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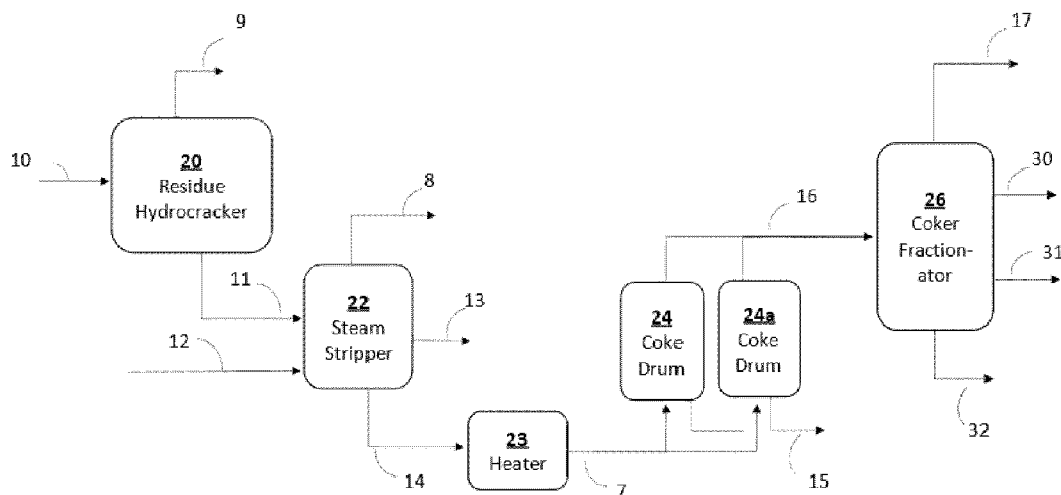
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(54) Title: INTEGRATED PROCESS FOR COMPLETE CONVERSION OF RESIDUE FEEDSTOCK

Figure 1



(57) Abstract: The focus of this invention is the economic integration of two well-known technologies to provide an economical, integrated process unit for the complete conversion of residue feedstock. The technologies employed are heavy oil hydrocracking, which can be via an ebullated-bed, fixed-bed or slurry bed process, and coking, which can be via a delayed coking or fluid coking (with or without integrated gasification). The invention is most applicable to residue hydrocracking of high CCR and metals atmospheric and vacuum residues where coking of the unconverted hydrocracker residue is the most practical and economical method of hydrocracking bottoms disposal.

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Integrated Process for Complete Conversion of Residue Feedstock

FIELD OF THE INVENTION

This invention relates to processes for hydrocracking heavy oils and oil residues such as vacuum gas oil, atmospheric residue and vacuum residue into substances having smaller molecules of greater utility.

BACKGROUND

Typically, crude oil is processed via distillation into various fractions such as naphtha, gas oil, and residuum. Each of these fractions has a number of potential uses, for example for the production of transportation fuels such as gasoline, diesel and kerosene, or as feed for some petrochemical and other process units.

Light crude oil fractions such as naphtha and some gas oils can also be used to produce light olefins and single ring aromatics via processes such as steam cracking, where the hydrocarbon feed stream is vaporized and diluted with steam and then exposed to very high temperature (800 °C to 860°C) furnace (reactor) tubes for short residence times (<1 second). In this process, hydrocarbon molecules in the feed are converted into lighter molecules and molecules with a lower hydrogen to carbon ratio (e.g. olefins) when compared to the feed molecules. The process also produces hydrogen as a useful by-product and significant amounts of lower value by-products such as methane and C9+ aromatics and condensed aromatics (containing two or more aromatic rings in common).

Typically, heavier (or higher boiling) fractions such as atmospheric or vacuum residue are further processed in crude oil refineries to maximize the yield of lighter (distillable) products from the crude oil. The treatment may be carried out by a process such as hydrocracking (whereby the hydrocracker feed is exposed to a suitable catalyst under conditions such that some portion of the feed molecules are broken down into lighter hydrocarbon molecules while being hydrogenated).

Hydroconversion processes disclosed herein may be used for reacting residuum hydrocarbon feedstocks at conditions of elevated temperatures and pressures in the

presence of hydrogen and one or more hydroconversion catalyst to convert the feedstock to lower molecular weight products with reduced contaminant (such as sulfur and/or nitrogen) levels. Hydroconversion processes may include, for example, hydrogenation, desulfurization, denitrogenation, cracking, conversion, demetallization, and removal of, Conradson Carbon Residue (CCR) or asphaltenes removal, etc.

