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The Oil and Gas value chain: a focus on oil refining

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INDEX

SCOPE OF THIS DOCUMENT

This document reviews the current state of the industry and the common practices used throughout the value chain, with particular focus on downstream.

Chapter 1 describes the current practices along the entire value chain, from exploration and appraisal to field development, production and abandonment. Follows the different types of trading and how vast quantities of oil are being transported and stored around the globe, nowadays, concluding with the downstream topic briefly explored.

Chapter 2 focuses on the common refining processes and the complexity of their facilities. It also analyzes the fine balance that refineries aim to achieve between the production of the desired product mix, the access to different types of crude oil and the capital availability. It approaches the objectives and priorities for players in this industry, diving on how refineries may identify growth potential and maintain profitability by protecting margins.

1. THE OIL AND GAS VALUE CHAIN

The O&G value chain represents the sequence of activities that occur from the supply sources to trading mechanisms, by which oil, oil products, and gas, are sold in the wholesale markets. This process includes upstream (exploration and production), midstream (transportation and storage) and downstream (refining and retail markets).

The representation of the value chain serves as a way of expressing the increase in commercial value that is created as crude is sold, at wholesale prices, from upstream production, transported and stored (midstream), processed or refined downstream, into petroleum products, and eventually sold at retail prices.

The upstream sector, also known as "exploration and production (E&P)", includes searching for potential O&G reservoirs, drilling exploratory wells, and developing facilities around those wells that produce commercial quantities of hydrocarbons. The upstream sector is the most high-risk segment of the O&G industry.

The midstream sector typically involves transporting and storing hydrocarbons, it consists of transport via pipelines, maritime, rail and road transportation, depending on the product.

The downstream sector involves crude oil refining to oil products (to final user or petrochemicals feedstock) and its marketing. It also includes the selling and distribution of processed natural gas and the products derived from petroleum crude oil, such as, among others, liquefied petroleum gas, gasoline, jet fuel, diesel oil, other fuel oils, petroleum asphalt and petroleum coke.

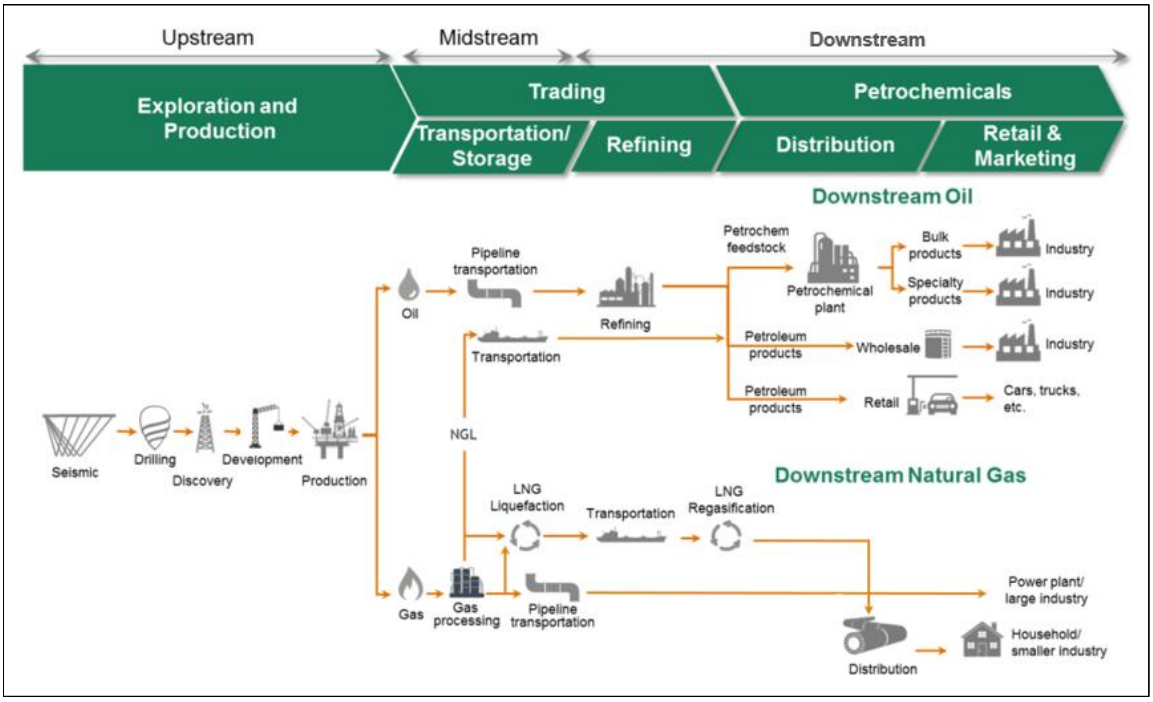
A general scheme of the Oil & Gas value chain activities is described in Exhibit 1.

1.1. Exploration and production

In a nutshell, the upstream sector is the phase in the value chain where O&G is discovered, developed and produced, so that it can be sold in the wholesale market. It represents the source of O&G supply and activities of the value chain that are shown in Exhibit 2.

This sector is technologically advanced, and one of the most complex of the up, mid and downstream sectors. It also involves high-risk economic activities, and likewise, the reward potential is generally the largest of all.

Exhibit 1. O&G value chain activities

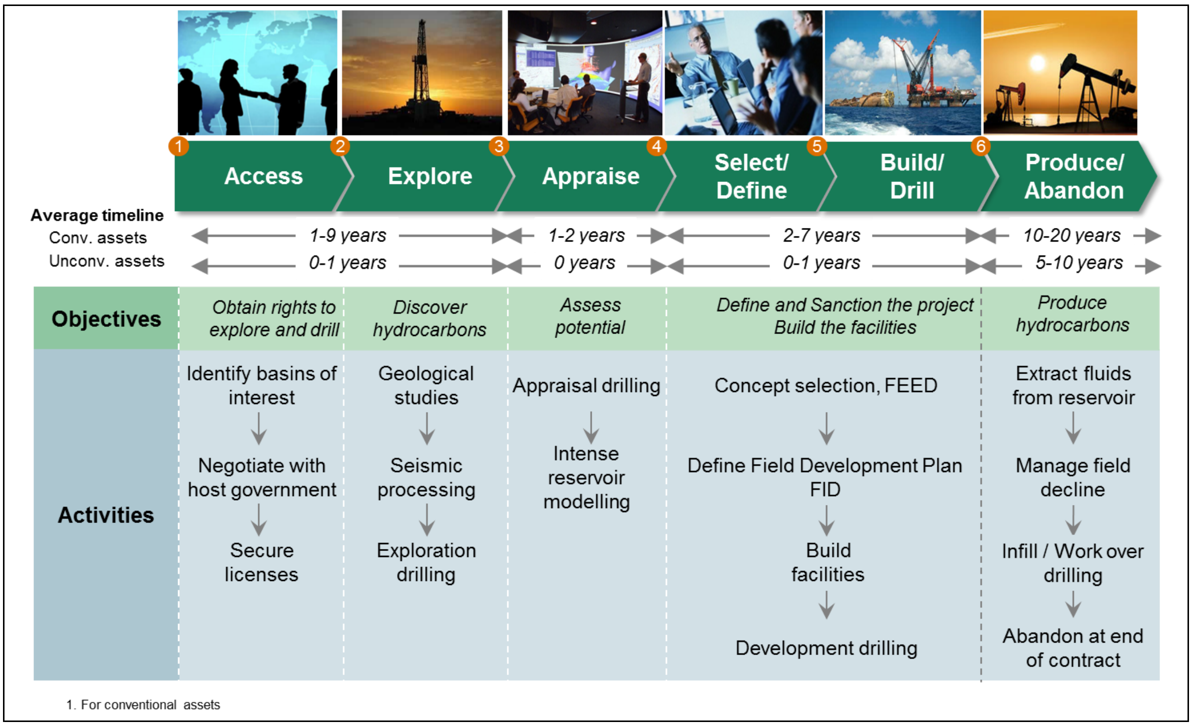


Source: BCG experience.

Upstream sector profit margins are impacted substantially by outside forces, such as political instability, international conflicts and agreements on supply control by production countries. However, some observers believe that, in the near future, volatility might decrease somewhat, as operators are more flexible today, betting for short-term cycle investments rather than mega-projects, which results in reduced lead times between discovery and the first year of production.

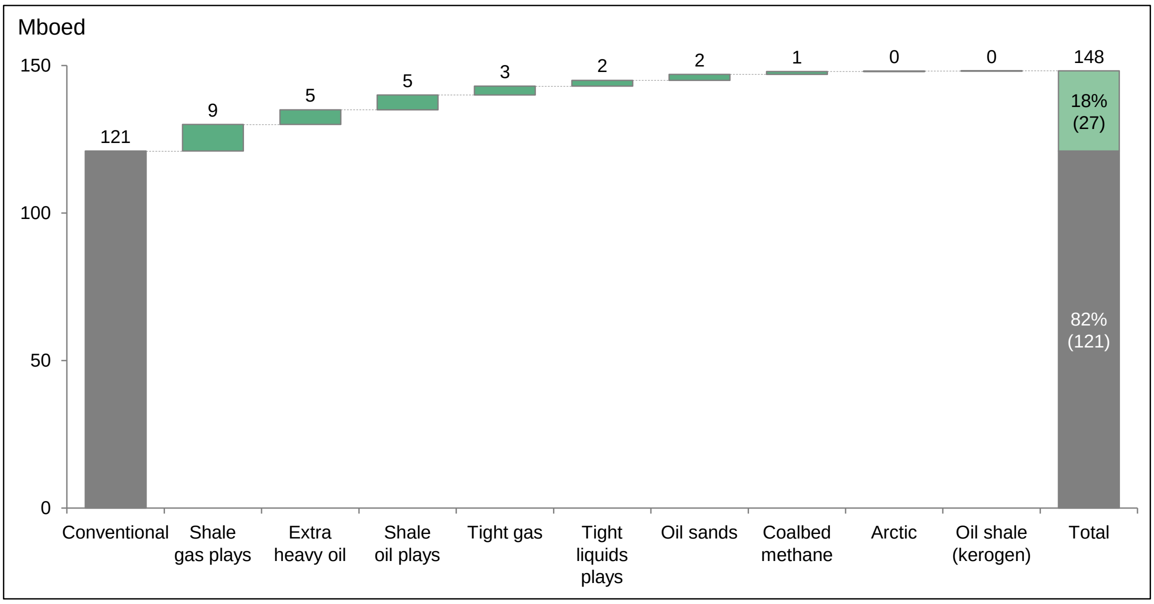
While in the past, lead times might be up to 10 years for big projects, nowadays tight US resources take a year at most, and the most complex existing play extensions take up to three years. This means that an increasing share of supply reacts more quickly to price signals. One additional factor that explains why the unconventional revolution may play an important role in this new dynamic, is that decline rates for these wells are steeper than for conventional fields. Exhibit 3 shows that, in 2016, unconventional global daily O&G production was close to 20%.

Exhibit 2. Exploration and production value chain



Note: FEED – Front End Engineering Design, FID – Final Investment Decision.
Source: BCG Experience.

Exhibit 3. Conventional vs. Unconventional global O&G daily production (2016)



Source: Rystad Energy.

The investment cycle of a conventional field typically ranges from around 15 to 40 years, from the moment when the operator starts obtaining the rights to explore and drill, until the decommissioning of the asset takes place (see Exhibit 2).

The development of a field is a high-cost venture, in particular in offshore areas, and the uncertainties are particularly high during exploration and appraisal. A typical capital investment for a medium-sized offshore oilfield (i.e. 100 Mbbl reserves) would be in the order of US$1 billion.

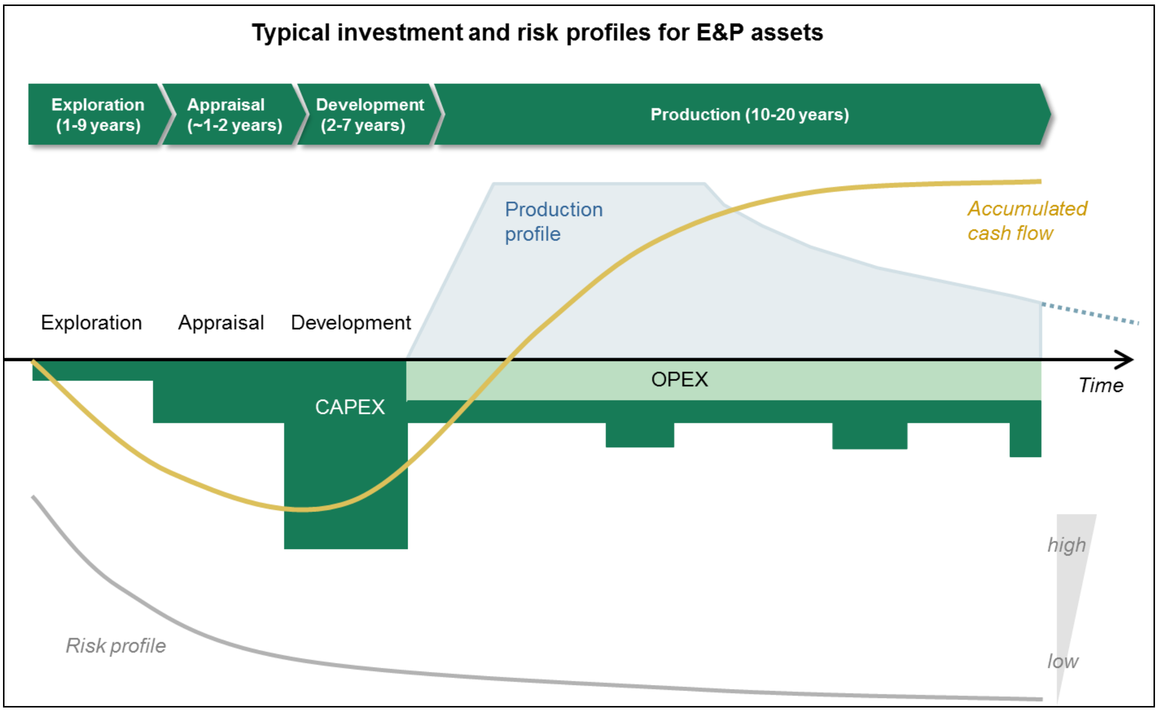
There are a few cost categories that are worth mentioning, with a typical investment profile being represented in Exhibit 4 and consist of the following:

a) *Finding costs,* comprising exploration and appraisal capital expenditure (CAPEX), are required to run geological and seismic studies, and to drill an exploration well to the target formation. They are also required to delineate and test the reservoir, ahead of making the development decision.

b) *CAPEX development* covers the costs of developing the field, including drilling the exploration and development wells and constructing the surface facilities and pipelines necessary to bring the field on-stream.

c) *Production costs* are the annual fixed and variable costs required to manage and produce the field during a given year of production. While most costs can be considered operating expenditure (OPEX), producing fields are also subject to brownfield expenditures, which are considered to be CAPEX.

Exhibit 4.Typical investment and risk profiles for conventional E&P assets



Source: BCG experience.

1.1.1. Access

Before an O&G company can start exploring in an area, it must negotiate an agreement with the owner of the mineral rights. Individuals own mineral rights in certain parts of the US, Canada and the UK, but in most onshore and offshore locations, these rights are owned by a national or state government, and so the negotiations are between the company and generally a designated government agency.

There are four main types of agreements between the exploration companies, also referred to below as the contractor and the owner of the mineral rights, which can be clustered under licenses and contracts (see Exhibit 5).

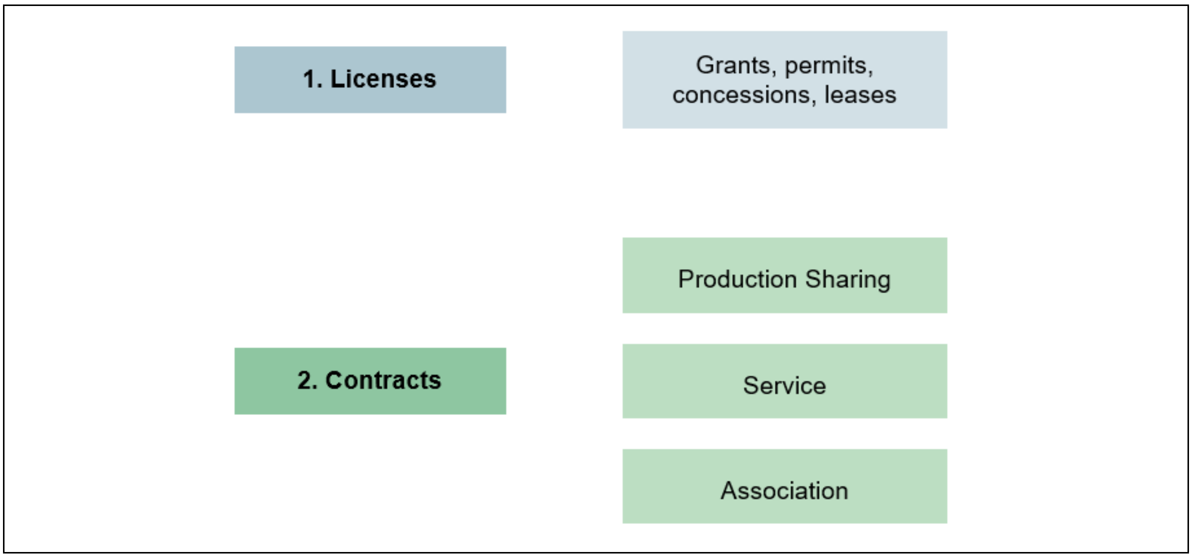
- Under a *license system*, the contractor receives all production, and then pays royalties and taxes to the government. Royalty payments are made from first oil, and thus secure early government revenues. Under these agreements, the contractor assumes all the risks and costs of finding, developing and production.

- *Production sharing agreements* (PSA) involve an O&G company bearing the exploration and production costs, and trying to recoup these costs over a fixed period of time, while owning an additional share of "profit oil". The typical time period ranges from 5 to 30 years, before the ownership of the entire venture transfers back to the mineral rights owner. Once investment costs have been recovered, production sharing agreements split production between the government and the oil company. In essence, a PSA is a concession arrangement between the state and the contractor, which emerged after criticism in some producing countries for the concession contracts in place back in the '60s.

- *Service contracts* provide a host government the greatest control over their resources, as they only assign work to a contracting firm. In order to do this, they must have both the technological know-how and the financial capacity. Within the category of service contracts, there are three specific types: technical assistance contracts, pure service contracts (PSC) and risk service contracts (RSC). During both a technical assistance contract and PSC, the service provider does not bear any risk of failure to deliver, however it is not so for third-party damage. Technical assistance contracts tend to have a very lean scope, and as such, the reward is a fixed price, with the potential resulting oil being of no interest. On the other hand, PSCs can have a much broader scope, and negotiations may be paid in either cash or oil. The third type of contract, RSC, as the name suggests, places the risk upon the service provider. Failure to deliver exploitable reserves implies lost funds to the service company, while successful discovery means compensation and the possibility of an equity option. Given that the contractor is often merely paid a fee, this type of contract category is not of so much interest to many oil companies, thus leaving space for "Service companies."

- An *association contract* creates an oil company or *joint venture*, which then typically operates under a tax and royalty regime, meaning a license.

Exhibit 5. Main E&P upstream contracts



Source: BCG experience.

1.1.2. Exploration

Once an E&P agreement is in place, the company's exploration team begins gathering the subsurface data that it will use to select locations for drilling one or more exploration, or "wildcat," wells.

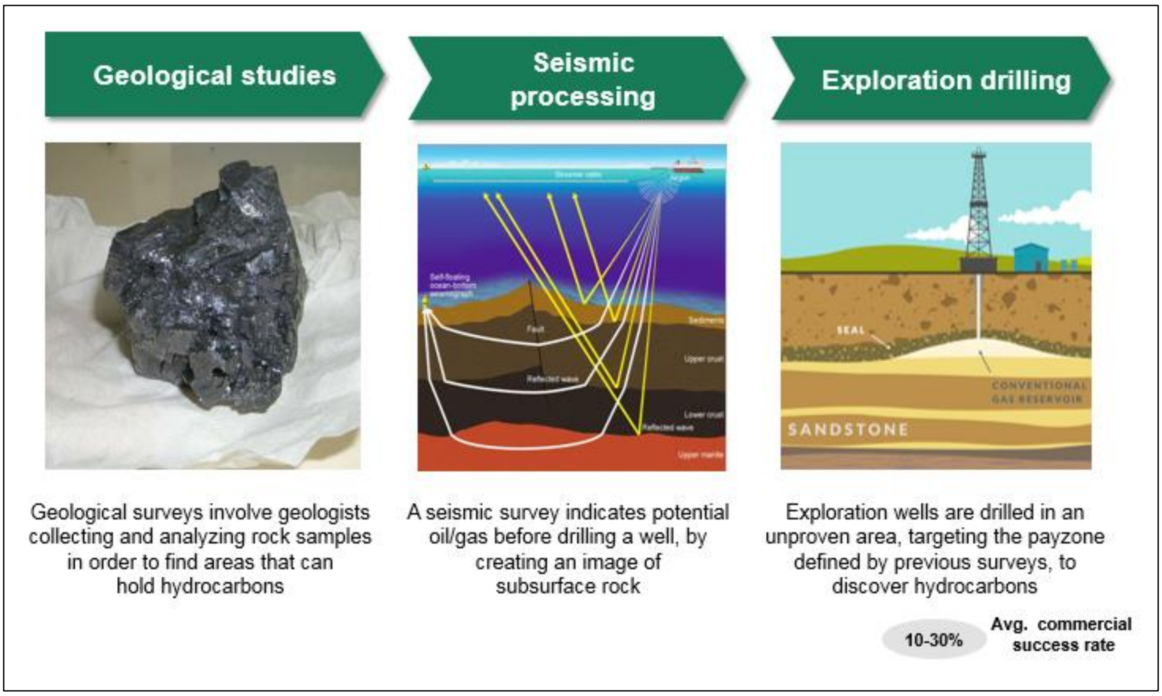
The main techniques used under exploration are briefly described below, and shown in Exhibit 6.

Geological surveys involve geologists collecting and analyzing rock samples, in order to find areas that may hold hydrocarbons. The sequence of rock layers in the basin is established to identify potential source rocks, reservoir rocks and seals.

A *seismic survey* indicates the potential of O&G before drilling a well, by creating an image of subsurface rock. The seismic method uses sound energy that is directed into the earth. The energy travels down through the subsurface rocks, and is reflected back by subsurface rock layers. Seismic surveys offer either a 2D or a 3D view, or even more recently, a 4D view or time-lapse seismic images.

Once geological and seismic surveys determine a pay zone in the subsurface, *exploration wells* are drilled, and if successful, discover hydrocarbons to be developed in commercial quantities.

Exhibit 6. Main activities under the exploration phase



Source: BCG experience.

1.1.3. Appraisal

After an exploration well has found hydrocarbons, considerable effort will still be required to accurately assess the potential of the discovery, and the role of appraisal is to provide cost-effective information.

During appraisal, more wells are usually drilled to collect information and samples from the reservoir, and another seismic survey might also be acquired, in order to better delineate the reservoir.

This phase of the E&P process aims to reduce the range of uncertainty in the volumes of hydrocarbons in place, define the size and configuration of the reservoir, and collect data for the prediction of the performance of the reservoir during the forecasted production life.

1.1.4. Field development

Once a promising discovery is made, teams of specialists prepare a development plan that integrates the field production schedule with market needs.

A *technical team* analyzes the subsurface reservoir in detail, and prepares several development options, together with their environmental impact, by selecting the number and location of development wells, and specifying the surface facilities required to process the oil production and export, project development plan, risk assessment and overall budget.

A *marketing team* may draw up a Letter of Intent and/or the long-term sale of the produced hydrocarbons, especially for natural gas, which is not yet an international commodity traded in a way that is similar to oil.

Financial analysts incorporate the technical and marketing teams' work into financial models, and prepare a detailed report of the project economics for each proposed development option. They include the fiscal terms of the Upstream Petroleum Agreement, so as to allocate the future cash flow to both the mineral owner and the contractor or the joint venture.

Ultimately, through an iterative process, the technical, marketing and financial specialists decide on an optimal development plan, and recommend it for the Final Investment Decision and for funding.

1.1.5. Production phase and abandonment

A newly-developed field's O&G production often builds up to a sustained plateau, which may continue for many years, before declining to a level where it is no longer economical. This is particularly true in the case of non-conventional fields, such as shale/tight plays, where steeper decline rates are present.

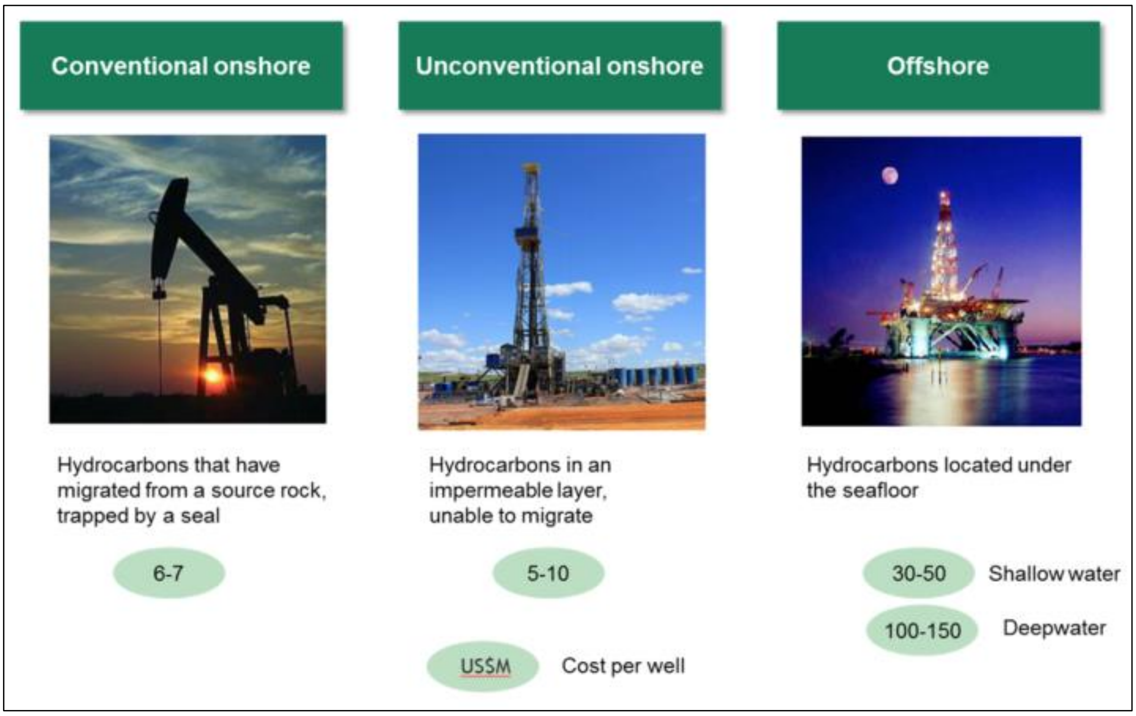
During the production time, engineering, operating and maintenance personnel design, construct, manage and maintain the production wells and surface facilities applying best practices to maximize hydrocarbon recovery, while complying with the safety standards and environmental constrains, to reach the expected production objectives.

