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Economic Assessment of a Crude Oil Hydrotreating Process

Wissam Muhsin*, Jie Zhang

Midland Refineries Company, Daura Refinery, Baghdad, Iraq
School of Engineering, Merz Court, Newcastle University, Newcastle upon Tyne NE1 7RU, United Kingdom
w.a.muhsin2@newcaslte.ac.uk

This paper presents the economic assessment of a crude oil hydrotreating process with a crude distillation unit. The hydrotreating of crude oil is a novel process that has great economic potential but has not been implemented widely in practice, where all the conventional hydrotreating processes are carried on each oil product separately. This new hydrotreating process of crude oil seeks to save costs and energy in crude oil refineries. The economics of this new process are compared with those of the conventional crude distillation unit where hydrotreating is conducted on each oil fraction individually. The results show that this new process of hydrotreating of the crude oil has an overall annual cost much less than that of the conventional process.

1. Introduction

Petroleum is still a major source of energy in the world (Behrens and Datye, 2013). It is a complex mixture of a large number of various hydrocarbons. The aim of the crude oil refining processes is to convert petroleum into beneficial oil products such as gasoline, kerosene, gas oil, diesel, and reduced crude (Danyelle et al., 2016). A crude oil refinery consists of different operating units such as crude distillation unit (CDU), hydrotreating (HDT), catalytic reforming units, Hydrodesulphurisation units (HDS), isomerisation units (Isom), kerosene hydrotreating units (KHT), fluid catalytic cracking (FCC), vacuum distillation units (VDU), hydrocracking units (HCK), alkylation units, coker units and others (Hsu and Robinson, 2017). In petroleum refineries, the primary purpose of HDT is to reduce the undesirable impurities, such as sulphur, nitrogen, oxygen and some other compounds (Ancheyta, 2013). In an HDT process, there are several variables and process parameters, which are feedstock, reaction temperature, pressure, liquid hourly space velocity (LHSV), and H_2/Oil ratio. Generally, HDT processes are conducted in fixed-bed reactors, and some of the HDT units operate under more severe operating conditions than others, depending on the type of feedstock (Nawaf et al., 2015). Operating conditions for HDT should be carefully chosen to obtain the best process performance (Jarullah et al., 2011).Over the past thirty years, there has been a dramatic increase in environmental concerns as a result of hazardous emissions from industries, particularly petroleum refineries (Sunita and Vivek, 2017). The increasingly stringent environmental regulations have increased the cost of producing clean oil products (Muhsin et al., 2016). Most refineries continuously try to improve and upgrade existing operating units or use new technology to meet the increasingly stringent environmental regulations which impose strict constraints on the quality and specification of oil products. Changes in operation units are made in response to internal and external categories which affect modern refineries (Khor and Elkamel, 2013). This motivates the work for producing petroleum products by using non-conventional techniques, such as by HDT of the whole crude oil. The economic analysis of an industrial refining unit, which involves the HDT of the crude oil process was studied by (Jarullah et al., 2012). However, they ignored some important economic parameters that are needed to evaluate the new process. Examples of these parameters are utility analysis and energy savings. The HDT of crude oil is a new process which has not been studied widely in the literature, where all the conventional HDT processes are conducted on each fraction separately, for instance, HDT of naphtha, HDT of kerosene, HDT of gas oil, and not on the whole petroleum. The paper is organised as follows. Section 2 gives the main chemical reactions in the HDT reactors. Section 3 describes the Aspen economic assessment. Comparison of the crude oil HDT process with CDU and conventional CDU with HDT on individual oil product is presented in Section 4. The last section draws some conclusions. The comparison results show that the

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total cost saving of the HDT of crude oil before CDU is about 50 %, which indicates that this process is better than the HDT of each oil cut separately.

2. Main reactions of HDT process

In hydrotreating reactors, various chemical reactions occur to remove harmful compounds which affect the quality of oil products. All hydrotreating reactions are exothermic, and the temperature difference along the reactor is between 3 °C and 11 °C (Bose, 2015). Additionally, desulphurisation is an essential hydrotreating chemical reaction. Sulphur compounds are transformed into hydrocarbons and hydrogen sulphide (H_2S), nitrogen compounds are converted to hydrocarbons and ammonia (NH_3), and aromatic compounds are saturated. Moreover, Hydrodesulphurisation (HDS) in oil refinery requires very sensitive procedures to reduce sulphur compounds because sulphur in high concentrations poisons the catalysts in the reactor. Thus, low levels of sulphur should be considered (Kolmetz, 2013). As discussed before, a typical HDS catalyst (Co-Mo/γAl_2O_3) has been specially developed to:

i. Decompose sulphur compounds into hydrocarbons and hydrogen sulphide.
ii. Hydrogenate oxygen compounds into hydrocarbons and water.
iii. Convert organic nitrogen compounds into hydrocarbons and ammonia.
iv. Remove metal contaminants from charge.
v. Saturate olefins.

