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METHODS AND APPARATUSES FOR HYDROCRACKING AND HYDROTREATING HYDROCARBON STREAMS

STATEMENT OF PRIORITY

5 [0001] This application claims priority to U.S. Application No. 14/319,816 which was
filed June 30, 2014, the contents of which are hereby incorporated by reference in its
entirety.

TECHNICAL FIELD

10 [0002] The technical field generally relates to methods and apparatuses for processing
hydrocarbons, and more particularly relates to methods and apparatuses for hydrocracking
and hydrotreating hydrocarbon streams.

BACKGROUND

[0003] Heavier hydrocarbons in refining complexes, such as hydrocarbon residues or
gas oils from atmospheric column or vacuum column distillation, can be cracked to
produce more valuable products, such as aromatics or fuels including gasoline and diesel.
15 Refining complexes may also process heavier hydrocarbons to produce distillate products.

[0004] Slurry hydrocracking is an exemplary process for upgrading heavy
hydrocarbon feedstocks, such as those mentioned above. In slurry hydrocracking, heavy
feedstocks are converted in the presence of hydrogen and solid catalyst particles in a slurry
phase. Typically, a slurry hydrocracking process includes mixing a heavy feedstock and
20 catalyst particles in an upflow reactor under a hydrogen-rich reaction environment. The
hydrogen-rich reaction environment facilitates a high conversion rate of hydrocarbon
residues and/or gas oils to liquid products, particularly to distillate boiling-range
components.

[0005] Theoretically, the effluent stream from a slurry hydrocracking process may be
25 processed in a distillate hydrotreater. Such processing allows for conversion of light
products, such as naphtha and diesel, in the slurry hydrocracking effluent to be treated to
meet required fuel specifications. However, the slurry hydrocracking effluent typically
includes a large volume of heavier components. To obtain naphtha and/or diesel product
streams, a large energy utility is required to hydrotreat the hydrocracking effluent
30 including heavier components. Additionally, after hydrotreating, a large energy utility is
required to vaporize the lighter naphtha and diesel components to separate them from

heavier components in the hydrotreated stream. Further, introduction of the heavier components to the distillate hydrotreater requires the addition of increased amounts of hydrogen, further adding cost to the process. Also, when processing an effluent with unsatisfactory levels of impurities from a hydrocracking process, the effluent must be severely hydrotreated, which raises the cost of the hydrotreating unit. In summary, processing the slurry hydrocracking effluent requires the hydrotreater to have higher capital and/or operating costs to produce a fuel product, such as naphtha or diesel, with a sufficiently low specification of certain contaminants, such as sulfur or nitrogen.

[0006] Accordingly, it is desirable to provide methods and apparatuses for upgrading heavy hydrocarbons (e.g., atmospheric column and vacuum column hydrocarbon residues and gas oils) with improved efficiency. In addition, it is desirable to provide methods and apparatuses that economically hydrotreat hydrocracking effluent. Furthermore, other desirable features and characteristics will become apparent from the subsequent detailed description and the appended claims, taken in conjunction with the accompanying drawings and the foregoing technical field and background.

BRIEF SUMMARY

[0007] Methods and apparatuses for processing hydrocarbon streams are provided. In accordance with an exemplary embodiment, a method for processing a hydrocarbon stream includes hydrocracking the hydrocarbon stream to form a hydrocracking effluent including vacuum gas oil range components. The method removes the vacuum gas oil range components from the hydrocracking effluent to form a stream of vacuum gas oil range components and a processed hydrocracking effluent. Further, the method includes hydrotreating the processed hydrocracking effluent to form a product stream.

[0008] In another embodiment, a method for processing a hydrocarbon stream includes feeding the hydrocarbon stream to a slurry hydrocracking zone. The method hydrocracks the hydrocarbon stream to form a slurry hydrocracking effluent. The method includes separating the slurry hydrocracking effluent to form an effluent vapor fraction and an effluent liquid fraction. The method cools the effluent vapor fraction to form a cooled stream and separates the cooled stream to form a liquid stream and a vapor stream. The method includes feeding the vapor stream to a hydrotreating zone and hydrotreating the vapor stream to form a distillate product.

[0009] In accordance with another exemplary embodiment, an apparatus for processing a hydrocarbon stream is provided. The apparatus includes a slurry hydrocracking zone configured for hydrocracking the hydrocarbon stream to form a slurry hydrocracking effluent. The apparatus also includes a first separator operating at first temperature and configured to separate the slurry hydrocracking effluent into an effluent vapor fraction and an effluent liquid fraction. A second separator operating at a second temperature lower than the first temperature is provided and is configured to separate the effluent vapor fraction into a liquid stream and a vapor stream. The apparatus further includes a hydrotreating zone configured for hydrotreating the vapor stream to form a product stream.