Meanwhile, marketing personnel manage the sale of produced hydrocarbons, and financial personnel report fiscal results and distribute payments to the host government and project participants, in accordance with the contractual agreements in place.

Not all hydrocarbons that are identified as being present ("in-place") in a field can be economically recovered with current technology. Typical recovery factors for oil reservoirs may range from around 15-50%. Recovery factors for gas fields are usually higher, on the order of 60- 85%.

As for types of upstream assets, we can differentiate broadly three types of O&G developments, according to the importance in the global supply curve today (see Exhibit 7): a) *conventional onshore fields*, with a share of 53% in global production, b*) unconventional onshore fields*, including shale oil and shale gas, with a production share of 50% in the US, and a share of 18% globally, and c) *offshore developments*, accounting for 29% of production.

Exhibit 7. Primary upstream asset classes and indicative costs per well



Source: BCG experience.

Unlike conventional resources, which reside in highly porous and permeable reservoirs where the oil can flow through, and can be easily tapped by standard vertical wells, shale resources remain trapped in their original source rock, the organic-rich shale that formed from the sedimentary deposition of mud, silt, clay, and organic matter on the floors of shallow seas. A comparison between conventional and shale developments is given in Exhibit 8.

Shale oil and shale gas are the fastest growing resource in the United States, as a result of two important developments: advances in *horizontal drilling* technology that allow a single well to pass through larger volumes of a shale reservoir, and thus produce more hydrocarbons, and of *hydraulic fracturing* technology (also known as hydrofracking, or simply fracking) provides improved access to shale oil and gas deposits. Hydraulic fracturing process requires injecting large volumes of water, mixed with sand and fluid chemicals, into the well at high pressure, in order to fracture the rock to increase its permeability and facilitate production rate[1]. Both technologies can also be used in conventional fields, in particular in those with low permeability.

Offshore developments are technologically the most complex, in particular when operations take place in deep or ultra-deep waters (500-3,500 meters in water

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[1] For more information, read Alvarez et al (2016).

depth), and the correspondingly offshore platforms can cost as much as US$1,000 Million to bring them online.

At the end of the production life, when production is not economical anymore, the field will be decommissioned and abandoned, and the site restored to safe condition, to eliminate potential risk of environmental contamination. O&G wells that are no longer economically viable, or are not in use because of wellbore issues, must be plugged in order to prevent O&G fluids to migrate uphole and contaminate other formations or fresh water aquifers. Wells are plugged by placing mechanical and cement plugs in the wellbore, to prevent any fluid flow.

Exhibit 8. Conventional vs. shale comparison

Main difference between Conventional gas and Shale Gas

		Conventional	Shale
Geological factors	Hydrocarbon migration and trapping mechanism	**Yes, required**: migration from source rock towards reservoir rock where they are trapped	**Not required**: the hydrocarbons are in the source rock and do not require trapping mechanism
Geological factors	Target zone for drilling	**Reservoir rock**	**Source rock**
Geological factors	Porosity (%) Volume within a rock which can contain fluids	North Sea Fields: **20 to 25%**	Low porosity: **4 to 15%**
Geological factors	Permeability (darcy – D) Ability of fluids to pass through a rock	Expressed in Mili-Darcy (10^{-3})	**Ultra low permeability**: expressed in Nano-Darcy (10^{-9})
Operational and commercial factors	Requires stimulation (Hydraulic fracking) to be commercial	**Only in some cases**, <20% of the conventional wells are fracked	**Yes always**, ~100% of the Shale wells have to be fracked
Operational and commercial factors	Typical well production profile	**Plateau** Stabilizes at a plateau for a few years Steady decline afterwards	**Immediate decline** Peak production in first 3 months Sharp decline afterwards
Operational and commercial factors	Number of new wells required to maintain production level	**Low** Typical well lifetime ~ several decades Typical reserves of 50 - 300 Bcf/well and 0.1-2 Mbbl/well	**Very high** – 'Factory drilling' concept Typical well lifetime ~several years Typical cumul. production of 0.5 Bcf/well and 150 Kbbl/well
Operational and commercial factors	Ability to plan Field Development ahead	**Yes**	**No** - You learn and adjust as you drill

Source: BCG experience.

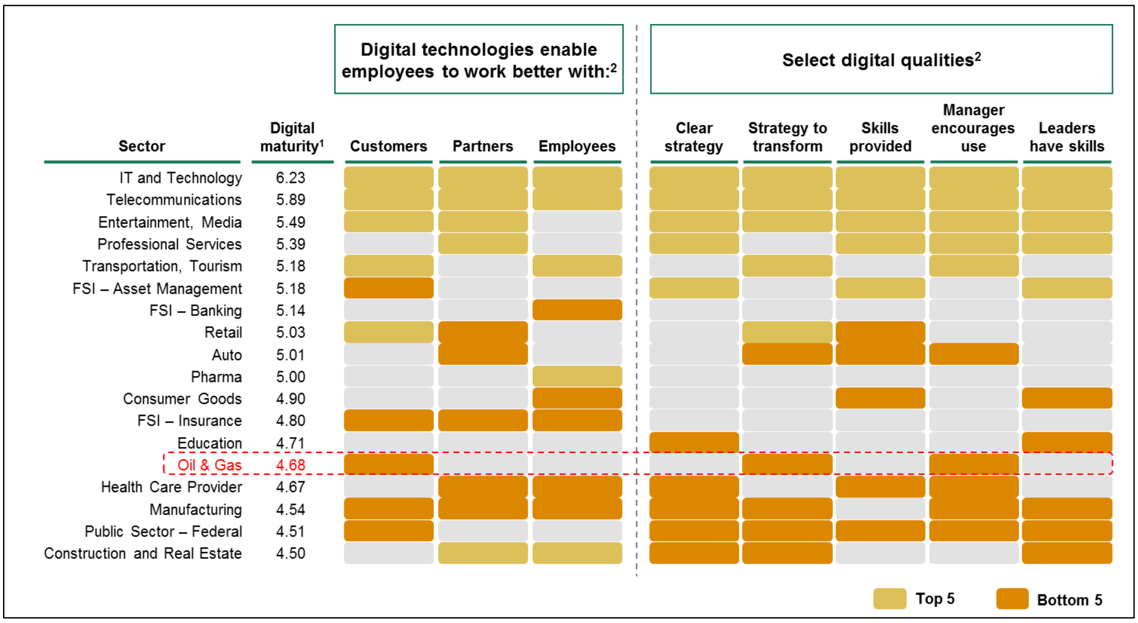
1.1.6. Digital oilfield

The digital oilfield refers to the modernization of the E&P by applying upcoming digital technologies. The adoption of digital technologies is increasingly popular among operators. However, this new space has also been infiltrated by oilfield services companies and technology providers, which on many occasions, collaborate with operators for specific digital initiatives. Nonetheless, as depicted in Exhibit 9, O&G companies are in some cases still lagging behind their peers, in industries such as utilities and automotive, in the adoption of the new digital trend.

It is true that the E&P sector has been somewhat slow in the integration of digital solutions into business operations. However, the low-price environment has pushed the sector to seek cost-cutting and efficiency gains, to remain competitive. Digital has now become a key area of opportunity, as companies realize the untapped potential. Exhibit 10 displays several digital applications along the E&P value chain, as well as their impact.

Traditionally, E&P has leveraged technology in analytics, monitoring, and remote operations, but it lags behind in exploring the potential of recently-developed digital technologies. The new wave of technology in E&P focuses on several main themes: big data & analytics, data handling, industrial internet (IoT), machine learning and artificial intelligence (AI), mobile solutions, virtual reality (VR), advanced robotics, and cybersecurity.

Exhibit 9. O&G companies lagging in the digital trend



1. Digital maturity is calculated as the average maturity of responses from a given sector. Respondents were asked to rate their organization's digital maturity on a 10-point scale of 1 being the least mature and 10 being the most mature. 2. These correspond to specific survey questions in the study. Percentage of respondents who agree/strongly agree that their organization has the relevant digital skills or capabilities.

Source: (2015), Digital business global executive study and research project, Deloitte-MIT Survey.

Big data & analytics focuses on harnessing key past and present real-time data and applying it to run operations more smoothly and efficiently. In operations, advanced analytics powered by big data can provide insights on production optimization, predictive maintenance, and reservoir patterns, among other areas.

Data handling refers to the set of procedures in place for transporting, handling, and sharing information. Cloud solutions and advanced knowledge boards have contributed enormously to having access to data across organizations.

The Industrial internet (Internet of Things) refers to the interconnection of digital devices embedded into operating equipment, or any other type of asset, that enables the asset to capture and transmit data. The remote monitoring of machinery conditions is a practical application.

Machine learning and AI encompasses the development and training of computer systems to be able to perform tasks that normally require human intelligence. Machine learning enhances AI, as it gives the system the ability to learn on its own from situations it encounters. Examples of this include assistants to answer queries from providers, and a portable engineering assistant for remote locations.

Mobile solutions enable people to have easy access to information, systems and connectivity in the field. Tablets, mobiles, and wearables are common tools used as work platforms in the field.

Virtual reality (VR) is used to add information and visual cues, to compliment the view of reality, for the purpose of quickly diagnosing issues. Examples of this are heads-up displays (HUDs) and augmented optics. VR is also widely utilized to create 3D environment simulations and trainings, to better prepare personnel for unfamiliar situations.

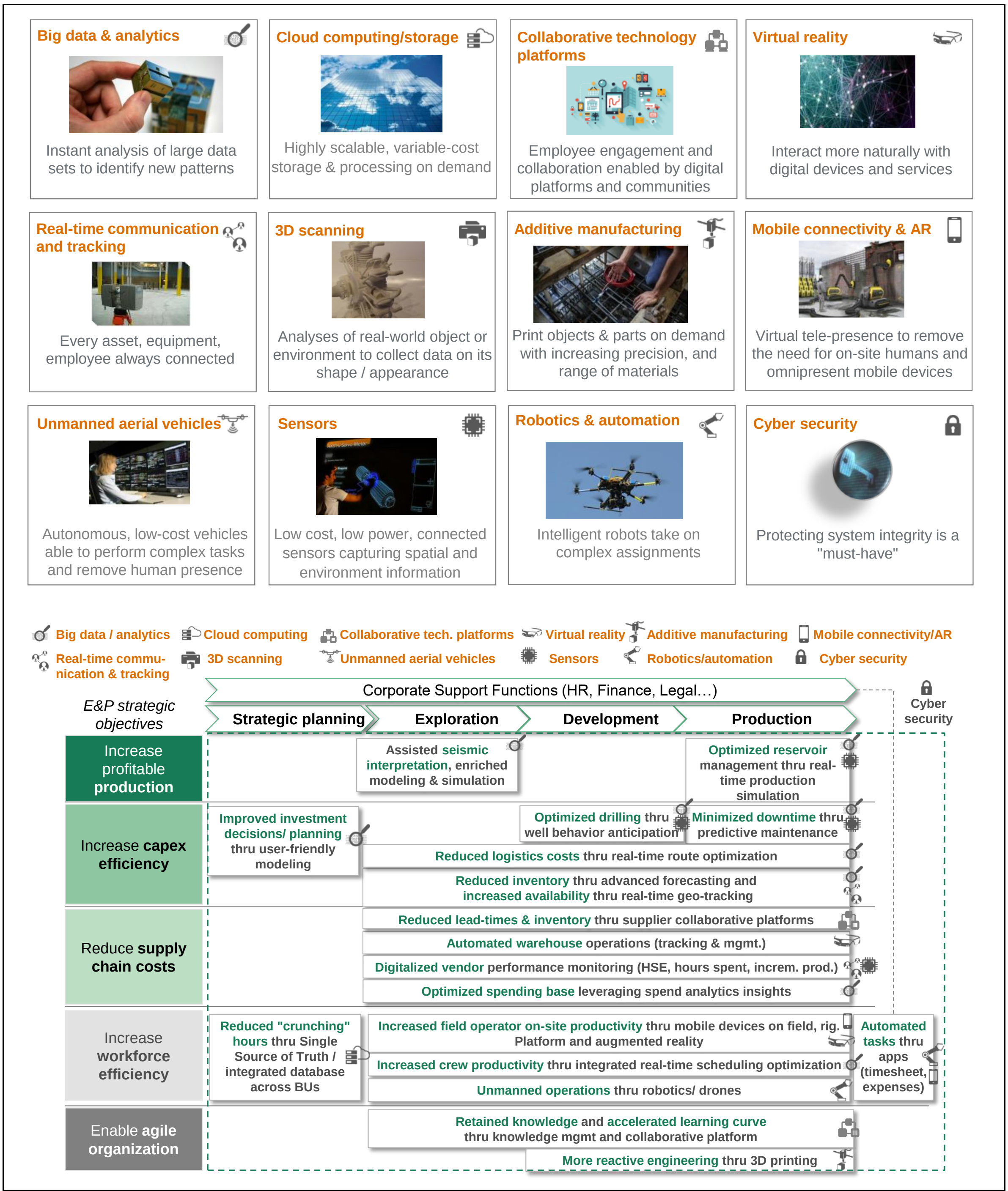
Advanced robotics seeks to enable robots and unmanned vehicles to solve complex or cumbersome tasks, such as inspections and light-intervention jobs in difficult-to-access areas.

3D manufacturing enables engineers to expedite the process of part design, installation, and replacement. Adoption of 3D manufacturing in the O&G industry is pretty much limited to making prototypes, as the use of this technology for producing pieces of equipment is uncertain.

Cybersecurity is tasked with reliably and efficiently protecting E&P assets and operations from cyber threats. Operations have become increasingly connected, and are therefore vulnerable to cyber-security threats. Some examples of cybersecurity include transparent data-sharing, utilizing blockchain, along with data fragmentation and encryption.

The aforementioned categories are not a comprehensive list, but they are the main themes observed in the industry. As the lowering of cost levels becomes imperative to remain competitive, digitalization is becoming a key area in supporting the end goal. Data is currently underutilized, and digital can provide solutions to create and harness data optimally. Exhibit 11 illustrates the impact of digital on E&P.

Exhibit 10. Digital technologies applicable along the E&P value chain



Source: BCG experience.

Exhibit 11. Use cases to illustrate the impact of digital on O&G

E&P strategic objectives	Use case	Example
*Increase profitable **production***	1 ***Real-time production optimization***	**Big data and machine learning** used for real-time production monitoring
*Increase **CAPEX efficiency***	2 ***Predictive maintenance***	**Big data analytics** used to predict pump failures in real time
	3 ***Route optimization***	**Advanced analytics** on **real-time GPS** feedback from fleets to optimize routes
*Reduce **supply chain costs***	4 ***Spend analytics***	**Spend analytics** used to optimize procurement spending
	5 ***Optimized warehouse operations***	**Augmented reality** leveraged to quickly pick correct parts in warehouse
*Increase **workforce efficiency***	6 ***Real-time optimized field crew scheduling***	**Advanced analytics and mobility** devices used to optimize real-time crew scheduling
	7 ***HR mobile apps***	Employees file expenses on-the-go on a **mobile app from the field**
	8 ***Automated inspections***	Inspection and mapping of equipment using **UAVs (drones)**
*Enable **agile organization***	9 ***Knowledge management/ collaborative platform***	Knowledge sharing enabled by **AI and cognitive computing**

Source: BCG experience.

Digital innovation is not only a matter of research and application. To remain on the forefront of technological advancement, a cultural change must take place from within the company itself. As the digital function becomes pivotal to companies, its structure and place in the organization must be defined. The digital function will eventually overlap, or even merge, with IT and other technology functions. Digital and IT will play an increasingly central role in organizations, shifting away from being cost centers. In addition to mapping the new company structure, the company will have to ensure that they have the right infrastructure and personnel to deploy digital initiatives. The feasibility of securing all required elements for digital initiatives will dictate whether digital development is kept in-house, or outsourced to better-equipped entities. Companies might decide to develop in-house capabilities, in order to reap the benefits of competitive advantages, or in turn, to jointly develop or completely outsource the initiative.

1.2. Trading

On average, around 90 million barrels of crude oil and natural gas liquids are traded every day[2]. This number is expected to grow, at least in the medium term, as demand increases, mainly in developing countries, especially in Asia, in response to expanding populations and rapidly-growing economies. However, this increase may be partially

[2] “Oil 101,” Morgan Downey.

offset by the measures taken to comply with low-carbon transition plans, on top of national agendas today, and which foster the substitution of oil with other energy sources. In fact, some believe that, at some point over the course of the next two decades, a peak oil demand might be reached.[3]

Crude oil, like other commodities, is physically traded under long-term and "spot" market transactions. These arrangements serve either of two purposes: first, to set the conditions, including quantity, type, time and place of delivery (price is normally set at the time of delivery) for transferring the title and possession of physical crude oil from the producer to the buyer (i.e. refiner or trader), and second, to manage the financial risks involved in trading a commodity that is subject to daily price fluctuations.

Physical and price management markets for crude oil have developed under different circumstances over the past century. Oil companies, traders and financial institutions may utilize these two different markets, either to transfer the ownership of the physical oil, or to manage prices.

Typically, 90-95% of all crude oil is sold under term contracts that are mainly annual. The remaining balance (5-10%), referred to as the marginal barrel, is traded on the spot market. The marginal barrel is therefore the unit that sets the price, and is fully responsive to supply and demand forecasts.

The physical oil market exists for the sole purpose of delivering and receiving physical oil. Refiners source crude oil globally, and producers compete for their business, creating a competitive marketplace.

The price management and financial markets were developed with the aim of managing oil price volatility. Hedging is the basic tool to protect against the risk of falling commodity prices for O&G producers, and to provide a cap for O&G consumers, in order to protect them from sharp price increases.

Paper trading markets

Traders on the *New York Mercantile Exchange* created the first crude oil futures contract on the early 1980s. Soon thereafter, three other financial exchanges were established in the regions of the marker crude oils, to facilitate futures trading.

The major exchanges and their futures commodities are the *New York Mercantile Exchange (NYMEX)*, the *ICE Futures Europe Exchange*, in London, the *Singapore Exchange* (SGX), the *Dubai Mercantile Exchange (DME)* and the *Tokyo Commodity Exchange (TOCOM).*

[3] The World Energy Council believes that peak oil demand will occur in 2030 (World Energy Scenarios 2016), while the Carbon Tracker association published that it will be reached around 2020 (*Stranded Asset Danger Zone*, Nov. 2015).

1.2.1. Types of trading

Oil derivatives are financial instruments that use crude oil as an underlying asset. They are only contracts for oil-related activities, and can be traded to access the value of the oil used as the basis of the contract. In the financial oil market, four kinds of derivatives are typically used: forward contracts, future contracts, options and swaps. Each derivative has different characteristics that minimize a particular risk.

A forward contract is made between two parties, either directly, or through a broker, to provide for the purchase or sale of a given quantity of oil at a specified future time, price and place of delivery. They are settled on a day at the end of the contract, and there is the possibility that one of the two parties may default. The contract stipulates a fixed price, agreed at the time of entering/agreeing to the contract. The amount, quality and delivery are established by mirroring practices in the physical oil market, which may allow for quality and quantity tolerances. Hedgers mainly use forward contracts to eliminate the volatility of an asset's price.

A futures contract is similar to a forward contract, with regard to the intention of reducing price risk, but futures have several distinct characteristics: they are highly liquid and do not have counterparty risk, as they are regulated by the Commodity Futures Trading Commission. Futures trades also have clearing houses that guarantee the transaction. In addition, the contracts are "marked-to-market" daily, meaning that their value changes daily, up until the end of the contract, and can be settled over a range of dates. As a result, they tend to be settled earlier than their initial end date, before maturity, and actual delivery of the goods rarely occurs.

Option contracts are financial instruments that convey the right, but not the obligation, to buy or sell an underlying security in the future. A call option is the right to buy a specific quantity of a security, for a given period of time, at a strike price, that is, a price selected by the buyer at the time the option is purchased. A put option is the right to sell a specific quantity of a security, over a given period of time, at a strike price.

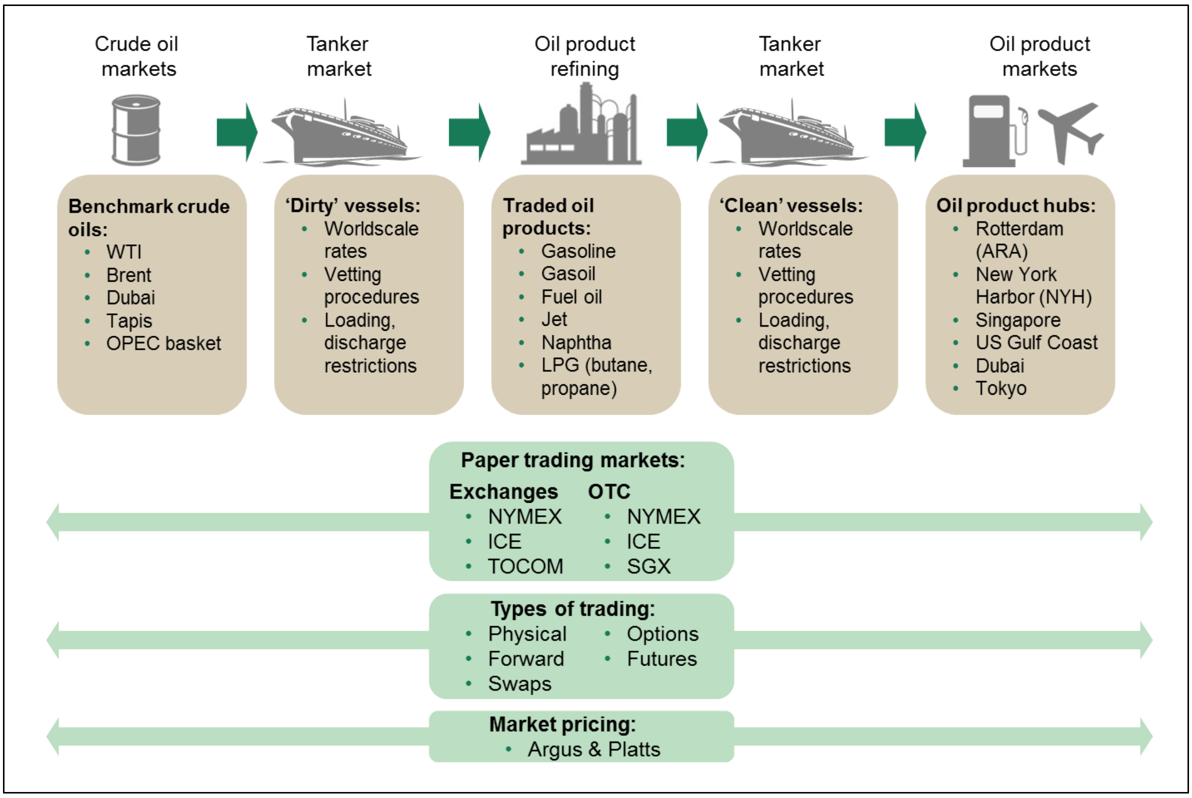
Swaps are the newest financial innovations in the oil trade and other financial markets. They are designed to convert variable prices to fixed prices, or vice versa. Swap contracts are agreements between two parties to exchange cash flows generated by the operation of underlying assets. There is no physical transfer of any asset or principle in a swap contract – simply payments of cash. They are not regulated by a centralized exchange, and are therefore over-the-counter derivatives.

1.2.2. Market pricing: O&G markets

The oil market is the structure that allows buyers and sellers to establish commercial relationships that better meet their own specific needs. These commercial interactions between well-informed traders assure that global oil prices reflect their market value. There are more than 300 grades of crude oil around the world, in addition to which the crude oils sold in the market are often blends of oils from different fields, thus they do not respond to standard quality parameters. Whether the oil is sold in the spot market or under term contract, it is generally sold under floating price mechanisms, which reflect the price difference with regard to a benchmark crude (marker crude) oil. Prices of marker crude oils are determined by future supply and demand conditions, and reported several times a day by price-reporting companies. These values can then be used as the basis for pricing all other crude oils bought and sold around the world. Platts and Argus are among a number of publishers who provide up-to-date price information on a subscription basis, as well as editorial and other commentary on the crude oil and petroleum product markets.

Depending on a known set of criteria, other crude oils will be priced at a discount or a premium to the dominant marker crude oil in the region.

Exhibit 12. Major elements of trading markets



Source: BCG experience.

Exhibit 12 displays five core stages of the trading value chain, from the raw crude oil product (such as one of the benchmark crude oils), through the transition via transportation to a refining hub, and subsequent delivery to the location of demand. Additionally, it shows that the various types of trading occur along the entire value chain.

Contrary to oil markets, world gas markets are based on the existence of an expensive transportation infrastructure, and they have traditionally been regional. The three main gas markets, North America, Europe and Far East Asia, have operated as three quasi "self-contained regions" without little or no extensive relationships amongst them. As a result of their lack of external infrastructure, these regions have largely developed their own supply/demand and pricing dynamics.

Except for several price spikes during the mid-2000s, when the US was thought to be running out of gas reserves, the North American gas market has traditionally had slightly lower prices among the three major markets. This is due to being a competitive gas market, with competition stimulated by many producers, and a pricing based on gas-to-gas competition. Whereas in the Continental Europe and Far East Asian markets, which are dominated by pipeline gas from Russia and LNG imports, pricing is largely indexed to oil prices. Price differences among the three markets have been accentuated since 2009, after the successful development of shale gas production in the US.

The technological advances in natural gas liquefaction and transportation have fostered LNG trading, and made the three major markets more interdependent, though with substantial price differences among them. The North American market depends on internal production, and will remain being gas-to-gas competitive, whereas the Continental Europe and Far East Asian market price will depend on LNG imports, and at least the transportation cost will explain the price gap.

1.3. Transportation, storage and distribution

As mentioned previously, around 90 million barrels per day (Mbpd) of crude oil are moved around the world from points of supply to major refinery centers. Of this amount, about 50 Mbpd of crude oil and products travel long distances, in trade between the major producing regions of Russia, Africa and the Middle East, to the major markets of North America, Europe and Asia.

Once crude oil is refined, the oil products are distributed to final consumers through a number of channels (see Exhibit 13).

The trading of natural gas is very different from that of crude oil, due to reasons outlined in the previous section. Of the 3,757 bcm of natural gas marketed in 2017, only 1,134 bcm (30.2%) was sold internationally. Of this internationally-traded total, 741 bcm were transported via pipeline, while 393 bcm could be attributed to LNG export/import[4].

[4]International Energy Agency: Natural Gas Information 2018.

1.3.1. Transportation and storage

While there are a number of ways to transport crude oil, the most practical and economic way to do so is via pipelines or marine tankers, especially over longer distances.

