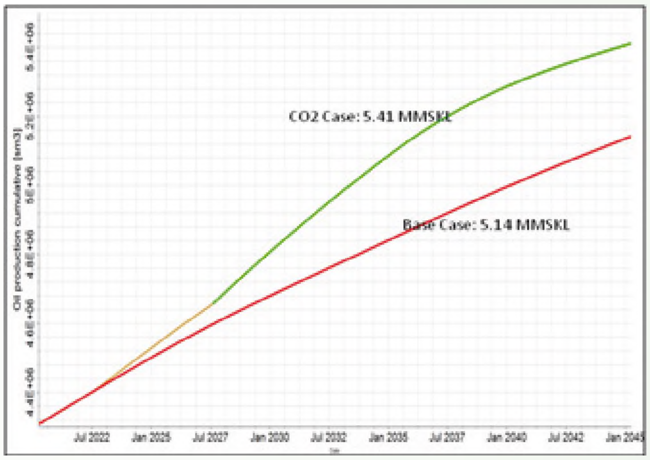


Figure 9: Incremental Oil over base case

Several other key results were obtained from the CO_2-EOR simulation study:

- The oil recovery from the CO_2 injection case was approximately 5.41 MMSKL over 25 years. This represents a recovery factor of 37.9% for the block.
- The incremental produced oil over the waterflood case is approximately

0.27 MMSKL (Figure 9). This gives an incremental recovery of around 11% within the pattern area OOIP or 3% of the OOIP within the general south-west area of the field (the south-west area has approximately 5.0 MMSKL OOIP).

- The decline rate for the CO_2 case is approximately 18% per year. This is more severe than the waterflood decline of 11%; the CO_2 flood recovers a larger quantity of oil earlier and then has a more rapid decline.
- The CO_2 utilization ratio is around 6.0 Mscf/bbl within the pattern area
- CO_2 is effective at mobilizing residual oil; the effects of the CO_2 flood are seen beyond the CO_2 injection period as the mobilized oil is swept by the injected water.

4.1.6 Conclusion

CCUS is vital for combating adverse effects of climate change globally and for India in particular. Success of CCUS in India will not only increase domestic oil production through CO_2 EOR, but also help in reducing carbon footprint. The current Study for Implementation of CO_2 EOR in one of its Field is an endeavor of Oil India Limited to align its objective in line with the vision of Government of India to reduce carbon foot-print by 2030. Based on the study, the CCUS project shows substantial potential for recovery enhancement while at the same time resulting in sequestration of CO_2 in the candidate reservoir. Successful implementation of the project will pave the way for implementation of the technology in other similar fields of the Company.

Acknowledgments

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4.2 GREEN HYDROGEN- The New Energy Vector

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4.2.1 Abstract

Currently, the greatest global problem is environmental pollution. To avoid climate catastrophe, spiking words around the world are being heard at different platforms raising pressing pollution concern. The striking demand for carbon neutrality with increasing energy dependency finds renewable energy as a one of the solution. Green Hydrogen has been put at the heart of Worlds Energy security and climate change. Green hydrogen is hydrogen that is produced using renewable energy through electrolysis emitting no hazardous gases. Green hydrogen has been labelled as the "Fuel of Future". This study addresses the green hydrogen production, hydrogen storage, hydrogen safety as a technological issue and possible hydrogen economy. India's green hydrogen market is currently in the nascent stages of development. Thus, this study reviews the solar energy-based hydrogen production potential in India. The total hydrogen production potential of India is estimated on potential renewable energy production possible, based on the available governmental data. A focus on on-going investment & steps globally has also been compared & discussed.

Keywords: Green Hydrogen, Solar Potential

4.2.2 Introduction

Hydrogen is the lightest element in periodic table. It is colourless, odourless, tasteless, non-toxic, and highly combustible. Most of the hydrogen in Earth exists in molecular form as water or organic compounds. Hydrogen can be produced using a number of different processes. The majority of hydrogen (95%) is produced from fossil fuels by steam reforming (SMR) of natural gas (CH4) and other light hydrocarbons, partial oxidation of heavier hydrocarbons & coal gasification.

The story of hydrogen is not new, Hydrogen was first recognized as a distinct element by scientist Henry Cavendish in 1766. In 1874 Jules Verne, in his book the Mysterious Island, "water will one day be employed as fuel, projected his vision for the use of hydrogen as a zero-carbon fuel. Despite long-known opportunity for hydrogen to be isolated from water and produce only water when combusted as fuel, techno-economic challenges hindered its widespread adoption as a clean fuel during the 19th and 20th centuries.

Currently, hydrogen is mostly used in oil refining, production of fertilizers and is responsible for 830 MtCO2 of annual CO_2 emissions. However, for it to make a significant contribution to clean energy transitions, it also needs to be adopted in sectors where it is almost completely absent at the moment, such as transport, building and power generation.

In 21st century hydrogen has become particularly attractive source of energy due to important component for achieving ambitious climate targets, synergy with the existing industries and rising demand of Industrial decarbonisation.

4.2.3 Spectrum of Hydrogen

Hydrogen is a colourless gas, however depending on production methods, it can be can be grey, blue or green – and sometimes even pink, yellow, turquoise or white.

Following are description of different types of hydrogen:-

Green hydrogen is defined as hydrogen produced by splitting water into hydrogen and oxygen using renewable electricity. Most of the methods for the production of green hydrogen consider obtaining hydrogen either through water splitting reactions (e.g. water electrolysis, water thermolysis, photocatalytic water splitting, and thermochemical water splitting) or via dehydrogenation of hydrogen carrier molecules.

Blue hydrogen is produced using a process called steam reforming. This involves bringing together natural gas and water (in the form of steam) to produce hydrogen gas and carbon dioxide as a by-product.

Grey hydrogen is created from natural gas or methane. It uses the steam methane reformation process but without capturing the generated greenhouse gases in the process.

Pink hydrogen is generated through the electrolysis of water using nuclear power. Pink hydrogen produced using nuclear energy can also be referred to as purple hydrogen or red hydrogen.

Turquoise hydrogen is a new entry in the hydrogen colour chart, and its production is yet to be proven at large scales. Creating turquoise hydrogen begins by converting methane into hydrogen gas and carbon using simple pyrolysis process.

Yellow hydrogen is a relatively new phrase referring to the method of inducing electrolysis through photoelectric-chemical reaction by using solar power

White hydrogen is the naturally occurring hydrogen gas found under the earth in underground deposits created through fracking. Presently, there are no procedures to exploit this resource.

Above all, the only 100% sustainable & commercial viable hydrogen is Green hydrogen. Green hydrogen is gaining momentum due to generation of energy through electrolysis process without generating any kind of hazardous waste for the environment.

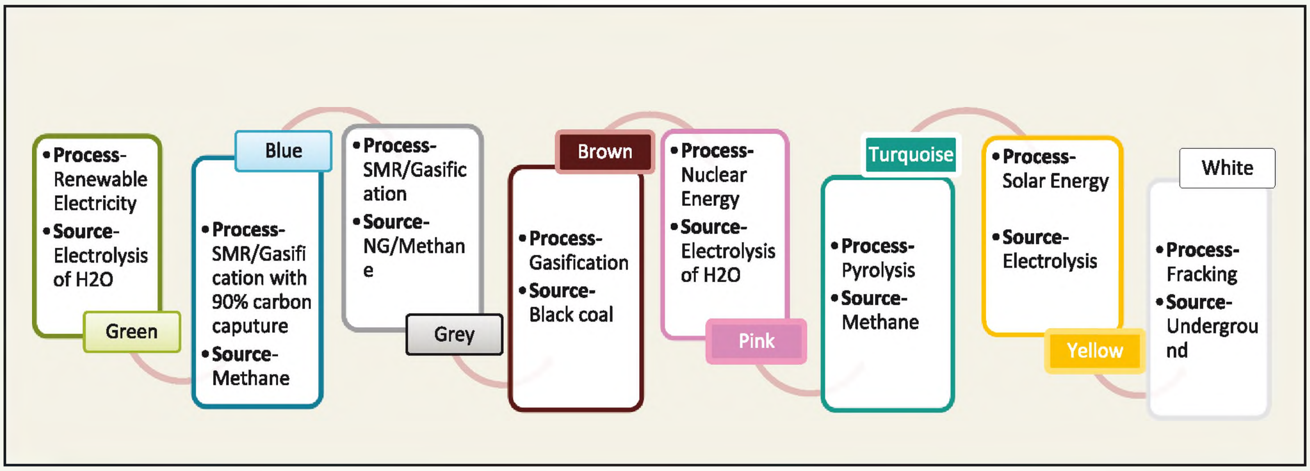

*Figure-1:- Hydrogen Production Origin-Colour Code - *Note-SMR- Steam Methane Reforming*

4.2.4 Fact for the Green choice

Global CO_2 emission has reached a record high of 36.7 Gt. India is the third largest emitter of carbon dioxide (CO^2) after China (10.6 Gt) and the US (4.7 Gt) and thus is vital in the fight against climate change currently focused on reaching zero emissions by the mid century or earlier.

India's current CO^2 emissions are 2.88 Gt. According to the Centre for Science and Environment (CSE)'s projections based on the median annual rate of change in the past decade 2010-2019, India's generation in a business-as-usual scenario will be 4.48 Gt in 2030.

In COP-26 held in 2021, India has promised for a more ambitious target of reducing the emissions intensity of its economy by 45% than the previous goal of 33-35% cut (in COP-21 held in 2015). According to new target, India will cut its carbon emission by (1 Gt) annually and therefore, the emissions in 2030 shall be 3.48 Gt.

Energy sector contributes 68.7% percent of GHG emissions in India. The environmental concern associated with booming industrialisation is growing due to its persistent impact on air quality, depletion of ozone layer, rising earth temperature, resulting in global warming.

According to a report of TERI in 2020, India's hydrogen demand stood at 6 million Tons (MT) per year (70MT globally). This can increase to around 28 Mt by 2050 and to meet the zealous ambition of net zero this needs to be decarbonised.

Use of hydrogen is currently dominated by oil refining (45%), ammonia production, primarily for fertilizer(40%), methanol production (10%) and steel production (5%).

Currently, the large share of hydrogen (approx. 95%) is produced by Steam Methane Reforming (SMR). Only a small proportion of hydrogen is produced from renewable sources. The high cost of renewable sources is the main reasons for this low level of production.

With renewable energy technologies reaching to a level of maturity allows a significant potential for emissions reductions from clean hydrogen.

Emissions from green hydrogen production using electrolysis is 43 gCO2e/kg of H_2 compared to 9.3 kgCO2e/kg of H_2 produced using steam reforming process without carbon capture.

Adopting green hydrogen as an admired fuel will be the most competitive route for hydrogen production by around 2030. Many experts believe a new energy era of hydrogen is dawning and that the age of oil is drawing to a close. New technologies are required to replace fossil fuels dependency aiming towards a net carbon neutral economy at the earliest.

4.2.5 India's Potential

Indian has more than 1000+GW renewable energy generation potential. As of September 2021, India had 101.53 GW of renewable energy capacity and represents ~38% of the overall installed power capacity i.e utilizing ~ 10 % of the available potential.

The Government of India is aiming to achieve 227 GW of renewable energy capacity by 2022, much ahead of its target 175 GW as per the Paris Agreement. Also, the target is kept ambitious to 500 GW of electric power generation through renewable energy sources by 2030.

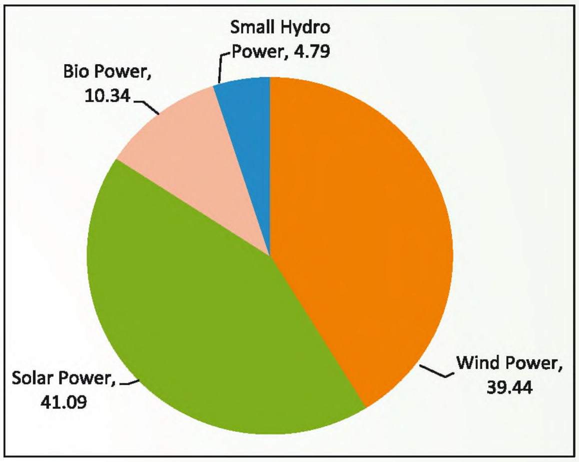

Figure-2:- Installed Renewable Energy Distribution (MW) -India

Top 10 countries (Installed Capacity MW)

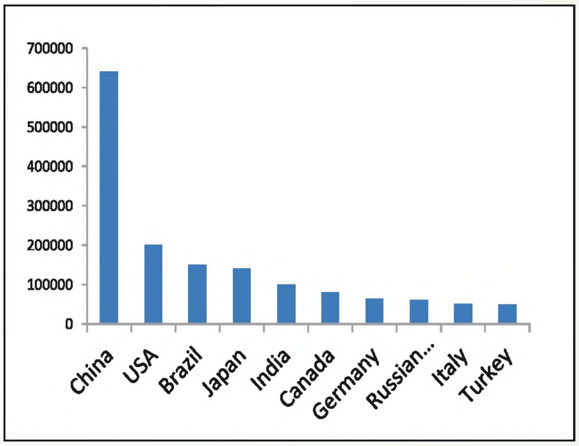

Figure-3:- Global Renewable Capacity Installed – Top 10 countries (IRENA-2020)

As per (IRENA, 2020) India ranked at 5th position among the top 10 countries with renewable energy installed capacity in 2020. Apart from installation, the largest cost reduction in the utility-scale sector has been observed by India, where between 2010 and 2020, costs declined by 85%, to reach USD 0.038/kWh – a value 33% lower than the global weighted average for that year.

The same projection has been made by TERI in one of publications stating "The projected cost of wind & solar by 2030, will be between Rs. 2.3-2.6 & Rs. 1.9-2.3 per kWH respectively which will be among the world's best. No doubt this shall provide economical practicability for the production of green hydrogen in India at a competitive rate.

India's energy transition to clean fuels, adoption of green hydrogen would bring in significant benefits. By leveraging low-cost domestic renewable electricity produced at scale, India could become a regional hub for exporting green hydrogen at competitive prices and command a reasonable share in the global hydrogen demand of 200 million tonnes by 2030. However, achieving a low cost of hydrogen production crucially hinges on policy support and strategic research priorities as well. To avoid missing out on the future benefits of the energy transition, India needs to be proactive in creating a productive innovation ecosystem for the development, deployment and diffusion of technologies.

Advances and challenges

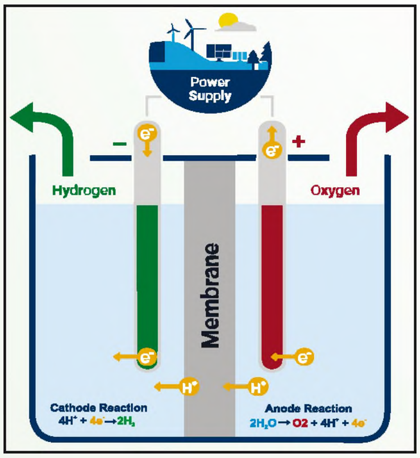

Figure-4:- Electrolysis Process for Green Hydrogen Generation

The peculiar advantage of green hydrogen is, it can be produced wherever there is water and electricity.

Freshwater scarcity is already a persisting issue worldwide; 1 kg of hydrogen production will require 9kg of water (50-55kWh of electricity). The excess water requirement for green hydrogen production can be resolved by seawater utilisation; however usage of same in hydrogen production is associated with challenges such as the corrosion of chloride ions in seawater to the anode metal.

Another main component in this simple process of electrolysis is the electrodes. Low electricity cost is not enough by itself for competitive green hydrogen production.

Commercially operated electrolysers are Alkaline Electrolysers (AE), Polymer Electrolyte Membrane (PEM), with Solid Oxide Electrolyser (SOE) and Anion Exchange membrane (AEM). Alkaline and PEM electrolysers' well advanced & well known technology. Alkaline electrolysers have the lowest installed cost, while PEM electrolysers have a much smaller footprint, combined with higher current density and output pressure. Meanwhile, SOE & AEM having the highest electrical efficiency are still in developing stage.

Table 1:- Comparison of different type of Electrolysers

	Type of Electrolysis	**Efficiency (%)**	**Opr.Temp (OC)**
1.	AE	70	60-80
2.	PEM	58	20-80
3.	SOE	99.99	500-850
4.	AEM	99.99	50-60

CAPEX requirement for AE is in range of USD500-1400kWe, for PEM is USD 1100-1800/kWe & 2800-5600/kWe for SOE [iea furture of hydrogen]. Gaps in cost and performance are expected to narrow over time as innovation and mass deployment of different electrolysis technologies drive convergence towards similar costs.

The areas that need further investigation are hydrogen transportation & hydrogen storage facility. The perceived high risk associated with hydrogen by society is an also an important challenge.

Hydrogen's ability to embrittle materials wide flammability range and the limited amount of energy needed to ignite are few of listed challenges for storage & transportation of hydrogen on large scale. At present among the several options proposed, metal hydride-based solid-state storage systems have been recognized as one of the most viable solutions for storing hydrogen in hydrogen-powered systems. Japan has been on forefront of development of hydrogen technologies, it claims to breakthrough in hydrogen storage by creation of a simple-structured interstitial aluminium alloy.

India"s OMC-IOCL is owner and operator of the 1st high pressure hydrogen storage and dispensing terminal in India, with the refuelling station located in Delhi. This refuelling station uses a PEM electrolyser, outputting hydrogen at 30Nm3/hr at a purity of 99.999%, which is required for fuel cell vehicles.

Apart from the hydrogen resources, the catalysts, production efficiency, and hydrolysis rate are aspects to explore during generation. Moreover, fuel cell systems are becoming increasingly important in both small-scale and large-scale hydrogen generation building the confidence in hydrogen as a safe, clean and renewable fuel for the future.

4.2.6 Commercialization of Green Hydrogen

As discussed earlier, hydrogen holds long term promises in many sectors i.e transportation, buildings & power. Hydrogen is already established in commercial market. More than 23,000 Fuel cell powered forklifts are in operation worldwide.

Fuel Electric Cell vehicle have potential to attract the competitiveness of Electric vehicle. hydrogen based liquid fuel provide potentially attractive options for aviation & shipping.