As used herein, residuum hydrocarbon fractions, or like terms referring to residuum hydrocarbons or residue feedstock, are defined as a hydrocarbon fraction having boiling points or a boiling range above about 340° C. but could also include whole heavy crude processing. Residuum hydrocarbon feedstocks that may be used with processes disclosed herein may include various refinery and other hydrocarbon streams such as petroleum atmospheric or vacuum residua, deasphalted oils, deasphalter pitch, hydrocracked atmospheric tower or vacuum tower bottoms, shale-derived oils, coal-derived oils, tar sands bitumen, tall oils, bio-derived crude oils, black oils, as well as other similar hydrocarbon streams such as heavy oil obtained from the pyrolysis of plastic or tire materials, or a combination of these, each of which may be straight run, process derived, hydrocracked, partially desulfurized, and/or partially demetallized streams. In some embodiments, residuum hydrocarbon fractions may include hydrocarbons having a normal boiling point of at least 480°C, at least 524°C, or at least 565° C.

In some embodiments, the residue feedstock has a nickel plus vanadium content of between 1 and 1500 ppmw and more typically between 50-500 ppmw, a sulfur content of between 0.1 and 8.0 weight percent and more typically between 2.0 and 5.0 percent weight, CCR content of between 1.0 and 50.0 percent weight and more typically between 10 and 25 percent weight, nitrogen content of between 500 and 8000 ppmw and more typically between 2000 and 5000 ppmw, and an asphaltene content of between 1 and 30 percent weight and more typically between 5 and 15 percent weight. In various embodiments, the residue feedstock may include at least one of petroleum atmospheric or vacuum residua, deasphalted oils, deasphalter pitch, hydrocracked atmospheric tower or vacuum tower bottom shale-derived oils, coal-derived oils, bioderived crude oils, tar sands bitumen, tall oils, black oils. For example, the residue feedstock may be derived from one or more of Arab Heavy, Arab Light, Arab Medium, Kuwait Export, Basrah Light,

Rubble, Bahrain, Oman, Upper Zakam, REBCO, Kumkol, Ural, Azeri Light, Siberian Light, Siberian Heavy, and Tengiz petroleum crude oils. The shale-derived oils may be generated either in an in situ extraction process or an above ground oil shale retorting process. The coal gasification byproduct oils may be derived from a fixed-bed gasifier or a fluid-bed gasifier or a moving-bed gasifier. The coal-derived oils may be derived from a pyrolysis unit or a hydrothermal liquefaction unit or a catalytic hydroliquefaction unit.

Heavy refinery stream hydrocracking is typically carried out at high pressures and temperatures and therefore has high capital costs. Hydrocracking of residue is not a complete conversion process, there is an unconverted oil (UCO) by-product stream from the process. This yield of this stream can be from about 5 to 50% depending on the operating conditions of the hydrocracking unit and the reactivity of the hydrocracker feed. The UCO is typically of poorer quality than the feed to the hydrocracker – higher in density and with more contaminants such as sulfur, CCR, nitrogen, asphaltene and metals. This UCO stream can be blended with lighter streams like diesel in order to be used as a fuel oil, which downgrades the value of the diesel stream. As environmental regulations such as IMO 2020 become more strict, it will become more difficult to use this UCO stream as a fuel even after blending. In order to fully convert the UCO from atmospheric or vacuum residue hydrocracker feedstocks, this product will require further processing via a process like coking or gasification. Coking processes are usually done at a separate facility thus dramatically increasing the costs.

Coking is a thermal process that allows refineries to process heavier hydrocarbons present in oil, tar sands and other hydrocarbon sources. Basically, coking thermal processes use complex thermal decomposition (or “cracking”) in the absence of catalyst or hydrogen to convert very heavy bottoms of crude oil to lower boiling, higher value hydrocarbon liquid products. The feed for such coking processes usually consists of refinery streams that cannot be economically further distilled, catalytically cracked, or otherwise processed to create fuel mixture streams. Typically, these materials are not suitable for catalytic operations due to rapid poisoning of the catalyst with ash or metals. Common coking feeds include bottoms from atmospheric distillation, bottoms from vacuum distillation, residual catalytic cracking oils, and residual oils from other processing

plants such as hydrocrackers. The yield of light hydrocarbon liquids from coking is generally lower than achievable by residue hydrocracking (< about 70%). There is no liquid UCO product from coking, the heaviest components of the coker feed are converted to a solid product, petroleum coke. This material can be used as a fuel for power generation and the production of metals and brick.