Pipelines are used on land and offshore to move oil from oil/gas separation units in the fields, or from gathering centers to port terminals for loading onto tankers, and to deliver oil from supply points to refineries and other market destinations.

A marine tanker is a ship designed to carry liquids in bulk. Unlike other vessels, where cargo is carried in containers, a tanker's cargo is kept in tanks that are built into the hull.

Over the long term, a pipeline is the preferred alternative for inter-regional or transcontinental oil movement. Its unit operating costs are lower, as compared with other forms of transportation. It is also the safest and the most environmentally-friendly form of oil transportation.

Crude oil storage terminals are built at the inlets and outlets of major pipelines, at port facilities, where the oil waits to be loaded/unloaded onto/from large crude oil carriers, and at refineries, where it waits to be refined.

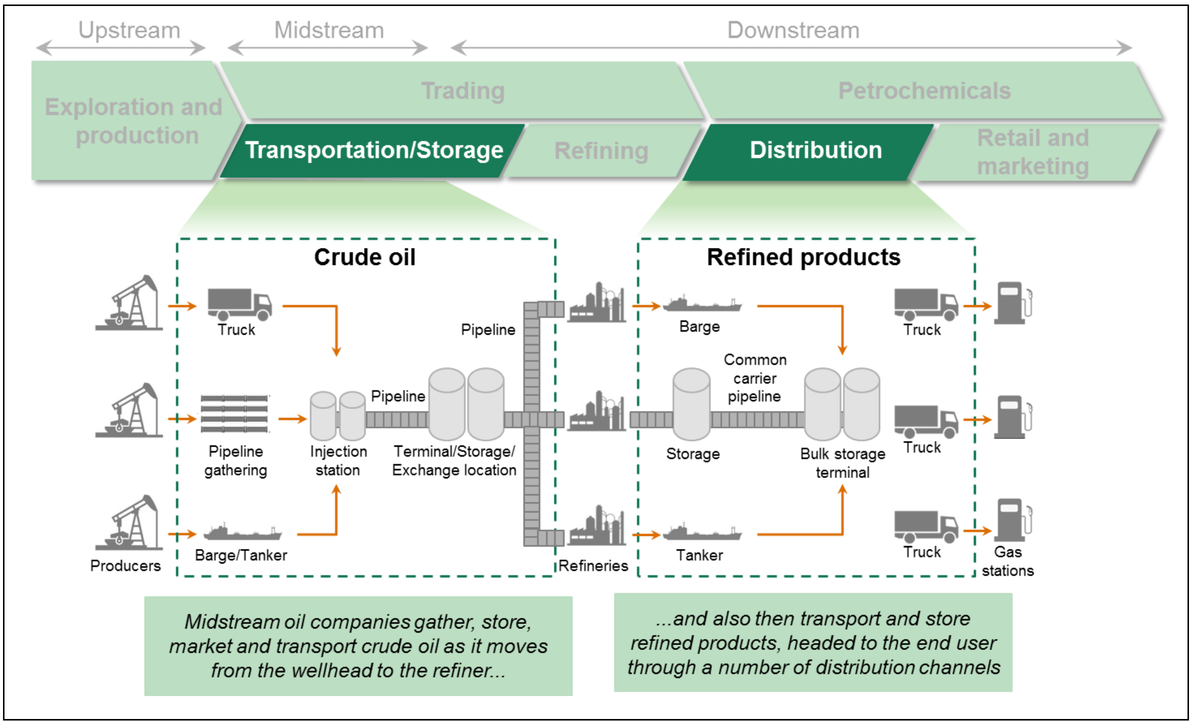
About one-third of marketed natural gas (3.2 million tonnes of oil equivalent) is moved internationally. Natural Gas is several orders of magnitude less dense than crude oil, its storage and transportation over large distances needs to be done under high pressures, and it requires expensive infrastructures.

Initially, the gas pipeline network provided the basis for natural gas storage; however, given the increase in demand and the fluctuations in consumption, and in order to ensure supply security in countries with low or no gas production, the need for having natural gas storage sites has arisen. Underground storage of gas in exhausted fields of gas, aquifers and salt caverns, being cheaper than those of liquefied gas, has an important role in this function; however, they have the difficulty of being linked to the structure of local networks to be used as support for global trading activity.

In the last few decades, engineering advances in the area of liquefaction, by which gas is converted into liquid form (LNG), have eased safe non-pressurized storage and transportation, and expanded the possibilities of more widespread natural gas trade. In liquefaction facilities, gas that is transported from nearby fields is treated for dehydration, condensate, CO_2, mercury and H_2S removal, and refrigerated up to liquefaction and stored as liquid in cryogenic tanks, from which it is transported to the destination terminals via specialized LNG tankers. There, the LNG is then unloaded, stored and regasified, and distributed through the local pipeline network. LNG storage can perform functions that are identical to underground storage, regarding balancing consumption/supply and optimizing the gas network, but possibilities have also opened up for the global trading of natural gas as LNG.

Globally, storage terminal operators include O&G companies and independent terminal companies. The independent companies differ from the others in that they do not own the oil that they handle, but rather, act as custodians of the oil for producing companies, refiners and traders. Relevant examples of these are Vopak, the largest independent tank storage company globally, and CLH Group, the leading company in Spain, Kinder Morgan, a giant in North American energy infrastructures, and Oiltanking GmbH, headquartered in Hamburg, Germany.

Exhibit 13. Transportation, storage and distribution value chain



Source: BCG experience.

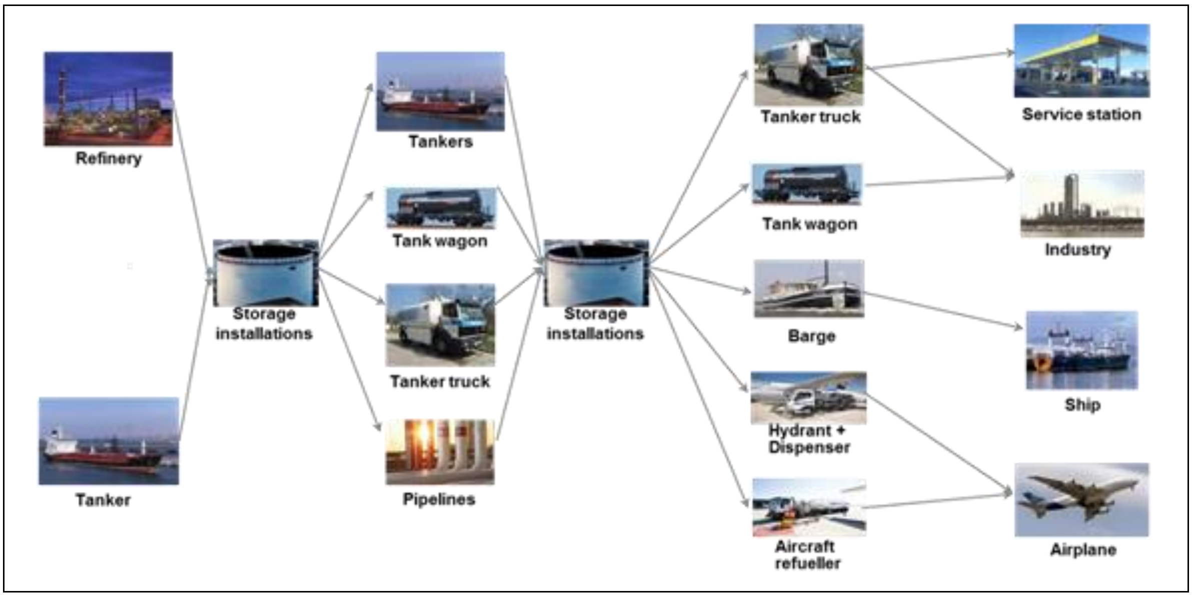
1.3.2. Distribution

The distribution of oil products (see Exhibit 14) takes place between refineries or importing ports, and the end consumer, and can be done through multiple channels.

Primary distribution considers the transportation of refined oil products from refineries to intermediate storage installations, where at a later stage, oil products are withdrawn by different operators and delivered to oil consumers. Primary distribution is done mainly through pipelines, but also via barges and tank wagons, and in some cases by tankers.

Secondary distribution, also called capillary distribution, involves distributing oil products to the end consumer via multiple channels (i.e. tank wagons, barges and trucks) to supply service stations, industries, ships or airplanes.

Exhibit 14. Oil product distribution channels



Source: BCG experience.

1.4. Oil downstream

After crude oil is extracted, going down the value chain, it is processed into refined products and chemicals, as per market demand.

In the refinery, crude oil is transformed into market fuels and specialty products. Some of these products constitute feedstock for the petrochemical industry, which together with natural gas liquids, produces base chemical products. All these products are then marketed through Business-to-Business (B2B) and Business-to-Consumer (B2C) channels.

1.4.1. Refining

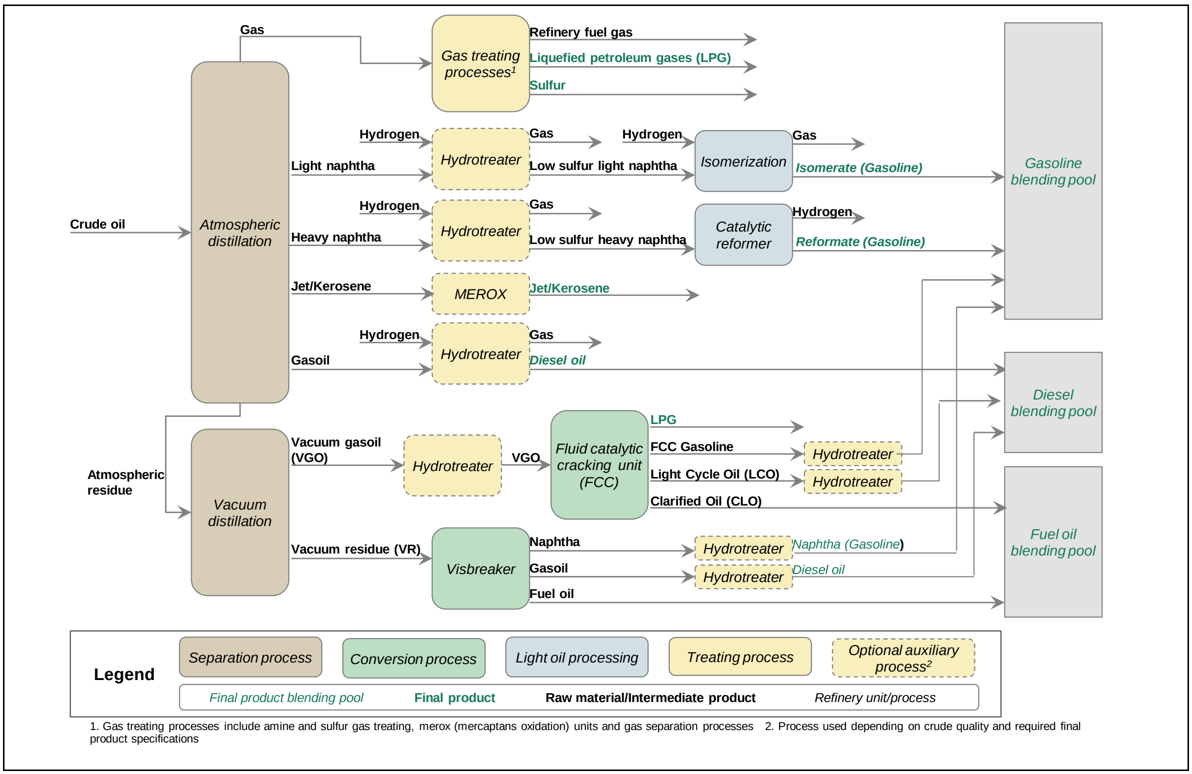
Refining refers to those processes that transform crude oil and other raw liquid hydrocarbons, which as such have limited value to final consumers, into oil products, such as gasoline, jet and diesel or liquefied petroleum gases (LPG) suitable for final consumption. To do so, refining entails a wide variety of physicochemical processes that usually start with distillation (separation processes), and might include several quality-improving and conversion processes. Oil refineries are the facilities where these processes, in particular, distillation, are implemented, alongside the auxiliary processes that are necessary for their proper operation (see Exhibit 15).

Distillation refers to the separation process whereby crude oil components are separated into several fractions with different boiling point ranges, in a distillation tower, at atmospheric pressure or under vacuum.

Conversion refers to the cracking processes by which lower-value hydrocarbons are transformed into lighter and higher-value products.

Quality improvement processes refer to those processes whereby the intermediate refinery hydrocarbons are treated, in order to ºº improve their performance characteristics, regarding efficiency and environmental aspects. These include the type of processes such as light oil processing, treating and blending.

Exhibit 15. Example of an basic oil refinery process basic scheme



Source: BCG Experience.

The oil refining industry was created, following the substitution of the whale oil used in oil lamps for kerosene during the second half of the 19th century, and then in power plants, after the development of electric power, and in the Internal Combustion Engines (ICE) in the transportation sector. The two latter sectors required an increasing supply of different oil products, like gasoil and fuel oil, gasoline and diesel. Virtually non-existent before 1850, the refining industry has increased its global capacity enormously over the past century, from a few small and primitive refineries at the beginning to around 34.8 Mbpd in 1965, and booming thereafter to around 91.3 Mbpd in 2010 (97.2 Mbpd in 2015)[5], which equates to an average total capacity growth of around 2.1% per annum over the last 50 years.

Oil refineries are also the key sources of feedstocks for the petrochemical and chemical industries, which supply basic materials (chemicals, lubricants, solvents, basic polymers and synthetic fibers, among others) to other industries. Exhibit 16

[5] 98.1 Mbpd in 2017.

shows a list of the main oil refinery products, along with their main characteristics and uses.

Exhibit 16. Key oil refinery products and uses

Product	Type of product	Uses	OECD consumption in 2015 (Mbpd)
Liquefied petroleum gases (LPG) & ethane	LPG & ethane	Transportation fuels and petrochemical feedstocks	5.2
Naphtha	Light distillate	Gasoline components, petrochemical feedstocks	3.4
Gasoline	Light distillate	Transportation fuels	14.4
Jet & kerosene	Medium distillate	Transportation fuels, heating, lighting	4
Gasoil & diesel	Medium distillate	Transportation fuels, heating, power generation	13.1
Fuel oil	Residue	Marine fuels, power generation	2.1
Lubricants	Specialty	Friction reduction in mechanical devices	n.a.
Waxes	Specialty	Lubrication, electrical insulation candles	n.a.
Asphalts	Specialty	Infrastructures, roads	n.a.
Chemicals	Petrochemicals	Several	n.a.
Solvents	Aromatics	Paints, coatings, cleaners	n.a.
Other	-	Several	n.a.

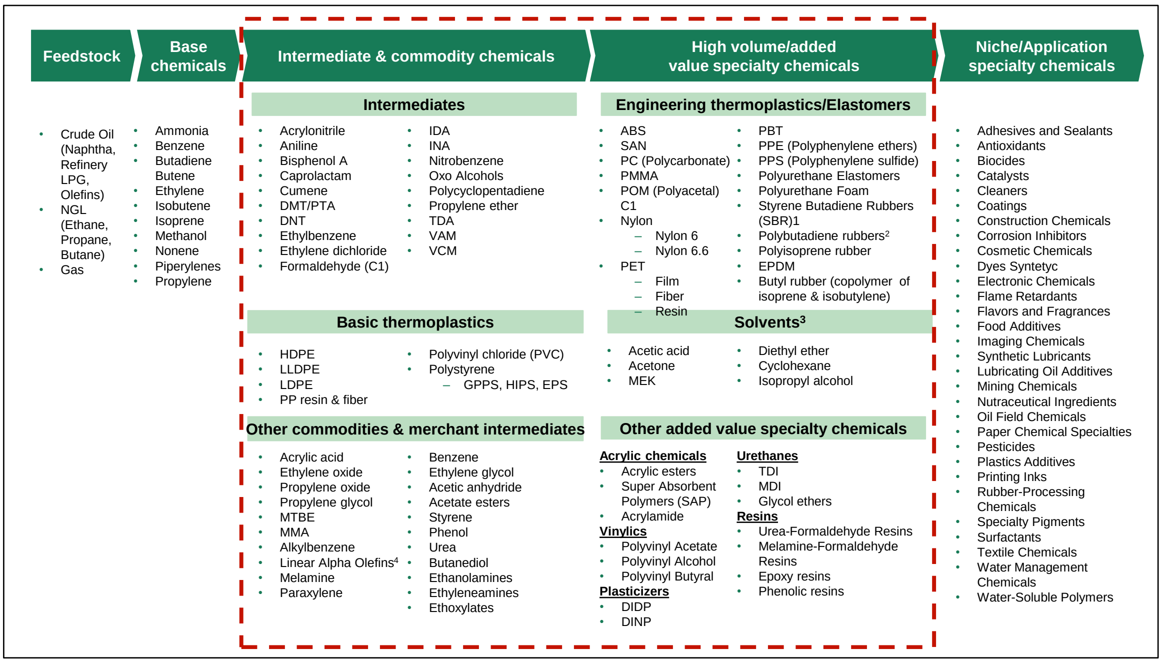
Source: International Energy Agency (IEA)

1.4.2. Petrochemicals

Petrochemical products are chemicals made from hydrocarbon feedstocks, through several processes and transformations. Petroleum products and natural gas liquids are the feedstock for petrochemical building blocks. These building blocks, in turn, are converted into a wide array of chemical products known as intermediates. The intermediates are processed into polymers and resins, which when molded, shaped and reformed, end up as consumer products.

The petrochemical value chain in Exhibit 17 shows how natural gas and petroleum products are transformed into a series of products whose values increase with each successive step in the chain.

Exhibit 17. Petrochemical manufacturing value chain



1. Includes Styrene Butadiene Latex 2. Includes Butyl-rubber 3. High purity grades. 4. Includes 1-Hexene, 1-Octene.
Source: BCG experience.

1.4.3. Marketing

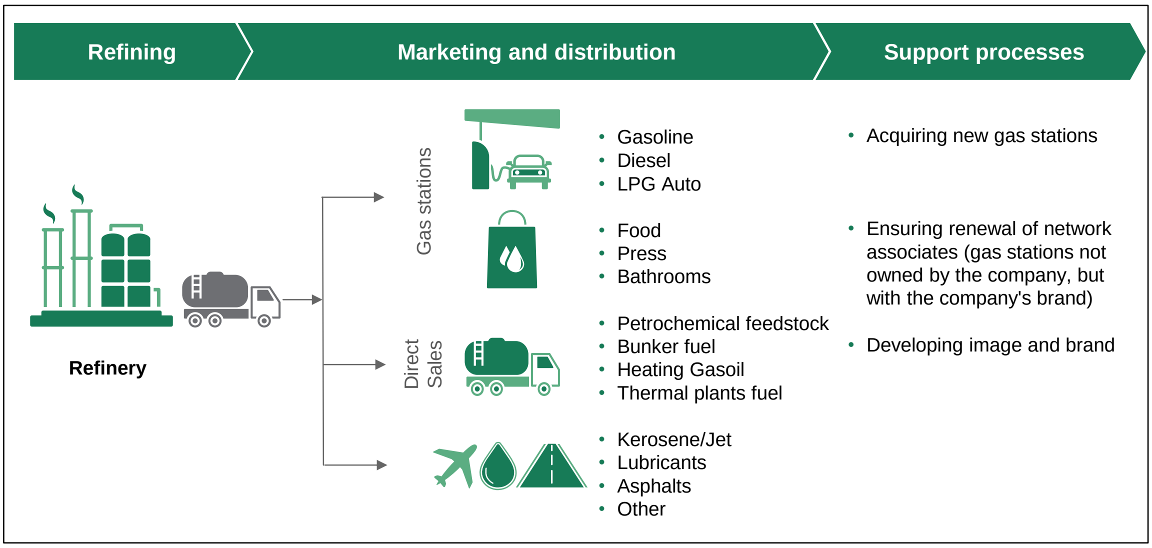
There are generally two types of petroleum product consumers: *retail customers* (i.e. individual consumers) and *business customers,* for which direct sales are done (see Exhibit 18). Each of these two customer types has very different market demands, which are met by the industry in different ways.

Retail customers are served through business-to-consumer trade channels, which are built around selling petroleum products to literally millions of individual customers on a daily basis.

Most retail customers purchase transportation products, which meet specific legal standards, such as gasoline, diesel and liquefied petroleum gas (LPG), at service stations, and other products, like lubricating oils or engine additives, through several different channels.

Business customers range from small businesses to the largest multinational corporations, and to local and national administrations. The business-to-business trade channel is also known as *direct sales,* distinguishing them from retail sales which are done through intermediaries. The products sold are final products that meet market specifications, such as aviation kerosene or intermediate products under contractual/commercial specifications, such as naphtha, asphalts, lubricant bases, paraffin, coke, etc.

Exhibit 18. Marketing value chain



Source: BCG experience.

The future evolution of the downstream will be heavily influenced by changing customer demand. As consumer behavior may vary over the coming years, often spurred on by environmental and GHG emission policies and their attached social benefits, the refining and marketing processes will also gradually have to be adapted.

1.5. Summary

As seen in this chapter, the O&G value chain includes the activities ranging from oil resources, as they are searched, identified and recovered, transported and refined, to oil products, and their transportation and distribution to end user, following the value chain through upstream, midstream and downstream.

The Exploration and Production section has discussed which steps a company must take in order to obtain the required licenses, and subsequently, the different types of development contracts that might be open to them. The Exploration and Appraisal segments then reviewed the geological and seismic imaging in which geophysicists and engineers collect and evaluate as much data as possible to narrow down the characteristics of a reservoir. This is done in order to make the best-informed engineering decisions for a project, which ultimately feed economic models to ensure viability. These decisions, in their own right, can be considered value-adding steps, as every decision here has a knock-on effect on the economics of such a project.

Teams of analysts and experts utilize the analysis provided by the technical team, to combine the economic landscape and assess the development possibilities within the engineering and environmental constraints. This brings about many alternatives and risks that must be weighed, and which are subject to politics in all geographies. In this sense, an O&G upstream development must have a fluid technical and economic approach, and past experience and knowledge must be harnessed, so as to reduce the risks as best as possible. While the risks are large, so are the possible rewards.

In addition, the opportunities where new technological developments can increase efficiency, safety and productivity should be identified. To do this successfully, adequate changes might be required within the organizations, in order to achieve maximum economic efficiency.

O&G companies looking to stabilize their results in times of low oil prices, are also paying greater attention to aspects such as trading, storage and transportation, whether they are vertically integrated or not. Having a strong understanding of the multiple options available when trading O&G helps a company control risk. Having some contractual agreement with the owners of infrastructures, such as pipelines, storage and/or oil tankers, premium fees can be mitigated, and volumes can be moved more efficiently to end destination markets. In any case, all of these benefits are realized, regardless of whether the price of the petroleum commodities is high or low. Emphasis should also be placed on the most recent global technical advances and economic policy trends, as “new” markets may show lucrative creation of value.

The final parts of the chapter have analyzed the current downstream value chain of Refining processes, from distillation and conversion to quality improvement processes and the use of refined products, Petrochemicals and an overview of final outputs, and finally Marketing and its general type of customers. The following chapter 2 provides a deeper dive on the Refining segment.

2. THE REFINING PROCESS

Refining is the stage of the oil value chain that adds value by converting crude oil, which by itself would have little end-use value, into a range of refined products, such as transportation fuels, suitable for specific end uses. Petroleum refineries are the industrial facilities where this transformation takes place. Refineries are large, capital-intensive manufacturing facilities that operate 24/7, and which spread across large areas. Their processing capacity is typically in the order of hundreds of thousands of barrels of crude oil per day. There are nearly 700 refineries worldwide, with capacity to process around 98.1 million barrels of crude oil per day (98.1 Mbpd, 2017).

2.1. The main processes of an oil refinery

An oil refinery includes a wide variety of processes focused on obtaining higher-value products from crude oil and other liquid hydrocarbons. These processes can be classified, according to the type of physicochemical transformation that they perform, into distillation (separation or fractionation) processes, conversion processes, and quality processes (light oil processing, treating and blending).

The history of the refining industry and processes is linked to the evolution of end-product specifications. The advancements made during the last century have transformed the refining industry into one of the most capital-intensive and technologically-advanced industries in the world, capable of delivering around 80 million barrels of high-quality refined products on a daily basis. Exhibit 19 shows the history of refining process development.

Exhibit 19. Historical development of refining processes

Year	Process	Purpose	By-products
1862	Atmospheric Distillation	Production of kerosene	Naphtha, tar, etc.
1870	Vacuum Distillation	Production of lubricants (original) Production of cracking feedstock (1930s)	Asphalt, residual Coker feedstock
1913	Thermal Cracking	Increment of gasoline production	Residue, bunker fuel
1916	Sweetening	Reduction of sulfur and odor	None
1930	Thermal Reforming	Improvement of octane number	Residue
1932	Hydrogenation	Removal of sulfur	Sulfur
1932	Coking	Production of gasoline base stock	Coke
1933	Solvent Extraction	Improvement of lubricant viscosity index	Aromatics
1935	Solvent Dewaxing	Improvement of pour point	Waxes
1935	Catalytic Polymerization	Improvement of gasoline yield and octane number	Petrochemical feedstock
1937	Catalytic Cracking	Higher octane gasoline	Petrochemical feedstock
1939	Visbreaking	Viscosity reduction	Increase in distillate, tar

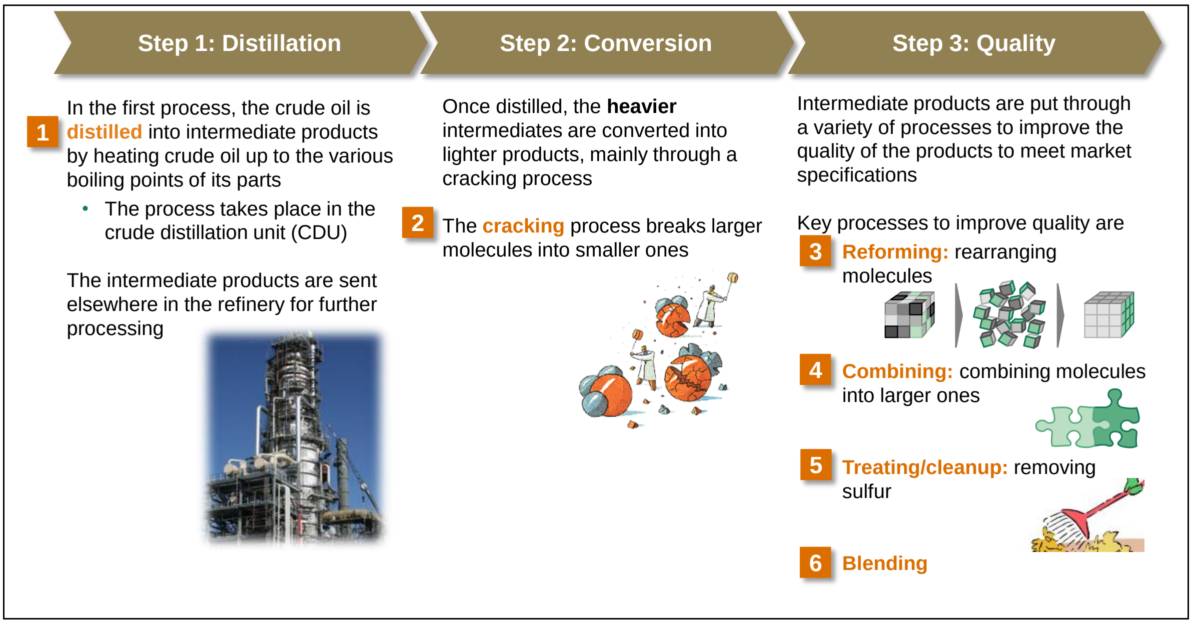
(cont.)