The operating conditions of hydrotreating processes play a significant role in the removal of impurities and the process variables, such as temperature, pressure, feedstock properties, liquid hourly space velocity (LHSV) and gas rates (H_2/Oil ratio), influence HDT reactions.

3. Aspen economic evaluation

The Aspen Process Economic Analysis (APEA) within Aspen HYSYS V8.8 is used to evaluate and size all equipment in petroleum refining processes. The equipment cost calculations in APEA includes three elements:

a. **Material cost:** The material costs are determined component by component using the material prices from the material database and the rough dimensions calculated as part of the mechanical design. Material prices can be changed to suit local market conditions.
b. **Labour cost:** The labour costs are determined from the labour rate (hourly rate) and the labour hours required to fabricate each component and assembly within the equipment. The labour hours come from correlations that have been developed from several hundred labour estimates for a wide variety of heat exchanger types and design conditions. These correlations are a function of design pressure, shell diameter, weight, tube length, and material. The hours required for every shop activity and the fabrication of every component can be changed by modifying the labour efficiency factors. These are denominator quantities.
c. **Mark-ups on material and labour:** The mark-ups are used to increase or decrease the calculated exchanger cost. In addition, the design codes used for sizing for each world region are used to size the equipment and therefore used for the cost estimate.

Table 1: The conditions and dimensions for HBED reactor (Technoexport, 1969) and CDU tower (Howe-Baker Engineering, 1982)

Equipment name	HBED reactor	Equipment name	CDU tower
Unit capacity (m^3/h)	66.24	Unit capacity (m^3/h)	66.24
Vessel diameter (m)	3.25	Tray type	VALVE
Vessel tangent to tangent height (m)	7.464	Shell material	CS
Design gauge pressure (kPag)	8940	Vessel diameter (m)	2.13
Design temperature (°C)	380	Vessel tangent to tangent height (m)	20
Packing type	ALMNA	Design gauge pressure (kPag)	276
Total packing height (m)	5.75	Design temperature (°C)	371
		Tray material	SS410
		Number of trays	29
		Tray spacing (m)	0.5

However, some unit operations are not recognised by APEA, for example, the hydroprocessor bed (HBED) reactor and CDU tower in Aspen HYSYS V8.8 are not currently supported for costing with APEA, and so these units are not automatically mapped, and the process results are not utilised. This can be manually worked around by defining the mapping for the hydrotreating unit operation and manually populating the economic data summary with such mandatory specifications as diameter, design gauge pressure, design temperature, packing type, and total packing height. In this work, the above procedure was used for both HBED and CDU. Additionally, the operating conditions and dimensions of CDU tower and HBED reactor were taken from the Midland Refineries Company in Iraq, which employs the same type of crude oil and the same capacity (66.24 m^3/h) used in this work. These conditions and dimensions for HBED reactor and CDU tower are shown in Table 1.

4. Comparison of the crude oil HDT process with CDU and conventional CDU with HDT on oil products

As stated previously, the main target of a crude oil HDT process is to reduce inorganic impurities, such as sulphur and other compounds with great efficiency (Speight, 2014). In this section, the economic analysis of a crude oil HDT unit with a conventional CDU is studied and compared to that of conventional CDU with HDT on individual oil products.