Three types of coking processes used for crude oil at refineries to convert heavy hydrocarbon fractions into lighter hydrocarbons and petroleum coke include delayed coking, fluidized coking, and fluid coking combined with gasification. In two of these coking processes, petroleum coke is considered a by-product that is allowed in the interests of more complete conversion of refinery residues into lighter hydrocarbon compounds. In fluid coking combined with gasification, the coke product is gasified to produce a syngas, leaving no solid by-product at the end. The resulting liquid hydrocarbons and other products are transferred from the coking unit to a distillation column for separation. Heavier liquid cracking products (e.g., gas oil) are typically used as feedstock for further processing (e.g., for cracking units with a fluidized catalyst or FCCUs), which turns them into a mixture of transport fuel fractions.

As mentioned above, the current state-of-the-art is to have completely separate residue hydrocracking and coking plants. In this current configuration, the residue hydrocracker products are first separated in an atmospheric fractionator and the atmospheric residue sent to a vacuum tower. The bottoms from the vacuum tower are the feed to the coking unit, which also contains a fractionator tower to separate the liquids generated in the coking process. The residue hydrocracker's atmospheric and vacuum fractionation sections are costly in terms of capital and operating expenses, and depending on the feed processed and the operating conditions employed, can exhibit high levels of fouling that can lead to premature shutdown for tower cleaning (particularly the vacuum tower), incurring high maintenance costs. This is true even with varying feed management techniques such as bypassing a portion of the residue hydrocracker feed to the fractionation section of the residue hydrocracking unit. This fouling can also occur in the heat exchange equipment associated with the vacuum tower (feed heater and downstream vacuum bottoms cooling). An advantage of this invention is to remove the

pieces of equipment likely to incur coking in the residue hydrocracking unit (where coking is not desirable) and have the coking occur in the coking unit.

SUMMARY OF THE INVENTION

It is an object of Applicant's invention to provide for a more economical method to process heavy residue feedstocks.

It is a further object of Applicant's invention to provide an integrated hydrocracking and coking process to process heavy residue feedstocks thus reducing the required investment for separate residue hydrocracker and coking plants and significantly increasing on-stream time.

It is yet another object of Applicant's invention to teach an optimized processing configuration most applicable to high CCR and high metals feedstocks with resulting lower investment and operating costs and higher on-stream time.

It is another object of Applicant's invention to teach and disclose an integrated hydrocracking and coking process resulting the complete conversion of residue in the feed to gas, light liquids and (depending on the coking technology selected) a solid coke product with no unconverted residue to dispose of.

It is yet another object of Applicant's invention to disclose an integrated hydrocracking and coking process to process heavy residue feedstocks that eliminates the residue hydrocracker atmospheric and vacuum towers. This results in large decrease in plant investment and operating cost but more importantly the removal of the major source of fouling and associated down time.

In light of the above, there is a need for a processing scheme for efficiently and effectively integrating hydrocracking and coking for the complete conversion of residue feedstock comprising:

a) feeding a residue feedstock and a hydrogen stream into a residue hydrocracker unit containing catalyst to partially convert said residue feedstock, creating a hydrocracker vapor product stream and a hydrocracker liquid product stream;

b) feeding said hydrocracker liquid product stream along with a steam stream to a steam stripper to create a stripper naphtha stream, a stripper vapor stream containing nominally C4 and lighter hydrocarbon gases and sour gases, and a stripper bottoms stream, said stripper bottoms stream comprising a heavy boiling fraction (nominal 540°C+) and a light boiling fraction (nominal 180-540°C);

c) feeding said stripper bottoms stream to a heater to produce a heated stripper bottoms stream, said heated stripper bottoms stream comprising a heated heavy boiling fraction and a heated light boiling fraction;

d) feeding said heated stripper bottoms stream comprising said heated heavy boiling fraction and said heated light boiling fraction into a coking unit wherein said heated heavy boiling fraction from said heated stripper bottoms stream produces a solid coke product and a light converted residue product stream;

e) feeding said light converted residue stream along with said heated light fraction of said heated stripper bottoms stream to a coker fractionation unit to produce a fractionator vapor stream, a coker naphtha stream, a light gas oil stream, and a heavy gas oil stream.