Long term prospects in hydrogen usage for heating of buildings could include direct hydrogen in hydrogen boilers. H2 & NH3 can be flexible options used in GTs.

Hydrogen Refuelling Station: Hydrogen can be used as transport fuel. Around 400+ hydrogen fuelling station have already been set up globally.[40] India's 1st hydrogen refuelling station was setup at IOC Faridabad in 2005.[41] India's first hydrogen fuelling train fuel is also set up to cover its first distance of 89km from Sonipat to Jind. Alstom Coradia iLint is the world's first hydrogen passenger train in Poland.

Hydrogen Fuel Cell Vehicle (HFCV) - HFCV are already commercial in terms of material handling applications. India's first H2 fuel cell was introduced by IOC & Tata Tata Motors in 2018, 15 such buses will soon be launched in Nations Capital. HFCV in Light Vehicle Category has already set a record selling of 3341 units in 2021 in US. Many countries depict HFCEV to be alternative Electrical Vehicles (EV) in upcoming future. (Currently the cost of HCEV is twice to EV). HCEV have higher efficiency than gasoline-based vehicles, long driving range, and no emissions, thus offering a potential solution for future sustainable transportation.

Hydrogen Pipelines- With skyrocketing price of natural gaseous one option which seems possible in future is conversion of natural gas pipelines (3 million km worldwide, 17k km India) for hydrogen transportation to refineries & fertilizers. Recent studies in Netherland have suggested that it could be possible with small modifications. Commercialization and deployment of green hydrogen on a large-scale faces significant challenges. Following are a few barriers to be knocked down before the commercial aspect of green hydrogen is advanced.

- Overall high costs of the hydrogen system including capital, operational, maintenance, and running costs.
- Integration with other energy vectors using information and communication infrastructure.
- Low social awareness and user acceptance.
- Supply chain development across all the world is still in its incipient phase.
- Need for legal and administrative adherence, policy for different components of the system.

4.2.7 The Green World

In this global energy scenario, hydrogen is experiencing an unprecedented historical moment for its future key role. In fact a great and widespread enthusiasm is growing up towards it, as indicated by the current worldwide economic and political strategies, which endorse the net-zero greenhouse gas emissions and the access to clean energy.

It can be clearly noticed how, in the last period (2020–2021), several countries have already mature strategy proposal.

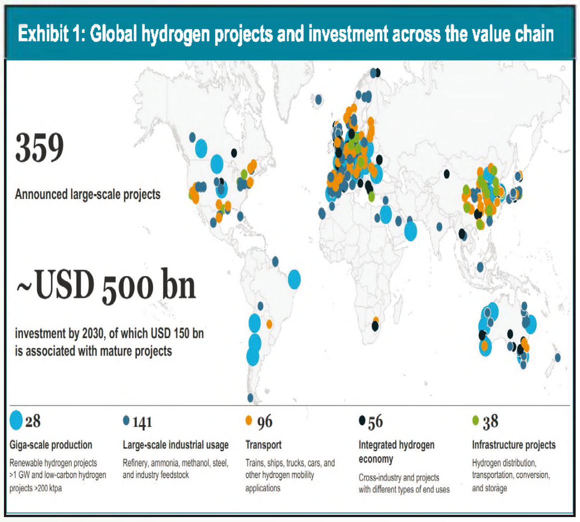

Figure-5:- Global hydrogen projects & investment-Hydrogen Council [4]

The world's largest green hydrogen project is currently Air Liquide's 20MW Bécancour facility in Quebec, Canada, which uses a PEM electrolyser, supplied by US-based Cummins and is powered by local hydroelectricity.

Australia-As per latest report of Nov'21 Australia may lead green hydrogen pack with 69GW project pipeline. This includes 28GW Western Green Energy Hub, 14GW Asian Renewable Energy Hub, 8GW HyEnergy Zero Carbon Hydrogen 5GW Murchison Renewable Hydrogen 3.6GW Pacific Solar Hydrogen, 3GW Gladstone projects in Queensland, 2.8GW Tiwi Hydrogen Project in the Northern Territory.

Chile- has set goal having 5GW of electrolysis capacity under development by 2025, being the world's lowest cost green hydrogen producer by 2030. 6 new projects of 3.96GW constituting of Enel Green Power for 240MW,

Air Liquide of 80MW, Engie 26MW,GNL Quintero for 10MW, CAP 20MW & Linde for 20MWhas proposed a strategy exclusively dedicated to the green hydrogen for producing 45,000 tons of green hydrogen per year by 2027

China is leading renewable energy technology producer & exporter. With Sinopec alkaline electrolyser facility of 260MW in Xinjiang, be completed in mid-2023,[52] will lead the new record beating 150MW Baofeng project.[53] The record had been previously held by Air Liquide's 20MW Bécancour facility in Quebec, Canada.

The European Union has fixed both short and long term targets. Among them, Germany plans to deploy up to 5GW of hydrogen generation capacity using water electrolysers by 2030 with an investment of $900mln. France sets the most ambitious absolute target for 2030 with a capacity of 6.5 GW.

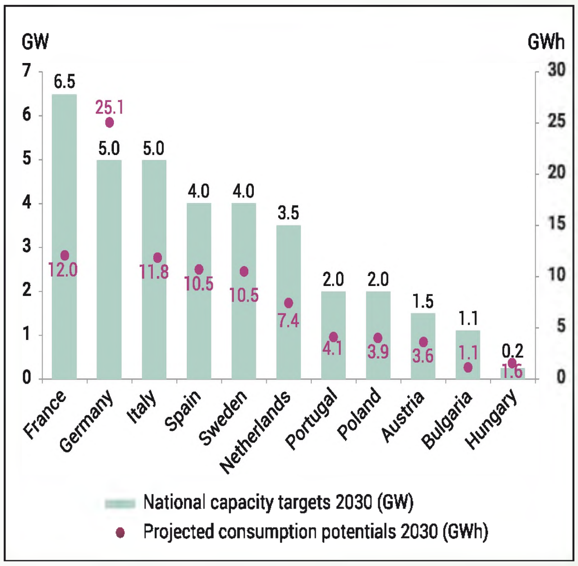

Figure-6:- European Union Renewable Energy Target/Projected

Japan imports almost 90% of the energy it uses, and has limited room to build out solar or wind arrays. [58] Still it has opened the largest green hydrogen plant, with a 20 MW solar array feeding a 10 MW electrolyser plant

(RECHARGE,2020). The Japanese government more than doubled its hydrogen-related R & D budget to nearly $300 million in the two years to 2019. Japan strategy on Net Zero is different as it is planning to import ammonia. Japanese utilities could first secure ammonia made from fossil fuels and find ways to capture or offset the carbon dioxide emitted during that process. They could switch to "green" ammonia as demand grows and prices come down.

U.S. has already released its hydrogen roadmap critically important hydrogen is to achieve a lower-carbon energy mix, concludes to strengthen economy by generating $140 billion per year in revenue and 700,000 jobs by 2030, and $750 billion per year in revenue and 3.4 million jobs by 2050," as stated by Fuel Cell and Hydrogen Energy Association (FCHEA). The U.S. is already heavily engaged in the hydrogen economy with hundreds of millions of dollars of public and private investment per year, and boasting more than half the world's fuel cell vehicles, 25,000 fuel cell material handling vehicles, more than 8,000 small scale fuel systems in 40 states, and more than 550 MW of large-scale fuel cell power installed or planned.

India's Union Budget for 2021-22 has announced a National Hydrogen Energy Mission (NHM) that will draw road map for using hydrogen as an energy source. India's ambitious goal of 175 GW by 2022 got an impetus in the 2021-22 budget which allocated Rs. 1500 crore ($200mln) for renewable energy development and NHM. Across Indian industry, there are considerable efforts to establish a hydrogen economy in India, not least, the work being taken forward by Indian Oil. IOCL is owner and operator of the 1st high pressure hydrogen storage and dispensing terminal in India, with the refuelling station located in Delhi. This refuelling station uses a PEM electrolyser, outputting hydrogen at 30Nm3 / hr at purity of 99.99%, which is required for fuel cell vehicles.

India's plan to lead the green hydrogen industry still needs a much clearer picture.

4.2.8 Conclusion

At the end it all land up to high cost. That means much more green hydrogen should be produced as production technologies become more and more mature with more competitive costs. In conclusion, the main actions to accelerate decarbonisation between now and 2030 are

1. Electrification with renewables
2. Acceleration in renewable power generation
3. Carbon Capture Technology, Scaling up Bioenergy-to produce green fuel that absorbs CO_2
4. Manufacturing of electrolyser on larger scale- to bring reduction in prices.
5. New technology that can convert the greenhouse gas carbon dioxide (CO_2) into fuel by using solar-powered to be explored.
6. Making green hydrogen competitive and ready for a further scale up in the 2030s, towards the objective of reaching net zero emissions by 2050.

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4.3 Review of Best Available Blue Hydrogen Technologies

Authors: Yassir Ghiyati, Director of Hydrogen Business Line, Topsoe &
Nitesh Bansal, Proposal Manager, Expert, Hydrogen, Topsoe

Mr. Yassir Ghiyati is Hydrogen Business Line Director , Topsoe. Having experience in Process Engineering & Commercial Management activities within P-T-X, hydrogen, syngas, ammonia, methanol and refining.

Mr. Nitesh Bansal, Proposal Segment Manager, Expert, Hydrogen Topsoe. He is having experience in process/ design engineering & Techno-commercial activities within hydrogen and syngas. Developed technology solutions with hydrogen/ syngas area and applied for the IP

Carbon dioxide (CO_2) emissions must be reduced to tackle global warming. Several governments have therefore already adopted relevant regulatory frameworks, such as emission trading schemes or carbon taxation, with the aim of reducing CO_2 emissions.

As just one example, the European Union (EU) Emission Trading System (ETS) directive drives CO_2 reductions by setting a cap on the total CO_2 emission allowance for each company and by reducing this cap figure over time. Companies can sell their surplus quotas of CO^2 emission and are thus incentivized to invest in the most efficient technologies with least CO^2 formation and to capture, utilize and/or sequester the formed CO_2.

Since its introduction in 2005, the EU ETS directive has passed through several phases. It is now in its fourth phase, in which the pace of annual cap reduction is set to increase significantly. The EU commission expects the directive to drive faster adaptation of both "blue" and "green" technologies that are essential for EU´s journey towards climate neutrality by 2050.

According to IEA, the annual hydrogen production accounts for 830 million tons or 3% of global CO_2 emissions. As such, there is a need to decarbonize hydrogen production. However, the potential role that hydrogen can play in the net zero carbon economy is much higher as it can decarbonize other sectors as well by becoming a preferred energy carrier, either in pure form or by being converted into ammonia. Hydrogen Council estimates that H2 production will increase 8-10 times by 2050 emphasizing the need for decarbonizing H2 production.

Hydrogen is traditionally produced by steam methane reforming using fossil-based feedstocks such as natural gas, LPG or naphtha. Hydrogen production from fossil sources without CO_2 capture is termed "grey hydrogen".

One promising way of decarbonizing hydrogen production is by steam electrolysis fueled by renewable energy. The hydrogen thus produced is completely green and leaves no CO_2 footprint, whether from production or use. Companies such as Haldor Topsoe have commercialized electrolysis solutions, that are easy to use as standalone hydrogen unit or in hybrid setups in combinations with traditional hydrogen production. However, one of the main current limitations of green hydrogen deployment at mega scale lies in the insufficient availability of green power capacity.

To unlock the full potential of hydrogen in the energy transition aimed at reducing CO_2 emissions, it is therefore necessary to supplement green hydrogen with other clean hydrogen sources with a low carbon footprint (known as “blue hydrogen”). Such hydrogen can be formed by combining traditional production methods with clean technology innovations. Blue hydrogen can thus be produced either by revamping an existing grey hydrogen plant or by constructing a grassroot blue hydrogen plant.

The definition of blue hydrogen is yet not completely agreed, but many key industry stakeholders correlate blue hydrogen with >90-95 % CO_2 recovery. One weakness of this definition, however, is that it disregards the inherent carbon intensity of the different hydrogen production methods. To discuss this important point, it is necessary to review the main methods used to produce hydrogen in greater detail.

4.3.1 Hydrogen Production Technologies

Steam methane reforming

Steam methane reforming (SMR) is currently the technology most widely used to produce hydrogen. The main reforming process occurs over nickel-based catalysts inside tubes placed in a hot reformer chamber.

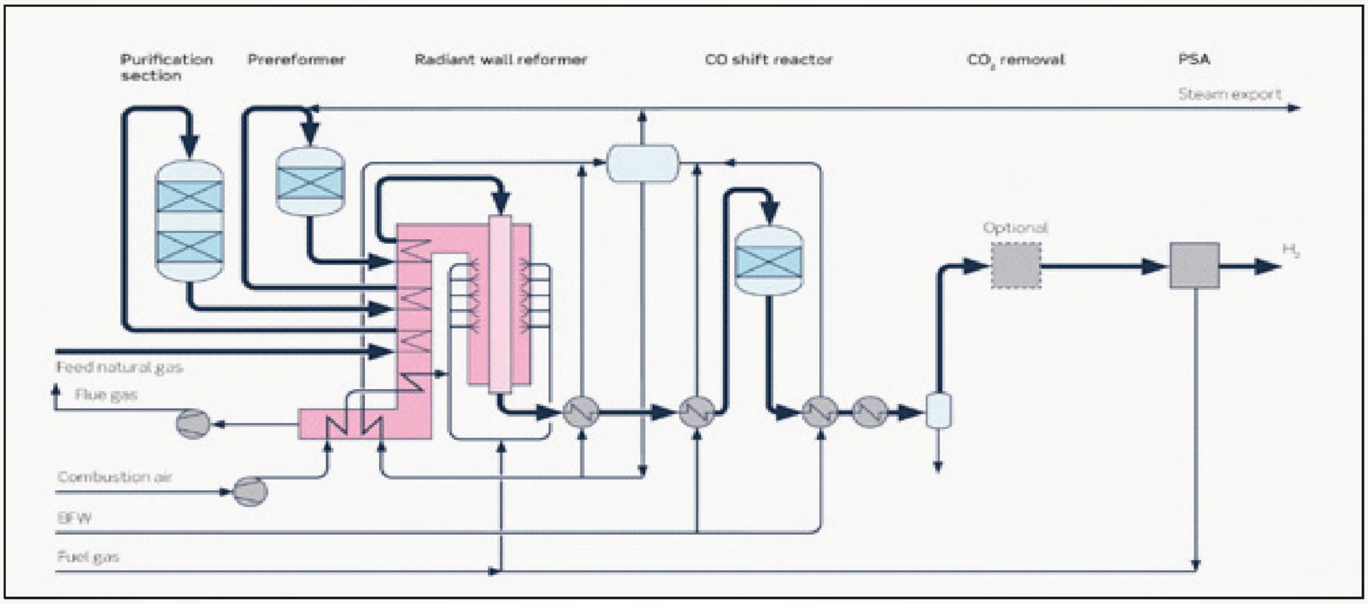


Figure 1: Traditional steam methane reforming

The steam reforming of hydrocarbons can be described by the following reactions:

$$CnHm + n\,H_2O \rightarrow n\,CO + [n+½m]\,H_2 \quad -\text{heat} \qquad (1)$$

$$CH4 + H_2O \rightleftarrows CO + 3\,H_2 \quad -\text{heat} \qquad (2)$$

$$CO + H_2O \rightleftarrows CO_2 + H_2 \quad +\text{heat} \qquad (3)$$

Reformer heat is generated by burning fuel gas, which is usually a combination of natural gas and PSA off-gas but can also include other off-gas streams imported into the hydrogen plant. Waste heat from the flue gas is recovered by preheating the feedstock and by steam generation, before the CO_2 rich flue gas is vented into the atmosphere. The hot process gas exiting the reformer contains a mixture of steam, H_2, CO and CO_2. This is cooled in a waste heat boiler generating utility steam before it is sent to the shift section where CO reacts with process steam to create more hydrogen and CO_2.

The effluent from the shift reactor is normally sent to a pressure swing absorption (PSA) unit to separate pure hydrogen from the offgas, which is sent to the reformer as fuel. In low hydrogen purity applications, the PSA unit can be avoided or replaced with a methanator.

In a blue hydrogen scenario, the CO_2 in the process gas from the shift section is recovered in a CO_2 removal unit before being sent to the PSA/methanator. Depending on the reduction targets for CO_2 emissions, it may also be necessary to add a flue gas CO_2 capture unit.

Heat exchange reforming

In some cases, steam generation in the hydrogen plant is not a viable solution, due to plant economics or CO_2 footprint. In such cases, the surplus energy can be utilized to drive additional reforming by either adding an HTER reactor downstream of the SMR or by modifying the design and operation of the SMR itself. Both options have been successfully used in industry.

In both HTER and SMR-B, the steam export is significantly lower than traditional SMR technology, hence the fuel consumption is lower per hydrogen yield, resulting in lower CO_2 footprint.

In a HTER layout, a portion of the feedstock bypasses the SMR and is instead fed into the HTER reactor, where it is heat exchanged with the hot effluent from the SMR. The reforming taking place in the HTER reactor results in an additional 25-30% more hydrogen production and is therefore also a good option for adding capacity to an existing hydrogen plant.

As mentioned above, another option is to alter the SMR design, using advanced bayonet catalyst tubes to capture heat from the effluent before it leaves the SMR. This bayonet design is referred to as SMR-B.

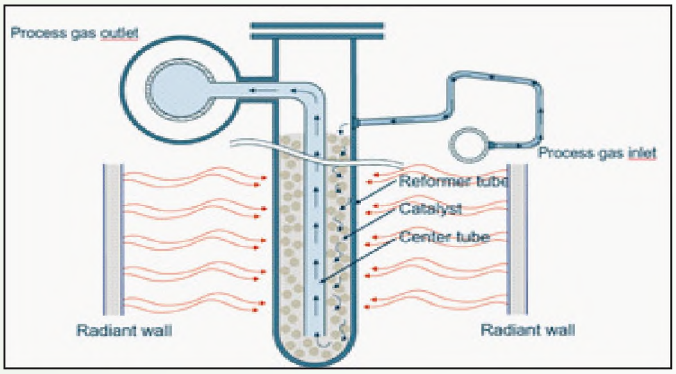


Figure 2. SMR-B reformer sketch

At high capacities, conventional SMR design is limited by the economical size of the reformer. Heat exchange reforming has been successfully deployed to extend the single train capacity limit up to 207 kNm3 per hour.