Year	Process	Purpose	By-products
1940	Alkylation	Increment of gasoline yield and octane	High-octane aviation gasoline
1940	Isomerization	Production of alkylation feedstock	Naphtha
1942	Fluid Catalytic Cracking	Increment of gasoline yield and octane	Petrochemical feedstock
1950	Deasphalting	Increment of cracking feedstock	Asphalt
1952	Catalytic Reforming	Conversion of low-quality naphtha	Aromatics
1954	Hydrodesulfurization	Removal of sulfur	Sulfur
1956	Inhibitor Sweetening	Remove mercaptans	Disulfides
1957	Catalytic Isomerization	Conversion to molecules with high-octane number	Alkylation feedstock
1960	Hydrocracking	Improve gasoil quality and reduce sulfur	Alkylation feedstock
1974	Catalytic Dewaxing	Improvement of pour point	Wax
1975	Residual Hydrocracking	Increment of gasoline yield from residue	Heavy residue

Source: Gary, J., Handwerk, G., Kaiser, M. (2007), Petroleum Refining: Technology and Economics, Fifth Edition, CRC Press.

A refinery uses three steps to transform crude oil into products, as described in Exhibit 20.

Exhibit 21. Process steps in a refinery



Source: BCG experience.

2.1.1. Distillation

Distillation or separation processes are those that split the crude feedstock into different components, by using differences in their boiling temperatures, without performing any chemical transformation.

Oil separation processes were among the first to be developed (atmospheric distillation in 1862, vacuum distillation in 1870), and they typically constitute the starting point of an oil refinery, and the end point of conversion process units (i.e. used to separate the different oil products after conversion).

Product yields (percentage of a specific product produced from crude oil and other feedstocks) of the distillation process (atmospheric distillation, plus vacuum distillation) are highly dependent on the type of crude oil processed. While light crude oils[6] tend to have a higher share of light and middle distillates (typically having a higher price), heavy crude oils are more residue-abundant. Therefore, selling at lower prices.

a) Atmospheric Distillation

The Atmospheric Distillation process is usually the starting point of an oil refinery. It is used to separate crude oil into different fractions, according to their boiling point ranges. Typical crude oil fractions include naphtha (generally split into light and heavy cuts), kerosene, diesel oil, atmospheric gasoil and atmospheric residue (which is then normally processed in a vacuum distillation unit).

When crude oil enters the distillation unit (from the tanks where it has been previously unloaded from ships, and stored for some days), it first undergoes a desalting process intended to remove the salts present that would cause fouling and corrosion in the refinery equipment. Fouling occurs from depositions on the heat transfer surfaces of the refinery equipment (in this case, salt depositions, but the same occurs with coke and other cracking residues), impacting its efficiency and performance, while corrosion is usually due to salt deposition, which eventually compromises refinery integrity. The desalting process consists of washing the crude oil with water at above 90°C, depending on crude density and viscosity (the salts are dissolved by the water) and then separating the water from the water/crude mixture by either use of chemicals or strong electric fields. Refineries can include one, two, or even three desalting stages before crude feed enters the Atmospheric Distillation unit, depending on the quality of the basket of crude oils that is being processed.

After the desalting process, the crude oil is heated up to 400°C in a furnace, before entering into the distillation tower where its vaporization and fractionation occurs. To make the process more efficient, distillation products and distillation unit internal streams are used to preheat the crude feed in a heat exchanger train.

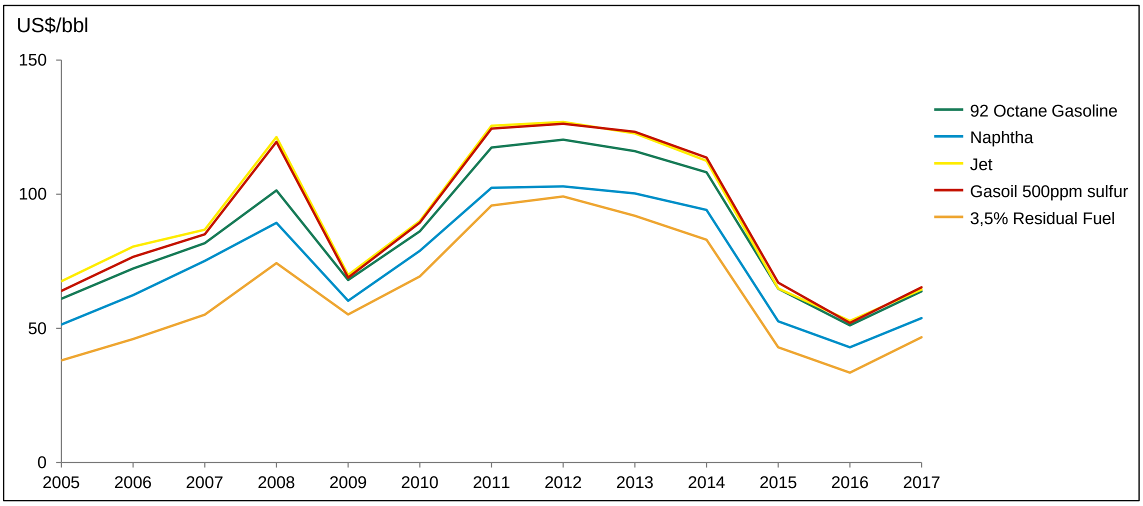
[6] Light crude oils are considered to have API>31.1º (this is only a rough estimation, as the exact demarcation between light and heavy oil in API gravity changes, depending on the crude oil's region of origin).

API gravity is a measure of the density of a crude oil (the higher, the lighter) and is defined as API gravity $= \frac{141.5}{SG} - 131.5$ where SG stands for standard gravity.

The heated crude oil enters into the flash zone of the atmospheric fractionator (distillation tower), where all distillate vaporized fractions start ascending. While ascending they meet a reflux of liquids, condensed at the top of the tower and from the different recovery sidestreams that are previously cooled down, which help them condensing and washing down fractions heavier than the reflux to the trays that recover the product. The distinct boiling points of the different products ensure their condensation in different trays: lower boiling products (lighter) condense in the trays placed near the top of the tower, where the temperature is lower, whereas heavier products condense in the lower sections, closer to the flash zone, of the distillation column, where temperatures are higher. Typically, it is necessary to have around 30 trays in an Atmospheric Distillation tower, which result in tall structures that are more than 50 meters (m) high.

Product yields of the crude oil distillation process are 100% related to their operating parameters, characteristics and composition of the processed crude oil (or oils, as refineries often process blends of crude oils). Lighter crude oils, which tend to be more expensive, result in a higher yield of lighter products, which in turn, tend to have a higher price. In contrast, heavier crude oils result in a higher yield of heavy products that require additional conversion process units to be transformed into higher-value products. See product price difference trends in Exhibit 21. Residual fuel oil normally shows a price clearly below other products.

Exhibit 22. Singapore hub refined product price



Source: Bloomberg.

Exhibit 22 shows a comparison of Atmospheric Distillation yields of different crudes. Other crude oil characteristics, such as sulfur content, density, viscosity or acidity, also impact the operating conditions of the distillation unit, the characteristics of the refinery to process them, and then their price.

There are thousands of oilfields and hundreds of different crude oils traded around the world. Different companies might market the same crude oil, as a result of shared production, or due to previous trading. It is important to note that the composition and characteristics of different crude oils evolve over time, as wells and fields are depleted, new crude oils are coming to the market every year, while others might see their production reduced to minimal levels, or even disappear. The refining industry must be able to adapt its operation constantly to this evolving raw material landscape.

Exhibit 23. Example of Atmospheric Distillation yields for different crude oils

	Bonny Light	Oman	Basra Heavy	Mars	Pazflor	Tapis
Company	Total	Total	BP	BP	ExxonMobil	ExxonMobil
Region	West Africa	Middle East	Middle East	Gulf of Mexico	West Africa	South East Asia
Country	Nigeria	Oman	Iraq	US	Angola	Malaysia
Crude API	35.1	30.4	23.7	28.8	24.7	42.7
%S	0.15	1.45	4.12	1.80	0.4	0.04
TAN[7]	0.25	0.61	0.3	0.46	1.63	0.21
Yields (% vol.)						
Gas / LPG	1.4	1.4	1.5	2.2	0.7	1.8
Light naphtha	7.9	5.3	6.6	7.8	1.9	7.2
Heavy naphtha	19.4	13.0	11.2	12.8	7.3	19.2
Kerosene	11.0	7.4	8.6	8.5	12.3	20.2
Gasoil	34.6	22.0	20.6	21.9	19.6	23.1
Atmospheric residue	25.7	50.9	51.4	46.9	58.2	28.5

Source: Total, BP, ExxonMobil.

b) Vacuum distillation

Vacuum Distillation is the natural continuation of the Atmospheric Distillation process, and consists of a distillation tower that separates the atmospheric residue (the bottom product of the Atmospheric Distillation process), by vacuum (at very low pressure), into a distillate: vacuum gasoil and vacuum residue (vacuum column bottom). The vacuum environment helps to lower the boiling temperature of the different fractions (light, medium, heavy) of vacuum gasoil that needs to be separated from the residue, to temperatures lower than those that would occur at atmospheric pressure, therefore, preventing the cracking of carbon molecules and the formation of coke along the furnace and the column, which would impact the operation. Vacuum Distillation units also include reflux circuits, which help improve the separation process.

[7] Total Acid Number is a measure of the acidity, determined by the quantity of potassium hydroxide, in milligrams, that is needed to neutralize the acids in one gram of oil.

There are also relevant differences in the product mix obtained after distillation (atmospheric + vacuum) depending on the crude oil. Heavier crude oils tend to have a higher portion of vacuum residue, compared to lighter crudes, and a higher percentage of vacuum gasoil. Exhibit 23 shows examples of the vacuum distillation yields of different crude oils.

Exhibit 24. Example of Vacuum Distillation yields for different crude oils

	Bonny Light	Oman	Basra Heavy	Mars	Pazflor	Tapis
Company	Total	Total	BP	BP	ExxonMobil	ExxonMobil
Region	West Africa	Middle East	Middle East	Gulf of Mexico	West Africa	South East Asia
Country	Nigeria	Oman	Iraq	US	Angola	Malaysia
Crude API	35.1	30.4	23.7	28.8	24.7	42.7
%S	0.15	1.45	4.12	1.80	0.4	0.04
TAN	0.25	0.61	0.3	0.46	1.63	0.21
Yields of Vacuum Distillation (% vol.)						
Vacuum gasoil	75.4	51.0	51.1	55.5	61.8	81.8
Vacuum residue	24.6	49.0	48.9	44.5	38.2	18.2
Yields of Total Distillation (%vol.)						
Vacuum gasoil	19.4	25.9	26.3	26.0	36.0	23.3
Vacuum residue	6.3	25.0	25.1	20.9	22.2	5.2

Source: Total; BP; ExxonMobil

Atmospheric and Vacuum Distillation towers are usually considered together in the industry, with the exception of less complex refineries as the teapot[8]. Crude oil assays provide information on distillation yields and product properties that include both atmospheric and Vacuum Distillation processes.

2.1.2. Conversion

In the oil refining industry, the conversion stage transforms heavy fractions into light products through cracking/hydrogenation. Cracking is the process of breaking down larger hydrocarbon molecules (heavier) into shorter ones (lighter), with the objective of increasing the production of higher-value products. Exhibit 24 shows the typical number of carbon atoms, density and boiling range of different oil market products.

There are several processes and technologies for cracking hydrocarbon chains used in the oil refining industry, with high temperature (or severity) being the common denominator in all of them, as the key cracking reaction that they trigger. Catalysts, steam and hydrogen addition are also used in some of the processes to increase the

[8] Teapot refineries are small (<60-80 kbpd), low-complexity refineries with no or minimal conversion capacity, considered uncompetitive in the current global market environment, but which might operate in certain locations/markets, due to fiscal advantages or exclusive access to markets.

efficiency of the cracking reactions and improve the quality of cracked products. Exhibit 25 shows the typical techniques employed in each process.

Exhibit 25. Number of carbon atoms, density and boiling point of key oil products

Product	Number of carbon atoms	Density (kg/L)	Boiling point range
LPG	C3-C4	0.55	< 20°C
Gasoline	C4-C12	0.75	100–150°C
Kerosene/Jet	C9-C16	0.8	175-275°C
Diesel/Gasoil	C15-C25	0.832	200-370°C
Fuel Oil	C22+	0.85+	350°C+

Source: BCG experience.

Exhibit 26. Techniques used in most common cracking processes

	Unit types	Process
Catalytic cracking	• Fluid catalytic cracker (FCC)	• **Temperature**, **low pressure**, and a **catalyst** break up large molecules • Feedstock is heated and pressurized in the presence of the catalyst—lighter gasoline products separate • **A catalyst** is a substance that speeds up a given chemical reaction without changing itself. Catalytic cracking uses synthetically produced catalysts called **zeolites**
Hydro-cracking	• Hydrocracker	• **Temperature**, **pressure**, **catalyst**, and **hydrogen** break up large molecules • Higher pressured catalytic cracking in the presence of hydrogen • Metal based catalysts eliminate sulfur
Thermal cracking	• Visbreaker • Thermal cracker • Coker	• **Temperature** and low **pressure** break up large molecules • Feedstock is quickly heated, pressurized, and cooked. As it cooks, the lighter products rise and separate

Source: BCG experience.

Fluid Catalytic Cracking, Hydrocracking, Visbreaking and Coking are introduced below, as these are the most representative conversion processes of an oil refinery.

a) Fluid catalytic cracking (FCC)

Catalytic cracking processes were developed in the early decades of the 20th century and boomed during the Second World War, as they provided high octane fuel for planes. Nowadays, FCC is the most widely-used refinery process, with a total global capacity of around 20 Mbpd (close to 20% of total distillation capacity).

The objective of the FCC process is to convert heavy lower-value products (usually vacuum gasoil (VGO) into lighter and higher-value products, such as LPG, propylene or gasoline. In order to do so, the FCC process uses a catalyst to improve the yields of the cracking reactions (compared to a simpler thermal cracking). The catalyst consists of very small particles, which when coming in contact with gases behave like a fluid. The hot catalyst fluid is mixed with the fresh feed to start the cracking reactions.

Exhibit 26 contains a comparison between the product yields of a thermal cracking unit and the product yields of a fluid catalytic cracking unit, showing the better performance of the FCC unit.

Exhibit 27. Thermal vs. catalytic cracking yields

	Thermal cracking		Catalytic cracking	
	wt.%[9]	vol.%[10]	wt.%	vol.%
Fresh feed	100.0	100.0	100.0	100.0
Gas	6.6		4.3	
Propane	2.1	3.7	1.3	2.2
Propylene	1.0	1.8	6.8	10.9
Isobutane	0.8	1.3	2.6	4.0
n-Butane	1.9	2.9	0.9	1.4
Butylene	1.8	2.6	6.5	10.4
C5+ Gasoline	26.9	32.1	48.9	59.0
Light cycle oil (LCO)[11]	1.9	1.9	15.7	15.0
Decant oil[12]	-	-	8.0	7.0
Residual oil	57.0	50.2	-	-
Coke	0		5.0	
Total	100.0	96.5	100.0	109.9

Note: wt.% - the percentage based on weight, vol.% - the percentage based on volumen.
Source: Gary, J. Handwerk, G., Kaiser, M. (2007), "Petroleum Refining: Technology and Economics", Fifth Edition, CRC Press.

The overall FCC process has two main stages: 1) reaction - the feed (usually VGO) enters the FCC riser, (see Exhibit 27) where it is mixed with the catalyst and flows into the reactor, where the cracked products vaporize and keep the catalyst fluidized. As soon as the catalyst particles enter into contact with the hydrocarbons, the cracking reaction begins. The heavy oil then cracks into lighter and more valuable products; 2) fractionation - after the reaction, the different hydrocarbons are separated in a distillation column in different fractions.

Following Exhibit 27 it's provided a deeper dive into reaction and fractionation:

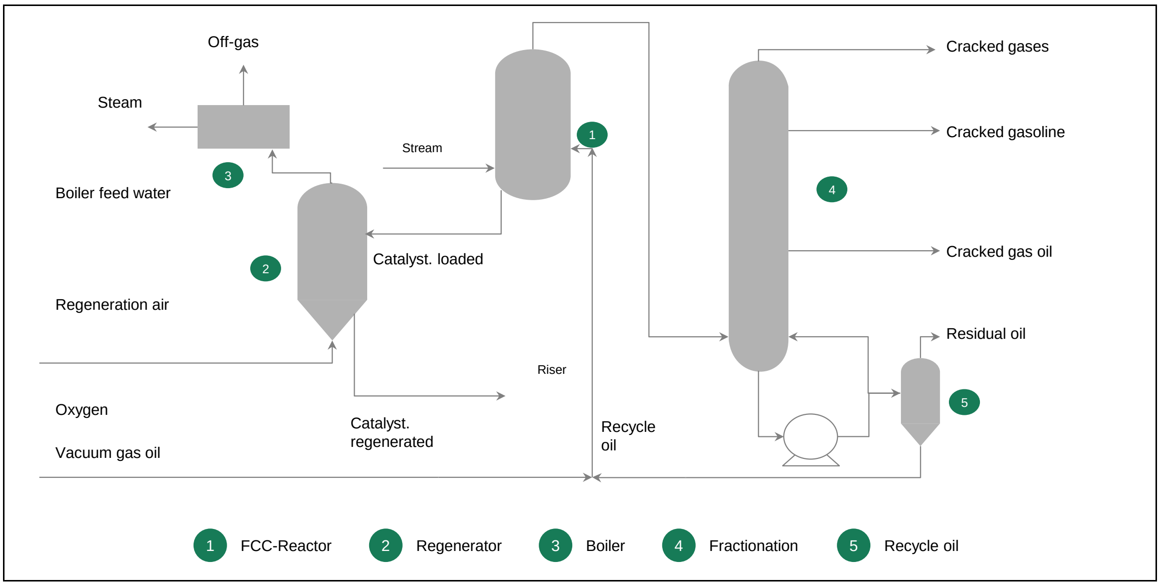
[9] Mass percentage.

[10] Volume percentage.

[11] Light cycle oil is a light lubricating oil, a liquid residue produced in the catalytic cracking process.

[12] Decant oil is oil-catalyst slurry, a byproduct from the fluid catalytic cracking process.

Exhibit 28. Basic schematic of an FCC plant



Source: Linde; BCG experience.

Reaction

After the feed enters the FCC, it is mixed with the catalyst in the riser (in Exhibit 27), where the reaction takes place. They ascend together while the reaction happens and end up separated by cyclones at the top of the reactor. High-pressure stripping steam is introduced to help the separation process. In modern units, with more advanced catalysts, a faster separation from hydrocarbons is needed to stop the cracking reactions and to control product distribution. The catalyst is heavier, and descends back to the regenerator, while the different products are pushed out of the top of the reactor to the fractionation (distillation) column.

The used catalyst that flows back to the regenerator has coke attached to it. Coke is one of the products of the cracking process. The used catalyst particles have a significantly lower activity when coated with coke, and must be regenerated, which takes place in the regenerator, see feature 2 in Exhibit 27. The coke combustion in the regenerator may (or may not) be completely to carbon dioxide (CO_2). The air flow from combustion is controlled, so as to provide the convenient ratio of carbon monoxide (CO) to CO_2, depending on the design of the plant.

The used catalyst, with the coke attached to it, enters the regenerator at a very high temperature, where the coke is burned to generate heat for reaction, getting effectively removed from the catalyst. Burning the coke is assured by the air introduced into the regenerator. The combustion reaction can give either CO (typical in older units) or CO_2 (improved catalyst activity recovery). The hot catalyst is then sent back to the reactor riser again, to be mixed with the fresh feed, closing the loop. Catalyst additions are necessary to maintain the catalyst level in the process, as a small part of it is always lost in the FCC products or in the regenerator. The flue gas resulting from the combustion exits the regenerator from the top.

Two of the most important factors in the reaction phase that allow better yields in the FCC are: the catalyst-to-oil ratio and the reactor temperature. The catalyst-to-oil (oil considered feed) ratio is determined by the amount of catalyst circulating between the reactor and the regenerator. The more it circulates, the higher the cracking rate, which allows for higher yields of lighter (and therefore more valuable) products. The reactor temperature is a function of the feed temperature and the catalyst temperature. Higher reactor temperatures allow for higher cracking (and therefore higher conversion yields).

Fractionation

After exiting the reactor, the hydrocarbon mixture is distilled in the fractionator into the final FCC products. The lighter products from the top of the distillation column are sent to the wet gas compressor. The heavier products exit the fractionator from intermediate and lower points in the tower. All products are sent to other units in the refinery, sold directly to clients, or used in the refinery as fuel.

The FCC unit is what is called a "heat balanced" unit. This refers to the fact that the FCC process combines both endothermic (cracking) and exothermic (catalyst regeneration) reactions, which allow using the regeneration process heat for reaction and to bring the feed to reaction temperature.

b) Hydrocracking (HCK)

The Hydrocracking process is one of the latest refinery process development that has a widespread adoption since it was commercially developed in 1960. Today, worldwide Hydrocracking capacity has reached 10 Mbpd (2017)[13]. The Hydrocracking process combines the effectiveness of catalytic cracking with a catalytic hydrogenation/Hydrocracking process in producing light distillates and improving product quality. The Hydrocracking unit has the ability to process a wide variety of feedstocks, ranging from atmospheric and vacuum gasoil, to FCC cycle oil, slurry[14] and Coker distillates. This versatility represents an important advantage for refineries.

Hydrocracking unit catalysts accomplish a dual function that includes: (i) facilitating the cracking of hydrocarbon chains and (ii) facilitating hydrogen addition to aromatics[15] and olefins[16].

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[13] Source: GlobalData.

[14] Slurry: an oil-catalyst mixture, simply called slurry. It is a heavy aromatic FCC byproduct, normally blended into heavy fuel as a viscosity cutter (within its low API limitations).

[15] Aromatic: a cyclic hydrocarbon, ring-shaped, planar molecule with a ring of resonance bonds with more stability than other molecules with the same set of atoms, but a different arrangement.

[16] Olefin: also known as alkene, this is composed of hydrogen and carbon, containing one or more pairs of carbon atoms, linked by a double bond.

The Hydrocracking process is a middle distillate oriented process, though it also produces LPG, naphtha and residue, depending on the feed used and process conditions. It also produces unconverted oil (UCO), which can be used as feedstock for FCC or for lube oil production. During the Hydrocracking reactions sulfur, nitrogen and oxygen are almost completely removed. Exhibit 28, shows an example of the applications for a Universal Oil Products (UOP) Hydrocracking technology (unicracking).

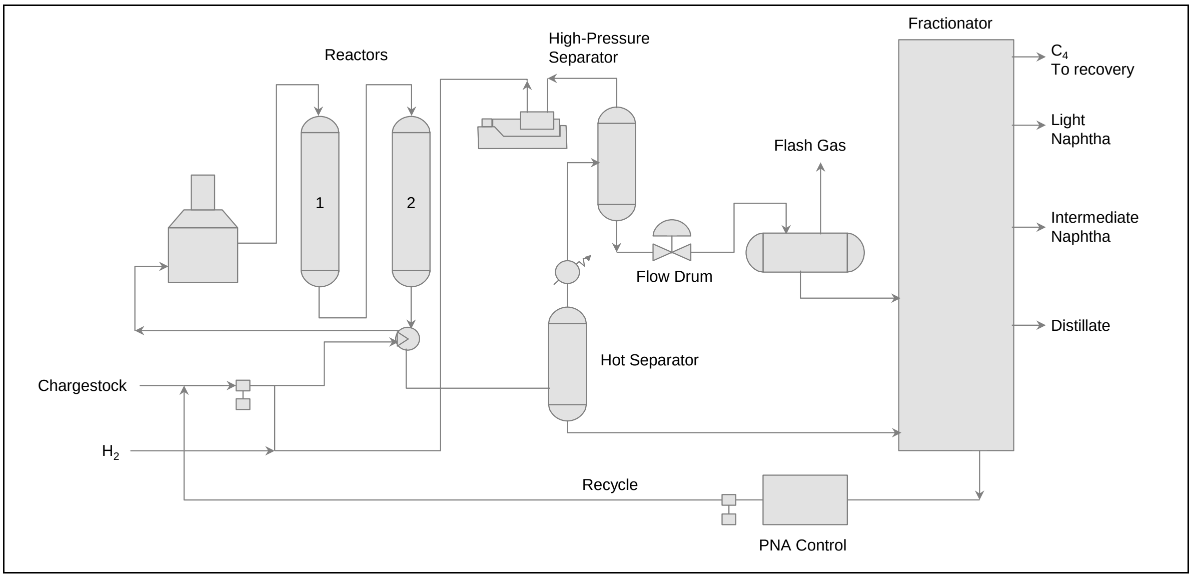
Exhibit 29. Applications of the unicracking process

Chargestock	Products
Naphtha	Propane and butane (LPG)
Kerosene	Naphtha
Straight-run diesel	Naphtha and/or jet fuel
Atmospheric gas oil	Naphtha, jet fuel, and/or distillates
Natural gas condensates	Naphtha
Vacuum gas oil	Naphtha, jet fuel, distillates lubricating oils
Deasphalted oils and demetallized oils	Naphtha, jet fuel, distillates lubricating oils
Atmospheric crude column bottoms	Naphtha, distillates, vacuum gas oil, and low-sulfur residual fuel
Catalytically cracked light cycle oil	Naphtha
Catalytically cracked heavy cycle oil	Naphtha and/or distillates
Coker distillate	Naphtha
Coker heavy gas oil	Naphtha and/or distillates

Source: Myers, R. (1997) Handbook of Petroleum Refining Processes, second edition

The Hydrocracker can present different flow schemes, such as: a) a single-stage, once through, with a partial conversion yielding some unconverted material, or a full conversion through recycling unconverted material (see Exhibit 29); gasoil driven (preferred in Europe and Asia); b) two stages reaction (preferred in the US); feedstock is treated in a first reactor and is partially converted; its products are fractionated, and the bottoms are processed in a second reactor for complete conversion; c) separate-hydrotreating – a single-stage reaction- and the reactor effluent (stripped of hydrogen sulfide and ammonia) is sent to the cracking catalyst reactor. This allows feedstocks with high contaminant levels to be processed, or contaminant-sensitive catalysts to be used in the cracking reactor.