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] Embodiments of apparatuses and methods for processing hydrocarbons streams will hereinafter be described in conjunction with the following drawing figures wherein:

[0011] FIG. 1 is a schematic illustration of an apparatus and method for processing a hydrocarbon stream in accordance with an exemplary embodiment;

[0012] FIG. 2 is a schematic illustration of an apparatus and method for processing a hydrocarbon stream in accordance with another exemplary embodiment; and

[0013] FIG. 3 is a schematic illustration of further components of the apparatus of FIG. 2.

DETAILED DESCRIPTION

[0014] The following detailed description is merely exemplary in nature and is not intended to limit the apparatuses or methods for processing hydrocarbon streams claimed herein. Furthermore, there is no intention to be bound by any theory presented in the preceding background or the following detailed description.

[0015] As described herein, a hydrocarbon feed is hydrocracked to form an upgraded hydrocracking effluent. The hydrocracking effluent is then separated into a vapor fraction and a liquid fraction. The vapor fraction is cooled and then separated into a vapor stream and a liquid stream. As a result of the two separation processes, heavy components, such as vacuum gas oil, are largely removed from the vapor stream. Specifically, an exemplary vapor stream includes less than 10 weight percent (wt%), such as less than 5 wt% or, for example, less than 1 wt%, of components having boiling points of greater than 343°C, based on the total weight of the vapor stream. The vapor stream is then hydrotreated to

form a product stream including, for example, diesel and naphtha components. This processing arrangement eliminates or reduces hydrotreating heavier components in the hydrocracking effluent and removes the need to vaporize the hydrotreated product stream to separate diesel and naphtha components from heavier components.

5 [0016] FIG. 1 is a schematic illustration of an apparatus 10 for processing a hydrocarbon feed stream 15 in accordance with an exemplary embodiment. An exemplary hydrocarbon feed stream 15 may be formed as a bottom stream from a vacuum fractionation zone (not shown). As used herein, "bottom stream" refers to a stream withdrawn at or near a bottom of a column, such as a distillation column. The exemplary
10 feed stream includes heavy hydrocarbons, such as light cycle oil, heavy gas oil, vacuum gas oil, and pitch. As used herein, "light cycle oil" refers to a hydrocarbon material boiling in a range of from 204°C to 343°C and can include one or more C₁₃-C₁₈ hydrocarbons; "heavy gas oil" refers to a hydrocarbon material boiling in a range of from 343°C to 524°C and can include one or more C₁₆-C₂₅ hydrocarbons; "vacuum gas oil"
15 refers to a hydrocarbon material boiling in the range of from 343°C to 524°C and can include one or more C₂₂-C₄₅ hydrocarbons; and "pitch" refers to a hydrocarbon material boiling above 524°C and can include one or more C₄₀₊ hydrocarbons.

[0017] While an exemplary feed stream 15 is a vacuum fractionation bottom stream, the feed stream 15 may be any suitable feed, such as a vacuum gas oil, a vacuum residue
20 boiling above 510°C, or a fluidized catalytic cracking gas oil boiling above 400°C. Exemplary feed streams 15 suitable for processing by the apparatus 10 have a composition of 90 wt% of components having boiling points of at least 300°C at an atmospheric equivalent boiling point as calculated from observed boiling temperature and distillation pressure, as determined by ASTM D1160-06.

25 [0018] As shown, the exemplary apparatus 10 includes a slurry hydrocracking zone 20 that receives the feed stream 15. As used herein, the term "zone" can refer to an area including one or more equipment items and/or one or more sub-zones. Equipment items can include one or more reactors or reactor vessels, heaters, exchangers, pipes, pumps, compressors, and controllers. Additionally, an equipment item, such as a reactor, dryer, or
30 vessel, can further include one or more zones or sub-zones.

[0019] The slurry hydrocracking zone 20 is provided with a catalyst 21 for supporting the hydrocracking reaction. The catalyst 21 may be any suitable material and may have

any suitable catalyst dimensions. An exemplary catalyst 21 has a mean catalyst particle size of from 2 microns to 100 microns, such as from 10 microns to 20 microns. Exemplary catalyst compounds include a catalytically effective amount of one or more compounds having iron. For example, the one or more compounds can include at least one of an iron oxide, an iron sulfate, and an iron carbonate. Other forms of iron can include at least one of an iron sulfide, a pyrrhotite, and a pyrite. The catalyst 21 can contain materials other than an iron, such as at least one of alumina, silica, titanium, molybdenum, nickel, and manganese, and/or a salt, an oxide, or a mineral thereof.