Convection reforming

For hydrogen production capacities below 30 kNm3/hour, convection reforming (HTCR) is normally a better option than SMR. In convection reforming, the reformer design is different since the tubes are bundled in a much smaller chamber and the heat required for the process is generated by a single burner. The tubes are in contact with the flue gas generated by the burner flame in a convection section.

Such HTCR design provide heat integration with no steam export and is therefore favored in cases where steam is not a desired product or is less valuable than hydrogen.

The compact design of the HTCR unit favors modularization and has thus been the preferred choice for small scale hydrogen production for decades.

SynCOR^{TM} Reforming

SynCOR^{TM} reforming is an advanced autothermal reforming (A-ATR) process, which is fundamentally different from the tubular steam reforming processes described above in the sense that the main reforming process takes place inside one SynCOR^{TM} reactor. It is also significantly different than any other ATR process, since it operates at much lower steam to carbon ratio. The SynCOR^{TM} reactor has a compact design consisting of a refractory-lined pressure vessel with a burner, combustion chamber and a catalyst bed.

The process gas enters the SynCOR^{TM} reactor and is mixed with oxygen and additional steam resulting in a combination of partial combustion and steam reforming.

Figure 3: SynCOR^{TM} reformer

Among blue hydrogen technologies, the SynCOR^{TM} process has the lowest OPEX since the reactor operates at a steam to carbon ratio of 0.6, which is 3-5 times less than SMR or less developed ATR´s. The lower steam throughput also has the benefit of reduced equipment and piping sizing – A benefit that is most pronounces at large scale since the equipment and piping are kept within standard sizes even at very large single line capacities.

SynCOR^{TM} technology has a proven track record from more than 80 years of industrial operation. The largest SynCOR^{TM} reactor in operation today has a hydrogen production capacity of 500 kNm3/hour, and the economical limit for single train capacity is 825 kNm3/hour. SynCOR^{TM} is therefore likely to remain the dominant technology for large-scale hydrogen production because of its favorable economics.

In SynCOR^{TM}, the external fuel demand is extremely low, hence a very high carbon recovery (>99%) can be obtained without needing to capture the carbon in the flue gas. It is therefore very well suited for blue hydrogen.

Partial Oxidation (POx)

Hydrogen can also be produced by partial oxidation (POx). It is a non-catalytic process where a fuel-oxygen mixture is partially combusted resulting in a hydrogen rich syngas, which is then shifted before being sent to product purification.

The partial oxidation reaction occurs when a sub-stoichiometric fuel-oxygen mixture is partially combusted in a series of partial oxidation reactors. This chemical reaction takes the general form:

$$C_nH_m + {}^{n}/_{2}\, O_2 \rightarrow n\, CO + {}^{m}/_{2}\, H_2$$

The POx technology has certain well-known limitations, including:

1. Continuous formation of soot, which must be removed frequently
2. Relatively high CAPEX due to the need of multiple reactor design, large air separation unit (ASU) & soot removal unit
3. High consumption of oxygen and power
4. Very high operating temperatures (1300-1400°C), which significantly limits the service life of the burners
5. Complicated water-cooled oxygen burner

Electrified steam methane reforming (eSMR)

A new hydrogen production method is electrified steam methane reforming (eSMR). In this method the main reforming reactions take place inside a catalytic reactor with reaction heat being generated by an electrical current. This means no hydrocarbon fuel is used in the reformer, which in turn means there is no reformer flue-gas. The energy density of an eSMR results in a reactor size, that is a fraction of an SMR unit.

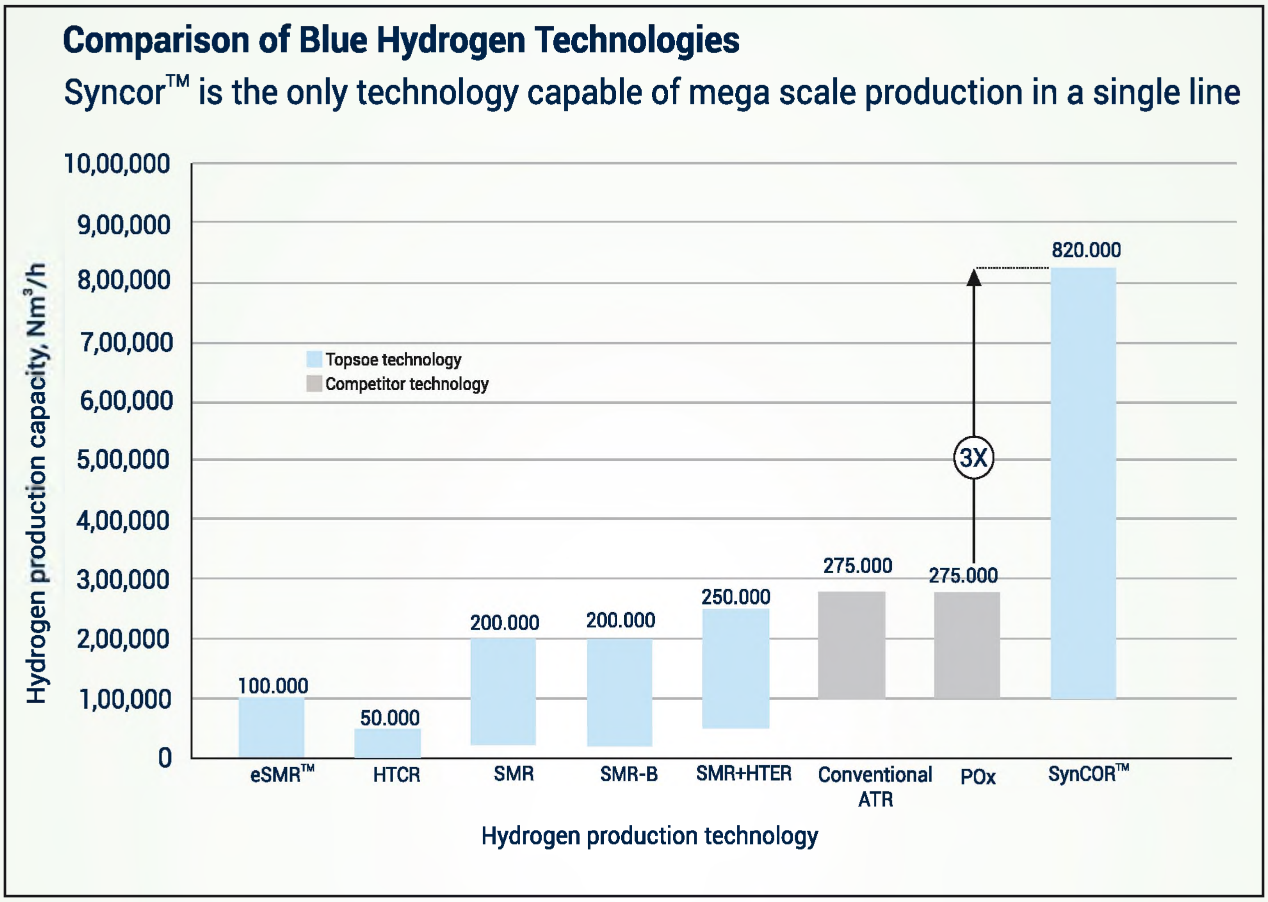
Furthermore, practically all the CO_2 in the shifted process gas can be recovered at low cost in a CO_2 removal unit making this process a very good candidate for blue hydrogen production in cases where electricity prices are favorable.

The eSMR process has been successfully tested at pilot scale and will soon be tested in a demonstration plant.

Comparing layouts

All the technologies mentioned above can be used to produce blue hydrogen. Selecting the technology best suited for any project will depend on multiple parameters, including capacity, yield and carbon intensity as well as the levelized cost of hydrogen (LCOH).

A technology comparison of the main parameters is presented below starting with production capacity in Figure 4.


Comparison of Blue Hydrogen Technologies

Syncor™ is the only technology capable of mega scale production in a single line

Figure 4: Optimal single line hydrogen production capacity with different reforming technology layouts

At small capacities, HTCR and e-SMR are most suitable technologies due to their compact design, whereas SynCOR™ is the preferable choice at higher capacities because of low capex. Its single reactor layout and very low steam-to-carbon ratio operation, enables the SynCOR™ design to benefit more from economy of scale.

The 'hydrogen yield per consumed natural gas feedstock' is very high in eSMR due to its fundamentally different design with electrically heated reformer, see Figure 5. Among other technologies, SynCOR™ and SMR-B have the highest yields. For SMR design, this is lower due to steam export, which is sometimes necessary to balance steam requirement outside the hydrogen plant.

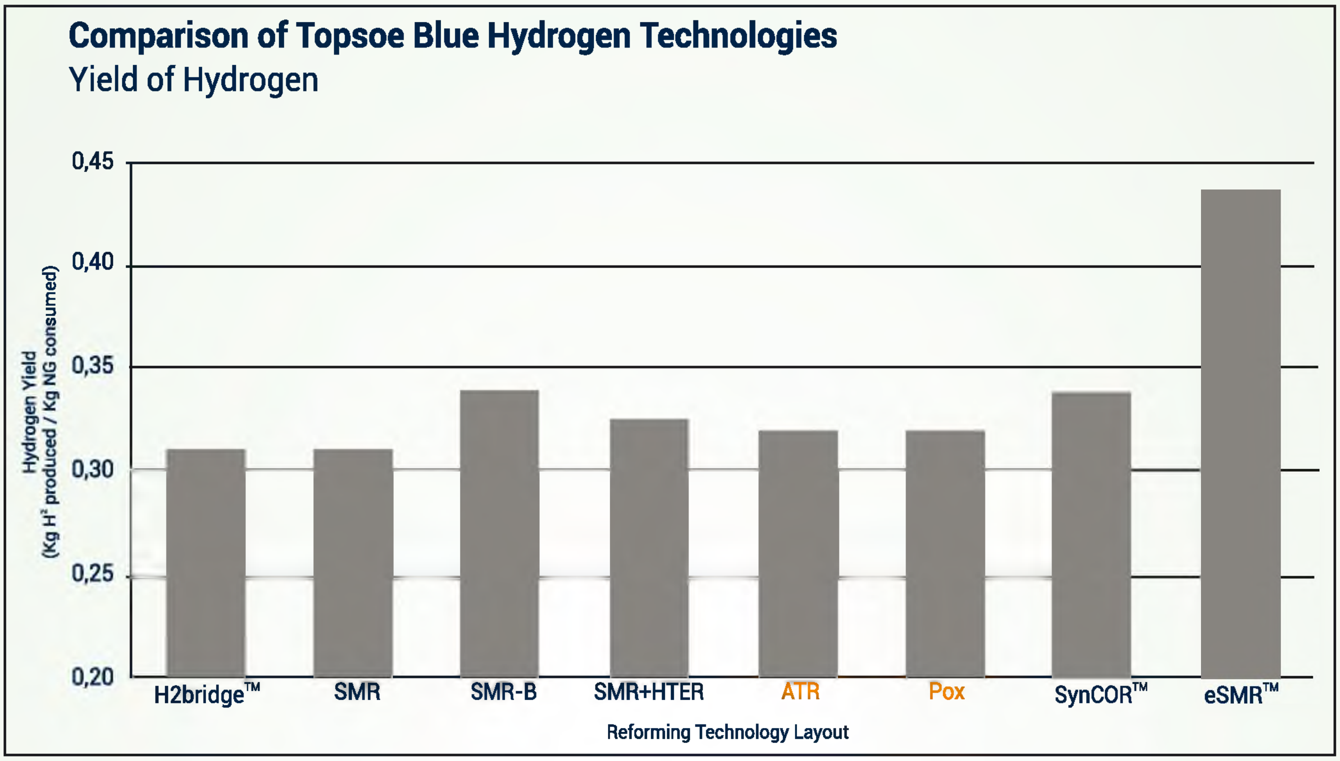
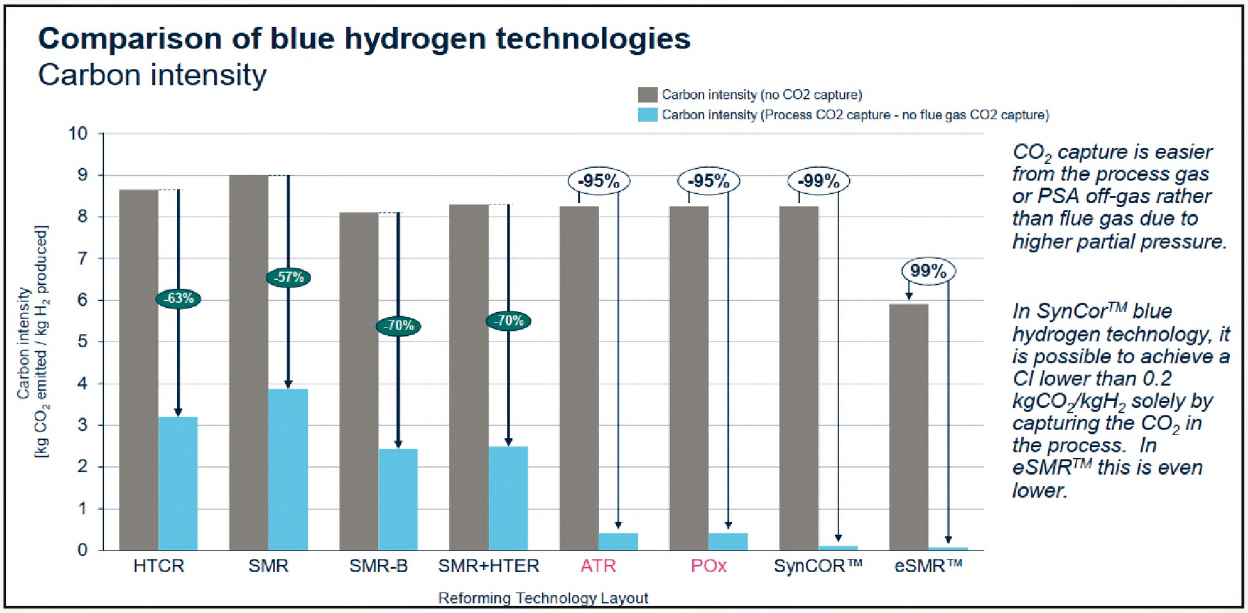


Figure 5: Hydrogen yield for different hydrogen production technologies



CO_2 capture is easier from the process gas or PSA off-gas rather than flue gas due to higher partial pressure.

In SynCor™ blue hydrogen technology, it is possible to achieve a CI lower than 0.2 $kgCO_2/kgH_2$ solely by capturing the CO_2 in the process. In eSMR™ this is even lower.

Figure 6: Carbon intensity of different blue hydrogen technologies.

Carbon intensity (CI) is now widely considered the most effective way to measure the success of a blue hydrogen technology in terms of reductions in CO_2 emissions. In Figure 6, CI is shown as the mass of CO_2 emitted per unit of hydrogen produced. The grey columns, which show CI with no carbon capture, are highest for the SMR design due to its lower efficiency and higher fuel consumption, converting waste energy to high levels of steam export. SMR-B has the lowest inherent CI among conventional technologies, since it has no steam export, whereas e-SMR CI is a step change better due to the nature of electrified reforming.

CI can also be reduced by capturing CO_2 from the process gas. This is more economical than capturing CO_2 from flue gas and is therefore normally the first step in CO_2 capture. In Figure 3, this is shown as light blue columns. For SynCOR™ and POx, which are both oxygen fired processes, as well as for e-SMR, achieving very low CI´s is fully feasible by removing the CO_2 formed in the process gas only. This feature makes these processes ideal for blue hydrogen production.

Going from light blue to deep blue hydrogen requires the removal of CO_2 from the flue gas. This is most cost effectively done in SynCOR™, due to lower levels of flue gas relative to Hydrogen yield. It is not a necessary step for eSMR, since there is no flue gas in an eSMR plant.

The final choice of the technology ultimately depends on achieving a certain target as cost effectively as possible. Figure 7 shows the relative differences in LCOH for each technology.

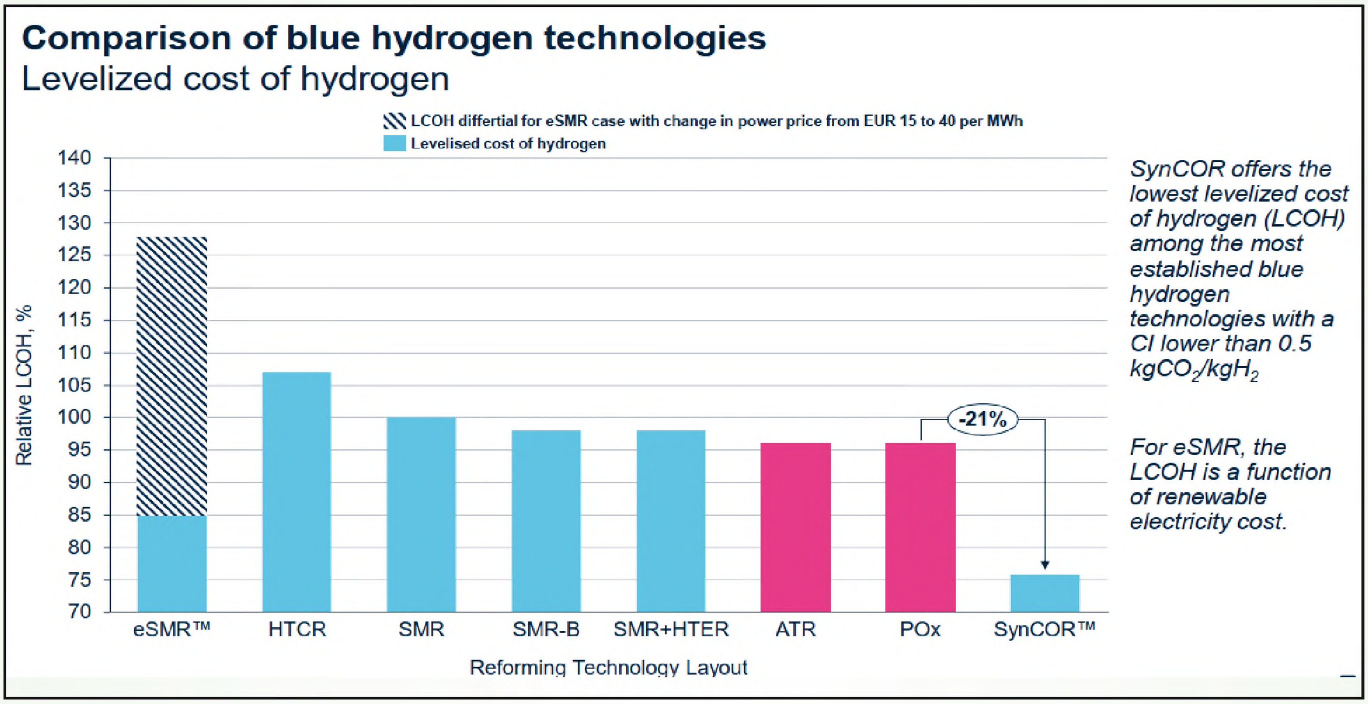


Figure 7: Levelized cost of hydrogen for different reforming technologies.