According to an embodiment, the process further comprises:

f) feeding said fractionator vapor stream, said stripper vapor stream from step b,) and said hydrocracker vapor stream from step a) to gas a recovery unit; and

g) feeding said coker naphtha stream from step e), said stripper naphtha stream from step b), said light gas oil stream, and said heavy gas oil stream to downstream processing units for production of final petroleum products.

Further, Applicant's have disclosed a processing scheme for efficiently and effectively integrating hydrocracking and coking for the complete conversion of residue feedstock wherein optionally the steam stripper from step b) above creates a stripper naphtha stream, a stripper vapor stream containing nominally C4 and lighter hydrocarbon gases and sour gases, a stripper bottoms stream, said stripper bottoms stream comprising a

heavy fraction and a light fraction, and a residue hydrocracker diesel stream having a typical nominal boiling range of between 180-350°C.

These and other features of the present invention will be more readily apparent from the following description with reference to the accompanying drawings.

5 **BRIEF DESCRIPTION OF THE DRAWINGS**

Figure 1 is a schematic showing Applicant's process for integration of hydrocracking and coking for the complete conversion of residue feedstock.

Figure 2 is a schematic showing an optional configuration of Applicant's process wherein a side draw is taken from the residue hydrocracker stripper column and this stream routed
10 directly to downstream processing.

DETAILED DESCRIPTION OF THE INVENTION

Figure 1 is a schematic showing Applicant's process for efficiently and effectively integrating hydrocracking and coking for the complete conversion of residue feedstock.

A residue feedstock 10 is first processed along with hydrogen and catalyst (both not
15 shown) in a residue hydrocracker unit 20 to partially convert the residue feedstock 10 and produce a hydrocracker gas stream 9 and a liquid conversion product stream 11 that comprises light hydrocarbon liquids from the cracking of the residue feedstock and unconverted residue.

Generally, for instance the residue hydrocracker unit 20 operates at a reactor temperature
20 of between 350-450°C, an inlet pressure of between 70-210 barg, and a space velocity of between 0.05 to 1.5 hr⁻¹ but preferably between 415-430°C, an inlet pressure of between 100-175 barg, and a space velocity of between 0.1-0.3 hr⁻¹.

Additionally, the residue hydrocracker unit 20 may consist of one or more ebullated-bed
25 reactors, one or more slurry bed reactors, one or more fixed bed reactors or some combination of the above.

The residue hydrocracking reactor(s) may employ a catalyst or catalysts, especially a granular catalyst comprising, on an amorphous substrate, at least one metal or metal compound with a hydrogenating function. This catalyst can be a catalyst comprising metals of group VIII, for example nickel and/or cobalt, most often in combination with at least one metal of group VIB, for example molybdenum and/or tungsten. For example, a catalyst comprising from 0.5 to 10% by weight of nickel and preferably from 1 to 5% by weight of nickel (expressed as nickel oxide NiO), and from 1 to 30% by weight of molybdenum and preferably from 5 to 20% by weight of molybdenum (expressed as molybdenum oxide MoO₃) on an amorphous metal substrate can be used. This substrate will be chosen from, for example, the group formed by alumina, silica, silica-aluminas, magnesia, clays and mixtures of at least two of these minerals. This substrate can likewise contain other compounds, and, for example, oxides chosen from the group formed by boron oxide, zirconia, titanium oxide, and phosphoric anhydride.

The liquid conversion product stream 11 from the residue hydrocracker unit 20 is routed along with a separate steam stream 12 to a steam stripper 22. The steam stripper 22 removes dissolved light gases (nominally C₄ and lighter hydrocarbons and sour gases) 8 and also separates the liquid conversion product stream 11 into a residue hydrocracker naphtha stream 13 (for instance with a typical nominal boiling range of isopentane (82°C) to 180°C) and a stripper bottoms stream 14 (with a typical nominal boiling range of greater than 180°C).