Exhibit 30. Typical flow diagram of a single-stage unicracking unit



Source: Myers, R. (1997) "Handbook of Petroleum Refining Processes", second edition

Process Description - single stage unicracking unit

In a single stage HCK feedstock, mixed with recycled oil, fresh and recycled hydrogen, is preheated by exchange with the reactor effluent, then is passed through a final heater, and then sent into the cracking reactor (see Exhibit 29). The reactor accommodates the catalyst that will provoke the cracking reactions facilitating the desired product slate[17].

The reactions are highly exothermic, and in order to control the rate of reaction and control reactor temperature, cold hydrogen is injected into the reactor through quenching internals on top of each catalyst bed, where reactants are quench and mixed with additional hydrogen and redistributed through the catalyst bed. Correct mixing and redistribution are vital, in order to ensure proper control of the catalyst temperature and optimal efficiency.

The reactor effluent flows to a hot high pressure separator, where liquid and gas conversion products are separated. The liquid stream flows to the fractionator and gas stream flows to a cold high pressure separator, where gas and condensable products are separated; liquid products are sent to fractionator and the gas (mainly hydrogen with some methane) is recycled to the reactor. This improves energy efficiency by allowing feed the hot liquid into the fractionator and prevent polynuclear aromatic (PNA) fouling cold parts of the plant.

The fractionation train usually has a pressure let down valve and a flash drum to remove hydrogen sulfide and ammonia, and from which liquid flows to the main fractionating column where the liquid product is split into products according to

[17] Production slate: production mix.

boiling point ranges. The bottoms are recycled back to the reactor section for complete feed conversion.

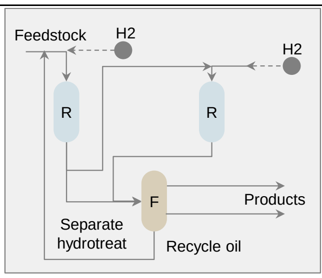
The Hydrocracker uses a bifunctional catalyst: the metallic compound promotes hydrogenation and the acidic compound promotes cracking. The different proportions of both components allow achieving the desired activity, yields and product properties.

Process Comparisons

In Exhibit 30, is presented a comparison between process modes.

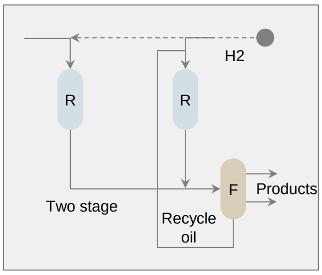
Exhibit 31. Comparison between process modes

Mode of operation	Single-stage recycle	Two stage	Once through
Advantages	• Low capital investment • Used for feeds with low end points to achieve total conversion	• More product yield flexibility • Used different catalyst each stage • Complete hydrogenation of the product, with reduction in aromatics and increase in smoke point	• Lower temperature and lower hydrogen partial pressure • Longer catalyst life because of the absence recycle • Lower capital cost
Disadvantages	• Less selective for liquid product • Used for low-capacity plants	• High capital investment	• High severity • Less flexibility • Lower quality of products • High aromatic content



Separate hydro treat

- Used when special product quality or product state requirements exist
- Used when special feed considerations are present
  - Larger amount of product in feed
  - Very high nitrogen level in feed



Two stage

- Most cost-effective for large-capacity units
- Provides high product quality and product state flexibility
- Efficient to process difficult feedstock's
- Low NH_2 environment in second stage

Source: (2007) Kuwait University – College of Engineering & Petroleum Department of Chemical Engineering; oil&gas portal.

The economics of Hydrocracking processes are not only dependent on product prices, but also on hydrogen cost and utilization efficiency within the refinery.

Hydrocracking is more expensive than catalytic cracking, as it operates at higher pressure, and with high hydrogen consumption; however, it can produce high-cetane ultra-low sulfur diesel (ULSD), whereas catalytic cracking cannot.

Hydrocracker Process Yields

In the following Exhibit 31 and 32, are present the typical yields for different HCK technologies.

Exhibit 32. VGO Hydrocracking process yield (%w) example	
$H_2S + NH_3$	2.3
C_1+C_2	0.27
C_3+C_4	2.33
Light gasoline	8.20
Heavy naphtha	10.19
Jet fuel	39.60
Diesel fuel	38.15
Residue	2.0
	100

Source: R. Serge, Taylor & Francis Group (2003) Thermal and Catalytic Processes in Petroleum Refining, CRC Press

Exhibit 33. Residual Hydrocracking process vs. Delayed Coker yields (%wt.) example

	Feedstock: Athabasca bitumen, %wt.	
	Hydrocracker	**Delayed Coker**
H_2S	3.8	1.7
NH_3	0.1	0.03
Light Gas	5.9	3.6
Propane/Propylene	3.5	1.7
Butane/Butylene	2.4	1.5
Naphtha (C5 – 204°C)	5.9	12.3
LGO (204 °C – 343°C)	22.5	18.3
HGO (343°C plus)	26.9	28.4
+538°C residual (HCK)/Coke (D. Coker)	29.1	32.6
	100	100

Source: ,Sayles, S., Romero, S. (2011) "Comparison of thermal cracking and Hydrocracking yield distributions", Digital Refining

c) Visbreaking (VB)

Visbreaking is a mild thermal cracking process for residue (typically vacuum residue) that produces a relatively low yield of light and middle distillates, which can be used to reduce the viscosity of fuel oil, decreasing the need for other diluents to achieve specification. The process, which balances temperature and residence time, needs to be mild in severity (temperature by time), to keep the resulting fuel oil stable, and thus avoid the formation of sludge. Typical yields of the Visbreaking process are shown in Exhibit 33.

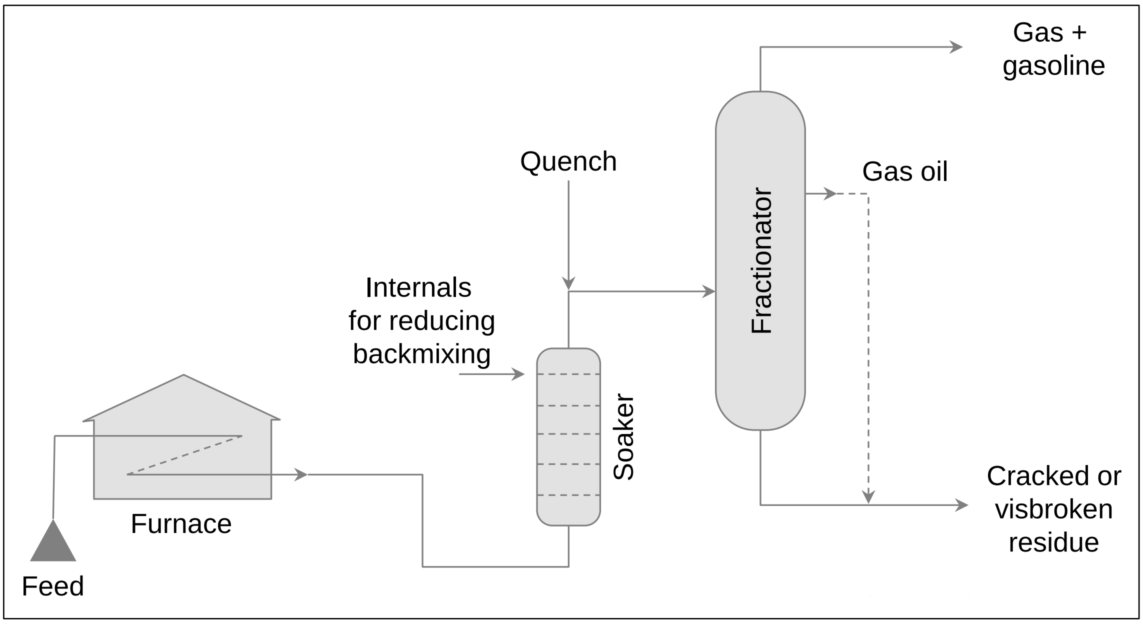
There are two types of visbreakers: coil visbreakers and soaker visbreakers (see Exhibit 34 for a soaker type example). In the coil variety, the cracking reaction takes place entirely in the furnace at a higher temperature (around 475-500°C), and thus with lower residence time, while in the soaker type, the cracking reaction occurs at a lower temperature (around 425-435°C), and takes longer times as the residue goes through the soaker. In both types of Visbreaking units, the resulting products of the cracking reaction are quenched to cool them down (and stop the cracking reaction), and then the hydrocarbons enter the fractionator area, which separates the lighter products from the fuel oil using a distillation tower.

Exhibit 34. Visbreaking yields

Product	Yields
Gases	2% - 4%
Naphtha	5% - 7%
Gas oil	10% - 15%
Tar	75% - 85%
Total	100

Source: Jarullah, A. (2017) Petroleum Refining, Tikrit University

Exhibit 35. Typical visbreaker schematics (soaker type)



Source: Speight, J. G. (2011) "Visbreaking: A technology of the past and the future", Scientia Iranica

As in all refinery processes, operational parameters depend on the quality of the feed: in some cases, the processed vacuum residue will allow the visbreaker to operate at higher severities, and in other cases, the severity will have to be lowered, in order to maintain the stability of the fuel oil, minimizing conversion and viscosity reduction, and thus minimizing margin.

d) Coking (Ck)

The Coking process is a thermal, non-catalytic cracking process that converts residual feedstocks into light hydrocarbons that will be further processed to obtain high-value products, such as LPG, naphtha or gasoil, in addition to coke. As opposed to Visbreaking, Coking is a severe thermal cracking process that generates distillates as primary products, and coke as a byproduct– the raw coke produced by a Coker is known as green coke. Coking is the refining industry's primary means of converting residual oil (the bottom of the barrel) into valuable products. Like in other refinery processes, Coking yields depend on the quality of the crude oil being processed in the refinery, as well as the end use of the produced coke, see Exhibit 35.

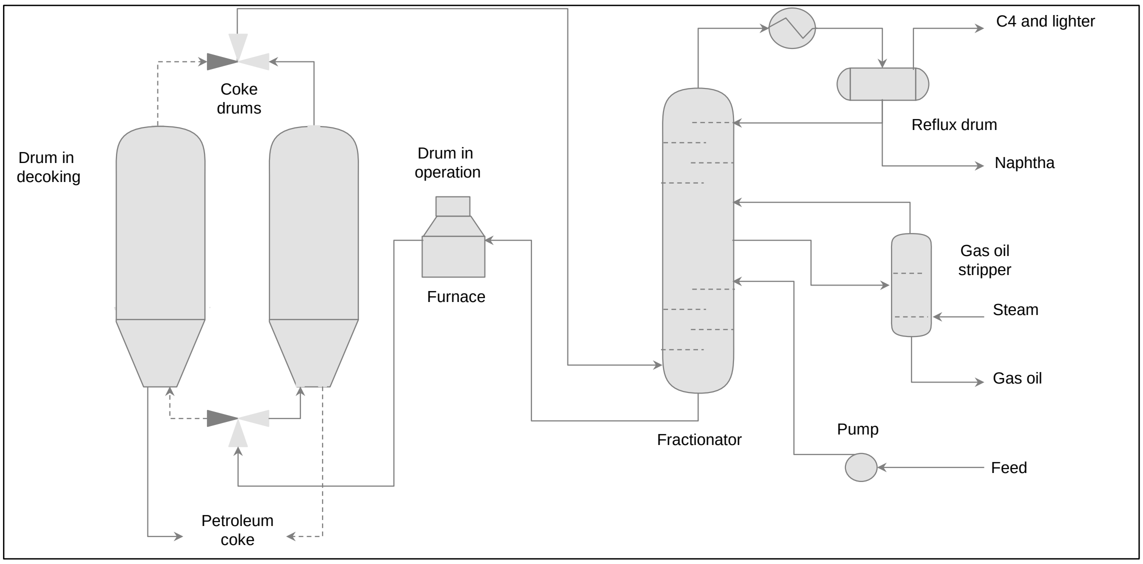
Exhibit 36. Typical Coker yields for 15 wt.% Conradson Carbon Residue (CCR)

	wt.%
Gas	10
Naphtha	16
Light gasoil	33
Heavy gasoil	17
Green coke	24
Total	100

Note: wt.% percentage based on weight.
Source: Jarullah, A. (2017) Petroleum Refining, Tikrit University.

There are different Coking processes, of which, the most used – by far – is Delayed Coking, showed in Exhibit 36.

Exhibit 37. Delayed Coker schematic



Source: Wisecarver, K., Pierre-Yves le Goff, W., Kostka, J. (2017), "Springer Handbook of Petroleum Technology", Springer

The Delayed Coking process is the only batch process in a refinery. Fresh feed is combined with any available coker slop, and is pumped into the bottom of the fractionator column, which acts to pre-heat the feed and remove any residual lighter hydrocarbons from the feedstock. It is then pumped into the furnace, which heats it to the thermal cracking temperature of 480-500°C, before passing through to the online coke drum. Thermal cracking of the feed begins to occur when it reaches the thermal cracking temperature, however cracking in the furnace and in the lines leading to the coke drums must be minimized, to prevent coke deposition and gradual blocking of the lines; to prevent this, steam is injected into the feed as it passes through the furnace. The vast majority of the cracking takes place in the coke drum (where pressure is kept constant at 2-5 bar), where the heavy hydrocarbon feed is broken down and split into gases, liquids and solid coke. The lighter components are generated in the vapor phase, and come out of the top of the drum, and into the fractionator. The remaining solid is deposited in the drum, and is referred to as coke. The coke deposit has a porous structure, allowing for the process to continue until the drum is filled with coke. When the online drum is filled with coke, the feed is switched to a paired standby drum, so that the full drum can have the coke removed; in this way, the process can continue without any down time. Once the lighter products pass into the fractionator column, they are then split according to their boiling points, typically into four products: gas, naphtha, light gasoil and heavy gasoil.

For the process to work as a continuous batch, while one drum is being filled, its paired drum must be decoked – having the coke removed. The process of decoking can take between 12-24 hours, and involves a number of steps outlined in the following Exhibit 37 (for a 16-hour cycle):

Exhibit 38. Delayed Coker cycle time

	Time (hours)
Steam to Fractionator	0.5
Steam to Blow Down	0.5
Depressure, Water Quench and Fill	4.5
Drain	2.0
Unhead Top and Bottom	0.5
Cutting Coke	3.0
Rehead / Steam Test / Purge	1.0
Drum Warm-up (Vapor Heat)	4.0
Total	16.0

Source: Ellis, P., Paul, C. (1998), "Tutorial: Delayed Coking Fundamentals", Great Lakes Carbon Corporation

Once the coke drum has been filled with coke, a steam-stripping step is required, to ensure that any liquids retained in the drum are carried through the fractionator column, instead of running down through the coke, condense during cooling and plugging the channels. Plugging the channels can cause issues, because it prevents the even cooling of the coke structure, and during the cutting process, the cold cutting water can come into contact with hot coke spots and cause steam explosions.

Water quenching is then used to cool down the coke, where water is slowly introduced into the coke drum. Controlling the water injection rate is critical to ensuring the even cooling of the coke, and to preventing the thermal stressing of the coke. Once the coke has been cooled, the water is then drained from the coke drum.

The top and bottom heads of the coke drum are then removed, so as to allow for the cutting process to take place. The cutting process is carried out with high-pressure cold water. Initially, a pilot hole measuring approximately 1m is drilled through the coke, and then the rest of the coke is cut out. The emptied coke drum is then reheated and pressure tested, before being warmed up by passing hot vapors from the online drum through it.

2.1.3. Quality improvement in refining

Refining quality processes are focused on changing the structure of hydrocarbon molecules, and on adapting their properties, to improve their specifications and make them to comply with those of the market.

Below are described Catalytic Reforming, other light oil processing units, hydrodesulphurization and blending processes.

a) Catalytic Reforming

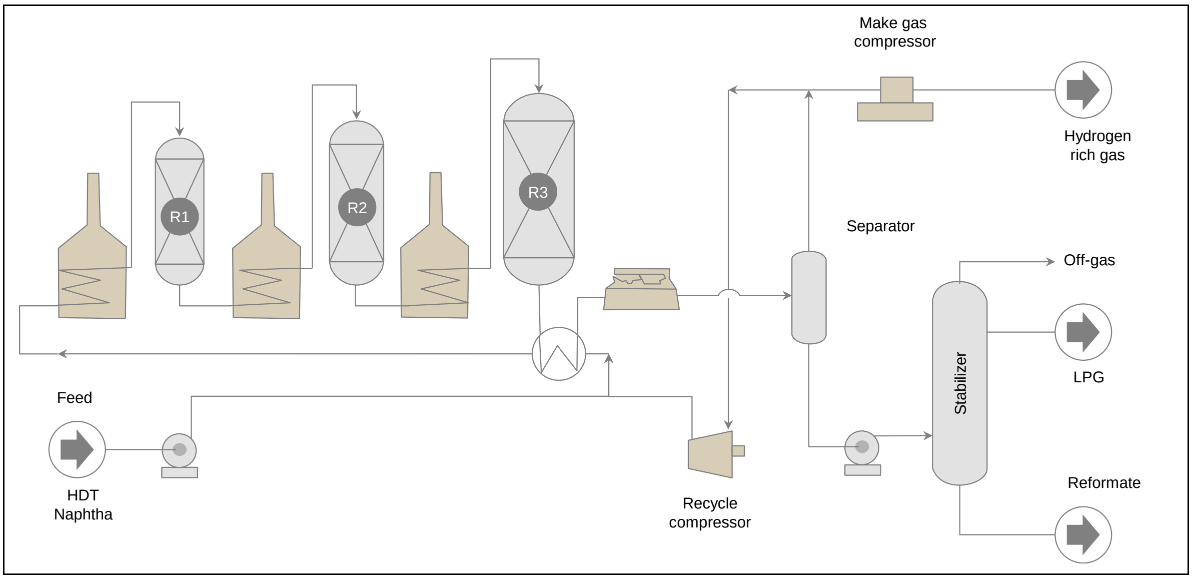
Catalytic Reforming is a chemical process that is used to convert naphtha into reformate, which due to its increased isoparaffins and aromatics content, has a higher-octane rating. There can typically be three primary goals for Catalytic Reforming: 1) produce high octane reformate for use in gasoline blending, to comply with octane specifications; 2) produce reformate with high content of aromatics that can be used in petrochemical operations; and 3) produce hydrogen for use in other refinery processes, such as Hydrotreating and Hydrocracking.

The feed to a catalytic reformer is predominantly straight-run naphtha from the topping unit, but naphtha output from other units could also be used as feed, e.g. FCC, Hydrocracker and Coker. Naphtha with boiling points between 80°C and 170°C (C6 to C9) are the preferred feedstock for the catalytic reformer. Lighter naphthas (boiling point lower than 80°C) are undesirable, because the lower molecular weight paraffins act as benzene formation precursors, increasing its content, which is unfavorable due to health regulations. Naphthas with final boiling point higher than 170°C are not ideal, because they hydrocrack and lead to excessive coke deposition on the catalyst. To ensure that the correct range of naphtha is sent to the catalytic reformer, a naphtha splitter is normally present upstream of the unit.

It is essential that naphtha is hydrotreated before being sent to the catalytic reformer, because any components that act as catalyst poisons must be removed. Sulfur, nitrogen, oxygen compounds, metals and olefins are all reduced to permissible levels by a hydrotreater, prior to the naphtha entering the reformer.

There are four main reactions that take place in reformers: 1) dehydrogenation of naphthenes: a fast and highly-endothermic reaction of naphthenes being converted into aromatics; 2) deydrocyclization of paraffins: a highly-endothermic reaction of paraffins being converted, first into naphthenes, and then into aromatics; 3) isomerization of paraffins and naphthenes: an increased branching of molecules; and 4) Hydrocracking of paraffins: an undesired slow and exothermic reaction, breaking paraffins down into shorter chained molecules. The first three reactions produce hydrogen, and the fourth consumes hydrogen.

Exhibit 39. Simplified Catalytic Reforming schematic

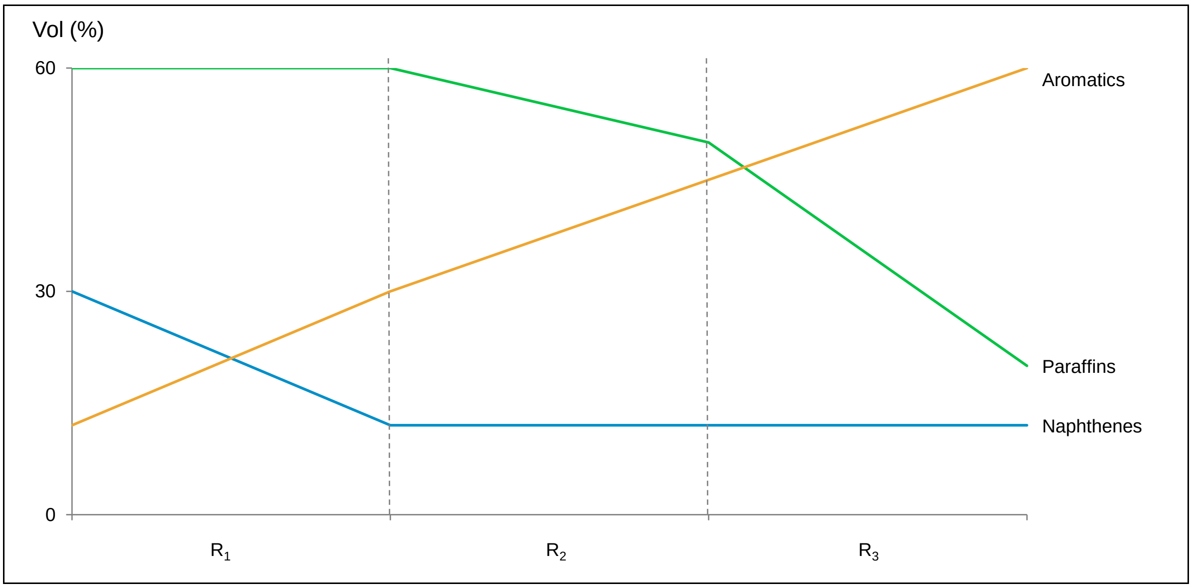


Source: Pierre-Yves le Goff, W., Kostka, J. (2017) Springer Handbook of Petroleum Technology, Springer

There are different methods for the Catalytic Reforming process that all follow the same general principles, but the most modern method is the continuous catalyst reformer, which will be explained here.

The feed, pressured up to the reactor pressure (4-10 bar), combined with hydrogen-rich recycled gas is preheated by a heat exchanger, which exchanges heat with the reactor exit product. It is and then passed through a process furnace, where it is heated up to the required reaction temperature (500-540°C) (see Exhibit 38). It then enters into the first of three reactors, where it comes into contact with the catalyst and begins to undergo the reactions explained above – in the first reactor, the endothermic dehydrogenation of naphthenes is the predominant reaction, and a great deal of temperature is lost across the reactor. The feed then leaves the first reactor and passes into a second furnace, which heats it up once again, to the required reaction temperature, before it passes into the second reactor, where it undergoes further conversion, losing temperature. The feed then leaves the second reactor and passes through a third furnace to heat it up once again, before it passes through the third reactor. The three reactors are positioned in a virtual stack, so that the catalyst can flow through all of them, due to gravity, before passing out into a catalyst regenerator, and then cycling back into the reactor stack. A typical catalyst regeneration cycle takes about seven days. The reactors increase in size down the stream, because the reactions are slower, so a larger volume is required. As reactions take place, the yields of aromatics, paraffins and naphthenes vary, as in Exhibit 39.

Exhibit 40. Product yields in each reactor



Source: own elaboration.

b) Other light oil processing units

Apart from the units detailed above, refineries have other options to add value to their production, such as Isomerization and Alkylation.

The Isomerization unit is used to improve the quality of the C5 (pentane) and C6 (hexane) fraction, also known as light straight run naphtha (LSR Naphtha). This unit's main objective is to increase the research octane number (RON[18]) of the LSR Naphtha from around 65 to 90, and is composed of three sections: feed preparation, Penex and Molex.

In the Alkylation unit, olefins with lower molecular weight C3-C5 and isobutene react together to produce isoparaffins with a molecular weight mainly in the range of C7-C9 in the presence of strong acid catalyst (sulfuric or hydrofluoric acids). The product is a liquid component called alkylate, with excellent gasoline blending characteristics in both octane number and volatility.

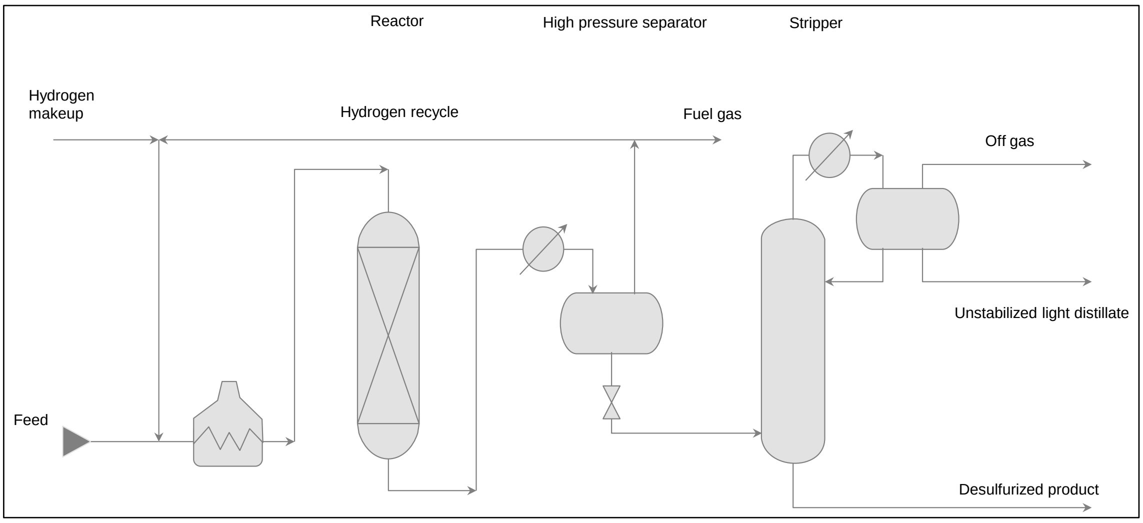
c) Hydrodesulfurization

Hydrodesulfurization (HDS) is the process that is used to remove sulfur from petroleum products at any stage within a refinery. There are two main applications of the HDS process: 1) as an essential process used to minimize sulfur levels in refinery products, to ensure that the sulfur content stays below the legal limits; and 2) reduce the sulfur to permissible levels in the feedstock to Catalytic Reforming units, since sulfur is a killer of the catalyst in these units.

[18] Research Octane Number (RON) is a measure of anti-knocking properties of gasoline, reflecting the behavior of the fuel to ignition, in the engine, during combustion.