Main assumptions:

Natural gas: EUR 4/ MMBTU

Power: EUR 50/ MWh (Power cost is varied from 15-50 EUR/MWh for eSMR to demonstrate cost sensitivity)

CO_2 credit: EUR 25/Ton

4.3.2 Conclusion

At the same operational targets and conditions, the hydrogen produced in SynCOR™ has the lowest levelized cost, mainly due the combination of high yields, lower CAPEX and lower OPEX. This is the main reason why SynCOR™ has become the preferred choice for large scale blue hydrogen production. However, eSMR is envisioned to be a better technology choice in niche conditions with low electricity prices and at small to medium production capacities.

* * *

4.4 A Vision for Transforming Carbon & Creating Value

Mr Sangeet Jain & Dr. Preeti Jain, LanzaTech Private Limited

Mr Sangeet Jain , Country Head (India) & Director working with LanzaTech Pvt Ltd. He is Chemical Engineer and management professional having led teams in Chemical Plant start up & commissioning /project implementation/operations /Business development . Area of interest includes Green chemicals & Biofuels

Dr. Preeti jain ,Director Business Development & Government Relations working with LanzaTech Pvt Ltd. She is Member USISPF Biofuels Task Force, CII Bioenergy Committee, ICC NR Executive Committee. Member National Task Force on Sustainable Aviation Fuels. She is Recognized as Winner Women Leaders In Oil & Gas by FIPI. Area of interest includes Energy transition, Low carbon technologies & Circular Economy, Renewables (with focus on advanced biofuels), Petrochemicals, Sustainability, Climate Change

The time is now.

Fossil carbon is in nearly everything we use in our daily lives. It is not just in fuels or used to generate power, but fossil carbon is in fibers, coatings, and materials used in our clothes, cosmetics, toys, and household goods. Both fuels and materials originate in refineries fed by petroleum or natural gas. Perpetuating virgin fossil carbon use in these products is not sustainable given the current understanding of the impact of extracted, emitted, and waste carbon on our environment, climate, and vulnerable populations. If we are to achieve climate goals and avoid catastrophic climate and pollution disasters, there must be a large scale, strong, rapid, and sustained effort to re-tool our entire carbon economy. To align with a "Net Zero Path" economies today are investing in innovative technologies that enable a closed loop, circular carbon economy where carbon is reused rather than wasted. In India, LanzaTech is a prime example of how advanced technologies, such as Carbon Capture and Transformation (CCT), can help achieve decarbonization and biofuel goals by changing the way the world procures, uses, and disposes of carbon. LanzaTech's commercial gas fermentation platform makes low carbon fuel (ethanol) and chemicals from waste carbon (such as industrial off-gases, agricultural residues, municipal waste, waste plastics) with the intent to displace products made from petroleum. The low carbon ethanol can be transformed into high-value products, including sustainable aviation fuels (SAF), cleaners, fabrics, and packaging used in every facet of our lives.

The 3rd largest energy consumer in the world, India is seeking solutions to diversify its energy basket, reduce reliance on imports, and harness domestic resources to address climate risks. CCT technologies like LanzaTech are expected to increasingly be applied across economic sectors such as agriculture, industry, and waste management, as an important strategy to reduce greenhouse gas (GHG) emissions and meet the nation's objective to reduce its reliance on imported oil and natural gas. India's commitment at COP 21 is indeed a laudable step, however, going forward, meeting this commitment will require judicious use of carbon resources in the future.

India is a global leader in biofuels. As we step forward, CCT technologies like LanzaTech's can address sustainability needs across the country by reducing air pollution, recycling waste, providing clean jobs, generating cleaner burning fuels, and producing low-carbon materials. This article provides an overview of LanzaTech's technology and our vision to support India in its transition to a clean energy future.

4.4.1 LanzaTech's Gas Fermentation Process

LanzaTech paves a way towards a sustainable future by recycling and reusing waste carbon. Waste carbon is simply carbon that's already seen a primary use, such as the emissions created during the steel making process or the carbon found in solid waste streams.

The LanzaTech gas fermentation platform (Figure 1) is a commercially proven, first-of-a-kind process which uses a biocatalyst (microorganism) to convert gas containing carbon monoxide (CO), hydrogen (H2), and carbon dioxide (CO_2) into ethanol, providing industries an economical, sustainable, and flexible means of creating value from residues and off-gas through conversion into products. Gas fermentation is an alternative to sugar fermentation. In this approach, instead of breaking down glucose, microbes build up products from carbon oxides (CO or CO_2), which are found in waste gases from heavy industry (for example, steel mills, processing plants or refineries), or syngas generated from solid wastes (including, for example, unsorted and non-recyclable municipal solid waste, agricultural residue or organic industrial waste or even landfill and manure digester gas) . Capturing and recycling waste carbon streams before they enter the atmosphere or environment offers routes to sustainable domestic fuels, carbon-negative manufacturing, and a circular economy.

The inherent flexibility of biology allows LanzaTech's technology to create value using a variety of different waste streams readily available in India (as shown in Figure 1). Industrial waste gas, biogas/landfill gas, and solid wastes are high volume and point sourced feeds which have low value and can be used for fuel and chemical production without adversely affecting food or land security. LanzaTech's ethanol produced from these wastes can have substantial savings in emissions compared to fossil ethanol and is competitive with plant-based ethanol without impacting land use. Beyond ethanol, LanzaTech's synthetic biology platform has allowed LanzaTech to produce novel biocatalyst strains capable of producing other chemical intermediates, such as isopropanol and acetone, with more in the pipeline, supporting India's strategic expansion into sustainable chemicals.

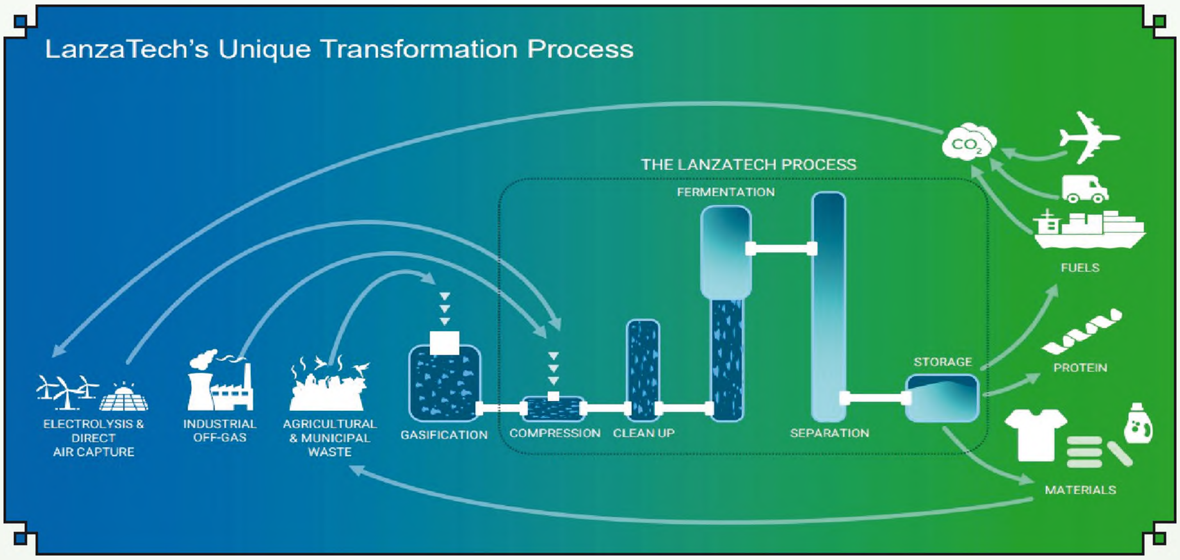


Figure 1: LanzaTech gas fermentation process

4.4.2 Capturing and Transforming Carbon around the World

LanzaTech's first two commercial scale gas fermentation plants are operating in China using industrial off-gases from Steel (Figure 2) and Ferro-Alloy plants. They have produced over 115 million litres of ethanol, avoiding the equivalent of over 180,000 metric tons of CO_2 released into the atmosphere.

In Europe, ArcelorMittal (Ghent, Belgium) is in the advanced stages of construction for a facility that will produce ethanol from blast furnace and basic oxygen furnace emissions. In India, LanzaTech's strategic partner, IndianOil, is building the world's first of its kind refinery off-gases to ethanol plant, which is expected to come online this year. In all, seven facilities implementing LanzaTech's technology are under construction in different parts of world. A summary of LanzaTech's global projects is shown in Figure 3.

LanzaTech's extensive network of customers and partners have committed approximately USD800 million to the development of new facilities using LanzaTech's CCT technology. The new facilities are expected to bring on significant new production capacity in the future and serve as a major validation to potential future customers as our roster of these notable partners continues to grow.

Figure 2: The LanzaTech-Shougang 1st commercial scale plant recycling steel mill offgases (China, 2018)

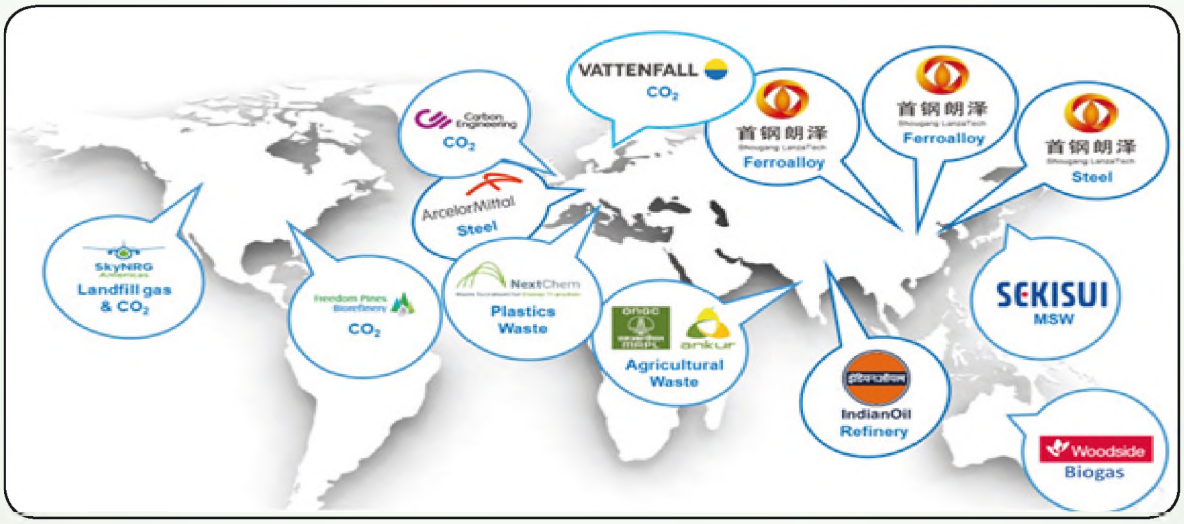


Figure 3: Global deployment of LanzaTech technology

4.4.3 Transforming Emissions, Transforming the Market

The total addressable market for LanzaTech technology is over USD1.0 trillion. The pathway enables India to invest in a sustainable supply-chain solution that will allow companies to advance their own sustainability objectives, as well as efforts to meet decarbonization mandates across the globe.

One exciting market segment created by LanzaTech's process is 'CarbonSmartTM Products'. When choosing paper or plastic bags, Fairtrade coffee, organic milk or recycled paper, consumers are given the choice of what sort of footprint they are leaving on the planet. LanzaTech envisions a world where a consumer can also choose where the carbon in their products comes from. This is the inspiration behind CarbonSmart.

LanzaTech is finding manufacturers, major brands, consumers, and sustainability-conscious governments like India desire products that are more sustainable than what is currently available in the marketplace. Over the past year, LanzaTech has completed campaigns with several major brands who have partnered with us to bring to market products made from industrial emissions.

LanzaTech ethanol from industrial emissions has been the feedstock for a diverse array of consumer products, most on the shelves today. Ethanol produced from waste carbon can be converted to ethylene, which can be further transformed into biopolymers, surfactants, or polyester fiber. LanzaTech is working with companies like Unilever, Mibelle, L'Oréal, and COTY to make packaging, perfume, laundry detergent and household cleaners (as in Figure 4) from our ethanol. India Glycols Limited has converted LanzaTech ethanol into MEG (monoethylene glycol), a key component of PET plastics.

Figure 4: LanzaTech CarbonSmart products

These products can have reduced GHG emissions by over 70% when compared to equivalent products derived from fresh fossil resources. Around the world, countries including India are developing low carbon growth trajectories to meet the demand for petrochemical products which contribute ~2% of global GHG emissions. Innovative pathways like LanzaTech's that produce sustainable chemicals from waste streams could be game changers, reducing emissions while promoting circularity.

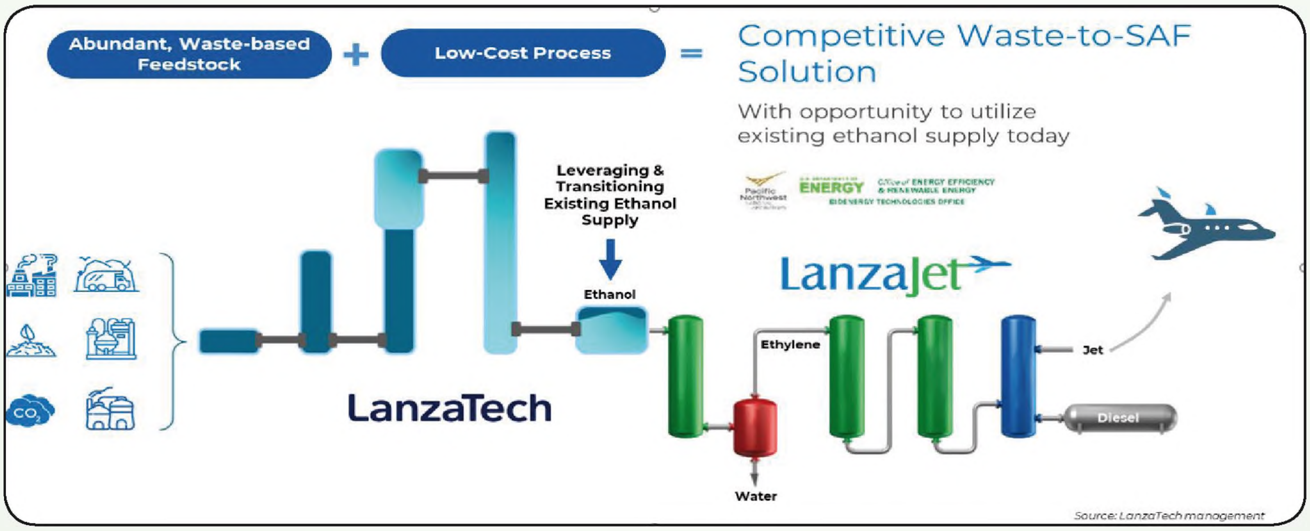
4.4.4 The Future of Flight: Sustainable Aviation Fuel

In October of 2021, the International Air Transport Association (IATA) announced that it had "approved a resolution for the global air transport industry to achieve net-zero carbon emissions by 2050", termed Fly Net Zero. IATA also urged the International Civil Aviation Organization (ICAO) to adopt a comparable commitment, well beyond that currently codified in the ICAO Carbon Offset and Reduction Scheme for International Aviation (CORSIA) which comes into full effect in 2027. The use of sustainable aviation fuel (SAF) is a key element of Fly Net Zero and IATA laid out a scenario in which the global demand for SAF is 17% of total aviation fuel by 2035 (~91 billion litres). To meet that demand, the capacity for SAF production must grow rapidly.

India recognizes decarbonization is essential, not just for road transport and industry, but also for aviation. As India is the 3rd largest domestic aviation market , this creates real urgency in creating a domestic SAF supply using sustainable feedstocks that are available today.

LanzaTech, in partnership with the U.S. Department of Energy (US DOE) Pacific Northwest National Lab and with US DOE support, has developed an innovative Alcohol-to-Jet (ATJ) platform to produce SAF from ethanol. The ethanol can come from any environmentally, economically, and socially sustainable feedstocks. To accelerate global commercialization of this SAF technology, LanzaTech spun out a new company, LanzaJet, in 2020. The ethanol-based ATJ technology is particularly well-suited to the Indian market due to India's strong ethanol industry.

In the LanzaJet™ ATJ process, ethanol is chemically converted to synthetic paraffinic kerosene (SPK) via the four steps defined in ASTM D7566 Annex A5: dehydration, oligomerization, hydrogenation, and fractionation. Key advantages to the LanzaJet ATJ process are its unprecedented product flexibility and selectivity. The process can produce a product slate that is 90% SAF and 10% renewable diesel or 25% SAF and 75% renewable diesel with only operational changes. This flexibility allows the operator to respond to demand swings effectively. The SAF from the process is qualified for use in commercial aviation in blends of up to 50% with conventional jet.



Source: LanzaTech management

Figure 5: Ethanol-based Alcohol-to-Jet (ATJ) creates flexibility for global deployment

Abundant, available waste carbon-based ethanol coupled with the LanzaJet ATJ process can play a key role in deploying SAF production across India and the world. The combination of LanzaTech's gas fermentation technology with ethanol-based ATJ technology (as shown in Figure 5) enables end-to-end conversion of waste into SAF without impacting the food chain, land use, or water supplies.