[0020] In addition to the feed stream 15 and the catalyst 21, the slurry hydrocracking zone 20 is provided with hydrogen 23. Generally, the hydrogen 23 can include recycled and/or make-up hydrogen, and as such can include other light hydrocarbon molecules, such as methane and ethane.

[0021] The exemplary slurry hydrocracking zone 20 may include a slurry hydrocracking reactor operating in an up-flow or down-flow configuration. An exemplary slurry hydrocracking reactor is a tubular reactor through which the feed, catalyst, and gas pass upwardly. Generally, the temperature in the slurry hydrocracking reactor is from 400°C to 500°C, for example from 440°C to 465°C. An exemplary reactor pressure in the slurry hydrocracking reactor may be from 3 megapascals (MPa) to 24 MPa, such as from 10 MPa to 18 MPa. An exemplary slurry hydrocracking reactor has a liquid hourly space velocity (LHSV) of less than 4 hr⁻¹. The LHSV (expressed in units of hr⁻¹) is the volumetric liquid flow rate over the catalyst bed divided by the bed volume and represents the equivalent number of catalyst bed volumes of liquid processed per hour. The LHSV is closely related to the inverse of the reactor residence time.

[0022] The hydrocracking reaction in the slurry hydrocracking zone 20 results in the formation of a hydrocracking effluent 25 in the form of a gas-liquid mixture. In an exemplary embodiment, the hydrocracking effluent 25 includes at least 50 wt% naphtha and diesel range components, such as at least 75 wt% naphtha and diesel range components. An exemplary hydrocracking effluent 25 includes from 20 wt% to 30 wt% naphtha and from 40 wt% to 60 wt% diesel. Further, the exemplary hydrocracking effluent 25 includes from 20 wt% to 30 wt% heavier components, such as components having boiling points of greater than 343°C.

[0023] The hydrocracking effluent 25 exits the slurry hydrocracking zone 20 and is received by a separation zone 30. The separation zone 30 may include a flash separator unit, providing for partial or flash evaporation through pressure reduction. In an exemplary embodiment, the separation zone 30 operates at a temperature of from 370°C to 500°C, such as from 400°C to 470°C, for example at 400°C.

[0024] As shown, the hydrocracking effluent 25 is separated in the separation zone 30 into a vapor fraction 33 and a liquid fraction 37. An exemplary vapor fraction 33 includes at least 80 wt% of the diesel and naphtha range components of the hydrocracking effluent 25, such as at least 90 wt% of the diesel and naphtha range components of the hydrocracking effluent 25. The exemplary liquid fraction 37 includes at least 80 wt% of the components having boiling points of greater than 343°C from the hydrocracking effluent 25, such as at least 90 wt% of the components having boiling points of greater than 343°C from the hydrocracking effluent 25.

[0025] The vapor fraction 33 is fed to a cooling zone 40. An exemplary cooling zone 40 includes at least one heat exchanger or other cooling unit to remove heat from the vapor fraction 33. In an exemplary process, the vapor fraction 33 is cooled to a temperature of from 250°C to 350°C, such as from 260°C to 315°C, for example from 260°C to 270°C. The cooled vapor fraction 45 exits the cooling zone 40 and is fed to a separation zone 50.

[0026] Separation zone 50 may include a flash separator unit, providing for partial or flash evaporation through pressure reduction. In an exemplary embodiment, the separation zone 50 operates at a temperature of from 250°C to 350°C, such as from 260°C to 315°C, for example from 260°C to 270°C. The separation zone 50 separates the vapor fraction 45 into a vapor stream 53 and a liquid stream 57. An exemplary vapor stream 53 includes at least 90 wt%, such as at least 95 wt%, for example at least 99 wt%, of components that boil below 343°C, based on the total weight of the vapor stream 53. The exemplary vapor stream 53 includes less than 10 wt%, such as less than 5 wt% or, for example, less than 1 wt%, of components having boiling points of greater than 343°C, based on the total weight of the vapor stream 53. In an exemplary embodiment, the vapor stream 53 has essentially no components having boiling points of greater than 343°C. Further, an exemplary vapor stream 53 includes from 70% to 85%,

such as from 75% to 80% of the diesel range components from the hydrocracking effluent 25.