The process consists of mixing the product to be desulfurized with hydrogen under pressure, bringing it to the required temperature and into contact with a catalyst by passing it across a fixed bed reactor. The chemical reactions that take place involve the hydrogen combining with sulfur atoms in the hydrocarbon molecules, to form hydrogen sulfide. Other reactions that can take place in an HDS unit are hydrodenitrogenation, where nitrogen atoms are removed from the hydrocarbon molecules to form ammonia, and the saturation of olefins into paraffins.

Exhibit 41. Simplified HDS unit schematic



Source: Kraus, R. (2011), "Encyclopedia of Occupational Health and Safety", Petroleum Refining Process in 78. Oil and Natural Gas, International Labor Organization

Following the simplified schematic of Exhibit 40, the feed is initially pumped up to 30-100 bar, and is then mixed with fresh hydrogen and a hydrogen-rich recycled gas, before being heated to 300-400°C across a range of heat exchangers and a process heater. It is then at the required reaction conditions, and it is passed into a fixed bed reactor, where it comes into contact with the catalyst and the key chemical desulfurization reactions take place. The product is then cooled and reduced in pressure, across a series of heat exchanges and a pressure controller, before passing into a gas separator (typical conditions are 3-5 bar and 30-50°C). The majority of the hydrogen-rich gas produced in the gas separator is combined with fresh feed as recycled gas, following a pass through an amine contactor to remove any hydrogen sulfide gas present; any extra gas produced in the gas separator, and not required for recycling, is combined with the sour gas to be sent to the main amine treating unit. The liquid product from the gas separator passes onto a stripper tower, and the product produced from the bottom of this tower is the desulfurized product. The sour gas produced from the top of the stripper, through the reflux drum, contains light hydrocarbons and hydrogen sulfide, and is sent to the main amine gas treating unit where the hydrogen sulfide is removed, so that the hydrocarbons can be recovered and used as refinery fuel.

d) Blending

The refining processes described previously generate products whose specifications not always comply with the market specifications requirements. Some exceed, but some others are below the minimum market requirements and then cannot be commercialized directly. Thus in order to recover those which are below the specifications and to avoid giveaway, final product specifications can be adjusted to those of the market by blending the different streams.

The objective of the blending stage is to optimize production by mixing components out of the units, often adding additives or other products (e.g. biofuels to satisfy legal requirements), in the most efficient way, ensuring that the desired product legal and commercial specifications are met. Refinery blenders work on optimizing the blending, and elaborate recipes, which must be followed precisely by the operators, in order to maximize production of high value products with specifications complying with the requirements and then margin. Positive deviations between the actual value and the target specification produce the so-called "quality giveaways," which imply a loss of margin for the refiner, since the product is sold without receiving a price premium for the exceeding quality.

Depending on the refinery characteristics, the blending can be performed online, with online analyzers that measure, in real time, the evolution of the blending, or directly in the end tank, by taking and analyzing product samples. The first of these two options is more efficient, as it allows for better accuracy in the final specifications, minimizing the quality giveaway for the product.

Product specifications must be checked before sending the products to the market, to ensure they comply with quality, health and environmental regulations and product market standards. The specification requirements depend on the type of final product, as can be seen in the following Exhibit 41 (only typically limiting requirements are shown):

Exhibit 42. Refined product specification requirements

	Gasoline	Kerosene	Gasoil
Octane number(s)	√		
Reid vapor pressure	√		
Density	√	√	√
Volatility / Distillation	√	√	√
Freeze point		√	
Flash point		√	√
Cloud point			√
Pour point			√
Cetane			√
Cold filter plug-in point			√
Viscosity			√

Source: own elaboration.

Most blending properties are non-linear, which means that the prediction of product quality must be done using experimental correlations that depend on the properties of the components, and their quantities in the mix. A common way to determine the properties of the blended product is by using the blending index (BI) of a property, as follows:

$$BI_{Property,Blend} = \sum_{i}^{n} x_i BI_{Property,i}$$

where x_i is typically the volume or mass fraction of component i, $BI_{Property,i}$ is the blending index of the analyzed property for product i, and $BI_{Property,Blend}$ is the blending index of the mix. Therefore, it is necessary to calculate the blending index of each property, in order to determine the properties of a blend, as can be seen in the following example equations for two of the blending properties.

BI for Reid Vapor Pressure (RVP): $BI_{RVPi} = RVP_i^{1.25}$ with x_i volume fraction

BI for Flash Point: $BI_{FPi} = FP_i^{1/-0.06}$ with x_i volume fraction

The importance of precisely determining the property of a blend, and the necessity to use the most accurate estimations, relies on the importance of the quality giveaway for refineries, i.e. loss of margin. Thus, blenders must determine the blending recipes rigorously, in order to achieve the highest margin per produced barrel.

2.2. Refinery complexity

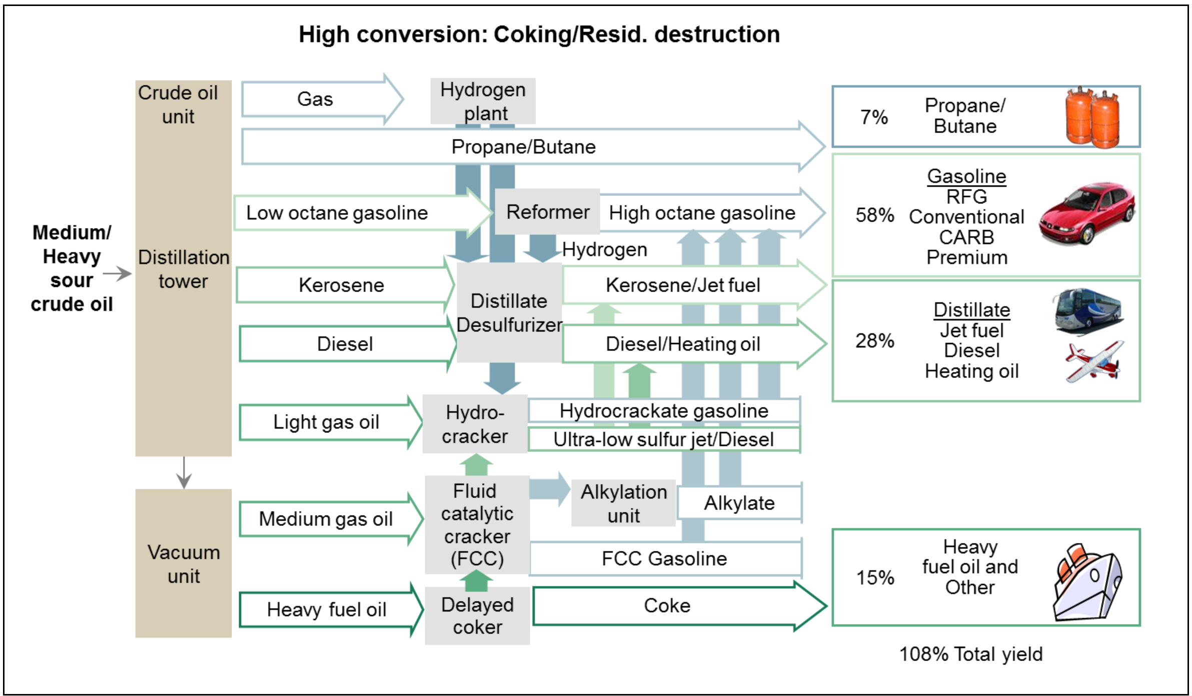
Refineries are complex industrial sites that adapt their refinery process configuration to the available crude oil and the desired production mix (depending on availability of capital to invest). Depending on the amount of conversion capacity (i.e. total capacity of processes dedicated to the conversion of heavy products, such as vacuum gasoil or vacuum residue, into high-value light products, such as gasoline or gasoil) of the refinery, it will be catalogued as a low-, medium- or high-conversion refinery, although there is no official definition. The term “conversion” is used as a reference to the percentage of oil that the refinery transforms into light and middle distillates.

Refineries range from simple to very complex, depending on the number of units they combine, and/or their type; the presence of conversion units are the main indicator of the complexity of a refinery. A low-conversion refinery is one with limited or no conversion capacity, and typically also limited desulfurization capacity, so that it has to process light and sweet (low sulfur) crude oils to achieve a profitable mix of marketable products. Low-complexity refineries produce more lower-value products, like fuel oils and asphalt. On the other hand, high-complexity refineries can process heavier and sourer crudes to make predominantly higher-value products.

There are three commonly known types of refineries: 1) Topping, mainly consisting of an Atmospheric Distillation unit; 2) Hydroskimming, consisting of Topping refinery plus Catalytic Reforming and Hydrotreating units; 3) Cracking, consisting of an Hydroskimming refinery plus any cracking process besides Coking; and 4) Coking, when the refinery also has a Coker unit.

Exhibit 42 shows an example diagram for a high-conversion refinery.

Exhibit 43. High-conversion refinery diagram[19]



Note: volume yields.
Source: Valero Energy Corp

Refinery complexity has evolved over time, as has market competition, resources and variables. Alternatives to heavy fuel oil (natural gas) have increased, heavier and more difficult-to-process crude oils are being produced, and higher crude prices, more stringent sulfur content and other product specifications have arisen. As heavier crude oils yield a higher share of residual products when distilled, a refinery needs conversion capacity, in order to process the bottom of the barrel with a positive economic impact. This implies the need for significant investments to build the new units, but also noticeably increases the complexity of the processes and operations of the refinery. A higher degree of expertise and more advance planning and support tools are required to run the refineries. On the other hand, heavier and other lower-quality crude oils sell at a discount price, which makes them an attractive opportunity, and provides bigger margins to more complex refineries when processing them.

Refineries with higher complexity may operate in multiple economic "configurations" or processing tranches, when the process units do not have balanced capacities. In

[19] American refinery, gasoline driven example.

order to maximize the economic value of the operations, refiners operate with filling their conversion units (Coker, FCC, HCK) in their most economic configuration as their primary objective. As capacity is exhausted for a unit, that tranche's capacity is capped and a new, less economic tranche starts with a new configuration: therefore, the higher the volume of crude oil that is processed, the lower the margin obtained from the marginal volume processed, as the most profitable units are already producing at their maximum capacity. Refineries process crude oil until the last barrel provides a positive net cash margin.

2.3. Objectives and priorities for players in the refining industry

In the context of challenging oil prices, O&G players are increasingly relying on their refining divisions, to support the company with their strong cash flow generation. In the current scenario, refiners are pursuing strategic alternatives to foster growth, and ensure their long-term sustainability in two basic objectives: increase profitability and protect margins, and develop growth opportunities, which are set out below.

2.3.1. Increase profitability and protect margins

To address this topic, the section is divided into three sub-sections: 'Refining margins', 'Transformational and operational excellence programs to increase profitability' and 'Increase in the level of integration/coordination across the value chain to optimize the integrated margin'.

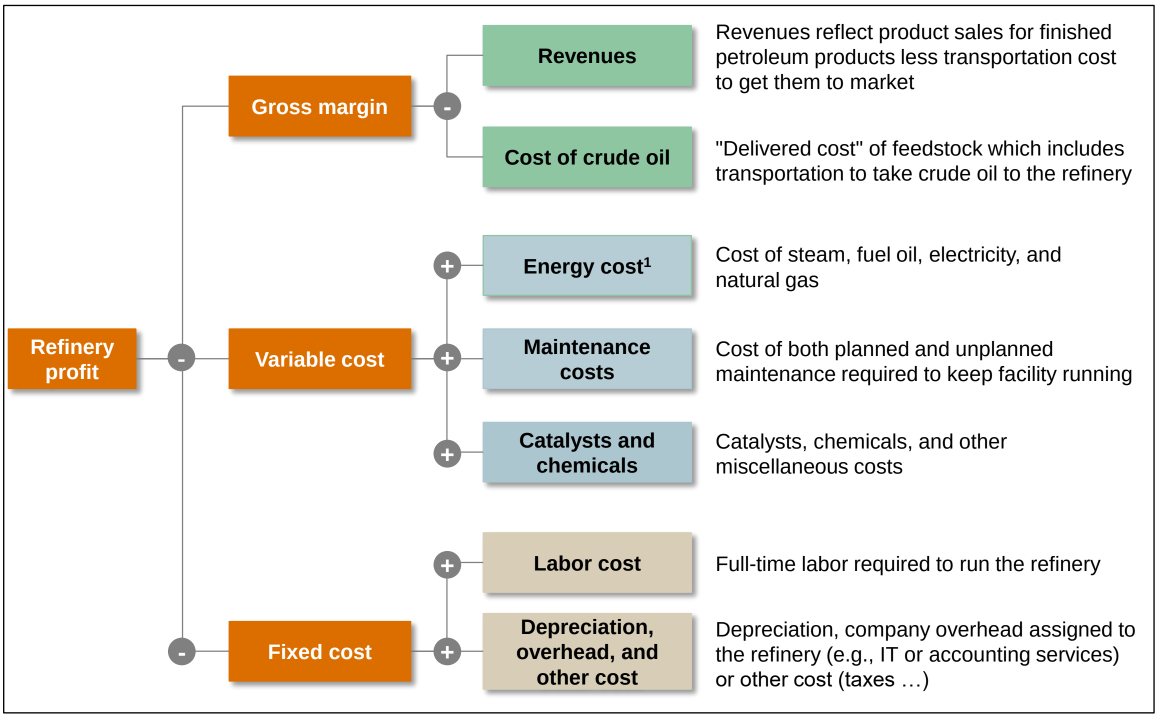
a) Refining margins

Gross margin of a refinery is preponderant for profit assessment. The most common way to define profit is as the difference between the gross margin (also represented by the so-called cracks or crack spreads) and all (variable and fixed) operating costs (see Exhibit 43).

The well-known oil industry crack spreads are a measure of the differential between the price of crude oil and the price of the petroleum products refined from it. They are often used as a proxy for theft profit that an oil refinery can expect to make by "cracking" crude oil. It applies for various crude oils (and their distillate yields) and different refinery complexities (e.g., 3-2-1, 5-3-2, 2-1-1, which mirror the ratio of crude oil to gasoline and middle distillate products and depend on the level of refinery complexity). It is easy to use but assumes overly-simple crude slates and product yields.

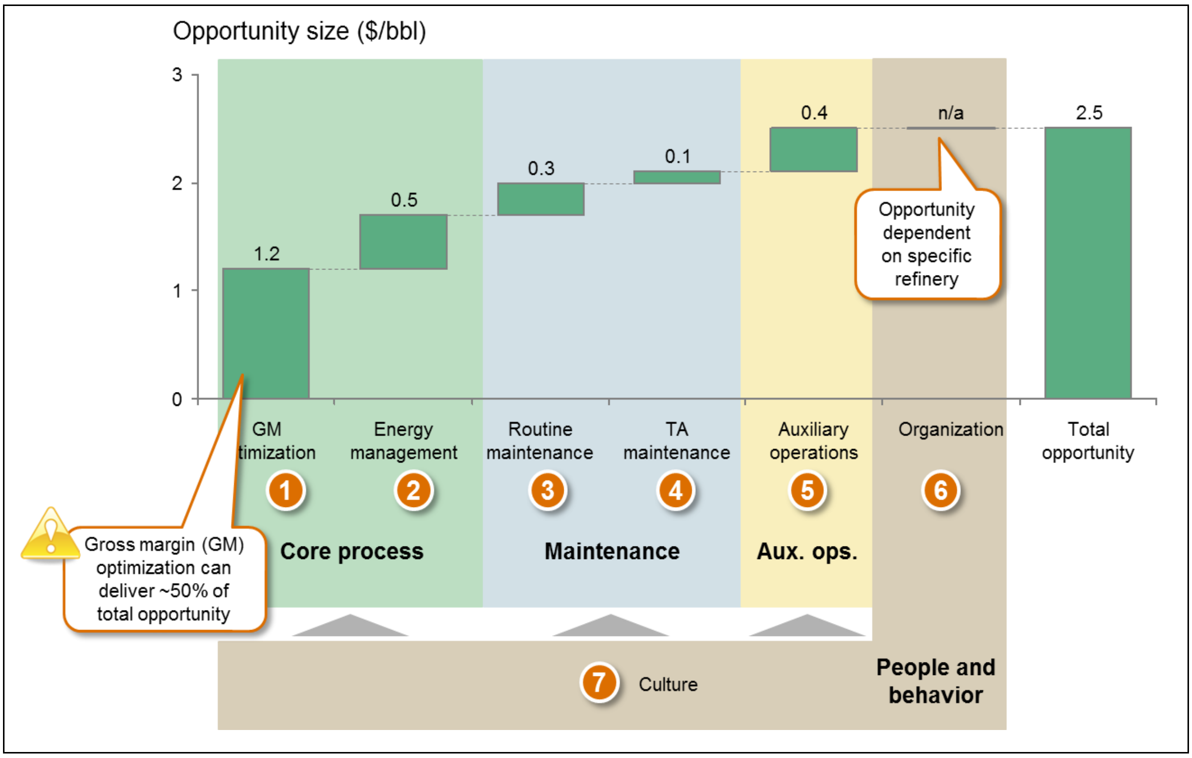
The operating costs include all the other costs that a refinery has to incur in order to run its operations: energy, maintenance and employee costs are the three main buckets.

Exhibit 44. Components of refinery profitability



1. Energy imported by the refinery (i.e. steam included if it is sourced from outside the refinery).
Source: BCG experience.

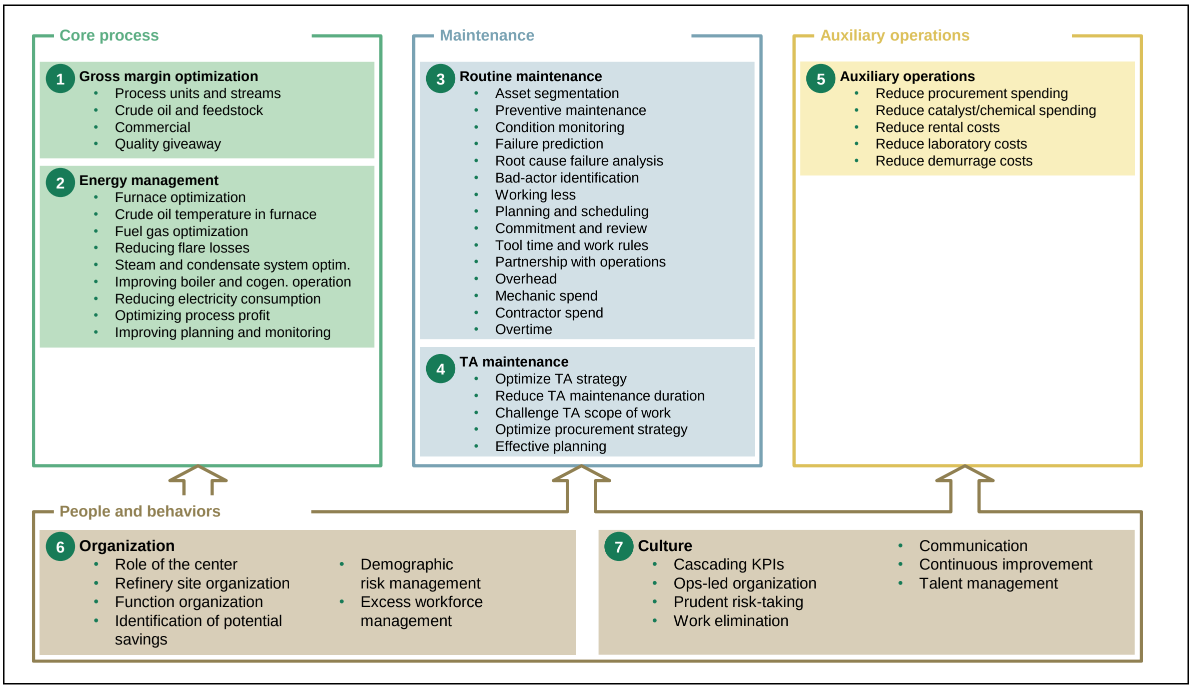
Exhibit 45. Total profit improvement opportunity



Source: BCG experience.

Overall, gross margin optimization alone can account for 50% of the total profit improvement opportunity, followed by energy management and auxiliary operations (see Exhibit 44 and Exhibit 45).

Exhibit 46. Improvement opportunity items of total profit



Note: maximum range of opportunity based on the economics of a refinery with a production of 300K bbl/d and $3/bbl margin in a "mid-cycle" or "average" margin environment.
Source: BCG experience.

In a nutshell, enhancing the core processes means making the best use of inputs to create the greatest possible product mix. This can be done by, firstly, optimizing the high value products' yields, based on the available crude oil, and secondly, by improving these products while maintaining low energy consumption (optimize 'energy management').

The following gross margin optimization levers can deliver an improvement of up to US$1.2 per barrel: a) *process units and streams*, to obtain the most value from various units, making sure that they are set at the best configuration, (with no losses, etc.); b) *crude oil feedstock*, to reduce the cost of the input (selecting the cheapest one that will still provide the required output at similar operating costs); c) *commercial*, to consider market conditions and contracts that may serve to optimize the gross margin; and d) *quality giveaway*, to help enhancing outputs, making sure that any specification required by law is met, but not exceeded.

Main factors that drive refining margins

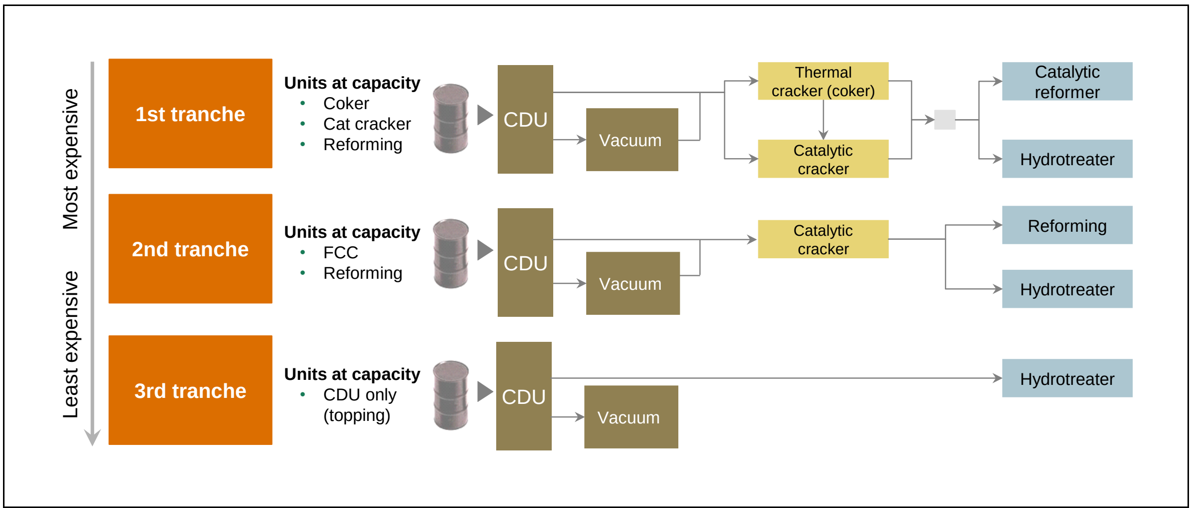
Margins in the refining industry experience important fluctuations such as those seen in recent years. They are affected by an array of factors at local, regional and global scale, such as:

Product demand is one of the main forces that drives prices and impacts margins. As seen in the previous section, overall product consumption is highly related to economic growth and to other dynamics at a lesser extent, such as seasonal consumption (e.g. heating oil in winter) or technological evolution. This allows for more efficient engines with lower fuel consumption, or specific product taxation. In addition, there are links to local/regional regulations on products, biofuel mandates, or alternative energy sources available.

The *marginal configurations* on which refineries can operate are called “tranches.” The first tranche is always the most complex, as well as the one offering the highest margin. However, refinery units are often not balanced, meaning that some of them – usually the most complex ones– reach capacity before others. Once this happens, the refinery operates on a less economical tranche that uses fewer units, and it will continue operating and going down to lower tranches as long as the margin remains positive.

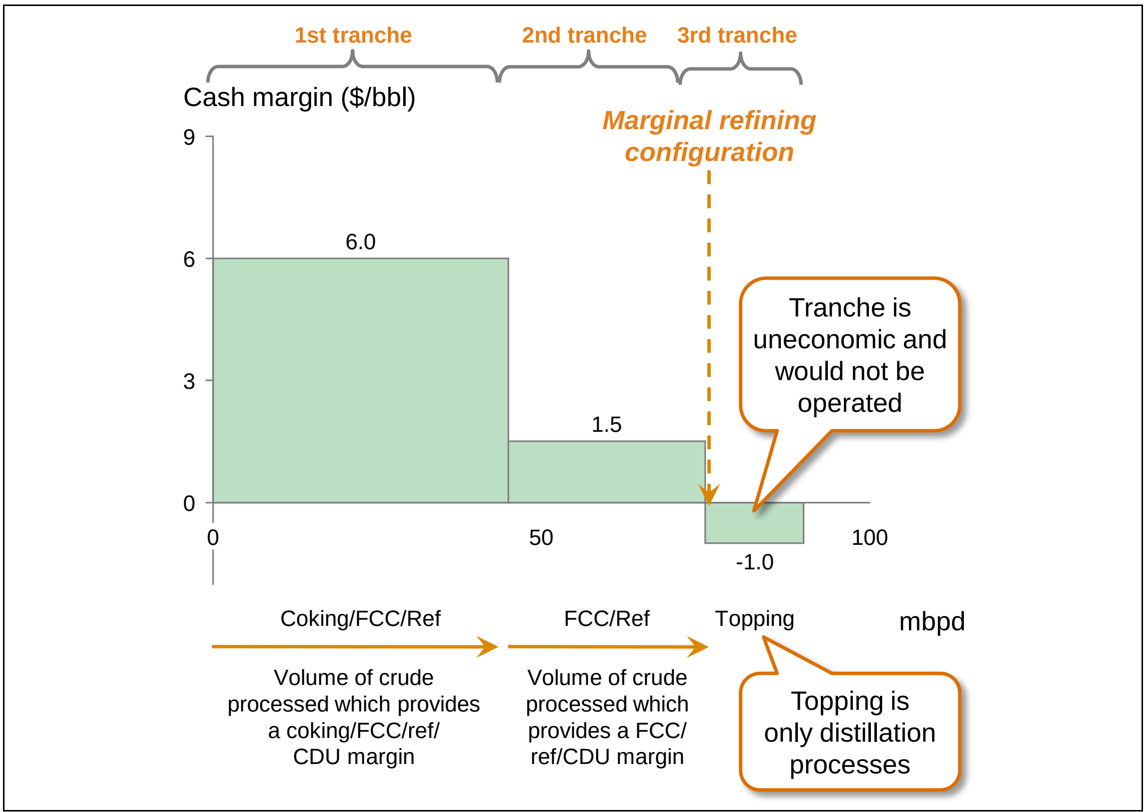
The last tranche offering a positive cash margin is called the marginal refining configuration. Hence, a complex refinery may be using its most complex units in its first tranche, but it can also operate on the marginal segment as a simple refinery (see Exhibit 46) and continue doing so as long as the margin from a barrel is greater than zero (see Exhibit 47).