4.4.5 India: An Opportunity for Energy Security & Decarbonization & Circular Economy

The Energy Transition Roadmap is at the forefront of policy considerations in India. Sustainable fuels like biofuels are being seen as an important pillar in the Roadmap. While India has made great strides toward blending of 1st generation ethanol into gasoline, advanced biofuels, made from agricultural, municipal and industrial wastes, will be very important to accelerate India's progress toward energy security and decarbonization of both road transport and aviation. Advanced biofuels from CCT pathways offer the opportunity to reduce carbon emissions, improve air quality and provide economic benefits in the sectors where the waste feedstocks originate.

India's 'National Policy on Biofuels' (NPB) 2018 envisioned developing sustainable domestic feedstocks to promote biofuel production. This policy enabled India to reach 9% ethanol blending in gasoline in 2021. Moving ahead, advanced biofuels from waste feedstocks can play a vital role in expanding the ethanol production pool in the country and building circular economy, as part of India's ambitious plan to achieve 20% blending by 2023 (requiring about 12 billion litres of ethanol) .

The overall ethanol feedstock potential in India from industrial off-gas and other waste resources is estimated at 30 billion litres per year. When used as feedstock for ATJ, this in turn could produce over 17 billion litres per year of hydrocarbon fuels, of which up to 90% can be SAF. This sustainable ethanol can also serve as a building block to produce low carbon chemicals and materials that today are made from petroleum. In addition to carbon benefits, these advanced biofuels, sustainable chemicals, and materials will offer employment and economic benefits for rural economies and urban communities as well as reduce industrial emissions.

4.4.6 Policy: Enabling the change we need

Simply put, CCT technologies like LanzaTech's can increase production of domestic ethanol and create an indigenous SAF manufacturing sector in India. At time when industry is looking to reduce its carbon footprint, this technology can be leveraged to create jobs and to replace fuels and other products currently made from oil and natural gas with recycled carbon. A supportive policy framework will be central to creating a circular carbon economy with a foundation on CCT technologies.

The future of sustainable fuels and chemicals can only be assured by technology-neutral policies that incentivize the early adoption of innovative technologies. A clear roadmap of supportive policies will be a great enabler to attract investment into the first few plants implementing a new technology. Such intervention is needed to reduce the cost of deploying CCT technologies at a scale that will subsequently bring down production costs in future plants. To fast-track sustainable ethanol and chemicals projects built on abundant available waste feedstocks in the country, industry needs policy interventions such as sustainable feedstock supply chain development, mandates and differential pricing for advanced biofuels and products, subsidies for renewable power used in production, as well as direct financial and fiscal incentives. The role of Government technical arms like CHT (Centre for High Technology) has been exemplary in recent years; their continued guidance to advance innovative pathways for production of sustainable fuels as well as chemicals from waste carbon would be of great value.

Stepping back to look at the bigger picture, it is clear to that India can play a pivotal role in moving the global economy away from fresh fossil carbon and into a circular model that addresses both fuels and products. This should be seen as strategic opportunity for India, in which a pragmatic approach to develop waste-agrarian-industrial value chains for sustainable fuels and chemicals will cement India's leadership position in a new circular carbon economy.

Part-5

Operations - Troubleshooting

5.1 Hazards and Safety of Fired Heater system

Re-ascertain your fired heater safeguards for better reliability and availability

Shilpa Singh, Rupam Mukherjee, Ankur Saini, Akhil Gobind, Engineers India Limited

Ms Shilpa Singh holds a B.Tech degree in Chemical Engineering and is working as General Manager in Engineers India Limited's Heat Transfer department. She leads a team of chemical engineers involved in grassroot designs, revamp studies, capacity and efficiency improvement projects for fired heater systems. she has over 24 years of experience in this field.

Mr Rupam Mukherjee is Sr. Manager in Engineers India Limited's Heat Transfer department. He has over 13 years of experience in design, engineering and troubleshooting of fired heater systems. He holds a post-graduate degree in Energy and Environment Management.

Mr. Ankur Saini is serving as Manager in EIL's heat Transfer Department. His active area of work includes revamping and troubleshooting of oil refinery fired heaters and furnaces. He holds a Bachelors degree in Chemical Engineering.

Mr.Akhil Gobind is Fired Heater Engineer in EIL. He has rich experience in design and revamping of fired heaters. He holds a B.Tech degree in Chemical Engineering.

5.1.1 Background

Fired Heater systems are complex as well as critically important to overall plant operation. At the same time, these equipment demand for a high level of safety within refinery operating conditions as they inherently bear the source of ignition. Furnace or fired heater safety has been of utmost priority over many decades with each decade bringing forth more stricter and stringent standards and guidelines. Hazards and safety in a process plant is assessed through HAZOP or Hazard and operability studies which are quintessential features of any new project either at design phase or at construction phase. However, there are number of units still operating worldwide which were built decades ago. Many of these are undergoing expansive debottlenecking and revamping exercise in order to improve profitability. Re-Hazop of the fired heater in such old units is required to re-ascertain the safety of the equipment post implementation of the de-bottlenecking project.

HAZOP of a fired heater system demands in-depth knowledge of the heater design and their expected behaviour when put into operation. Neither building too much safeguards, nor being too confident serves the purpose. Whereas on one front, building too much safeguards causes the system to be sluggish and costly, being complacent on the other hand can lead to mishaps leading to loss of property and even life. To strike the perfect balance, the HAZOP team is expected to allocate proper weightage to the safety instrumented system and the safeguards incorporating the in-built design considerations.

5.1.2 Objective of Fired Heater Hazop

Hazop study is conducted to effectively analyse and estimate the possible failure scenarios and their safeguards. Another critical aspect of this study is to properly evaluate the maintainability and operability aspect of any process equipment facility, including fired heater. Key objectives of the Hazop study can be shown as below:

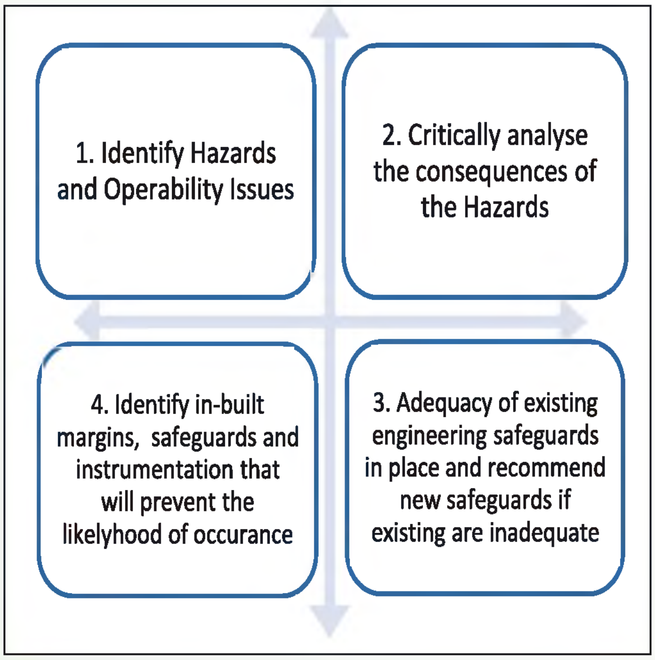


Fig.1

An important aspect to note is that the Hazop study is a qualitative analysis of possible scenarios. To properly gauge this qualitative aspect, a multi-disciplinary team is generally employed to properly conduct a fired heater Hazop. Since fired heater system comprises of various sub-systems and auxiliaries like Burner, Air-preheaters, control valves and other safety instrumented function, presence of experts from multiple disciplines like Thermal designer, Rotary specialist, Instrument specialist and safety expert helps in better appreciation of the Hazards as well as their safeguards. In fact, some of these safeguards may even fall into the category of basic design features such as design pressure and temperature considered for equipment design, for which the original designer may be better placed to guide the outcome.

The inherent nature of a fired heater system with elaborate air preheat system is to have simultaneous, parallel and synchronised working of various circuits in tandem. These non-interlinked circuits are:

- Fuel Circuit
- Process Charge Circuit
- Combustion Air circuit
- Flue gas Circuit

Interestingly enough, each of the above circuit presents its own set of failure scenarios and hazards. Although, in many of the cases, multiple scenarios may lead to similar outcome of consequence or similar safeguards, a holistic approach is adopted to identify each and every scenario and evaluate its potency for dire consequences. The article addresses these scenarios targeting a balanced draft type of fired heater system, although majority of the inferences can be extended to Natural draft fired heaters also which are less complex compared to balanced draft systems.

5.1.3 Methodology of Hazop

In general, each of the above circuit is taken up and evaluated on the following pathway:

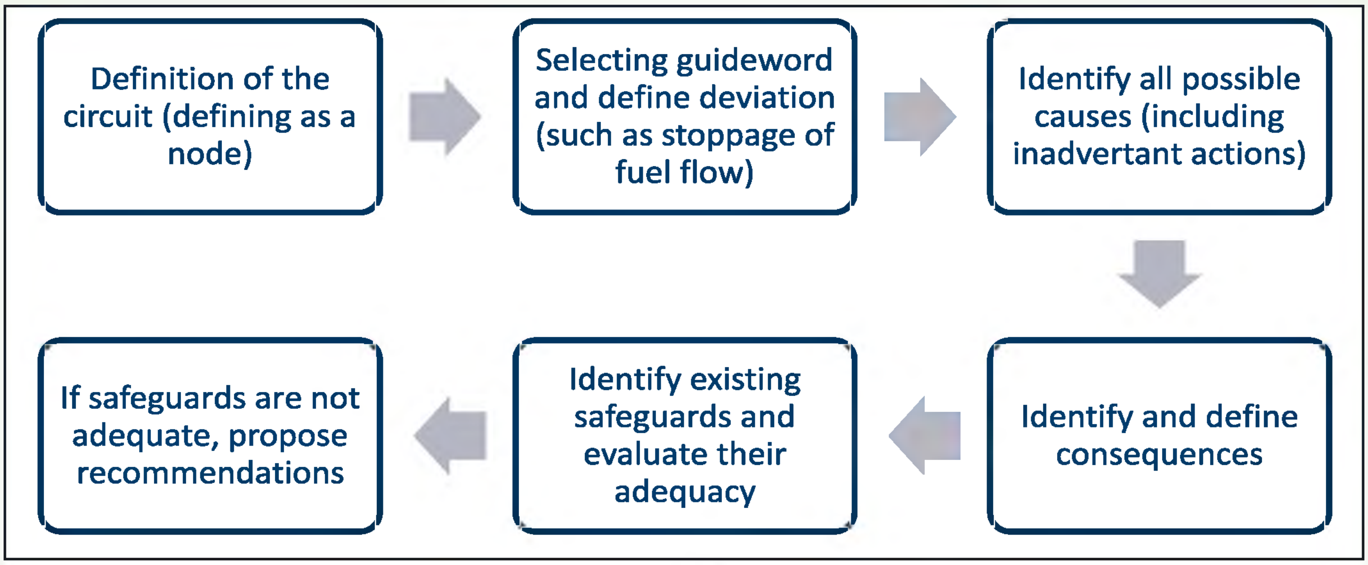


Fig.2

Notwithstanding above proven systematic approach, there are certain assumptions which are well noted and recorded which sets the tone for a fired heater Hazop. For example, it is assumed that the fired heater is in a workable and well maintained condition. It is assumed that mechanical protection devices shall function when necessitated. Also, certain causes such as sabotage, natural calamity or simultaneous occurrence of two unrelated events are not considered applicable. To the extent possible and felt necessary, certain extra-ordinary cause such as Tube rupture or tube leakage is taken up for evaluation to estimate their impact.

For the brevity of this article and for easier understanding of the fired heater Hazop process, four very common and debated safety concerns are elaborated below. The examples have been chosen in a fashion to encompass the major nodes and circuits and to highlight the most critical safeguards. Additionally, an extra-ordinary cause is also included for better appreciation of the Hazop objective.

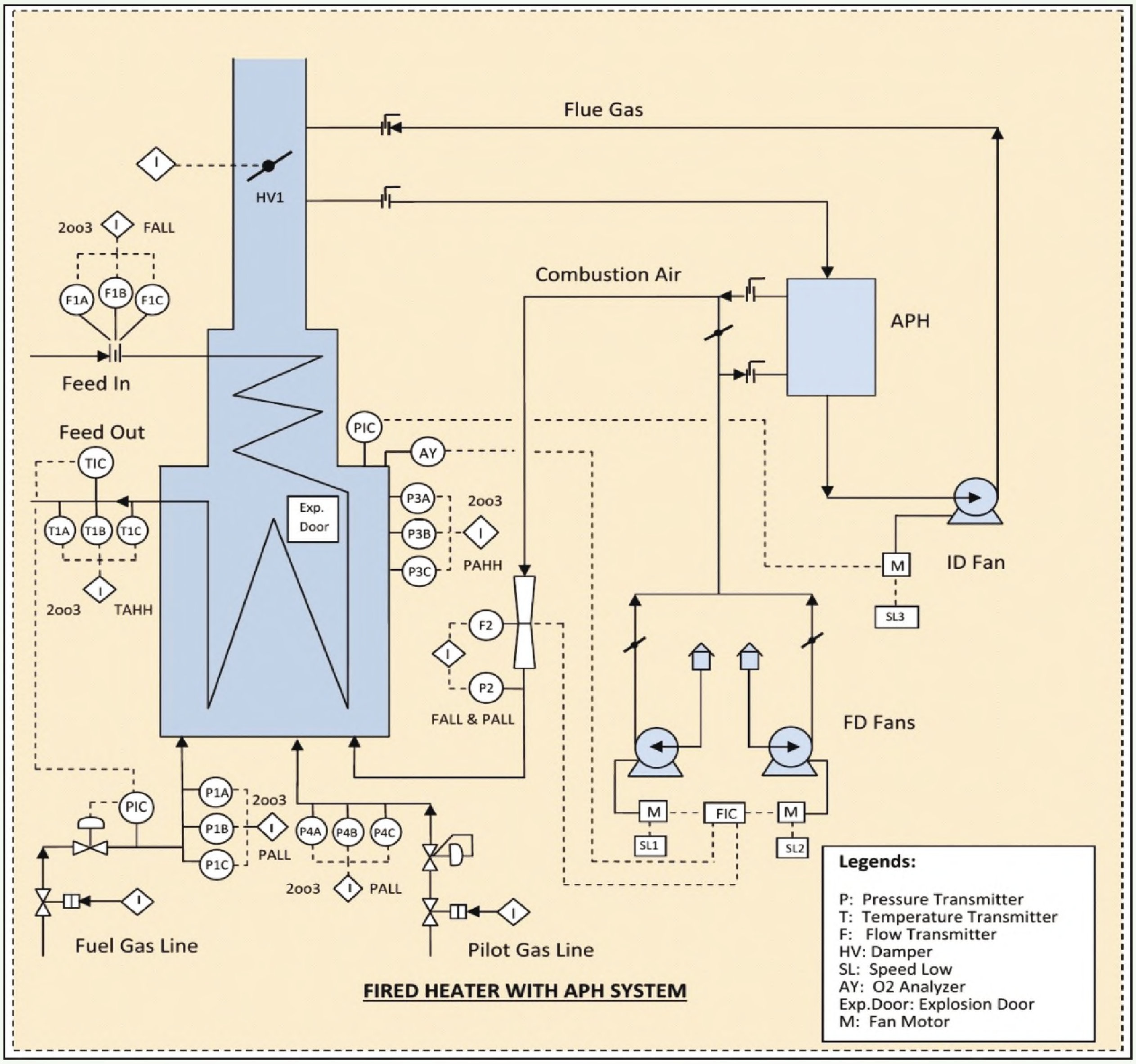


Fig.3

Fig.3 illustrates a typical fired heater with outboard air preheating system. Basic Instrumentation and controls have been shown in the figure. Relevant references to the tag numbers of instruments in this figure have been included in parentheses at appropriate locations in tables exemplifying the common deviations.

Hazard-1: Sudden loss of fuel and possible re-ignition leading to explosion

Sudden loss of flame is a potential critical hazard in fired heater operation. Unsolicited extinguishing of burner flames due to any process reasons or due to inadvertent instrument failures may lead to accumulation of large quantities of unburnt combustibles in the furnace, if the fuel gas flow continues unabated. Possible re-ignition of the large quantity of potentially explosive air-fuel mixture may result in major explosion leading to loss of life and property. As safeguards, generally there are low pressure trips provided on the fuel gas line which gets activated as soon as the flow ceases. This low pressure activated trip leads to complete closure of the fuel system through actuation of shutdown valves in block-and-bleed arrangement. A typical HAZOP sheet for this cause may look like:

Probable Cause	Consequence	Possible Safeguards
Inadvertent fuel loss due to Temperature controller on coil outlet malfunctions and closes the fuel gas control to complete closure or less than that required	1. Potential flame extinguish in all burners. 2. Fall in furnace draft 3. Potential flammable mixture build-up inside firebox. 4. Loss of process fluid heating.	1. Low pressure override (Case specific) 2. Low flow alarm on fuel flow meter. 3. 2 out of 3 (2oo3) tripping of fuel to furnace on fuel pressure low-low which will turn the shutdown valves to close position (P1A/P1B/P1C reading Low-low)
Upstream process upset leading to shutdown of fuel gas contributing units	In addition to above consequences, this cause will also lead to loss of pilot flame leading to potential incombustible mixture in firebox	1. Pilot flame detection through ionization rod or flame scanner. 2. 2oo3 PALL on pilot gas line activates and initiates shutdown. (P4A/P4B/P4C reading low-low)

The above two causes are commonly experienced or perceived, however, there can be a multitude of other causes for this deviation. Inadvertent closure of the control valve, malfunction of the air fuel ratio control block and other causes can also lead to similar consequences. However, with presence of above similar safeguards, the consequences can be well covered. In some installations or in some countries, use of main flame scanner may be a mandatory requirement and credit for fail signal of the same can also be accounted. Furthermore, in certain cases, dedicated Burner Management System (BMS) is provided which initiates a systematic start-up of the fired heater through a pre-determined purging sequence with preset time logic. Going a step further, some of the installations may also have complete heater trip linked to Main and pilot burner flame detection systems.