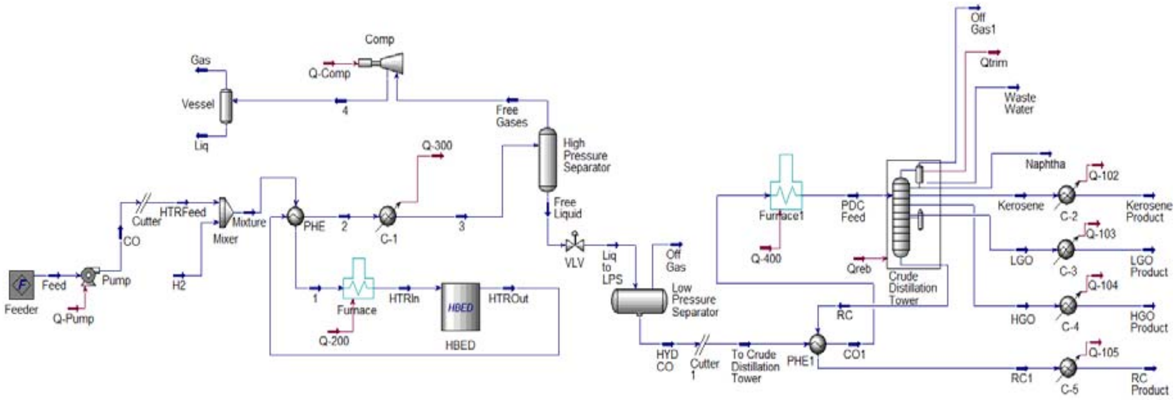

Figure 1 HDT of CO with the CDU

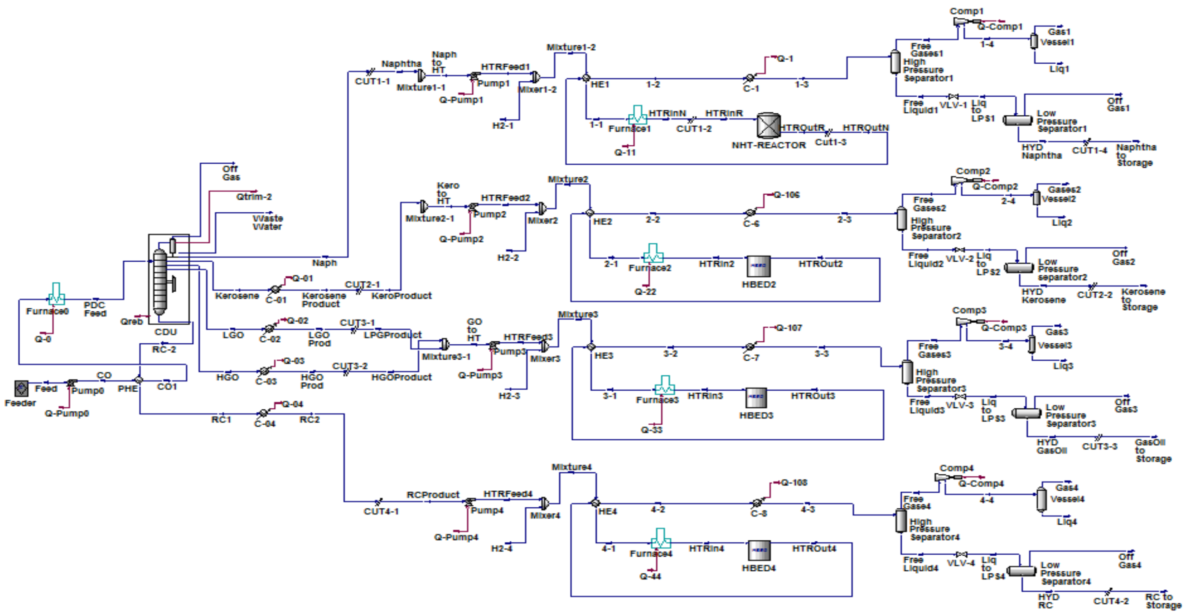

Figure 2: The conventional CDU with the HDT for each oil cut

4.1 Process description

Figure 1 shows a flow sheet diagram of an HDT of crude oil with an atmospheric tower. This process was simulated using Aspen HYSYS V8.8. In this process, petroleum is pumped to the unit and mixed with hydrogen. After that, the mixture is passed to a heat exchanger (PHE) for preheating. The charge is sent to the furnace to increase its temperature to the reaction temperature and then fed to the reactor (HBED), which contains the catalyst (Co-Mo/Al_2O_3). In the following step, the reactor effluent is partially cooled by flowing through the heat exchanger (PHE) and further cooled using the cooler. Next, the resulting mixture of gases and liquid enters the high-pressure separator to separate gases like hydrogen sulphide and unreacted hydrogen from the liquid. The gases are compressed (Comp) to the hydrogen gas net, and the liquid is sent to the low-pressure separator to release gases that cannot be separated from the high-pressure separator. Finally, the hydrotreated petroleum is sent to CDU.