[0027] In FIG. 1, the vapor stream 53 exits the separation zone 50 and is fed to a hydrotreating zone 60. The exemplary hydrotreating zone 60 provides for removal of sulfur and/or nitrogen from the vapor stream 53 to form a distillate product stream or streams 65. The exemplary distillate product stream 65 includes less than 10 wt%, such as less than 5 wt% or, for example, less than 1 wt%, of components having boiling points of greater than 343°C, based on the total weight of the product stream 65. In an exemplary embodiment, the distillate product stream 65 has essentially no components having boiling points of greater than 343°C. According to exemplary embodiments, for example, a distillate product stream 65 may be obtained having a sulfur content of less than 50 ppm by weight, such as less than 10 ppm by weight, or for example less than 5 ppm by weight. Hydrotreating the vapor stream 53 may therefore provide low-sulfur products and even ultra-low-sulfur products, such as naphtha and diesel fractions, in compliance with applicable tolerances.

[0028] An exemplary hydrotreating zone 60 includes a hydrotreating reactor having a fixed bed of hydrotreating catalyst. The hydrotreating reactor receives a hydrogen stream 67, either directly or with the vapor stream 53. The hydrogen stream 67 can include recycled and/or make-up hydrogen, and as such can include other light hydrocarbon molecules, such as methane and ethane. Typical hydrotreating conditions include a temperature from 260°C to 426°C, a pressure from 7.0 MPa to 21 MPa, and an LHSV of from 0.1 hr⁻¹ to 10 hr⁻¹. Suitable hydrotreating catalysts include a metal selected from the group consisting of nickel, cobalt, tungsten, molybdenum, and mixtures thereof, on a refractory inorganic oxide support.

[0029] The apparatus 10 including an integrated slurry hydrocracking zone 20 and hydrotreating zone 60 may additionally be integrated with crude oil fractionation columns, such that a straight-run distillate from a crude oil atmospheric distillation column is hydrotreated together with the slurry hydrocracking distillate products in vapor stream 53. FIG. 1 shows the hydrotreating zone 60 receiving an additional refinery distillate stream 69, such as a straight-run distillate.

[0030] In exemplary embodiments, the hydrotreated product stream 65 has a sufficient API gravity for incorporation into a crude oil or synthetic crude oil obtained, for example,

from tar sands. Representative API gravity values are greater than 20° (e.g., from 25° to 40°) and greater than 35° (e.g., from 40° to 55°). Particular sources of synthetic crude oil of increasing interest, and for which blending components are sought to improve their flow characteristics, are bitumen and oil sands. Bitumen refers to the low-quality hydrocarbonaceous material recovered from oil sand deposits, such as those found in the vast Athabasca region of Alberta, Canada, as well as in Venezuela and the United States. Bitumen and oil sands are recognized as valuable sources of “semi-solid” petroleum or synthetic crude oil, which can be refined into many valuable end products including transportation fuels such as gasoline or even petrochemicals.

[0031] As shown in FIG. 1, the liquid fraction 37 from the separation zone 30 and the liquid stream 57 from the separation zone 50 are fed to a fractionation zone 70. The fractionation zone 70 is operated to recover any naphtha and/or diesel range components to form a stream 75 including heavy diesel components and/or unstabilized or “wild” naphtha. The stream 75 is fed to the hydrotreating zone 60 for hydrotreatment with the vapor stream 53 to form the product stream 65.

[0032] Exemplary embodiments of the apparatus 10 are directed toward integrated slurry hydrocracking and hydrotreating processes that eliminate the conventional post-hydrotreating fractionation necessary to separate distillate products from heavy components, such as components having boiling points of greater than 343°C. Further, exemplary embodiments of the apparatus 10 avoid or minimize hydrotreatment of heavy components, such as components having boiling points of greater than 343°C. As a result, utility costs are reduced as compared to methods that pass heavy components through hydrotreating units and that fractionate hydrotreated distillate streams to remove heavy components from desired product streams.

[0033] FIG. 2 illustrates an exemplary apparatus 100 for processing hydrocarbon feed stream 102 in accordance with another embodiment. The hydrocarbon feed stream 102 may be similar to or the same as the hydrocarbon feed stream 15 described in FIG. 1. In an exemplary embodiment, the hydrocarbon feed stream 102 is formed from a vacuum residue feed 104 and a heavy vacuum gas oil recycle stream 106 and may be held in a tank 107. The exemplary feed stream 102 is pumped by pump 108 through heat exchangers 110 and 112. The feed stream 102 is heated by the heat exchangers 110 and 112, and is further heated by heater 114. As shown, catalyst particles in slurry 116 are pumped by

pump 117 into the feed stream 102 before being heated by heater 114. Alternatively, the catalyst particle slurry 116 may be added to the feed stream 102 downstream of the heater 114.