In continuation to above, the trip setting for the 2oo3 tripping logic on fuel pressure low-low should be selected with care so that the instruments actually detect the loss of fuel. Nonetheless, gas freeing or steam purging of the firebox is to be mandatorily adopted whenever burners are being reignited after loss of complete flame. This will ensure any residual combustibles are flushed out safely even when all interlock worked reliably.

Hazard-2: Loss or less flow of combustion air leading to fuel rich mixture in firebox

Combustion air is driven into the firebox by means of mechanical equipment like forced draft fans in any balanced draft system. As is the case with all rotary equipment, they have their probability of failure. In such case of fan failure, the combustion air flow to the system will cease which may lead to a fuel rich mixture inside the firebox. To evade this hazardous situation, numbers of safeguards are adopted. For example, a low flow trip is generally provided on the combustion air line which can be combined with low pressure induced trip for higher reliability. This trip leads to closure of fuel to the furnace ensuring that fuel rich conditions are avoided. Similarly, alarms are provided on fan running as well as on flue gas oxygen analyser that will alert the operator of any discrepancy to normal operating conditions. A typical HAZOP sheet for this cause may look like:

Probable Cause	Consequence	Possible Safeguards
Trip of both FD Fans or trip of one FD Fan	1. Potential flameout in burners 2. Accumulation of incombustibles in firebox. 3. Firebox pressure will fall due to loss of firing	1. Flow low-low (FALL) tripping of the heater on combustion air circuit (sometimes in combination with Pressure low-low PALL to ensure more robustness). (P2 + F2 reading low-low) 2. Loss of running signal of the fan leading to failure alarm which will alert the operator.(SL1 and/ or SL2) 3. Oxygen analyser at arch (AY) set with low alarm for alerting the operator. 4. Tripping of one FD Fan will lead to the second FD Fan being ramped up to take full process load.

Loss of both FD fans is quite unlikely in refinery Fired Heaters, however, this cause presents a wider picture for better evaluation of safeguards. Moreover, even with one fan tripping and other fan ramping to full load; a dearth in combustion air is expected during the ramping up period. However, with the safeguards as mentioned above, the consequences can be negotiated well. In addition to above safeguards, Hydrocarbon/ Combustible analyser is provided in firebox in some cases for additional protection. Albeit, this comes at an additional premium.

A very notable argument in majority of Hazop reviews arises on the status of pilot flame on loss of FD Fans. In general, the inspirator for pilot air is located outside the burner windbox and does not rely on the FD fans for pilot air requirement. Thus, even with failure of FD fans, pilots should remain inline. Pilots are safety devices and are preferably kept inline which helps in combusting any minor residual fuel gas left in the main gas line or in vicinity of the burners. This is one specific example with intricate knowledge of individual heater auxiliary comes handy.

Hazard-3: Pressurization of firebox leading to hot flue gas exposure

Process fired furnaces are maintained under slight vacuum conditions to ensure safe operation and to prevent personnel injury. This slight vacuum is created by the stack in a natural draft furnace or by Induced draft (ID) fan in balanced draft furnace. This possible hazard is generally nullified by adoption of high firebox pressure trip. Even before this trip condition arises, there are number of alarms provided which alert the operator on tripping of the ID fan or even upon reaching the high pressure level in the firebox. Explosion doors are sometimes provided which serve as a mechanical protection in case of firebox pressurization. A typical HAZOP sheet for this cause may look like

Probable Cause	Consequence	Possible Safeguards
ID Fan trips due to mechanical or electrical failure / Inadvertent closure of stack damper in Natural draft heater	1. Firebox pressure increases reaching to positive pressure levels. 2. Potential flame instability issues leading to incombustible gas accumulation.	1. Loss of ID Fan running signal (SL3) leading to stop alarm. In case of Natural draft furnace, a high arch pressure alarm will sound immediately. 2. ID fan trip signal or arch pressure PIC in case of Natural draft furnace will lead to opening of main stack damper (HV-1) which releases the pressure build-up inside the firebox. 3. The stack is adequate sized to take care of 100% heater design duty even without ID fan circuit being inline. 4. High-High Firebox pressure (P3A/P3B/P3C reading High-High) triggering heater trip which will immediately stop firing. 5. Explosion door provided in many cases.

Considering stack as an additional safeguard is again an example of how the presence of the original heater designer can lend more credibility to the Hazop study. One more critical point here is the opening time of the stack damper. The time of opening and sensitivity to be devised so that pressure build-up inside the furnace is prevented. Use of relief devices which can operate of minimal positive pressure and their location must be ensured as per code requirements. All these help in crediting the safeguards for this deviation.

Hazard-4: Low or total loss of process feed to furnace pass leading to coking inside the coil

Loss of feed to the furnace is again a hazard that may lead to overheating and mechanical damage of the coil, if firing continues unabated. Even, partial loss of feed may lead to overheating of the feedstock leading to coking inside the coil. To avoid such occurrences, generally low flow trip is provided on the fluid passes as well as high coil temperature trip is provided. Actuation of these trips shuts down the fuel to the furnaces leading to safe situation. A typical hazop table for this cause may look like:

Probable Cause	Consequence	Possible Safeguards
Charge feed pump trips / Inadvertent closure of control valve on individual pass	1. Overheating of heater coils leading to potential mechanical damage to coils. 2. Potential coking in coils due to low velocity and high coil outlet temperature.	1. FALL or charge flow low-low (F1A/F1B/F1C) triggered trip of furnace which will shut down firing. 2. TAHH (T1A/T1B/T1C) on individual pass outlet will trip the heater shutting down fuels.

Failure of charge pump is a common cause for furnace trip. Even with the above safeguards in line, it is advised that the residual process fluid remaining inside the coils should be swept out as quickly as possible by a suitable purging medium. This will help in preventing cracking of the hydrocarbon remaining inside the coil and formation of coke. However, purging medium should be decided based on equipment downstream and Licensor recommendations.

Hazard-5: Extra-ordinary cause- Coil rupture/ Leakage

Coil leakage or, in the worst case a coil rupture, may lead to large quantity of combustible being spewed into an ignition source. This is indeed a dangerous situation and may lead to medium to major degree of explosion. Coil leakage can result out of prolonged operation of the tube or operating the heater outside its design limit. The safeguards in this case are induced judgements only like higher firebox temperature, pressure or higher tube metal temperature reading. A typical hazop sheet for this cause may look like:

Probable Cause	Consequence	Possible Safeguards
Coil leakage due to aging of tube or due to flame impingement	1. Potential uncontrolled fire due to spillage of combustible material.	1. Arch temperature provided with high alarm which will detect sudden rise. 2. Higher heat release in firebox will lead to higher coil outlet temperature leading to coil outlet high alarm. 3. Tube skin thermocouples will read high temperature alarm. 4. Oxygen analyser at arch will have low alarm. 5. Explosion door provided in many installations A very important point to note here is that all of the above safeguards shall only help in preventing a major consequence but they cannot prevent the cause.

Coil leakage is emergency. Adequate protection measures and methodology to deal with this situation should be governed by specific company guidelines and in some case, certain licensor guidelines. Safeguards listed against this cause are just indications which will alert the operator about possible tube leakage and help in preventing a possible 'major' consequence. Necessary immediate actions should then be initiated by authorised company personnel in compliance to SOPs. There can be certain other practices like providing high stack temperature trip which automatically shuts the fuel; however, this should be discussed on case-to-case basis.

5.1.4 Key Takeaways

The benefits and advantages of detail Hazop review of fired heater system are known to all as this review is not a luxury, but a 'necessity' nowadays for upcoming installations. However, there are numbers of very old installations still in operation worldwide which can be taken up for re-Hazop to further evaluate their protection status. That exercise, if performed by an expert safety audit team, will be of immense help to the refiner in ascertaining and crediting the safety of the fired heater and ensure safety of their employees and the asset for years to come. This is especially important in view of the ongoing capacity expansion of many hydrocarbon processing units which were built decades ago.

Another advantage of such detail Hazop review of existing assets is to ensure and upgrade the equipment for the latest technological and code advancements in the field of fired heaters, which can enhance their reliability and availability as well as comply with local statutory guidelines. This is one more critical aspect while debottlenecking an existing unit. This Re-Hazop exercise will in fact add immense value to the debottlenecking project in terms of enhancing the safety of the unit as well as to operate the furnace within its Safe

Operating Window (IOW).

Added to Hazop review, another critical tool which forms an integral part of Hazop study is to evaluate the safety integrity level (SIL). This SIL study helps in identifying the interlocks, instruments and control elements to be provided with higher reliability that should perform when in demand. The SIL level is accorded to the instruments and components based on the degree of safety it shall provide against loss of life, environment and asset. Higher the SIL level, higher is the cost and higher is the protection. Thus a competent authority or agency will always be better placed in assisting the end-user in optimising the plant machinery and instrumentation cost balancing the benefits against the risk.

Finally, nothing can substitute the expertise of a well trained fired heater operator and shift supervisor. A detail Hazop study can only re-verify possible scenarios, however, actions and SOPs during an emergency very much still depend on adaptability and expertise of specialised operators. The article highlights only a handful of common scenarios and is not intended to elucidate a complete fired heater Hazop. In fact, readers are advised to consult specialized safety and hazard analysis professional organizations like Engineers India Limited (EIL) to define and properly evaluate their specific fired heater system which would surely lend value to their asset and add on to the integrity of these critical equipment. Also, as highlighted in this article, presence of a multi-disciplinary team including representatives from end-user during the Hazop and safety study will help in ensuring a complete 360° degree review of the fired heater setup and ensure better preparedness and emergency action plans.

* * *

5.2 Improvement in pressure control of CDU-4 Stabilizer column by in-house developed Auto-Tuning Method

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Mr Susanta Sadhukhan holds degree in chemical engineering and is currently working as Senior Manager (Process Engineering). His areas of expertise include plant operations, troubleshooting, personnel management, and Advanced Process Control. He was involved in Advanced Process Control (APC) implementation projects of Continuous Catalytic regeneration Reformate (CCR) unit, Crude distillation Unit, Diesel Hydrodesulfurization Unit (DHDT), MTBE unit etc. Currently he is working as process technologist of hydro-processing units. An article by him has been published by "Hydrocarbon Processing" magazine in Oct'20 edition.

5.2.1 Introduction:

Auto-Tuning of the DCS PID controller has been incorporated for the first time in Refinery thru in-house idea and efforts by APC Team. Because of disturbance like crude changeover, water carry over, high stabilizer feed rates CDU-4 Stabilizer column pressure fluctuates, leading to unsteady operation and off-spec product which has been observed on many occasions in past.

To mitigate this problem, experience of manual tuning gained during such instances was consolidated and converted into mathematical logic for changing the controller tuning parameters (Proportional Band and Integral Time) automatically. Thru this logic, whenever the stabilizer column pressure swings more than 0.38 Kg/cm2 g, the tuning parameters change automatically as per the logics.

5.2.2 Background:

Feed to Stabilizer column comes from overhead system of atmosphere column .The condensed Atmospheric Column overhead hydrocarbons from overhead naphtha accumulator are pumped to the Naphtha Stabilizer. Stabilizer column has 48 trays with feed entering on the #24th tray. Necessary heat to re-boiler is provided by LGO CR to the thermo syphon re-boiler. The overhead products are totally condensed in the stabilizer overhead condenser before routing to stabilizer Reflux Drum. Stabilizer pressure is controlled by the pressure controller (DPC270) situated at overhead line.

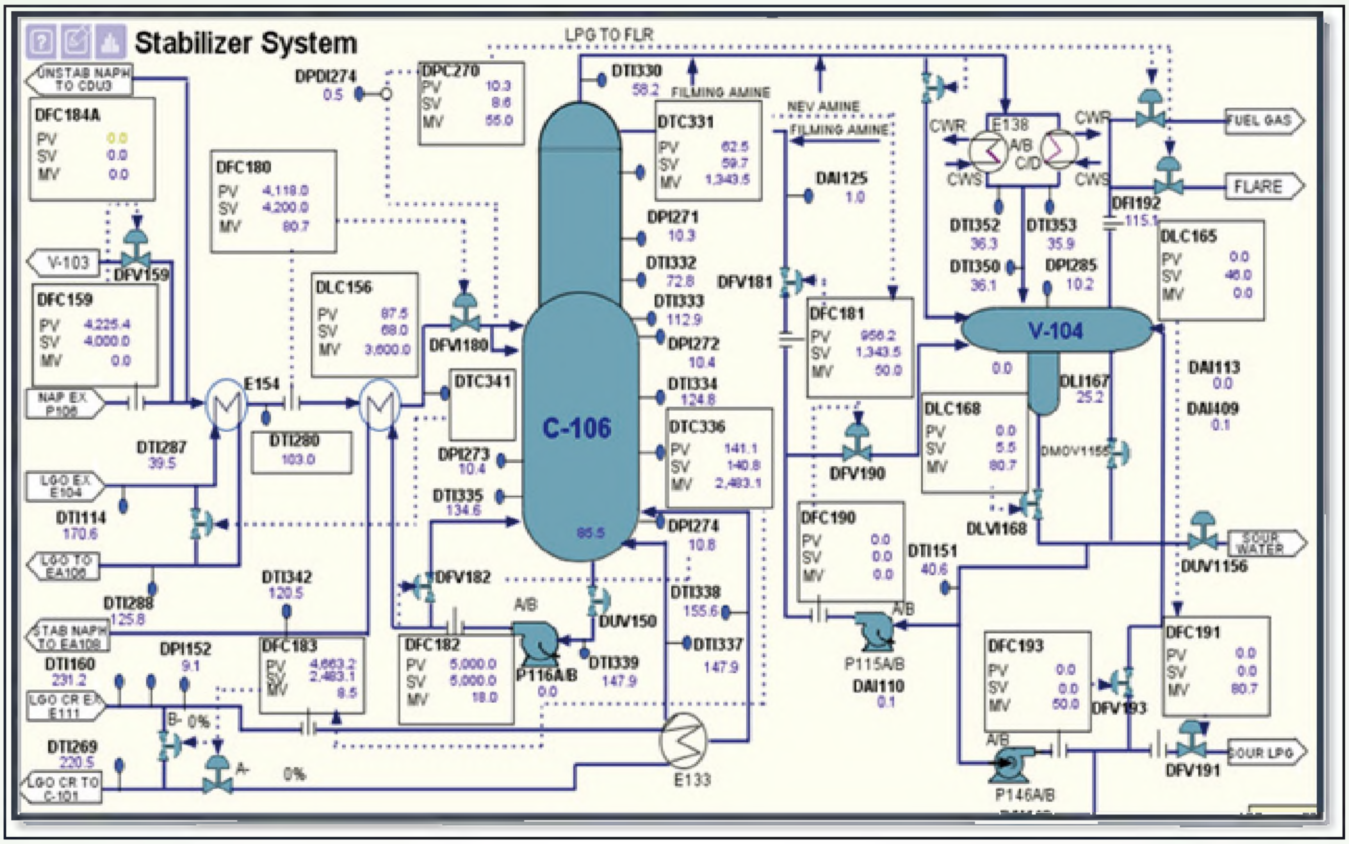


Fig 1: CDU-4 Naphtha Stabilizer Column System

5.2.3 Fluctuation in Column Pressure:

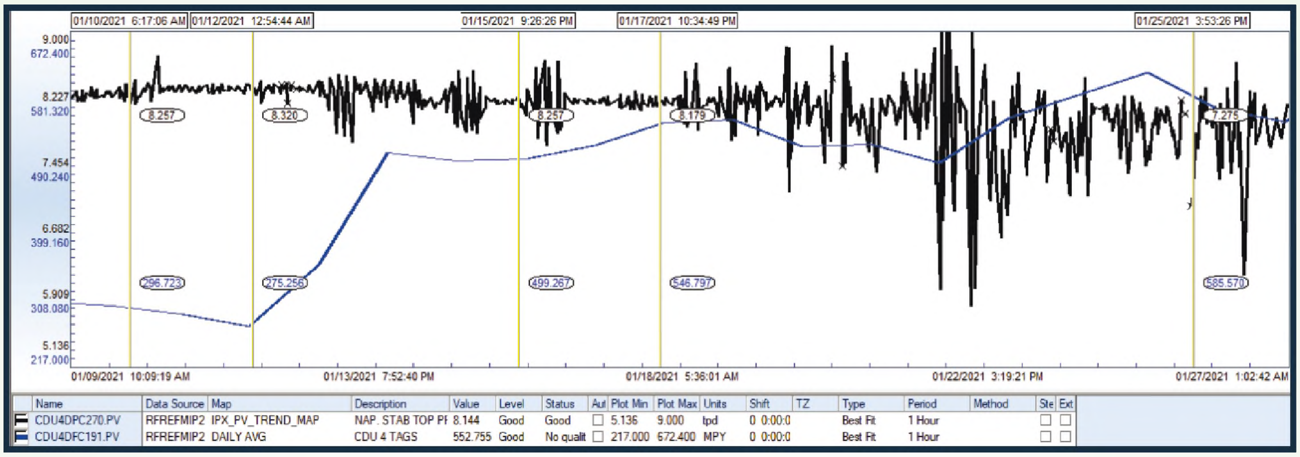
Frequent pressure fluctuation in the range of 7 to 9 kg/cm2g in naphtha Stabilizer Column is recorded since 2019 after addition of new high efficiency trays into the column and increasing LPG processing. The pressure fluctuation problem resulting in disturbance in the overall column and downstream units.

Every time manual tuning has to be done whenever pressure fluctuation is recorded in the column which results in a temporary solution for the issue.

5.2.4 Analysis to solve the Problem:

Data for all the important parameters were collected to see the relation with stabilizer top pressure and identify the actual reason for pressure fluctuation.