Exhibit 47. Refinery operational tranches



Note: CDU – crude distillation unit; expenditure trend does not relate to the unit’s refining margin.
Source: BCG experience.

Exhibit 48. Refinery supply curve example



Note: in this case, the marginal refinery configuration is given by the tranche FCC/Ref, which combines the use of FCC and Reforming, on top of Crude Distillation.
Source: BCG experience.

Crude throughput is the amount of oil that a refinery processes. This is mainly driven by the demand for oil products (mainly by gasoline and middle distillates) in the refinery area of influence, but it also depends on the availability and reliability of its process units.

Structural factors are linked to the processing structure, logistics and location in order to access the markets. As the complexity of a refinery increases, product yields and the gross margin follow this behavior, as long as access to the markets is feasible (see Exhibit 48).

Refinery operations refer to the ability to maximize margins by lowering crude supply costs, which enhances operational flexibility, and to minimize operating costs (see Exhibit 49).

Exhibit 49. Structural factors impacting refinery competitiveness

	Description	Range of margin advantage
1 Supply and/or energy factors	• Access to lower-cost crudes or other refinery feedstocks • Lower energy cost (gas)	$1.0–1.5/bbl $0.5–1.0/bbl
2 Scale	• Scale effect can lead to lower operating and maintenance costs per barrel	$0.5–0.8/bbl
3 Complexity	• The ability to transform low-value residue into high-value products	$4.0–6.0/bbl
4 Petrochemical integration	• Colocation with petrochemical activities can generate synergies, lowering cost or increasing the value of what is produced	$0.5–1.1/bbl
5 Access to markets	• "Short" or "balanced" markets where supply doesn't exceed demand • Ability to access markets via land and water expands options	$1.0–2.5/bbl

Source: BCG experience.

Exhibit 50. Refinery operations impacting refinery competitiveness

	Description	Opportunity size
1 Gross margin optimization	• Maximization of the margin between the commercial value of the outputs and the cost of the inputs (crude oil) by lowering costs and maximizing revenues by producing the most valuable final products	$1.2/bbl
2 Energy management	• Energy cost reduction, including optimizing the furnace, fuel gas, and the steam and condensate system	$0.5/bbl
3 Routine maintenance	• Maintenance cost reduction and optimal maintenance planning	$0.3/bbl
4 TA maintenance	• Turnaround productivity increases and cost decreases by effective planning, optimizing procurement strategy, challenging the scope of work, and reducing maintenance duration	$0.1/bbl
5 Auxiliary operations	• Auxiliary operations cost reductions, including reducing nonfuel procurement, equipment rental, lab test, and logistics costs	$0.4/bbl
6 Organization	• Organizational design improvement, headcount rationalization improvement, and excess workforce management	Varies

Source: BCG experience.

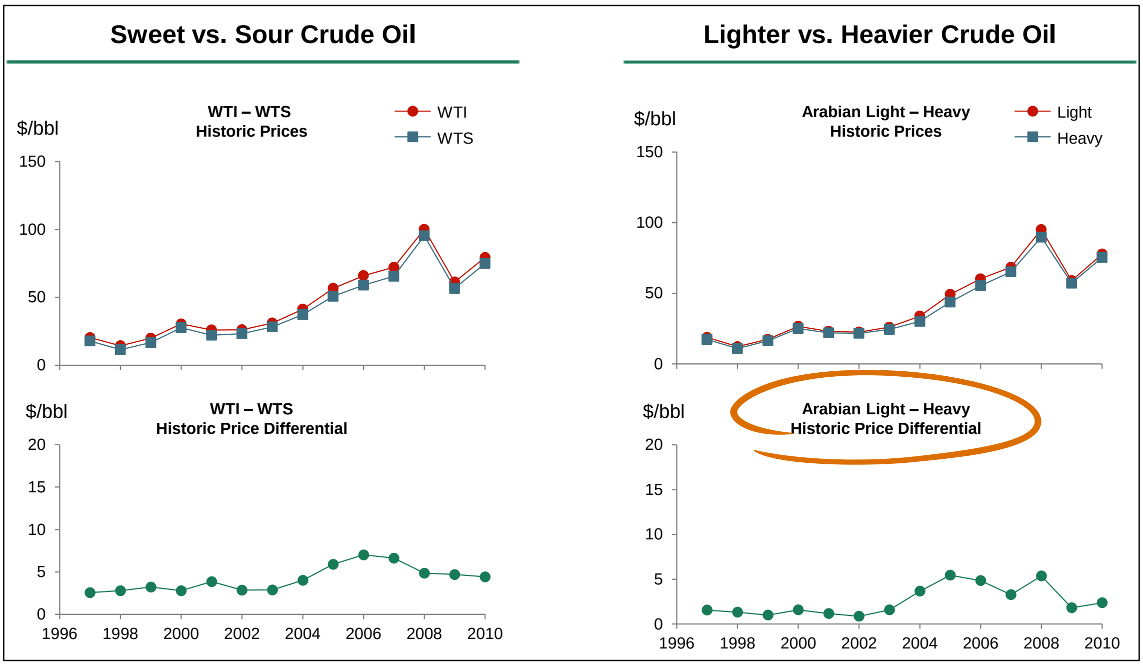
Light-heavy product price differentials (LH). The LH differentials calculated using the difference between the price of light products, such as gasoline and diesel, and the price of heavy products (priced below crude oil), such as fuel oil, is an essential driver of refinery margins, particularly for complex sites. The greater the difference between the prices of the light products and the heavy products that a refiner sells, the higher the margin is.

Refineries that can convert crude oil into light products with high yields benefit from wider LH differentials. Complex refineries that can run different oil types and process slates with sour and heavy crudes, are generally priced lower than sweet and light (see Exhibit 50) to produce light products at high yields.

Sweeter (oils with a smaller amount of sulfur) and lighter crude oils are normally more expensive, as they do not require the same complexity or severity of processes and energy consumption as a sourer and heavier oil, in order to be processed into the different value-added refined products.

Taking into account the large diversity of oils, the price of a particular type is normally set at a discount, or at a premium, against marker or reference prices, known as benchmarks. Periodically, the differentials are adjusted to reflect disparities in their quality, as well as the relative supply/demand dynamics of the various types of oil.

Exhibit 51. Sour and heavy crude oil price differentials evolution



Source: Energy Information Administration

Determination of marginal profit

Taking a deeper dive into marginal demand for heavy material, which drives fuel oil prices and the light-heavy differential, there are three main uses for fuel oil: a) traditional, such as bunker (or ship/tanker) fuel, power plants, and industrial uses; b) refinery upgrading to lighter products, c) and natural gas and coal replacement when fuel oil drops below their prices.

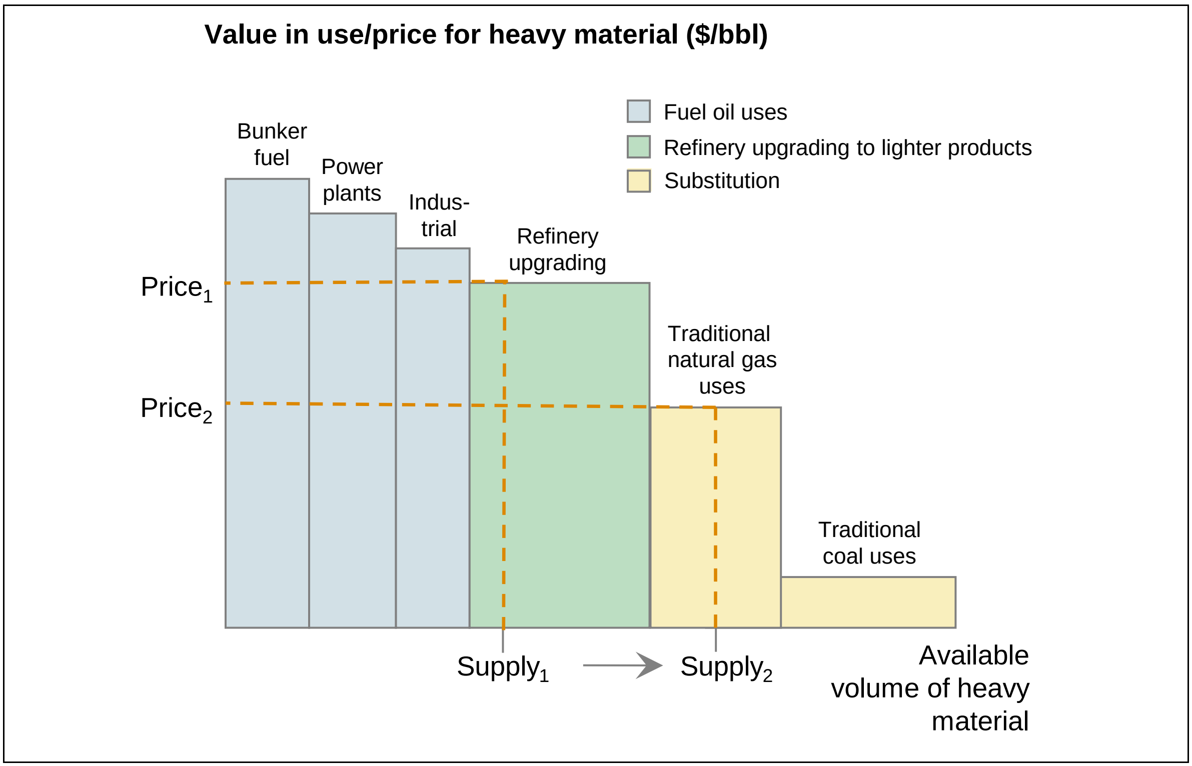
In Exhibit 51, the x-axis portrays the demand from each use, while the y-axis shows the marginal profit in each market.

When the supply of fuel oil is lower than its demand plus the refinery upgrading capacity (the blue and green columns), conversion economics determines fuel oil prices and the light-heavy differential. In this case, L/H spread is narrow.

On the contrary, if the supply is higher than the demand plus the refinery upgrading capacity (within the yellow column space), substitution economics determines fuel oil prices and the light-heavy differential. In this field, the price is determined by its equivalent heat-value to gas or coal, and the L/H differential goes from moderate to wide, depending on the absolute value of coal and gas prices. This means that the price of fuel oil is very low in comparison to lighter products.

As the supply of heavy materials moves from $supply_1$ to $supply_2$, the price falls from $price_1$ to $price_2$ and the L/H spread widens.

Exhibit 52. The supply curve determines marginal profit



Source: BCG experience.

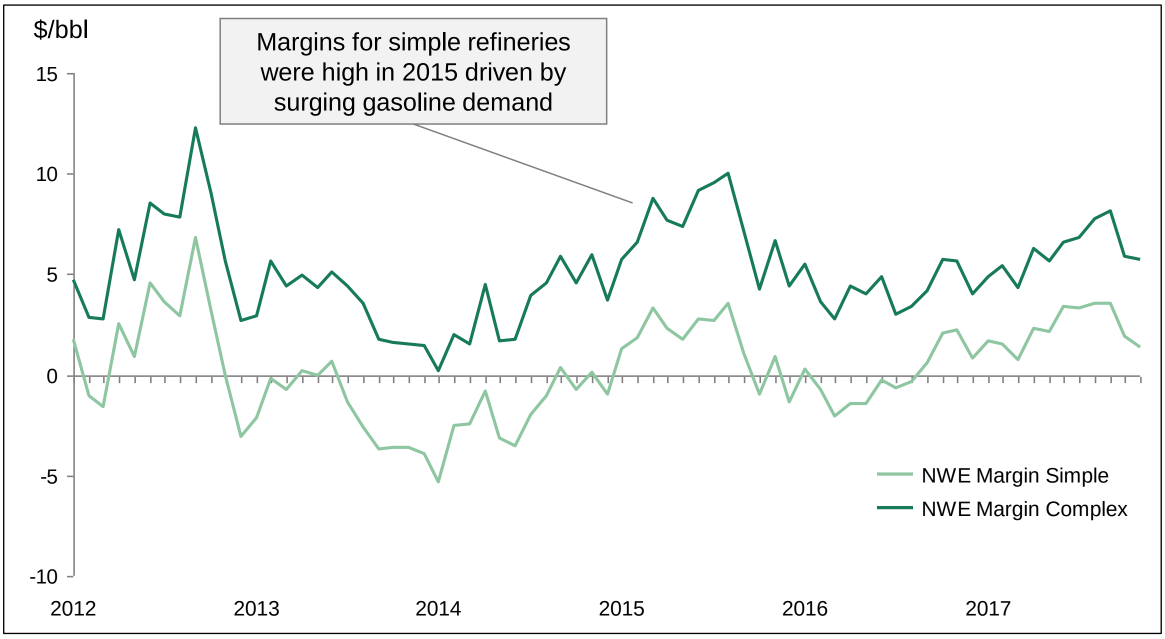
Margin evolution

Now more than ever, refineries should strive to maximize their business. Before a new rise at the end of 2014, their margins have been narrow for several years, mostly due to a low demand for products and overcapacity. This pushes their owners to aggressively look for ways to improve their profits by decreasing costs and increasing revenues. The sudden decline in prices was a key contributor to this state of balance, which was followed by a delay in their movement. Many refineries filled their inventories, provoking an apparent higher demand.

As shown in Exhibit 52, a complex refinery configuration retrieves higher variable margins.

"EU refineries are negatively impacted by the demand-reducing impact of biogasoline, as there is a surplus production of conventional gasoline at the EU level. If, hypothetically, biogasoline consumption had remained at its year 2000 level, then the EU demand for conventional gasoline in transport would have been 3.4 % higher in 2012, and 1.1 % higher cumulatively over 2000-2012. A model-based analysis by IHS suggests an associated impact on average EU refining margins between EUR 0.01 and EUR 0.20 per barrel of throughput during 2006 to 2012, and between EUR 0.01 and EUR 0.35 in 2012. Nevertheless, the overall drop in EU gasoline demand exceeded the policy-driven increase in biogasoline consumption by a factor of more than 10. Biogasoline is, consequently, only a minor cause of the current EU gasoline surplus." (in *EU Petroleum Refining Fitness Check: Impact of EU Legislation on Sectoral Economic Performance*, 2015, European Commission).

Exhibit 53. NWE[20] Complex vs. Simple refining margins



Source: International Energy Agency.

After defining the context for refining margins, the most urgent matter now is to explain how to increase profitability. To this end, the following paragraphs will address: 'Transformational and operational excellence programs to increase profitability'; and 'Increase in the level of integration/coordination across the value chain to optimize the integrated margin'.

[20] NWE: North West Europe; NWE simple: hydroskimming; NWE complex: cracking.

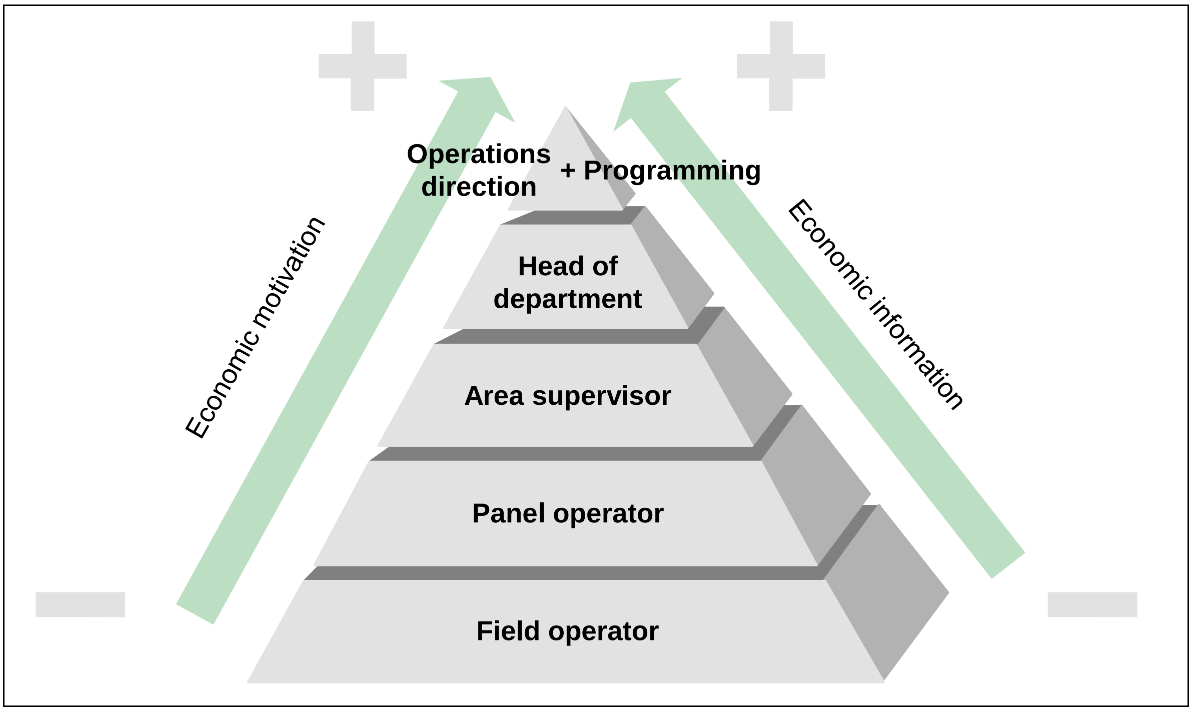
a) Transformational and operational excellence programs to increase profitability

In the short term, it is likely that the refining industry will experience important reductions in investments and challenges in generating cash flows which will mainly impact Europe. As such, net cash margins will be a key factor for competitiveness. Refiners are increasingly carrying out transformation programs to align their cleaner processes and products in order to comply with regulation requirements. Companies with excellent operational capabilities (a strong focus on margins, shared targets and aligned departments, and flexible enough to respond quickly to market opportunities) will provide superior value to their stakeholders. This can be achieved by optimizing operations in three different layers: processes and culture, tools; and skills and know-how.

Processes and culture

All operational processes need to be aligned and driven towards the joint optimization of margins. To do so, companies need to have a clear understanding of economic drivers throughout the value chain by engaging in active communication and using auxiliary tools. Key questions on refinery operations include: Does the trader understand the economic impact of his/her decisions throughout the value chain? Does the scheduling team know the impact of a distressed crude oil cargo? Are the operators aware of the cost of changing the quality in a diesel blending stream? Are there clear and shared criteria for economic risk at all levels (e.g. to decide when edging is required, or how to test a new opportunity in crude oil)?

Exhibit 54. Economic information in the operation organizational pyramid



Source: BCG experience.

Many refineries have a programming and planning department (PPD) dedicated to maximizing value from the crude oil barrels processed. However, the more roles are operationally focused on a refinery, the more this economic culture tends to be lost throughout the organization. Therefore, reinforcing the flow of economic information in this pyramid is key, as illustrated in Exhibit 53. This may well happen in refineries where the PPD and operations departments do not have a functioning, open and all-inclusive communication channel, or lack a guidance tool that allows operational collaborators to be aware of the economic impact of the decisions of this field. Imbuing an entire organization with an economics-focused culture is the first step to optimize margins across the value chain.

With the aim of excelling in this field, companies must empower all levels of the organization, which involves having the adequate mechanisms to delegate decision-making, and to enable a flexible structure that minimizes processing times to take action and capture opportunities. Centralized decision-making centers need to shift towards a model with accountability mechanisms for operators that provide them with the right information necessary.

Finally, strong cooperation must be present between areas to maximize total profits. As it will be explained later on, refineries must ensure that the general interest of the company is prioritized over local KPIs. In order to guarantee this, workforces require a shared, common economic language. With the combination of technical and cultural factors, significant opportunities are often identified.

Tools

Maximizing margins is one of the most complex processes in the refining industry, as it involves sophisticated models and numerical analyses that are constantly carried out in the planning and programming departments. Linear programming (LP) is a powerful tool to reach a complete understanding of economics throughout the value chain. Nowadays, major improvements have been made on these tools, and the top ones have evolved in different forms: multi-asset and multi-period models, non-linear and recursion for optimum blending, linked with simulation tools for key non-linear operations.

Paradoxically, the sophisticated tools used by today's operators to run refining units -e.g., Dynamic Matrix Control (DMC), Real Time Optimization (RTO), etc. - regularly attempt to optimize the operations economics, but the workers that manage the systems are not aware, from a quantitative point of view, of the economic consequences that an immediate decision to implement a change in the process operation could have. All these tools need to be accessible in almost all levels to be able to track and optimize margin contributions; otherwise, some margins will be systematically left on the table.

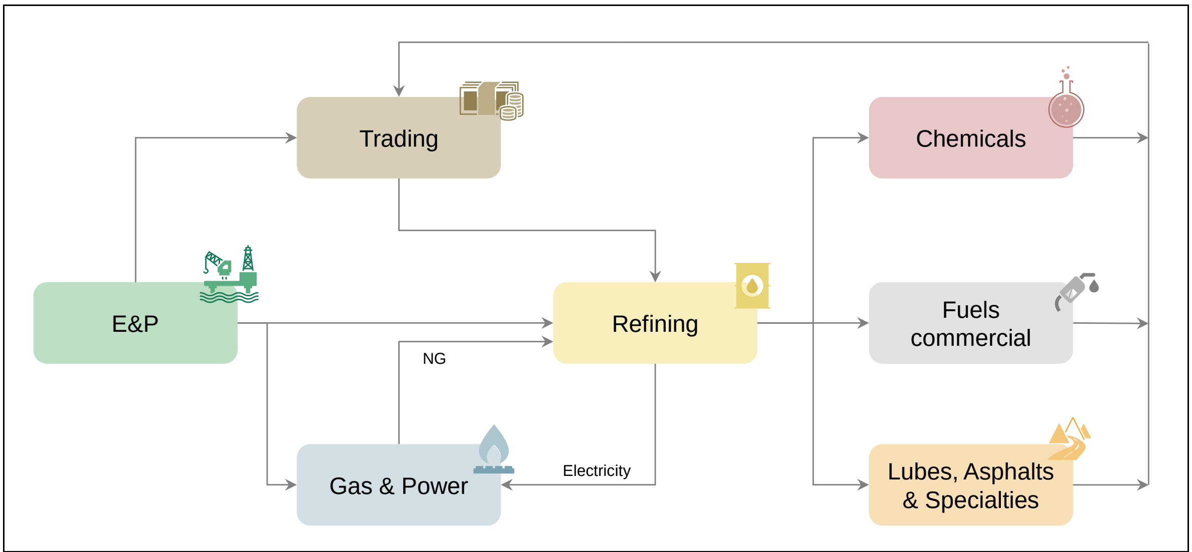
Skills and know-how

Even with an adequate organizational process and the best technology, operational excellence is impossible to achieve without a motivated, knowledgeable workforce clearly focused on reaching the highest results. Every modern refinery should have, at least: a) an established strategy to attract local talent, through cooperation with institutions and in-company rotations, b) incentives and recognition processes to retain top talent, c) a process and supporting platform in place to identify margin improvement initiatives at all levels, track them, and generate feedback (i.e. ideas from the largest group. Shift workers' ideas are normally neglected, despite the fact that they are the closest to the units and can offer relevant recommendations for improvement), d) mechanisms to share know-how throughout the organization and across divisions, to stay up to date on best practices in refining operations, and e) a training system that consistently detects and fills gaps in the development of the workforce.

a) Increase in the level of integration/coordination across the value chain to optimize the integrated margin

Margin integration with other business units is also a key element for downstream companies, so that they can acquire value from their refinery assets and technologies.

Exhibit 55. Interconnections between refining and other businesses



Source: BCG experience.

There are several interfaces that are key to maximize value, as illustrated in Exhibit 54. Adding businesses to refining -e.g. trading or chemicals- can create synergies in both businesses and make them more competitive than independently. For a company with a naphtha steam cracker with a capacity of 1Mt/year, and a refinery of

200 kbd, synergies could reach around US$100/t for ethylene, or on the refinery site, around US$1.4/bbl.

In another example, multiple refineries are integrated right next to petrochemical complexes, interchanging intermediate streams, utility units and storage. This drives the generation of synergies between the two facilities, which results in savings in transportation, maintenance and overheads, etc.

Achieving synergies may seem trivial, but there are significant opportunities even for many top-performing companies. In margin integration, the difference between mid- and top- players can vary approximately from US$0.2 to US$0.6/bbl.

Exhibit 56. Gain opportunities with integration

Source of integration value		Type of benefit	Integration value: Petchem[1]	Integration value: Refinery[2]	Financial cat.
Margin maximization	Product exchange	Intermediate product flows	37-87 $/tn[4]	25-58 $c/bbl	EBIT (up)
	Linear programming	Linear programming optimization, feedstock flexibility, ...	8-16 $/tn	5-11 $c/bbl	EBIT (up)
Operating cost reduction	Logistic savings	Minimizing transport costs, stock level optimization, ...	13.5-26 $/tn	9-17.5 $c/bbl	OPEX (down); NWC (down)
	Scale effects	Utility costs, Overhead cost, Maintenance costs, procurement...	7.5-16 $/tn	5-10.5 $c/bbl	OPEX (down)
Portfolio optionality		Includes benefits such as: • Earnings stability • Market re-balancing • LT investment opportunities	n.a	n.a	Other
Capex Optimization (illustrative for few item examples)		Capex savings on items such as: • Storage capacity • Auxiliary equipment • Common off-sites	0.6-1.0 $/tn	0.4-0.7 $c/bbl	CAPEX (down); EBIT[3] (up)
Environmental benefits		Benefits include: • Smaller footprint • Reduce emissions • Lower water demand	n.a	n.a	Sustainability (up)
Total			66-146 $/tn	44-97 $c/bbl	

1. Measured in US$/tn of Ethylene. All value of integration is attributed to petrochemicals 2. Measured in US$cent/bbl of topping. All value of integration is attributed to petrochemicals 3. Assuming 20 years of amortization 4. A maximum of 87 $/tn is for the case where the refinery has an FCC and a reformer and the petchem plant has a steam cracker and BTX extraction.

Note: the petchem and the refining values represent 100% of the savings allocated to either the petchem or to the refinery.

Source: BCG experience.

As seen in Exhibit 55, there are several types of benefits for each source of integration, with effective gains from US$0.4c/bbl to US$58c/bbl, and a greater opportunity in margin maximization and operating cost reduction.

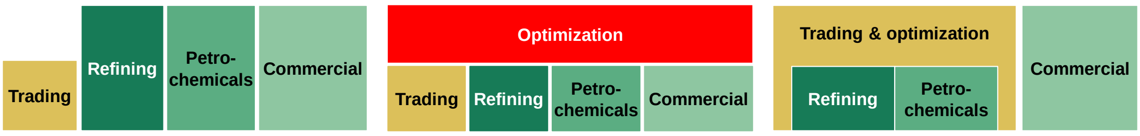
Companies can use a number of levers to make the most of the integration, adapted and tailor-made to each specific company. These can be predominantly focused on 1) Processes and coordinating mechanisms such as i) Processes/mechanisms to identify integration opportunities; ii) Transfer pricing/long-term contracts; iii) Joint linear programming; iv) Incentive systems; and v) Operating processes; and 2) Organization such as i) Business Unit level; ii) Ad hoc organizations; iii) Business teams; iv) Culture; and v) Site level.