The aim of the atmospheric distillation unit is to separate different oil fractions of hydrocarbons, such as off-gas, naphtha, kerosene, light gas oil (LGO), heavy gas oil (HGO), and reduced crude (RC). In the beginning, the hydrotreated crude oil is sent to a number of heat exchangers (PHE1) to increase its temperature by coming into contact with RC and then fed to the furnace (Furnace1) to raise it to the required temperature. The warm feed enters the atmospheric tower. The underlying concept of the CDU depends on the boiling point of each oil cut because each oil fraction has a specific boiling point. In addition, light naphtha and heavy naphtha are passed to the catalytic reforming unit to produce gasoline with a high octane number. Kerosene is used for domestic purposes, for instance, heating. Also, aviation turbine kerosene can be produced from this product. The next fractions are LGO and HGO, which are used mainly as a fuel for cars and buses. The last fraction is RC, which is utilised as a fuel oil for ships or as lubrication oil. Wax and asphalt are also produced after RC is sent to the vacuum distillation unit.

Figure 2 illustrates the conventional CDU with HDT on oil products. This unit is sometimes called the atmospheric distillation unit because it works at atmospheric pressure. Initially, petroleum is pumped through a series of heat exchangers (PHE) to preheat the crude oil by exchanging heat with the hot RC and other oil cuts. Following this, the charge is further heated by the furnace (Furnace) to raise the temperature, before entering the bottom of the distillation tower. As shown in Figure 2, HDT is conducted on each fraction separately. Light naphtha and heavy naphtha are sent to the hydrogen desulphurisation treating unit to produce treated light and heavy naphtha. Kerosene is passed to the ultra-low sulphur kerosene (ULSK) to produce treated kerosene or aviation turbine kerosene, which can also be produced from this unit. LGO and HGO are sent to the (ULSD) to generate treated gas oil. RC is sent to the RC hydrotreating unit to reduce sulphur and other undesirable compounds from RC and produce treated RC. In general, all hydrotreating units are carried out on a fixed bed reactor, and Co-Mo/Al_2O_3 is used as the catalyst. Moreover, the heavier oil cuts such as gas oil and RC require more extreme operating conditions (high temperature and pressure) than other oil products to obtain significant sulphur and nitrogen removal (Gray, 2015).

4.2 Capital costs

Capitals costs are fixed and involve the buying of land, equipment, design, engineering, piping, instrumentation, buildings, construction equipment and other facilities. These costs are needed to bring the operation process on the stream. A capital cost can be indicated as an annual cost if it is considered that the capital cost was obtained from a source at a fixed period over a fixed rate of interest. Thus, it is important to define annualised capital cost (ACC) of the unit, which can be expressed as follows:

$$\text{Annualised Capital Cost (ACC)} = \text{Total Capital Cost (TCC)} * \frac{i(1+i)^n}{(1+i)^n-1} \tag{1}$$

where i is the interest rate per year and n is the number of years.

The above equation can be used to compare alternative designs for a project (Smith, 2016).

Consequently, the data are obtained from the APEA in Aspen HYSYS can be shown in Table 2:

4.3 Operating costs

Operating costs can be defined as the cost of purchasing chemicals or the annual cost of maintaining all operating processes on stream. The total operating cost can be estimated utilising the following equation:

$$\text{Total Operating Cost (TOC)} = \text{Fixed costs} + \text{Variables costs} \tag{2}$$

The operating cost can be classified into two groups, fixed and variable costs: (Smith, 2016)

A) Fixed costs: operating costs which do not change with production throughput. Examples of these are maintenance, laboratory costs, insurance, operating labour, supervision, overheads, and licence fees. They can be summarised as follows: (Coulson, 2009)

Maintenance: Includes the cost of maintenance labour and the materials, usually represents 5-15 % of the total installed costs.

Operating labour: This item is one of the highest operating costs. The operating labour costs normally 15 % of the annual operating cost.

Supervision: It covers direct operating supervision and estimated as 20-25 % of the operating labour cost.