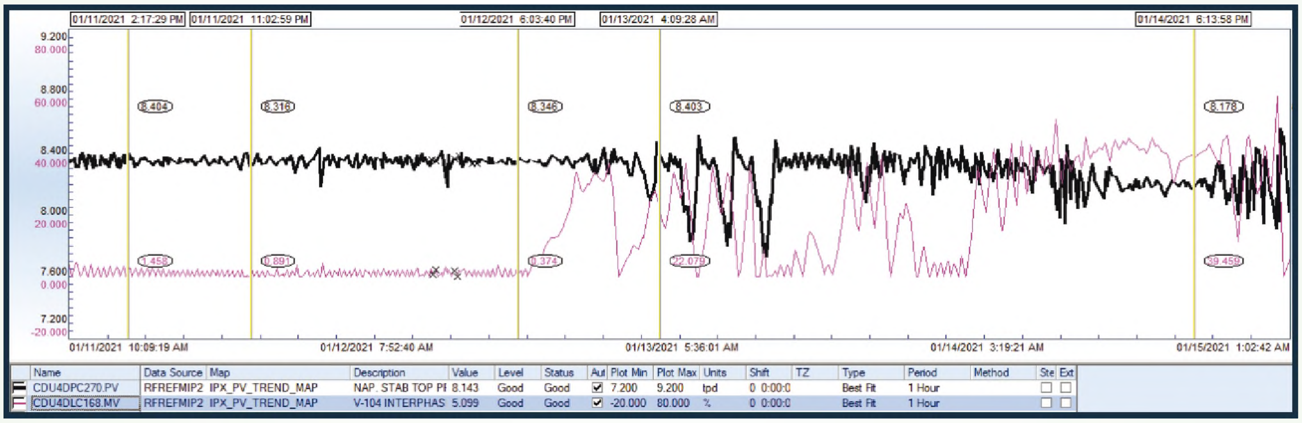
It has been observed that, when feed composition changes it results in high LPG production. It has been observed that, if LPG is more than 500 MTPD in the feed, pressure swing will start. From IP.21, we see the variation of top pressure with LPG production as shown in fig. 2 below.



Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
CDU4DPC270.PV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PI	8.144	Good	Good	☐	5.136	9.000	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DFC191.PV	RFREFMIP2	DAILY AVG	CDU 4 TAGS	552.755	Good	No qualit	☐	217.000	672.400	MPY	0 0:00:0		Best Fit	1 Hour		☐	☐

Fig.2: Top pressure swing with change in LPG production.

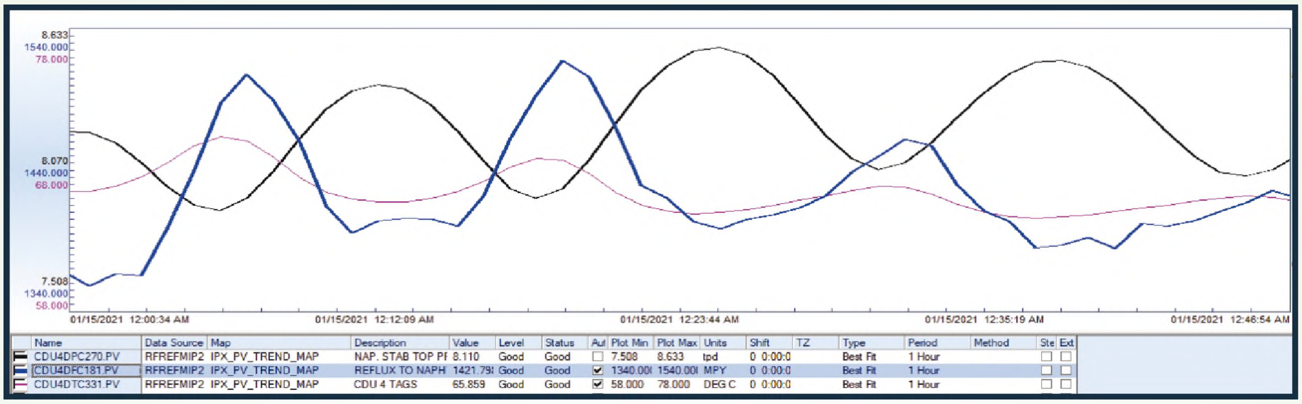
As discussed with operation, water carry over in feed leads to pressure fluctuation as indicated in water boot level in overhead reflux drum. From IP.21, as water level in boot of reflux drum at stabilizer column overhead shows unsteady behavior over a certain period of time and fluctuation in top pressure was observed with it. This water might be coming from the overhead system of crude column. Provision to control the water entering with feed is not yet available. The relation between top pressure and reflux drum boot level is shown by variation in trends in fig. 3.



Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
CDU4DPC270.PV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PI	8.143	Good	Good	☑	7.200	9.200	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DLC168.MV	RFREFMIP2	IPX_PV_TREND_MAP	V-104 INTERPHAS	5.099	Good	Good	☑	-20.000	80.000	%	0 0:00:0		Best Fit	1 Hour		☐	☐

Fig 3: Reflux drum Boot level vs. column top pressure.

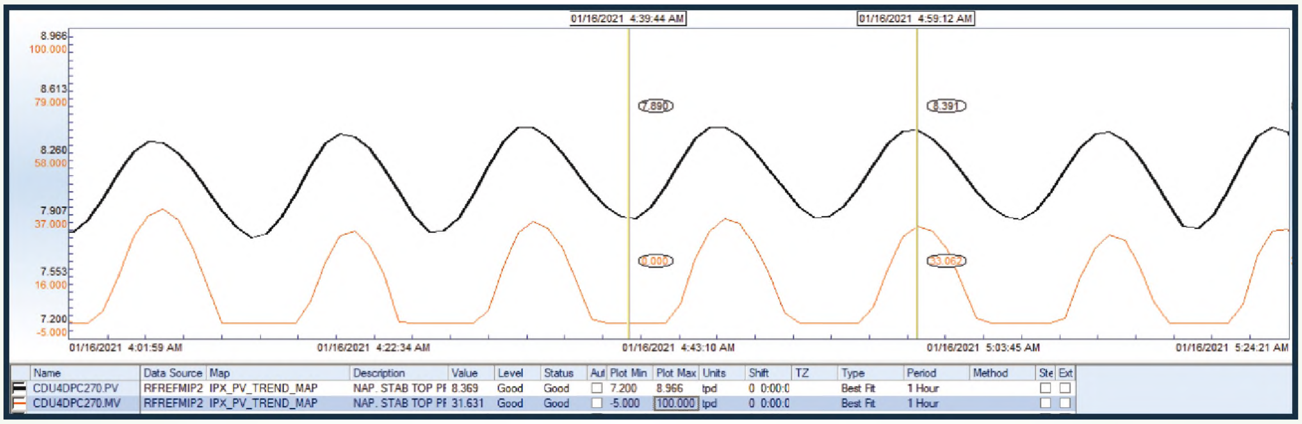
When pressure of stabilizer column decreases because of some aforesaid reason, hot vapor from bottom section comes to top and increases the top temperature. Since top temperature controller is in cascade with the reflux flow controller, it increases the reflux flow. But effect of reflux flow in column pressure is very high. Increase in reflux flow increases the column pressure suddenly which actually suppress the upcoming hot vapor and results in reduction of top temperature suddenly. It starts the reverse cycle of earlier action of pressure, temperature and reflux controllers. This interactive action actually provides resonance in fluctuation.



	Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
▬	CDU4DPC270.PV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PI	8.110	Good	Good	☐	7.508	8.633	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐
▬	CDU4DFC181.PV	RFREFMIP2	IPX_PV_TREND_MAP	REFLUX TO NAPH	1421.79	Good	Good	☑	1340.00	1540.00	MPY	0 0:00:0		Best Fit	1 Hour		☐	☐
▬	CDU4DTC331.PV	RFREFMIP2	IPX_PV_TREND_MAP	CDU 4 TAGS	65.859	Good	Good	☑	58.000	78.000	DEG C	0 0:00:0		Best Fit	1 Hour		☐	☐

Fig. 4: Interactive fluctuation in top pressure, top temperature, reflux flow

Pressure fluctuation problem not only comes only when LPG production is high, another main reason of pressure fluctuation is very low LPG generation which leads to fully closing of pressure controller DP270 (i.e. DPC270.OP = 0). That time efficiency of pressure controller DPC270 reduces significantly because around 50% time of pressure fluctuation cycle, it remains fully closed.



	Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
▬	CDU4DPC270.PV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PI	8.369	Good	Good	☐	7.200	8.966	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐
▬	CDU4DPC270.MV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PI	31.631	Good	Good	☐	-5.000	100.000	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐

Fig 5: Pressure controller output (DPC270.OP) vs Pressure Value (DPC270.PV)

5.2.5 Highlights and findings:

- Liquid and Vapor loading of the Stabilizer column is observed near to 133% loading of BH case during operation of high LPG and Naphtha feed.
- Increasing the loads by 5-10% causes percent jet flood beyond tolerable limit of 85%.
- It is suspected that beyond this operating case load, the top section trays might start to flood resulting into pressure fluctuations.
- It is suspected one of the major contributor for pressure swing is continuous processing of high API crude which may led to flooding in upper trays.

5.2.6 Actions taken:

Frequent tuning of PID controllers (DPC270) has been done to handle the pressure fluctuation issue. But it became a regular work to do the tuning of DPC270 controller to stabilize the fluctuation.

Process tech. have extended stabilizer adequacy study to check frequent stabilizer pressure swing issue, also involved M/s Sulzer tray supplier to study and advice action plan as it is expected to process high API crudes on continuous basis.

Many journals and articles have been studied to find out similar case and it solution.

5.2.7 Introduction of Auto-Tuning of PID controller:

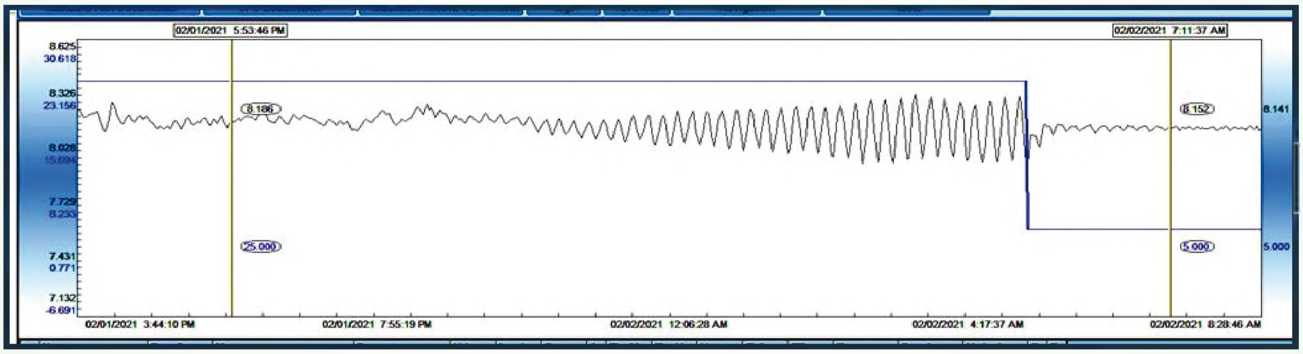
Basically in practical implementation of a PID controller and tuning its control parameter, there is a possibility that due to external disturbances, the process is not tuned to obtain optimum control. Hence auto-tune method serves a masterpiece as it automatically tunes the parameters (which in other case have to be tuned manually and frequently). Many products are available from different vendors for automatically tuning the PID controllers, but they are very expensive. An in-house developed Auto-Tuning of PID controller has been developed and implemented for tuning of DPC270 pressure controller whenever is required. Some logics have been written using APC software to automatically calculate and incorporate the value of proportional gain (P of PID controller) automatically in DCS as per different process conditions and disturbances.

Following are the features of Auto-tuning logics:

- Auto-tuning logics run on every 2 minutes to check for fluctuation in DPC270.
- If fluctuation is more than 0.38 kg/cm2g, tuning happens.
- Once auto-tuning done, it waits for 2 hours for stabilization. During this period no further tuning happens even if fluctuation is more than 0.38 kg/cm2g.
- Auto-tuning makes the DPC270 slow and fast in consecutive cycle to break the cyclic fluctuation effect.
- Automatically tuning never happens if there is no fluctuation of DPC270 (less than 0.38 kg/cm2g).

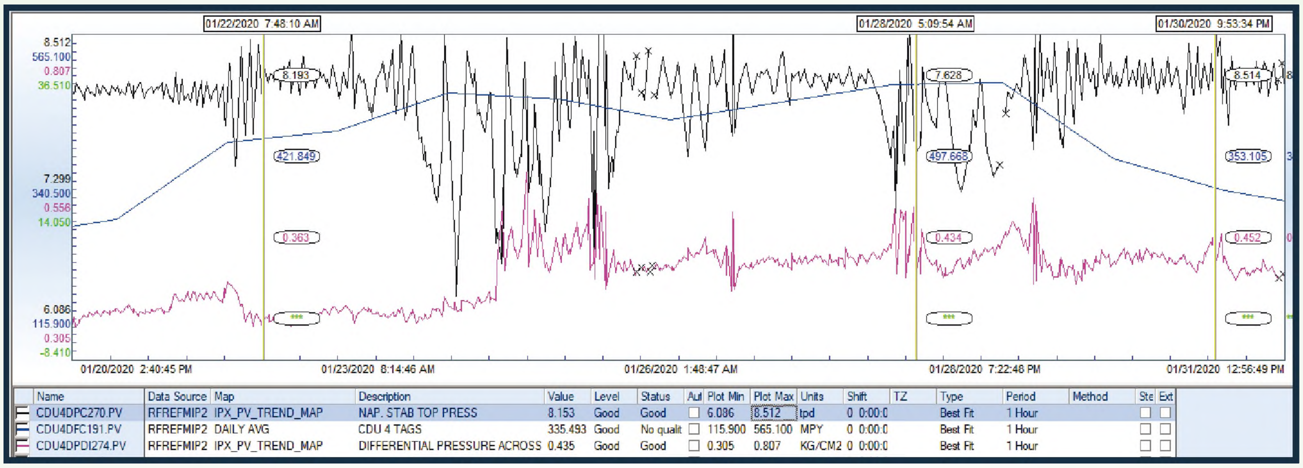
Below are the some cases of process disturbances in before and after the implementation of Auto-Tuning methodology, to understand the benefit of this in-house developed method.

On 2nd Feb'21 night stabilizer pressure fluctuation started and at 5:00 hrs. fluctuation increased to more than allowable limit and Auto-tuning of DPC270 happened (blue line in the trend). The pressure fluctuation stopped immediately.



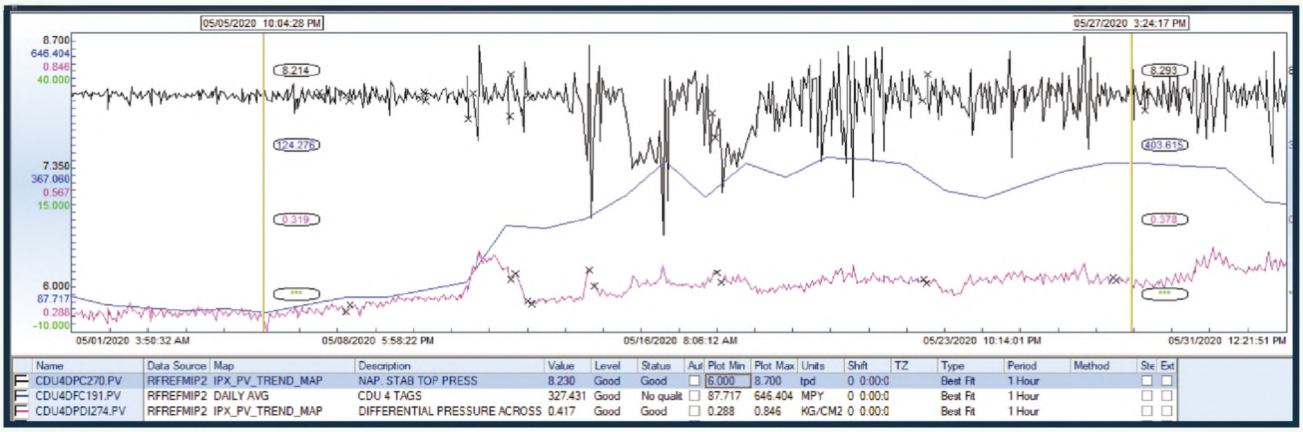
5.2.8 Before implementation of Auto-Tuning:

LPG production was increased on 21st Jan'20 and stabilizer pressure fluctuation was started and continued for more than 8 days.



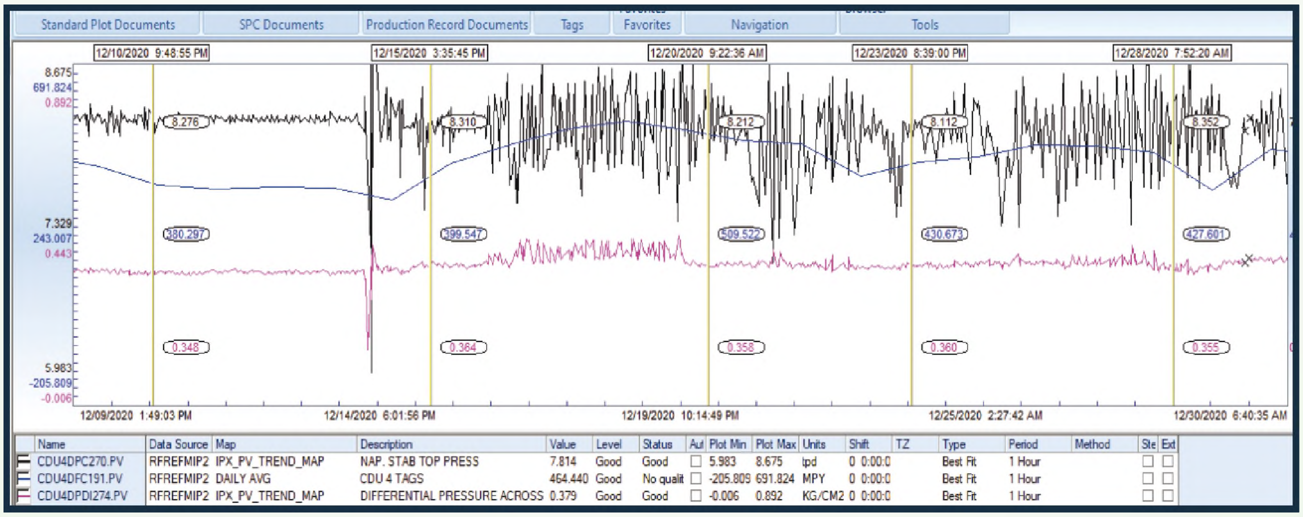
Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
CDU4DPC270.PV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PRESS	8.153	Good	Good	☐	6.086	8.512	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DFC191.PV	RFREFMIP2	DAILY AVG	CDU 4 TAGS	335.493	Good	No qualit	☐	115.900	565.100	MPY	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DPDI274.PV	RFREFMIP2	IPX_PV_TREND_MAP	DIFFERENTIAL PRESSURE ACROSS	0.435	Good	Good	☐	0.305	0.807	KG/CM2	0 0:00:0		Best Fit	1 Hour		☐	☐

LPG production was increased on 10th May'20 and stabilizer pressure fluctuation was started and continued for more than 20 days.



Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
CDU4DPC270.PV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PRESS	8.230	Good	Good	☐	6.000	8.700	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DFC191.PV	RFREFMIP2	DAILY AVG	CDU 4 TAGS	327.431	Good	No qualit	☐	87.717	646.404	MPY	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DPDI274.PV	RFREFMIP2	IPX_PV_TREND_MAP	DIFFERENTIAL PRESSURE ACROSS	0.417	Good	Good	☐	0.288	0.846	KG/CM2	0 0:00:0		Best Fit	1 Hour		☐	☐

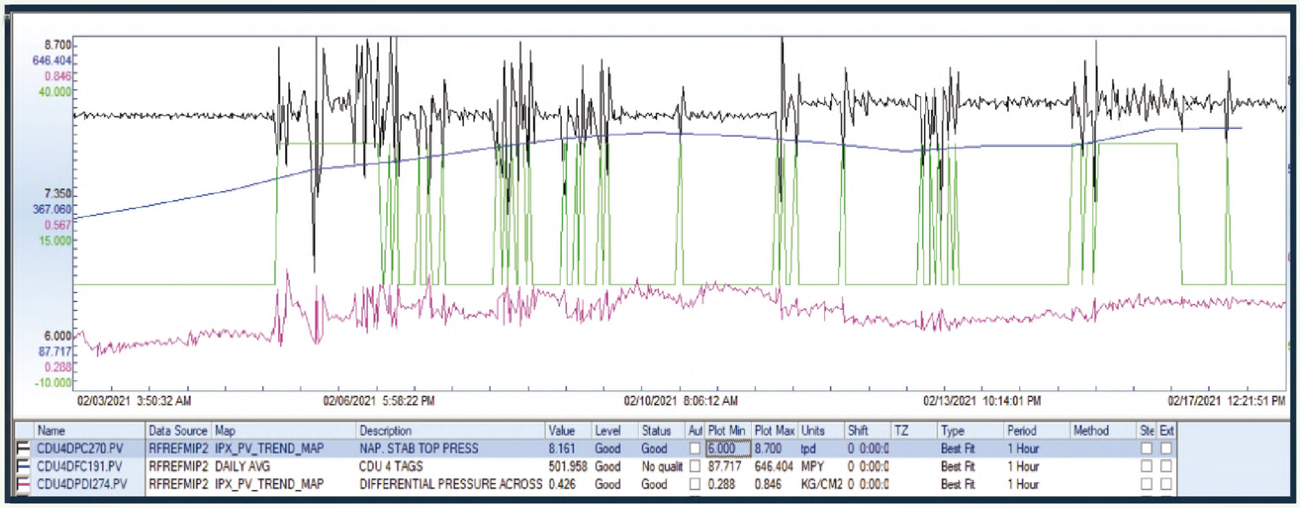
LPG production was increased on 14th Dec'20 and stabilizer pressure fluctuation was started and continued for more than 15 days.



Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
CDU4DPC270.PV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PRESS	7.814	Good	Good	☐	5.983	8.675	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DFC191.PV	RFREFMIP2	DAILY AVG	CDU 4 TAGS	464.440	Good	No qualit	☐	-205.809	691.824	MPY	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DPDI274.PV	RFREFMIP2	IPX_PV_TREND_MAP	DIFFERENTIAL PRESSURE ACROSS	0.379	Good	Good	☐	-0.006	0.892	KG/CM2	0 0:00:0		Best Fit	1 Hour		☐	☐

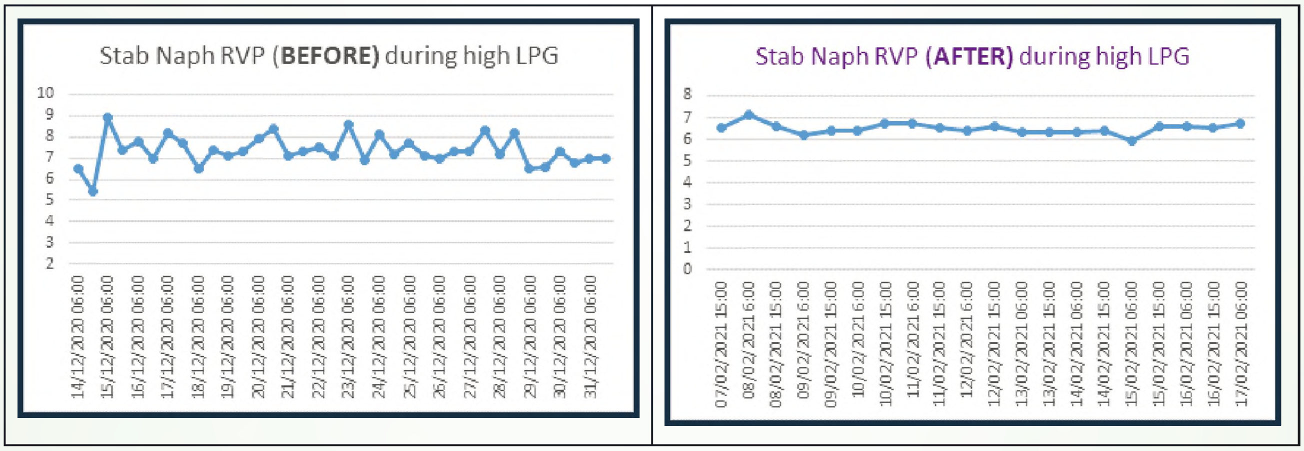
5.2.9 After implementation of Auto-Tuning:

Below trends are for after the implementation of Auto-tuning. LPG production has increased on 4th Feb'20 and subsequently stabilizer pressure fluctuation has started. Green pen is for tuning parameter P. Till today from then, because of high LPG make more than 60 times fluctuation started and auto-tuning happened. Pressure fluctuation has reduced immediately or within few hours. The Magnitude of Max and Average fluctuation are also smaller than earlier.

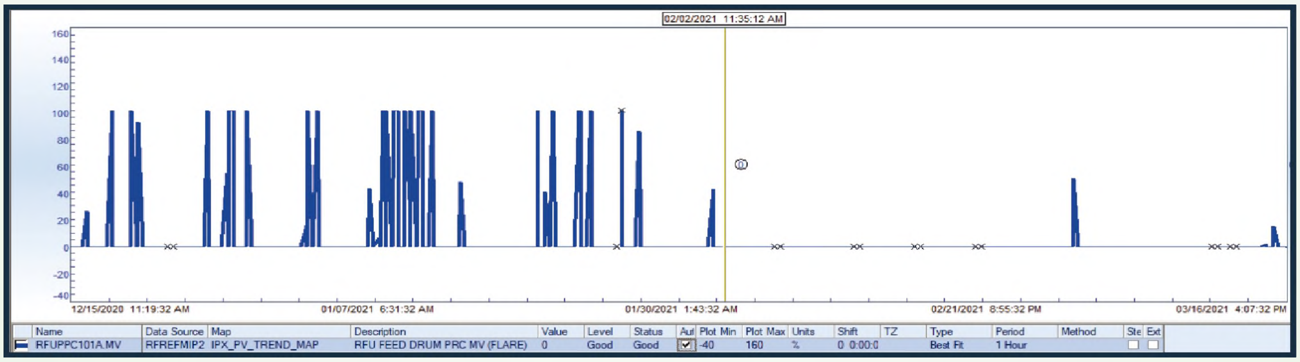


Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
CDU4DPC270.PV	RFREFMIP2	IPX_PV_TREND_MAP	NAP. STAB TOP PRESS	8.161	Good	Good	☐	6.000	8.700	tpd	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DFC191.PV	RFREFMIP2	DAILY AVG	CDU 4 TAGS	501.958	Good	No qualit	☐	87.717	646.404	MPY	0 0:00:0		Best Fit	1 Hour		☐	☐
CDU4DPDI274.PV	RFREFMIP2	IPX_PV_TREND_MAP	DIFFERENTIAL PRESSURE ACROSS	0.426	Good	Good	☐	0.288	0.846	KG/CM2	0 0:00:0		Best Fit	1 Hour		☐	☐

Effects on products (Stabilization of Naphtha RVP):



Since lighter carryover in product naphtha due to pressure fluctuation has reduced, Flaring from RFU FSD has reduced significantly.



Name	Data Source	Map	Description	Value	Level	Status	Aut	Plot Min	Plot Max	Units	Shift	TZ	Type	Period	Method	Ste	Ext
RFUPPC101A.MV	RFREFMIP2	IPX_PV_TREND_MAP	RFU FEED DRUM PRC MV (FLARE)	0	Good	Good	☑	-40	160	%	0 0:00:0		Best Fit	1 Hour		☐	☐

5.3.0 Conclusion

A description and case study of an unstable process has been provided in this paper. The procedure and thought behind the in-house developed method to make the system stable by taking continuous actions automatically, also has been summarized in the theoretical part of this paper. On experiment basis this method was implemented for CDU stabilizer column. But in any refinery, this type of many unstable process are available. The process becomes unstable may be because of bad performance of control system or may be the because of continuous changing requirement of behavior/speed of control system to reject the disturbances. The only option to stabilize these systems is frequent adjustment of controller speed to synchronize it with process requirement. Software which are available for automatically tuning the PID controllers are expensive. An in-house developed Auto-Tuning of PID controller has been developed and implemented in BPCL refinery for tuning these type of controllers automatically whenever is required. The practical application and benefits achieved from this work has been explained in this paper

◆

5.3 Averting Unplanned Shutdowns during Utility pipeline ruptures- Line Stop technique application at Refinery–Experience at MRPL

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Mr. Sudesh Kamath is working as General Manager (Process Engineering)

Mr. Sudheer Pai M is working as Chief General Manager (Process Engineering)

5.3.1 Introduction:

To stay competitive and thrive in today's uncertain and volatile energy market that is characterized by major shifts in supply and demand dynamics, refiners must find ways to increase operational efficiencies, maximize productivity and produce refined products at lower costs. A major consideration for boosting a refinery's profitability and improving operational safety is to keep operating units running and available for service. Further any unplanned shutdowns are not desirable as such interruptions can have a profound impact on the company production planning activities as well as integrity of equipment's which undergo mechanical shock. Vigilance in operating rigor, quickly determining or even predicting negative impacts, and being able to efficiently correct deviations from the operating process plan are keys to maintaining high equipment reliability. Wisely investing in monitoring tools, training, catalyst and chemical treatment programs is a proven strategy for consistent top performance.

Utility supply systems in a refinery are the lifelines for units to operate. Any interruptions in utilities such as steam, cooling water, boiler feed water or DM water can have potential to bring the unit down causing serious production losses. During Pandemic, there has been shutdown of several units due to lack of demand of products and in case systems are not preserved adequately during such time, can also lead to failures. Among all utilities, circulating cooling water system is highly prone for corrosion and failures. In a modern refinery, where treated effluent to recycled back to cooling towers, there can be often leakages and even failures of the pipeline. Keeping pipelines at their best operating condition is every refiner's objective, however, it's not as easy as it sounds due to various constraints

Mangalore Refinery and Petrochemicals Ltd., operates a 2.20 MMTPA Petro-FCC unit (PFCC), produces propylene which is feedstock for valuable Poly-Propylene product. Any interruptions can seriously hamper the profitability of the company. The scenarios can be severe, as the refining industry wakes up on setting of Pandemic with increased product demand. It was observed that there was a rupture of cooling water pipeline supplying to a critical exchanger in the PFCC Unit. Line stop/Flow stop technique method is method of plugging which is used to isolate system components for repair or replacement and provides a shut-off option for pressurized pipes and vessels. And this is normally planned on long distance transfer pipe lines with well in advanced plans and executed accordingly. However, this paper shall discuss the experience of using this technique for emergency scenario of arresting Cooling water leak online within short duration of time and avoiding the unplanned shutdown of Propylene fluid catalytic cracker at Mangalore refinery &Petrochemicals limited. This paper shall definitely help and guide other Indian refineries also to venture and check into the feasibility of opting this method during emergency leak scenarios especially in the main header utility lines which if unattended could lead to specific unit or complex shutdowns.

5.3.2 Experience of Cooling water leak at Propylene Fluid catalytic cracker unit at MRPL

PFCC unit at MRPL is a major margin driver for the refinery as it produces valuable products such as Propylene, LPG and Motor Spirit. Therefore, any production interruptions to PFCC can result in a significant impact on refinery profitability. It was observed, the cooling water return header line of the Propylene Recovery Unit (PRU) within the PFCC unit sheared while leak attending was attempted. The cooling water return header operates at 4 kg/cm^2 pressure, and due to higher spray of cooling water, the approach towards the leak for arresting was not possible. The entire area was flooded with water making it unsafe to do any repair work. Due to leakage from the header, the water makeup in the cooling tower increased by around 400 m^3/hr. considering the criticality of the situation, an emergency meeting and a brainstorming discussion was carried out to avoid the shutdown of the Plant.

Among the various options "Line Stop/Flow Stop" technique was chosen and execution process was started for the same. Line plugging is used to isolate system components for repair or replacement and provides a shut-off option for pressurized pipes and vessels. The plugging of a pipeline is accomplished by first performing a hot tap and then using a special plugging machine. By inserting a line-plugging head into the line flow and using a special sealing element attached to the plugging head, the flow is stopped.

Fig 1: Representative schematic of "Line stop" Operation

Line pressure was optimized by taking additional cells in the cooling tower. Further all necessary measures were in place to ensure a large amount of water leak would not overload ETP. The vendors were quickly approached the line tapping & plugging vendors and arranged the related requirements on an emergency basis. The site was prepared with necessary scaffoldings, tools and tackles for carrying out the hot tapping, followed by a line stop. Pre-mobilization and post-mobilization (i.e. all Hot Tap and line stop Equipment along with its related accessories were tested prior to mobilization at work base and on site prior to commencing operations) checks & function tests were carried out to ensure that the equipment supplied is suitable for the work scope. Equipment were calibrated and fully certified before the usage at site. The entire process was carried out safely with all required PPE's usage and all priority given to work site safety and procedures. During the procedure the surrounding area around off point access was restricted by use of barricade.

On a brief procedure following points were followed for attending the leak

1. Welding of 8" Line stop fitting and ancillary fittings: 8" Line stop tees were welded on the main 8 inch line.(one on the upstream and other downstream) Along with these 2" fittings were provided for pressure equalization and Product draining.
2. Installation of sandwich valve: 8" Sandwich valves were fitted on 8" line stop fittings which serves the purpose as a control valve throughout the operation and 2" Ball Valve were fitted on the pressure equalization fittings and on drain fittings and the valves were made sure for 100% open
3. Hot tapping operation: Hot Tapping Operation was done on all Line stop points, pressure equalization points & drain points
4. Installation of line stop assembly: pre-fabricated 8" bypass line was fitted on to the line stop housing to divert the flow & One line stop assembly which consists of line stop head with 8" sealing element, actuating hydraulic cylinder and the line stop housing was fitted on 8" sandwich valve on each side.
5. Line stop operation: After ensuring leak proof joint in all flange connections, the pressure in 8" stopple housing was equalized with the pressure in header pipeline and After confirming the pressure equalization on top and bottom side of the 8" sandwich valve, it was then opened at both upstream and downstream side and 8" line stop head was inserted by actuating the line stop cylinder on both the side. After both the upstream and downstream line stop heads were in place, product from the isolated section was drained from Drain Point.
6. Line modification work: After the draining was complete and 100% stopple seal ensuring, Water was purged into the isolated section using the vent plug opening from 2" TOR fitting. And the line modification works were completed.
7. Line stop equipment retrieval: After the completion of line modification works, the line was recommissioned by using 2" pressure equalization connection and both Line Stop heads on upstream and downstream location was retrieved and 8" Sandwich valve was closed followed by depressurize the product from the Line Stop assembly and retrieving line stop assembly.

PROFILE CHECK OF 8 INCH STOPPLE TEE

PROFILE CHECK OF 4 INCH PAD GAS BAG FITTING

DIMENSION CHECK

DIMENSION CHECK

The above jobs were swiftly & continuously carried out with clock-work precision and the heavy cooling water leak on the return was arrested within short duration and the system was restored . The entire process was successfully done without shutting down the Propylene fluid catalytic cracker which was very critical for the refinery operations.

Figure 3: Before Leak Arresting

Figure 4: After Leak Arresting with Line

5.3.3 Conclusion and Future uses:

Keeping pipelines at their best operating condition is always the refiner's objective, however, it's not as easy as it sounds due to various constraints within the complex refineries where all the units & utility sections are also interrelated. Line stop/Flow stop is safe and cost-effective approach for such utility leaks and can be important part of the overall "pipeline intervention system" for keeping a refinery processing system up and running sustained operations. Line stop technique has been predominantly used/applied in the long-distance transfer lines with thoroughly planned executions and very rarely during emergency short duration scenarios.

Mangalore refinery and petrochemicals limited has successfully demonstrated that Line stop/flow stop method can be effectively executed within short duration for emergency scenarios of attending heavy utility cooling water line leaks and avoid unplanned shutdown of critical units.

Reference

1. *"Plant-Tech project method statements": Courtesy: Plant tech Industrial services. Mangalore. (https://www.youtube.com/watch?v=5uj5Ky9YhA0- Plant Tech power)*

Note

Note

सत्यमेव जयते

पेट्रोलियम एवं प्राकृतिक गैस मंत्रालय

Ministry of Petroleum and Natural Gas

Government of India