5 **[0034]** In the exemplary embodiment, the feed stream 102 is received by a slurry hydrocracking reactor 120. The slurry hydrocracking reactor 120 also receives a hydrogen stream 122. The hydrogen stream 122 may be heated in heater 124 before being fed to the slurry hydrocracking reactor 120. As shown, the hydrogen stream 122 may be alternatively added to the feed stream 102 upstream of the heater 114.

10 **[0035]** As described in relation to FIG. 1, the exemplary slurry hydrocracking reactor 120 is a tubular reactor through which the feed, catalyst, and gas pass upwardly. In an exemplary embodiment, the temperature in the slurry hydrocracking reactor 120 is from 400°C to 500°C, for example from 440°C to 465°C. In an exemplary embodiment, the reactor pressure in the slurry hydrocracking reactor is from 3 MPa to 24 MPa, such as from 10 MPa to 18 MPa. An exemplary slurry hydrocracking reactor 120 has a LHSV of
15 less than 4 hr⁻¹.

20 **[0036]** In the hydrogen atmosphere of the slurry hydrocracking reactor 120, the hydrocarbons in the feed stream 102 react over the catalyst 116 and form a hydrocracking effluent 125 in the form of a gas-liquid mixture. In an exemplary embodiment, the hydrocracking effluent 125 includes at least 50 wt% naphtha and diesel range components, such as at least 75 wt% naphtha and diesel range components. An exemplary hydrocracking effluent 125 includes from 20 wt% to 30 wt% naphtha and from 40 wt% to 60 wt% diesel. Further, the exemplary hydrocracking effluent 125 includes from 20 wt% to 30 wt% heavier components, such as components having boiling points of greater than 343°C.

25 **[0037]** The hydrocracking effluent 125 exits the slurry hydrocracking reactor 120 and is received by a separator 130. The separator 130 may be a flash separator unit, providing for partial or flash evaporation through pressure reduction. In an exemplary embodiment, the separator 130 operates at a temperature of from 370°C to 500°C, such as from 400°C to 470°C, for example at 400°C. In the exemplary embodiment, the separator 130 receives
30 a wash oil 132 that is pumped by pump 134 from tank 136.

35 **[0038]** As shown, the separator 130 forms a liquid fraction 137 and a vapor fraction 138 from the hydrocracking effluent 125. An exemplary vapor fraction 138 includes at

least 80 wt% of the diesel and naphtha range components of the hydrocracking effluent 125, such as at least 90 wt% of the diesel and naphtha range components of the hydrocracking effluent 125. The exemplary vapor fraction 138 includes no more than 20 wt% of the components having boiling points of greater than 343°C from the hydrocracking effluent 125, such as no more than 10 wt% of the components having boiling points of greater than 343°C from the hydrocracking effluent 125.

[0039] The vapor fraction 138 passes through a heat exchanger 139 where it is cooled. Then, the vapor fraction 138 passes through heat exchanger 112 where it is cooled further through heat exchange with the incoming hydrocarbon feed stream 102. Passing through the heat exchangers 139 and 112 may cool the vapor fraction 138 to a temperature of from 250°C to 350°C, such as from 260°C to 315°C, for example from 260°C to 270°C.

[0040] The cooled vapor fraction 138 is fed to a separator 150, such as a flash separator unit providing for partial or flash evaporation through pressure reduction. In an exemplary embodiment, the separator 150 operates at a temperature of from 250°C to 350°C, such as from 260°C to 315°C, for example from 260°C to 270°C. The separator 150 separates the vapor fraction 138 into a vapor stream 153 and a liquid stream 157. An exemplary vapor stream 153 includes at least 90 wt%, such as at least 95 wt%, for example at least 99 wt%, of components that boil below 343°C, based on the total weight of the vapor stream 153. The exemplary vapor stream 153 includes less than 10 wt%, such as less than 5 wt% or, for example, less than 1 wt%, of components having boiling points of greater than 343°C, based on the total weight of the vapor stream 153. In an exemplary embodiment, the vapor stream 153 has essentially no components having boiling points of greater than 343°C. Further, an exemplary vapor stream 153 includes from 70% to 85%, such as from 75% to 80% of the diesel range components from the hydrocracking effluent 125.