Several enablers that allow the capture of margins across the entire value chain are detailed below and refer to: ‘Organization and processes’; ‘Incentives and culture’; and ‘Vertical integration development in adjacent countries’.

Organization and processes

In Exhibit 56, there are different structures to maximize the value chain. The first and most common approach is when refining business units (BUs) lead in capturing integrated margins.

Exhibit 57. Different value chain integration structures



Led by refining

- Businesses act in autonomously maximizing their own internal objectives
- Coordination basically established though transfer pricing
- Refining as a Business Unit

Value chain optimization

- Focus on optimizing the integrated margin
- Optimization is the key source for decision-making regarding programming and coordination
- Trading focused on accessing the market (crude oils and products)
- Refineries focused on optimizing their operations

Optimization led by trading

- Strengthen trading as a source of value creation
- Trading leads decision-making regarding programming and coordination
- Optimization becomes a middle office function within trading
- Refineries focused on optimizing their operations

Source: BCG experience.

Incentives and culture

Incentives are a key enabler to align all Business Units (BUs) and their departments in order to work on common goals. They are differentiated into three types: a) Individual: rewarding BUs based on their individual P&Ls, e.g. a chemical BU, according to how much it contributes to the business. No reward is given for helping other BUs to make money. These incentives are the most common ones in the refining industry because they foster accountability, and dissuade against “free rider” behaviors. If a chemical BU's P&L is €10M, a refining BU's is €200M, and chemicals are compensated according to a total amount of €210M, there is little incentive to increase their own P&L (5%); b) Collective: these are established by adding the P&Ls of different Bus (e.g. the €210M in the example above). These incentives avoid using transfer prices and foster overall profit maximization and collaboration; however, the risk of “free riding” exists in this group; and c) Hybrid: these are quite new to the industry. They reward BUs according to their P&L, but at the same time, they give incentives to certain departments within BUs for collective P&Ls.

Finally, to foster a culture of collaboration, companies can use several techniques: a) rotating personnel through BUs, b) sitting certain departments together, and c) introducing words or sentences to emphasize the idea (e.g. general interest, enterprise first) to be “drilled” into the employees’ heads.

Vertical integration development in adjacent countries

Usually, refining companies try to diversify their business and strengthen their cash flows by acquiring retail positions in nearby countries with common product specifications, which allow them to secure the demand for their products. By fully integrating these international positions, they can improve their financial performance and take advantage of the multiple synergies between businesses.

Marketing also offers refiners an easy entry to new markets, which helps them reinforce their international presence and gives them the chance to soften declining sales in the local market. The retail market is very sensitive to a reputable international brand, and refiners can make the most of their wholesale and fuel station businesses.

At the other end of the supply chain, there is serious discussion on the vertical integration of E&P and refining, with recent spin-offs of integrated companies, and divestment of some refineries in Europe made by major corporations. However, with a few exceptions, major companies and NOCs still go for integration, though under different economic criteria. Value creation is not clear in those cases where disintegration has occurred on the refining side of the business.

The integration between both fields has value sources whose importance depends on each company's position and objectives, which include the optimization of production and margins. Vertical integration helps maximize the value of crude oil and other byproducts and therefore, the supply cost, which has associated logistics advantages: it can reduce lead times, storage needs, stock and the number of vessels. Logistics optimization for a country with specific trading flows can represent a source of substantial value. It also helps maximize the benefit captured from the light-heavy price spread in the crude oils produced.

Vertical integration is also used as a source of risk diversification. It enables to guarantee stable markets for crude oils by hedging the risks from the evolution of the supply-demand balance. It also merges businesses with different fundamental drivers that are often uncorrelated, and eventually achieve advantages linked to risk diversification and return volatility. On top of that, it also generates options to manage regulatory risk in regulated markets.

2.3.2. Develop growth opportunities

Three main issues are explored below: Trading, Conversion and Niche markets and products.

Trading

There are many different types of players that seek to take advantage of oil-price scenarios, and these include: financial institutions, independent traders, major O&G companies and specialized trading divisions of regional O&G players.

A low and turbulent oil-price environment makes profitability in upstream operations a much harder task; however, these conditions can create a promising opportunity for trading. The driving force behind this is high oil-price volatility, which creates an increase in temporary pricing imperfections and provides a greater opportunity for arbitrage. Investing time and resources in trading can be a way for oil companies to diversify and become more stable – trading revenues are not correlated with upstream or downstream operations, so having a trading division makes a company less vulnerable to sharp swings in revenues resulting from uncertainties in other parts of the value chain. Trading can also be a standalone growth driver, and a source of competitive advantage, particularly in times of market turbulence.

The opportunities in trading can be categorized into three main categories: time, location and quality.

a) Time

Moments at which future prices for delivery are higher than current prices are known as "contango" situations. Oil companies with large marginal storage capacity are best placed to take advantage of these situations, because they can store extra inventory for future sales at a higher price, instead of selling at the current lower one.

The degree to which these situations can be exploited also depends on the cost of financing at the time – low financing costs are advantageous because the marginal profit that can be earned from the difference in spot and future prices compensates for the relatively small financing cost of the inventory buildup.

b) Location

Location arbitrage involves exploiting pricing discrepancies between different geographies. If the price difference of a product - between those locations - is larger than the cost of transporting the product between them, this extra margin can be captured. The key to being able to exploit these opportunities is to have access to the relevant logistics - terminals, pipelines, rail and storage facilities - and also to be able to physically reroute the products to different locations.

c) Quality

The supply-and-demand balance for key oil grades is continuously changing, and this, in turn, affects the price differentials between light and heavy grades and between sweet and sour grades, which directly affect the netback margins of refineries. The ones that closely follow the changing prices of different crude grades, and which have the required complexity to process a large range of crude oils, are in a strong position to maximize their profitability by changing the crude oils they purchase and process.

Traditionally, O&G companies have not focused on trading because it was not seen as their core business and entails an extra degree of risk. However, in turbulent oil-price periods with a professional oil trading team who fully understands and minimizes the risks, there is a large potential for oil companies to diversify, stabilize and grow. As a result, many regional O&G companies have begun to place a larger focus on trading in recent years, including China National Petroleum, ExxonMobil and SOCAR.

Conversion

Many companies are upgrading their assets, which increases the conversion capacity of their refineries. This allows taking advantage of a wider range of heavier (cheaper) crude oils and increasing their margins. When deciding on something as important as constructing a new unit in a refinery, economic analysis alone is not enough to make a well-informed decision. The vast amount of capital, and other resource requirements needed to carry out a project of this magnitude, may be better invested in alternatives that are more suited to the particular conditions of the company, or by taking the very same project elsewhere.

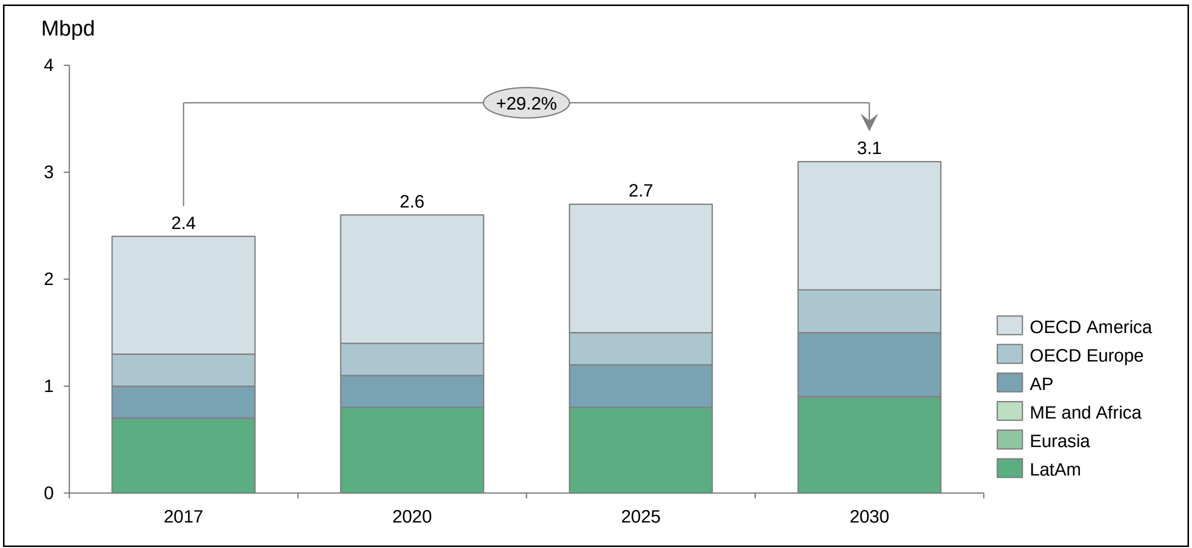
Niche markets and products

Refineries have the opportunity to leverage their infrastructure and expertise to expand their business in niche markets and products, which can provide a source of diversification and overall business growth. In this section, a few potential niche markets are introduced: Hydrotreated vegetable oil and Lubricants.

a) Hydrotreated vegetable oil (HVO)

HVO can be produced in traditional middle distillate hydrotreating units, which is an option that has been explored by several O&G companies, including Repsol, Eni and Indian Oil. The supply for biofuels is expected to grow (see Exhibit 57) as a result of political support for their development in many regions, with the aim of increasing the security of supply and reducing environmental impact. The current biofuel objectives set will require significant investments in production capacity. Therefore, refineries could seek to expand their business in the field of hydrotreated vegetable oil, where they already have the basic infrastructures in place.

Exhibit 58. Expected biofuel penetration



Source: World Oil Outlook 2017, OPEC – Table 4.10

b) Lubricants

Lubricants are more specialized and technology-dependent products than direct refinery outputs, and thus have a market price that varies less strongly with the crude oil price than their key component – base oil. As a result, at times of low crude oil prices, the margin for lubricants increases.

Many O&G companies have large investments in lubricant production and marketing, including Shell, BP and Total.

The lubricant industry is trending towards higher-quality lubricants, as a result of environmental regulations and machinery demands, which require Group II, Group III and synthetic base oils, instead of the previous most prevalent Group I base oil, resulting in greater demand for these components that will need to be met.

The main differences between the base oils groups are as follows in Exhibit 58:

Exhibit 59. Base oil group's specifications

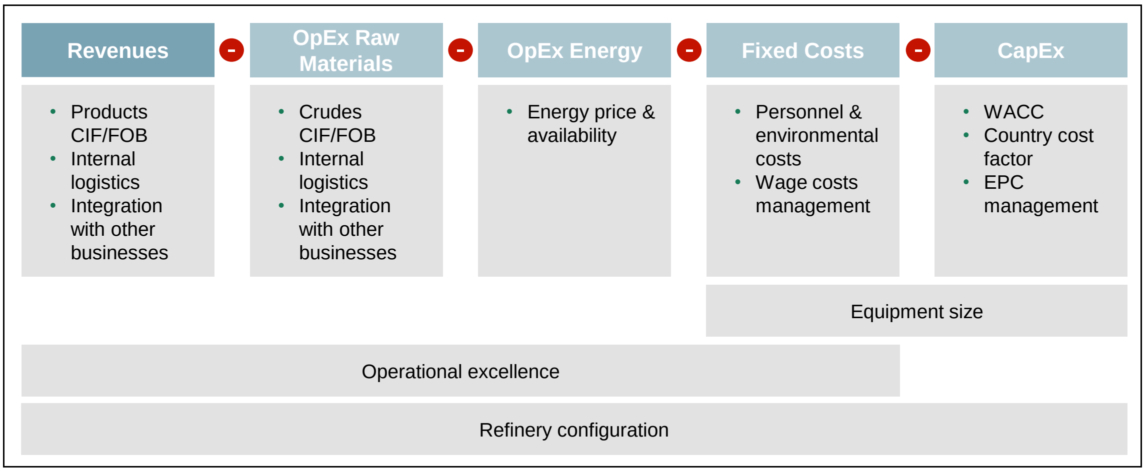
Group		Saturates	Sulfur Weight %	Viscosity Index	Process
Mineral	I	< 90%	> 0.03	80 - 120	Solvent refined
	II	> 90%	< 0.03	80 - 120	Hydro-processed
	III	> 90%	< 0.03	>120	Severe "Hydrocracked"
Synthetic	IV	Polyalphaolefins (PAOs)			Chemical reaction
	V	All other base oils not included in Groups I, II, III and IV			

Source: Noria, Machine Lubrication.

2.4. Key drivers for a successful investment

Refining investments are particularly delicate due to their complexity, elevated initial investment and the typically-lengthy payback periods, as well as the numerous factors that can turn an investment into a success or a failure. That being said, some key success drivers that affect all aspects of refineries are identified. Below is an example (see Exhibit 59), using investments in residue HCKs in Europe, as a guide to analyze some of the key economic factors mentioned.

Exhibit 60. Key success drivers in refinery investments



Source: own elaboration.

The key success factors – external and internal – are exposed below.

External Factors

a) Maximizing revenues

Three key drivers maximize the investment revenues. Understanding product pricing (CIF or FOB) in the region or the inland refinery is fundamental, as product pricing indicates whether a product is scarce or abundant in the region.

If scarcity arises, products must be imported from other regions, and consequently, the pricing mechanism - in a free market – sets the price to import parity (CIF: the price of a product will be equal to its price in the marginal exporting region, plus the transportation costs from the exporting to the importing region). On the other hand, if a product is abundant in a region, it can be exported to others, and therefore, the price is set to export parity (FOB: the price of the product will be equal to its price in the marginal importing region, minus the transportation costs). In turn, in a free market, investing in units that consume FOB products (low prices vs. global market) and yield CIF products (high prices vs. global market) would generally be more attractive than vice versa.

Another important factor which is closely related to the previous point is the region's logistics. Higher transportation costs make differences between CIF and FOB products even more significant. For example, differences between CIF and FOB prices in a country with a population that is mainly concentrated along the coast, will be much lower than in a land-locked country with a limited external connection infrastructure.

These drivers must be analyzed along with national regulations, since regulated prices may differ greatly from free-market prices. One last driver to maximize revenues is investment and retail business integration. Investments that maximize synergies with retail businesses will be more valuable.

b) Reducing raw material costs

Pricing mechanisms for crude oils (CIF/FOB) also play a pivotal role, together with the product pricing mechanisms mentioned. Investments that facilitate the consumption of FOB crude oils will be more attractive than those that require the use of imported crude oils. For example, in a refinery located in a region that exports heavy crude oils, imports light crude oils, and has problems evacuating fuel oil, investing in residue upgrading units would probably be the optimum solution. These units enable the consumption of more heavy crude oils, thereby reducing the need for light crude oils. As in the case of products, internal logistics can maximize or minimize the impact of this driver.

Another relevant factor to consider is the synergies existing with a company's upstream division, if any. Investments that facilitate integration with upstream businesses will typically be more attractive. An example would be an investment that enables the consumption of crude oils produced by upstream and with difficulties in evacuation.

c) Cutting energy costs

Energy costs can turn a theoretically-successful investment into a failure, which is why the addition of energy consumption, as well as the price and availability of energy, must be analyzed in depth. Thus, a unit consuming large quantities of gas will be more competitive in a region with an abundance of natural gas and low prices than in a region with natural gas scarcity and elevated prices.

The primary operating cost of residue HCKs stems from hydrogen consumption, whose cost is linked to the price of the gas used in its production. European gas prices are relatively high, when compared to the Middle East or the US, since the region imports large amounts of gas.

d) Minimizing fixed costs and CAPEX

The limited availability of cash has become one of the industry's primary constraints. As with any investment, the initial capital expenditure is particularly important, and recurring fixed costs in personnel, maintenance and environment-related costs must be understood and analyzed. An investment's impact on working capital is also a key driver of the success of investments in refining. As an industry that requires vast amounts of working capital to achieve a small margin, those investments that reduce working capital requirements—such as enabling the consumption of cheaper crude oils—will be very attractive. These factors are affected by two main elements: the cost of capital and country costs.

The weighted average cost of capital (WACC) accounts for the country and debt risk. It seems reasonable not to require the same returns for an investment in the European free market as one in a developing country with an elevated risk of regulatory changes. On the other hand, investments with higher risks will require lower capital costs and higher cash flows to account for the extra discount applied to the returns on riskier investments. In this case, the low interest rates and reduced associated risk in Western Europe imply lower requirements for return on investments in Europe.

Another driver to consider is the management of country costs and EPC (engineering, procurement and construction). Cost differences between countries (workforce efficiency and costs, technological developments in the country, etc.) may often tip the scale in favor of a particular location. For instance, building a state-of-the-art unit along the US Gulf Coast, with an experienced workforce, and near a strong technology industry, would clearly be different than building the same unit in a developing country where importing technology may prove difficult - and potentially twice as expensive.

The availability of expertise in EPC management is key to preventing elevated construction costs. For a company with limited experience in EPC management, investing in high-pressure-requiring technologies would be extremely risky.

Internal factors

a) Size

The size of new units is key to determine the profitability of investments, as scale is a relevant factor in boosting the return on units. With economies of scale, unit costs can be reduced in terms of the initial capital expenditure and operations. In the case of size and scale, the factor is not affected by the geographic location. In refinery units, the two-thirds rule applies quite well (e.g. for double the size, the cost is 60% greater).

b) Operational excellence

Operational excellence is also pivotal in specific refineries, as it accounts for a company's efficiency in managing investments and operation. Most of the drivers mentioned can be managed more efficiently if a refinery's operations are highly efficient on a daily basis, as this makes it easier to minimize added costs that stem from new investments (e.g. maintenance and energy costs).

Furthermore, refineries with optimized integration in other businesses will be able to maximize their investment-based revenues.

c) Refinery configuration

Finally, it is essential to analyze the marginal configuration of refineries in depth, so as to understand which investments are the most profitable.

Exhibit 61. European Residue HCK investment decision – key determining factors

Source of advantage	European player	
Feedstock: Vacuum Residue cost	FOB+	✗
Products: Diesel/Jet/Naphtha cost	CIF-/FOB	
Operation: H_2 cost	CIF	
Cost of capital	Low	✓
Labor cost	High	✗
Size	Refinery specific	?
Operational excellence	Refinery specific	?

Source: BCG Experience.

A refinery's configuration can indicate inadequacies and problems, or it can help it turn an investment into a successful one. For example, if the FCC is not operating at maximum load, and the refinery is a net exporter of fuel oil, investing in the upgrade of residues would probably be attractive.

Exhibit 60 shows a list of key determining factors for a HCK investment decision at a European player.

To sum up, in order to make such a significant investment in a region, a refinery would need to satisfy specific internal conditions, and have a competitive edge.

The conditions mentioned include being large enough to take advantage of the economies of scale, and more importantly, having a track record of operational excellence to guarantee returns - even in potentially negative future scenarios.

2.5. Summary

Refining capacity has been growing (within all the different process units), at an uneven rate, following the market demand and competitive landscape. Asia-Pacific and its emerging markets have contributed to a substantial relocation of capacity (to Asia), driven by increasing demand.

When looking at refinery complexity, it is also observed that the ratio between conversion unit capacity and distillation has been growing at a faster pace, due to the existence of new heavier crude oils in the market, which offer lower prices, and therefore, the possibility of capturing higher margins, if prepared with a robust processing complex. The requirements for very complex processing plants often include incredibly high CAPEX, to scale up operations to the point of profitability. In many cases, intuitive new engineering methods are currently not being adapted, because ultimately, the longevity, shutdown time for implementation, scant operational experience, economics and current plant design and equipment do not favor their implementation.

Refinery margins have collapsed for several years, mostly due to low demand for products, alongside refinery overcapacity. In the last few years, margins have rebounded, and the sudden decrease in crude oil price was a key contributor to this state of equilibrium, followed by delayed product price movement, while many refiners filled their inventories, provoking an apparent higher demand.

Looking at the regulatory framework, is clear the need for refiners to invest in cleaner processing structures, in order to produce less polluting products. This implies a high investment effort, which affects margins to a higher or lower extent, depending on the preparedness of each player.

Digitalization will continue to penetrate the industry in the future, but the rate at which individual companies can profit will depend on their willingness to invest in, test, and adapt to these new technologies. As digitalization is still relatively new to the industry, in the context of Industry 4.0, many of the technologies are still in their nascent stages, and real-life results are not readily available, which means that companies must perform detailed analyses, and develop strategies regarding which technologies to adopt, and how to adapt their operations to maximize their benefits.

LIST OF EXHIBITS

LIST OF ACRONYMS

Acronym	Term
ADR	The European Agreement concerning the International Carriage of Dangerous Goods by Road
AI	Artificial Intelligence
ARB	Reducing Air Pollution Program
ASEAN	Association of Southeast Asian Nations
BAT	Best Available Techniques
BI	Blending Index
BoKW	Based on Know How
BoT	Based on Technology
BU	Business Units
C2ES	Center for Climate and Energy solutions
CAFÉ	Corporate Average Fuel Economy
CAGR	Compounded Annual Growth Rate
CAPEX	Capital Expenditure
CARB	California Air Resources Board
CCR	Conradson Carbon Residue
CFD	Computational Fluid Dynamics
CI	Compression Ignition
CIF	Cost Insurance and Freight
CIS	Commonwealth of Independent States
CK	Coking
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COP	Conference of Parties
CSS	Carbon Capture Storage
DAFI	Directive on Alternative Fuel Infrastructures
DME	Dubai Mercantile Exchange
ECAs	Emission Control Areas
EE	Energy Efficiency
EGR	Exhaust Gar Recycle

EISA	Energy Independence and Security Act
EOR	Enhanced Oil Recovery
EPA	(U.S.) Environmental Protection Agency
EPAct	Energy Policy Act
EPC	Engineering Procurement Construction
EST	ENI Slurry Technology
ETS	Emissions Trading Systems
EU	European Union
EV	Electric Vehicles
ExpEx	Exploration Expenditure
FC	Fuel Cells
FCC	Fluid Catalytic Cracking
FCEV	Fuel Cell Electric Vehicles
FCF	Free Cash Flows
FOB	Free on Board
F-T	Fischer-Tropsch
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GTL	Gas to Liquids
HCCI	Homogeneous Charge Compression Ignition
HCK	Hydrocracking
HDS	Hydrodesulfurization
HSFO	High Sulfur Fuel Oil
HUD	Heads-up display
ICAP	International Carbon Action Partnership
ICE	Internal Combustion Engine
ICT	Information and Communication Technologies
IEA	International Energy Agency
IETA	International Emissions Trading Association
IMO	International Maritime Organization
INDC	Intended Nationally Determined Contributions
INOCS	National Oil Companies with International Operations
IOCs	International Oil Companies
IoT	Internet of Things

IVTM	Mechanical Traction Vehicles Tax
JV	Joint Venture
KM	Kilometer
KPI	Key Performance Indicator
LCFS	Low Carbon Fuel Standard
LDV	Light Duty Vehicles
LNG	Liquefied Natural Gas
LP	Linear Programming
LPG	Liquefied Petroleum Gases
LSFO	Low Sulfur Fuel Oil
LSR	Light Straight Run
MARPOL	International Convention for the Prevention of Pollution from Ships
MEPC	Marine Environment Protection Committee
MGO	Marine Gasoil
MON	Motor Octane Number
N2O	Nitrous Oxide
NDC	National Determined Contributions
NEDC	New European Driving Cycle
NGO	Non-governmental organization
NHTSA	National Highway Traffic Safety Administration
NOC	National Oil Company
NOx	Nitrogen Oxide
NYMEX	New York Mercantile Exchange
OFSE	Oilfield Services
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operating Expenditure
OTC	Over-The-Counter
O&G	Oil and Gas
PFCs	Perfluorocarbons
PM	Particulate Matter
PNA	Polynuclear Aromatics
PSA	Production Sharing Agreement
RD&D	Research, Development and Demonstration

RED I / RED II	Renewable Energy Directive 2009/28/EC
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
ROA-ROCE	Return on Assets – Return on Capital Employed
RON	Research Octane Number
RVO	Renewable Volume Obligation
RVP	Reid Vapor Pressure
SACROC	Scurry Area Canyon Reef Operators Committee
SECA	Sulfur Emission Control Area
SGX	Singapore Exchanges
SI	Spark Ignition
SPR	Strategic Petroleum Reserve
SOX	Sulfur Oxide
STEO	International Energy Agency Short Term Energy Outlook
TANAP	Trans Anatolian Pipeline Project
TOCOM	Tokyo Commodity Exchange
TSR	Total Shareholder Return
UCO	Unconverted Oil
UIC	Underground Injection Control
UDW	Ultra-deepwater
ULSD	Ultra-low Sulfur Diesel
UNFCCC	The United Nations Framework Convention on Climate Change
US	United States
VB	Visbreaking
VCR	Variable Compression Rates
VGO	Vaccum Gasoil
VR	Virtual Reality
WACC	Weighted Average Cost of Capital
ZEV	Zero Emissions Vehicle
%wt.	Percentage Weight

LIST OF UNITS

API	American Petroleum Institute crude grade	API gravity = (141.5 / Specific gravity) – 131.5
bbl	Barrel (of oil)	1 bbl = 42 US Gallons 1 bbl = 159 liters 1 bbl of oil equivalent= to 6003 scf (NG)= 170 scm (NG)
bpd	Barrels per day	1 bpd= 50 tonnes per year
Btu	British thermal unit	1 Btu = 0.293 Wh = 1,055 kJ
c/bbl	US cents per barrel	
kbpd	Thousand barrels per day	
kWh	Kilowatt hour = 1000	1 kWh = 3.6 MJ = 860 kcal = 3,413 Btu
Mbbl	Million barrels	
Mbpd	Million barrels per day	
Mscf (Natural Gas)	Million standard cubic feet	1 Mscf = 23.8 toe = 167 barrels of oil equivalent
Mt	Million metric tons	
PSI	Pounds per square inch	1 PSI = 6.9 kPa = 0.068 atm
scf (Natural Gas)	Standard cubic feet (of gas) defined by energy, not a normalized volume	1 scf = 1000 BTU = 252 kcal = 293 Wh = 1,055 MJ = 0.028 scm
Scm (Natural Gas)	Standard cubic meter (of gas, also Ncm)	1 scm = 39 MJ = 10.8 kWh 1 scm = 35.315 scf 1 scm = 1.122 kg
toe	Tonnes of oil equivalent	1 toe = 1000 koe 1 toe = 1 Tonne oil equivalent (US) 1 toe = 6.85 boe 1 toe = 41.87 GJ = 11.6 MWh 1 toe = 39.68 MBtu 1 toe = 1.51 ton of coal 1 toe = 0.855 tonnes of LNG 1 toe = 1,163 Scm of NG = 41,071 Scf of NG
US$ M	Million US dollars	

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