Using the steam stripper 22 to remove the dissolved light gases stream 8 and hydrocracker naphtha stream 13 serves at least two important features of Applicant's unique processing configuration. First, the stripper bottoms stream 14, which serves as the feedstream for the coke drums in the coking unit, (24 and 24a), do not contain the lighter residue hydrocracker naphtha products 13, thus reducing the size of the coke drums required for processing the feed. Moreover, the removal of the residue hydrocracker naphtha stream 13 avoids co-mingling the coker naphtha stream 30 and residue hydrocracker naphtha 13. This is important since these streams require different downstream processing conditions and catalysts mainly due to the silicon compounds and

diolefins found in a typical coker naphtha but not in a typical residue hydrocracker naphtha.

The stripper bottoms stream 14 contains all of the unconverted residue (also called in the present invention as “heavy boiling fraction” which has typically nominal 540°C+ boiling range) as well as conversion products from the residue hydrocracker (also called in the present invention as “light boiling fraction” having nominal 180-540°C boiling range) and, as mentioned above, comprises the feed to the coking unit. The stripper bottoms stream 14 is first routed to a heater unit 23 for heating. The heater may be a fuel gas-fired or oil-fired heater or an electric heater. According to the invention, the stripper (heated) bottoms stream 14 which comprises a heavy boiling fraction (nominal 540°C+) and a light boiling fraction (nominal 180-540°C) is treated in a coking unit wherein said heated heavy boiling fraction from said heated stripper bottoms stream produces a solid coke product and a light converted residue product stream (via cracking). Further, the nature of the coking unit is such that the heated light boiling fraction of the heated bottoms stream passes through said coking unit substantially unconverted (less than 20% of this fraction converts).

As shown in Fig. 1, the heated stripper bottoms 7 are injected into the coke drums 24 and 24a of the coking unit. . According to the invention, the coking unit can be a delayed coking unit which is a batch process typically utilizing pairs of coke drums. As one is being filled with heated feed, the coke is being removed from the second via a hydraulic process using high-pressure water. According to another embodiment, the coking unit can be a fluid coking unit, with or without gasification, which is a different process, more akin to fluid catalytic cracking. Fluid coking is a continuous process in which coke is continuously removed and at least partially used to provide heat for the process in place of the heater 23. Fluid cokers operate at higher temperatures than delayed cokers (typically 510-570°C). The drawings are representative of a delayed coking unit. Two coke drums 24 and 24a are indicated in this drawing but it is possible to have configurations utilizing different numbers of coke drums. The feed to the coke drums is heated to typically 450-490°C and the drums typically operate at a pressure of 2.0-8.0 barg.

In the coke drums 24 and 24a, the final conversion of the residue feedstock 10 is completed with gas products and light liquid products produced and, depending on the coking technology selected, a solid coke product may also be produced. In the embodiment of Figure 1, the coke drums 24 and 24a produce a combined hydrocracked product stream 16 comprising a liquid product (of a typical nominal boiling range of isopentane (82°C) to 540°C) and a coker gas stream comprised of nominal C4 and lighter hydrocarbons and sour gases and a coke product 15. The combined cracked product stream 16 is thereafter sent to a coker fractionator 26.

The coker fractionator 26 produces a gas stream comprised of nominal C4 and lighter hydrocarbons and sour gas 17, a liquid coker naphtha stream 30 (typically nominal isopentane (82°C) to 180°C), a combined coker and hydrocracker light gas oil stream 31 (typically nominal 180-350°C), and from the column bottom, a combined coker and hydrocracker heavy gas oil stream 32 (typically nominal 350-540°C). These streams (30, 31, and 32) are routed to downstream processing for production of final products (not shown). Although not shown, the fractionator vapor 17 is combined with overhead vapor from the residue hydrocracker stripper 8 and from the residue hydrocracker 9 and sent to a gas recovery section.

Importantly, the invention alleviates the need for and cost of atmospheric and vacuum fractionators specific to the residue hydrocracker and associated heat exchange equipment. As stated, this equipment is a major source of fouling for residue hydrocracking units and its elimination will result in a large increase in the plant on-stream time.

As noted above, the stripper bottoms are sent directly to the coker heater. The operation of the coker will be identical to the current state of the art with the exception that the feedstock will contain a higher content of vacuum gas oil necessitating larger coke drums due to higher vapor velocity in the drums. The inclusion of residue hydrocracker light products in the common atmospheric fractionator will result in a larger tower than in a stand-alone arrangement.