[0041] In FIG. 2, the vapor stream 153 exits the separator 150 and is heated by heat exchanger 158 and by heater 159 before being fed to a hydrotreating reactor 160. The temperature of the vapor stream 153 when entering the hydrotreating reactor 160 may be from 260°C to 426°C. Typical hydrotreating conditions include a temperature from 260°C to 426°C, a pressure from 7.0 MPa to 21 MPa, and an LHSV of from 0.1 hr⁻¹ to 10 hr⁻¹.

[0042] The exemplary hydrotreating reactor 160 provides for removal of sulfur and/or nitrogen from the vapor stream 153 to form a hydrotreated effluent stream 165. The exemplary hydrotreated effluent stream 165 includes less than 10 wt%, such as less than 5 wt% or, for example, less than 1 wt%, of components having boiling points of greater than 343°C, based on the total weight of the hydrotreated effluent stream 165. In an exemplary embodiment, the hydrotreated effluent stream 165 has essentially no components having boiling points of greater than 343°C. According to exemplary embodiments, for example, a hydrotreated effluent stream 165 may be obtained having a sulfur content of less than 50 ppm by weight, such as less than 10 ppm by weight, or for example less than 5 ppm by weight. Hydrotreatment of the vapor stream 153 may therefore provide low-sulfur products and even ultra-low-sulfur products, such as naphtha and diesel fractions, in compliance with applicable tolerances.

[0043] An exemplary hydrotreating reactor 160 includes a fixed bed of hydrotreating catalyst. Suitable hydrotreating catalysts include a metal selected from the group consisting of nickel, cobalt, tungsten, molybdenum, and mixtures thereof, on a refractory inorganic oxide support. In the exemplary embodiment, the hydrotreating reactor receives a hydrogen stream 167 and an additional refinery distillate stream 169 together in stream 170, which is mixed with the vapor stream 153 upstream of the hydrotreating reactor 160. As shown, the hydrotreated effluent stream 165 is heat exchanged with the incoming vapor stream 153 at heat exchanger 158 and with the stream 170 at heat exchanger 172. The refinery distillate stream 169 may be formed from a straight run diesel stream 174, a recovered heavy diesel stream 175, and/or a recovered wild naphtha stream 176. The refinery distillate stream 169 may be pumped from a tank 177 by pump 178 to the hydrotreating reactor 160.

[0044] In the illustrated embodiment, the hydrotreated effluent stream 165 is fed to a separator 180 that forms a vapor fraction 181 rich in hydrogen and a liquid fraction 182. The vapor fraction 181 is passed through heat exchanger 110 where it heats the incoming hydrocarbon feed stream 102. Further, the vapor fraction 181 passes through heat exchangers 184 and 186 where it is cooled further and may condense. Then, wash water 188 is added to the fraction 181 before passing through air-cooled heat exchanger 190 and into separator 192. Hydrogen stream 167 is formed by separator 192 and may be fed through a recycle gas compressor 194 for recycle to the hydrotreating reactor 160, to the

separator 130, or to hydrocracking reactor 120 (as stream 122) through heat exchangers 184 and 139. As shown, make up hydrogen 195 may be provided by compressor 196 to the hydrogen stream 122 flowing to the hydrocracking reactor 120. A portion of the hydrogen stream 167 formed by separator 192 may be fed through a scrubber 198 for exhaust.

[0045] The liquid fraction 182 may include liquid hydrotreated product such as naphtha and diesel fractions and is fed to a flash drum 202. A vapor fraction 204 is removed and passes through air-cooled heat exchanger 206 before entering a flash drum 208. A liquid fraction 210 is formed and may be delivered to a product fractionation section (shown in FIG. 3) to isolate desired product fractions. As shown, a sour water stream 212 and hydrotreated light hydrocarbon stream 214, consisting primarily of naphtha and diesel, are also fed to the flash drum 208. At flash drum 208, offgas 216 and sour water 218 are separated from a recovered fraction 220 of naphtha or diesel range hydrocarbons. The recovered fraction 220 is heat exchanged with the fraction 181 at heat exchanger 186 before being delivered to the product fractionation section (shown in FIG. 3) for separation into desired product fractions.

[0046] As shown in FIG. 2, the liquid fraction 137 formed by separator 130 is fed to a flash drum 230 along with a portion of the wash oil 132. A liquid fraction 232 separated by flash drum 230 may be delivered to a recovery fractionation section (shown in FIG. 3) for recovery of desired hydrocarbon fractions. A vapor fraction 234 separated by flash drum 230 may be fed to a stripper overhead receiver (shown in FIG. 3). Also, the liquid stream 157 formed by the separator 150 is fed to a flash drum 240. A liquid fraction 242 separated by flash drum 240 may be delivered to the product fractionation section (shown in FIG. 3) for separation into desired product fractions. A vapor fraction 244 separated by flash drum 240 may be fed to a stripper overhead receiver (shown in FIG. 3). As shown, the vapor fraction 234 and vapor fraction 244 may be combined into stream 246.