Table 2: The economic data of the HDT of crude oil with CDU and the conventional CDU with HDT from the APEA in Aspen HYSYS

Name	HDT of crude oil + CDU	Conventional CDU with HDT of oil products
Equipment cost ($)	3,208,400	8,410,400
Total installed cost ($)	6,759,800	16,362,400
The cost of design, engineering, piping, instrumentation, building and other facilities ($)	4,775,800	8,328,100
Total capital cost ($)	14,744,000	33,100,900

Table 3: Comparison of the economic impact of this work and the conventional CDU

Name	HDT of crude oil + CDU	Conventional CDU
Unit capacity (m^3/h)	66.24	66.24
Economic:		
Equipment cost ($)	3,208,400	8,410,400
Total installed cost ($)	6,759,800	16,362,400
The cost of design, engineering, piping, instrumentation, building and other facilities ($)	4,775,800	8,328,100
Total capital cost ($)	14,744,000	33,100,900
Maintenance ($/y)	337,990	818,120
Operating labour($/y)	376,807	628,456
Supervision ($/y)	75,361	125,691
Laboratory cost ($/y)	75,361	125,691
Plant overheads ($/y)	188,403	314,228
Insurance ($/y)	147,440	331,009
Local taxes ($/y)	147,440	331,009
Licence fees ($/y)	147,440	331,009
Total utilities cost ($/y)	595,788	794,825
Other variables cost (catalysts, chemicals, etc.) ($/y)	420,020	389,672
Total operating cost ($/y)	2,512,050	4,189,710
Overall annual cost ($/y)	4,182,357	7,939,711
Total cost saving (%)	47.32	0.00

Laboratory cost: It is a substantial item in the most current plants. The cost can be estimated as 20-30 % of the operating labour cost.
Plant overheads: This item includes the cost connected with operating the factory which is not involved with other headings, for instance, factory security, health centre, warehouses and safety. The cost can be estimated as 50-100 % of the labour cost.
Insurance: It covers the cost of the site and factory insurance, insurers are roughly 1-2 % of the capital cost.
Local taxes: It covers local taxes, which can be taken as 1-2 % of the capital cost.
Royalty payments and license fees: They can be paid as annual fees, or fees depending on the quantity of product sold. A typical range would be 1-5 % to the sales price.
B) Variables costs: They will rise as production throughput rises, and decline as production throughput declines. This includes raw materials, catalysts and other chemicals used in the refinery, utilities, packing and shipping. In addition, examples of utilities (services) are fuel, steam, electricity, cooling water, instrument air, an inert gas like N_2 (Sinnott and Towler, 2013).
The overall annualised cost (OAC) of a crude oil hydrotreating process can be identified as:

Overall Annualised Cost (OAC) = Annualised Capital Cost (ACC) + Total Operating Cost (TOC) (3)

To calculate ACC (equation 3), 7.5 % and 15 were assumed for the interest rate of interest (i) and the number of years (n), respectively. The results of the economic evaluation of the HDT of crude oil with CDU and the results for the conventional CDU with HDT on individual oil product are summarised in Table 3. It can be seen that the operating cost typically has the largest influence on the overall annual cost, with changes in production throughput per year compared with the capital cost. The comparison of the economic analysis in this study indicates that the overall annual cost of the conventional crude distillation unit is more than that achieved by the HDT of crude oil merged with the CDU. The total cost saving is about half 47.32 % compared with the conventional atmospheric distillation process. This is due to several reasons, summarised as follows:

- The industrial equipment and rotary machine equipment used in the conventional CDU (furnaces, reactors, vessels, coolers, heat exchangers, compressors, and pumps) are more than those used in the crude oil hydrotreating process which leads to increased operating and utility costs and the overall annual costs.
- The conventional process where all hydrotreating units are conducted on each oil product consumes H_2 more than a petroleum HDT process. The conventional method requires more energy and other utilities, such as fuel, steam, instrument air, cooling water, and electricity.

5. Conclusions

HDT of the whole crude oil can be used in crude oil refineries to remove a significant amount of sulphur, nitrogen, oxygen and some other compounds from crude oil. This kind of technology operates under extreme operating conditions such as high temperature and pressure. The economic assessment of a crude oil hydrotreating process with CDU is conducted here in this work and then compared with the conventional process where all hydrotreating processes are carried out on each oil product. The comparison results reveal that the total cost saving of the HDT of crude oil before CDU is 47.32 %, which gives an indication that this process is better than the HDT of each oil product separately. It is recommended that further research be undertaken and focused on the maximising the energy savings in a refinery.

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