An advantage of the current invention is that there is no unconverted residue (UCO) stream to dispose of. All of the feed residue is converted to gases, light liquids, and (depending on the coking technology employed), a solid coke product.

Figure 2 shows an optional configuration wherein an additional side draw 6 comprising diesel fraction with a typical nominal boiling range of 180-350°C is taken from the residue hydrocracker steam stripper column 22 and this stream routed directly to downstream processing. The effect of adding the side draw 6 would increase the cost of the stripper tower, but reduce the cost of the coker heater, coke drums and coker fractionator.

The current invention results in a more economical and more reliable process for hydrocracking/coking of heavy residue. Relative to the current state-of-the-art, the invention configuration will save an estimated 25-30% of the cost of separate ebullated-bed/delayed coking fractionation sections and for certain feedstocks will increase the on-stream time by 5 – 10%.

The invention described herein has been disclosed in terms of a specific embodiment and application. However, these details are not meant to be limiting and other embodiments, in light of this teaching, would be obvious to persons skilled in the art. Accordingly, it is to be understood that the drawings and descriptions are illustrative of the principles of the invention, and should not be construed to limit the scope thereof.

We claim:

1. An integrated process for converting residue feedstock comprising:

a) feeding a residue feedstock and a hydrogen stream into a residue hydrocracker unit containing catalyst to partially convert said residue feedstock and to create a hydrocracker vapor product stream and a hydrocracker liquid product stream;

b) feeding said hydrocracker liquid product stream along with a steam stream to a steam stripper to create a stripper naphtha stream, a stripper vapor stream containing nominally C4 and lighter hydrocarbon gases and sour gases, and a stripper bottoms stream, said stripper bottoms stream comprising a heavy boiling fraction and a light boiling fraction;

c) feeding said stripper bottoms stream to a heater to produce a heated stripper bottoms stream, said heated stripper bottoms stream comprising a heated heavy boiling fraction and a heated light boiling fraction;

d) feeding said heated stripper bottoms stream comprising said heated heavy boiling fraction and said heated light boiling fraction into a coking unit wherein said heated heavy boiling fraction from said heated stripper bottoms stream produces a solid coke product and a light converted residue product stream,;

e) feeding said light converted residue stream along with said heated light boiling fraction of said heated stripper bottoms stream to a coker fractionation unit to produce a fractionator vapor stream, a coker naphtha stream, a light gas oil stream, and a heavy gas oil stream;

2. The process of claim 1 further comprising:

f) feeding said fractionator vapor stream, said stripper vapor stream from step b,) and said hydrocracker vapor stream from step a) to gas a recovery unit; and

g) feeding said coker naphtha stream from step e), said stripper naphtha stream from step b), said light gas oil stream, and said heavy gas oil stream to downstream processing units for production of final petroleum products.

3. The process of claim 1 wherein said residue hydrocracker unit operates at a reactor temperature of between 350-450°C, an inlet pressure of between 70-210 barg, and a space velocity of between 0.05 to 1.5 hr⁻¹.
4. The process of claim 1 wherein said residue hydrocracker unit operates at a reactor temperature of between 415-430°C, an inlet pressure of between 100-175 barg, and a space velocity of between 0.1-0.3 hr⁻¹.
5. The process of claim 1 wherein said residue hydrocracker unit comprises one or more ebullated-bed units operating in series or in parallel.
6. The process of claim 1 wherein said residue hydrocracker unit comprises one or more slurry bed reactors operating in series or in parallel.
7. The process of claim 1 wherein said residue hydrocracker unit comprises one or more fixed bed reactors operating in series or in parallel.
8. The process of claim 1 wherein said residue hydrocracker unit comprises one or more ebullated-bed reactors and one or more slurry-bed reactors operating in series or in parallel.
9. The process of claim 1 wherein said residue hydrocracker unit comprises one or more ebullated-bed reactors and one or more fixed-bed reactors operating in series or in parallel.
10. The process of claim 1 wherein said residue hydrocracker unit comprises one or more slurry-bed reactors and one or more fixed-bed reactors operating in series or in parallel.
11. The process of claim 1 wherein said heater from step c) is selected from the group comprising a gas-fired heater, an oil-fired heater, or an electric heater.