[0047] FIG. 3 illustrates that the apparatus 100 further includes a recovery fractionation section 250 and a product fractionation section 254 for further processing as mentioned above. As shown, the recovery fractionation section 250 receives the liquid fraction 232 and the liquid fraction 242. Specifically, the liquid fraction 232 and the liquid fraction 242 enter a hot stripper 258 that also receives a steam stream 260. A vapor stream 264 including lighter components, such as naphtha, from the liquid fractions 232 and 242

exits the hot stripper 258 and is fed to an overhead receiver 268. Receiver 268 also receives the stream 246 including vapor fractions 234 and 244. At receiver 268, offgas 272 and sour water 274 are separated from a recovered unrefined naphtha stream 176. The recovered unrefined naphtha stream 176 is introduced into the hydrotreating reactor 160 in FIG. 2. A portion 276 of the recovered wild naphtha stream 176 may be recycled to the hot stripper 258 to facilitate the stripping process.

[0048] As shown, a liquid stream 278 exits the bottom of the hot stripper 258 and includes heavier components, such as vacuum gas oil and unconverted pitch. The liquid stream 278 is heated by heater 280 and fed to a vacuum fractionation column 282, which are components of the recovery fractionation section 250. The vacuum fractionation column 282 also receives a steam stream 284. As is conventional, the vacuum fractionation column 282 provides for separation and withdrawal of a number of streams. For example, an overhead stream 286 including diesel range components is withdrawn and fed to an overhead receiver 288 where sour water 290 is removed from the recovered heavy diesel stream 175 that is fed to the hydrotreating reactor 160 in FIG. 2. Further, a light vapor gas oil stream 292, a heavy vapor gas oil stream 294, heavy vacuum gas oil recycle stream 106, and a pitch stream 296 may be formed. As shown, a portion of the heavy vacuum gas oil stream 294 may be formed as the wash oil 132 fed to the separator 130 in FIG. 2.

[0049] In FIG. 3, the product fractionation section 254 further receives liquid fraction 210 and recovered fraction 220. Specifically, the liquid fraction 210 and recovered fraction 220 are fed to a diesel stripper 300. The diesel stripper 300 also receives a steam stream 302. As shown, the diesel stripper 300 forms a product diesel stream 304. The diesel stripper 300 forms an overhead vapor stream 310 including naphtha and lighter range components. The vapor stream 310 is fed to an overhead receiver 312 where sour water 314 and offgas 316 are removed to form a naphtha stream 318. A portion of the naphtha stream 318 may be recycled to the diesel stripper 300 to facilitate separation therein. The naphtha stream 318 is fed to a debutanizer 320 that forms a treated naphtha stream 322. A portion of the treated naphtha stream 322 may be recycled to the debutanizer 320 to facilitate processing therein.

[0050] Lighter components are removed from the debutanizer 320 in an overhead stream 324 that is fed to an overhead receiver 326 where sour water 328 and offgas 330

are removed to form a wild liquefied petroleum gas stream 332. A portion of the liquefied petroleum gas stream 332 may be recycled to the debutanizer to facilitate processing therein.

[0051] As described herein, apparatuses and methods for processing hydrocarbon streams have been provided. Exemplary embodiments of the apparatuses and methods hydrocrack a hydrocarbon stream and separate a vapor fraction from the hydrocracking effluent at a first temperature. The exemplary embodiments then cool the vapor fraction to a second temperature lower than the first temperature and separate a vapor stream from the cooled fraction. The vapor stream is then hydrotreated to form naphtha and/or diesel product streams with reduced contaminants. Heavier components in the hydrocracking effluent are not hydrotreated, and vaporization of the naphtha and/or diesel product to provide for separation from the heavier components is not needed. As a result, energy utility costs are reduced.

SPECIFIC EMBODIMENTS

[0052] While the following is described in conjunction with specific embodiments, it will be understood that this description is intended to illustrate and not limit the scope of the preceding description and the appended claims.