12. The process of claim 1 wherein said coking unit from step d) is selected from the group comprising a delayed coker, a fluid coker, and a fluid coker with gasification.
13. The process of claim 1 wherein said coke product from said coking unit from step d) is completely gasified.
- 5 14. The process of claim 1 wherein said steam stripper from step b) creates a stripper naphtha stream, a stripper vapor stream containing nominally C4 and lighter hydrocarbon gases and sour gases, a stripper bottoms stream, said stripper bottoms stream comprising a heavy fraction and a light fraction, and a residue hydrocracker diesel stream.

Figure 1

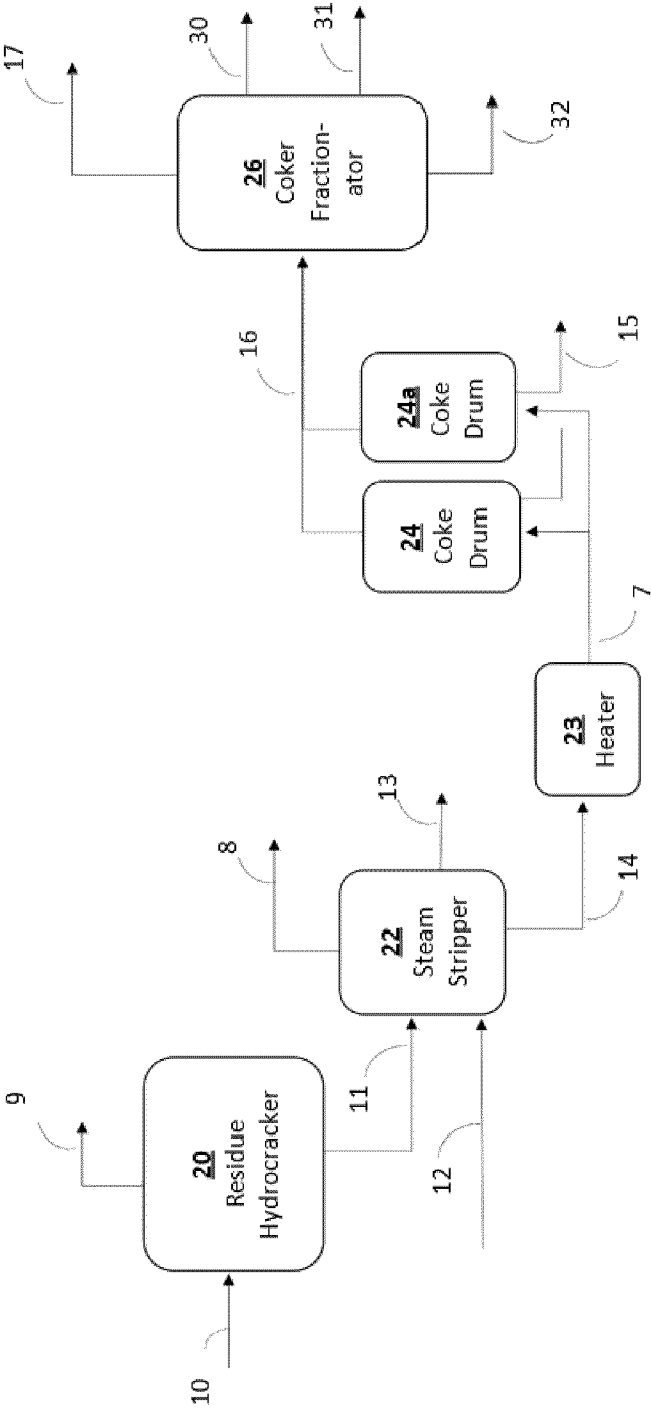
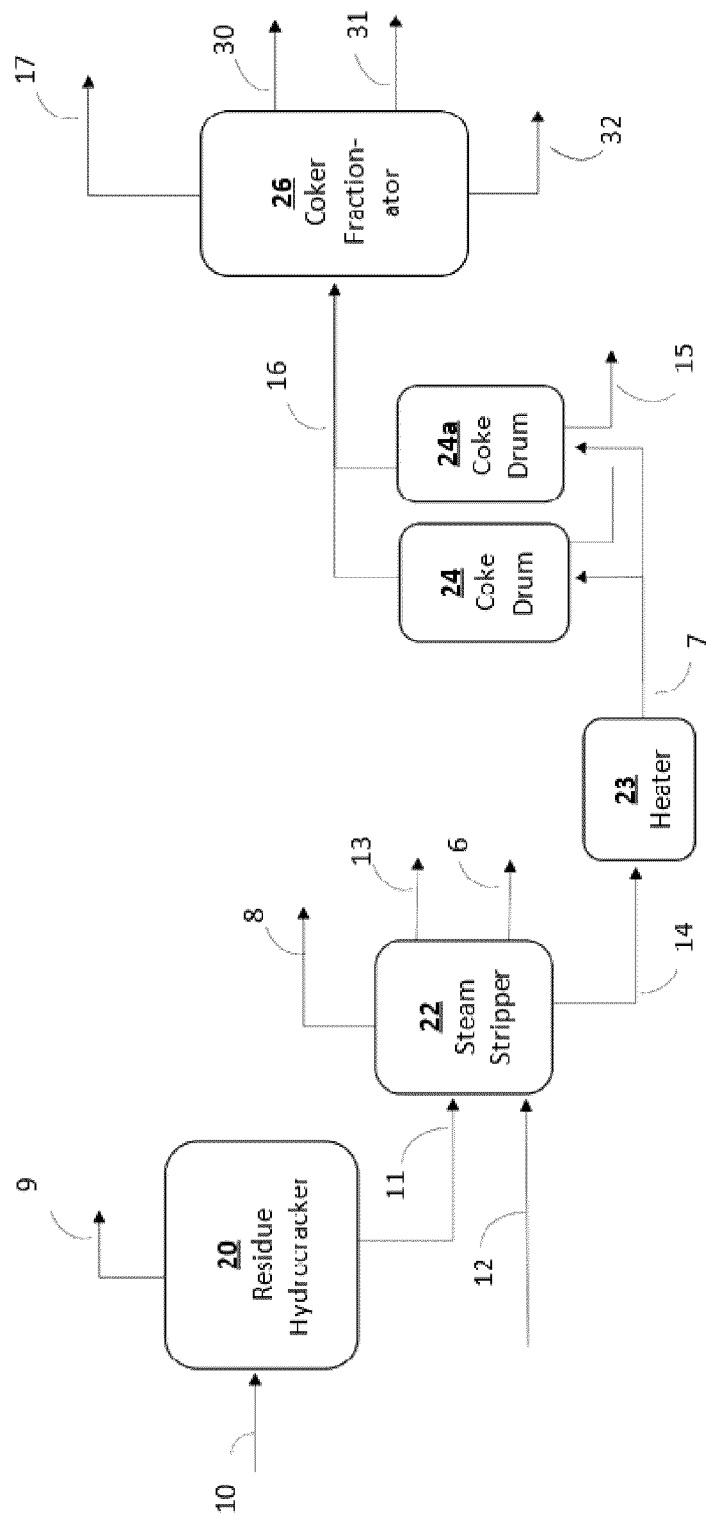


Figure 2



INTERNATIONAL SEARCH REPORT

International application No
PCT/EP2024/065304

A. CLASSIFICATION OF SUBJECT MATTER INV. C10G9/00 C10B55/00 C10G69/06 ADD.		
According to International Patent Classification (IPC) or to both national classification and IPC		
B. FIELDS SEARCHED Minimum documentation searched (classification system followed by classification symbols) C10G C10H C10B Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched Electronic data base consulted during the international search (name of data base and, where practicable, search terms used) EPO-Internal		
C. DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 9 452 955 B2 (LUMMUS TECHNOLOGY INC [US]) 27 September 2016 (2016-09-27)	1 - 14
Y	claims 1, 10, 12, 13 figures 1-3 column 14, lines 8-10, 49-54 -----	1 - 14
Y	US 2019/390124 A1 (OPRINS ARNO JOHANNES MARIA [NL] ET AL) 26 December 2019 (2019-12-26) claim 1 -----	1 - 14
Y	WO 2021/133657 A1 (SAUDI ARABIAN OIL CO [SA]; KOSEOGLU OMER REFA [SA]) 1 July 2021 (2021-07-01) claim 1 paragraph [0050] ----- - / - -	1 - 14
☒ Further documents are listed in the continuation of Box C. ☒ See patent family annex.		
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Date of the actual completion of the international search 6 September 2024		Date of mailing of the international search report 20/09/2024
Name and mailing address of the ISA/ European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016		Authorized officer Pardo Torre, J

INTERNATIONAL SEARCH REPORT

International application No
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C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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