[0053] A first embodiment of the invention is a method for processing a hydrocarbon stream, the method comprising the steps of hydrocracking the hydrocarbon stream to form a hydrocracking effluent including vacuum gas oil range components; removing the vacuum gas oil range components from the hydrocracking effluent to form a stream of vacuum gas oil range components and a processed hydrocracking effluent; and hydrotreating the processed hydrocracking effluent to form a product stream. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the first embodiment in this paragraph wherein removing the vacuum gas oil range components from the hydrocracking effluent comprises forming the processed hydrocracking effluent with no more than 10 wt% of the vacuum gas oil range components from the hydrocracking effluent. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the first embodiment in this paragraph wherein removing the vacuum gas oil range components from the hydrocracking effluent comprises forming the processed hydrocracking effluent with no more than 1 wt% of the vacuum gas oil range components from the hydrocracking

effluent. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the first embodiment in this paragraph wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent, a diesel feed stream, and/or a naphtha feed stream to form the product stream.

5 An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the first embodiment in this paragraph wherein removing the vacuum gas oil range components from the hydrocracking effluent comprises separating the hydrocracking effluent to form a vapor fraction and a liquid fraction; cooling the vapor fraction to form a cooled stream; and separating the cooled stream to form a liquid stream

10 and the processed hydrocracking effluent. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the first embodiment in this paragraph wherein separating the hydrocracking effluent comprises separating the hydrocracking effluent to form the vapor fraction and the liquid fraction at a temperature of from 370°C to 500°C; and cooling the vapor fraction comprises cooling the vapor

15 fraction to form the cooled stream at a temperature of from 250°C to 350°C. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the first embodiment in this paragraph wherein separating the hydrocracking effluent comprises separating the hydrocracking effluent to form the vapor fraction and the liquid fraction at a temperature of from 400°C to 470°C; and cooling the vapor fraction comprises cooling the vapor fraction to form the cooled stream at a temperature of from 260°C to 315°C. An embodiment of the invention is one, any or all of prior embodiments

20 in this paragraph up through the first embodiment in this paragraph further comprising removing naphtha range components and diesel range components from the liquid stream and from the liquid fraction, wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent, the naphtha range components, and the diesel range components to form the product stream. An

25 embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the first embodiment in this paragraph further comprising fractionating the liquid fraction and the liquid stream to obtain an unstabilized naphtha stream, wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent and the unstabilized naphtha stream to form the product stream.

30 An embodiment of the invention is one, any or all of prior embodiments in this paragraph

up through the first embodiment in this paragraph further comprising stripping the liquid fraction and the liquid stream to form a stripped liquid and a stripper vapor; recovering diesel range components from the stripped liquid; and removing offgas and sour water from the stripper vapor to obtain an unstabilized naphtha stream, wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent, the diesel range components, and the unstabilized naphtha stream to form the product stream. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the first embodiment in this paragraph further comprising stripping the liquid fraction and the liquid stream to form a stripped liquid and a stripper vapor; fractionating the stripped liquid into a pitch range component, a heavy vacuum gas range component, a light vacuum gas range component, and a diesel range component; and removing offgas and sour water from the stripper vapor to obtain an unstabilized naphtha stream, wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent, the diesel range component, and the unstabilized naphtha stream to form the product stream.

[0054] A second embodiment of the invention is a method for processing a hydrocarbon stream, the method comprising the steps of feeding the hydrocarbon stream to a slurry hydrocracking zone; hydrocracking the hydrocarbon stream to form a slurry hydrocracking effluent; separating the slurry hydrocracking effluent to form an effluent vapor fraction and an effluent liquid fraction; cooling the effluent vapor fraction to form a cooled stream; separating the cooled stream to form a liquid stream and a vapor stream; feeding the vapor stream to a hydrotreating zone; and hydrotreating the vapor stream to form a distillate product. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the second embodiment in this paragraph wherein the slurry hydrocracking effluent includes vacuum gas oil range components, and wherein separating the cooled stream to form the liquid stream and the vapor stream comprises forming the vapor stream with no more than 10 wt% of the vacuum gas oil range components from the slurry hydrocracking effluent. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the second embodiment in this paragraph wherein the slurry hydrocracking effluent includes vacuum gas oil range components, and wherein separating the cooled stream to form the liquid stream and the vapor stream comprises forming the vapor stream with no more than 1 %

of the vacuum gas oil range components from the slurry hydrocracking effluent. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the second embodiment in this paragraph wherein separating the slurry hydrocracking effluent comprises separating the slurry hydrocracking effluent to form the effluent vapor fraction and the effluent liquid fraction at a temperature of from 370°C to 500°C; and cooling the effluent vapor fraction comprises cooling the effluent vapor fraction to form the cooled stream at a temperature of from 250°C to 350°C. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the second embodiment in this paragraph wherein separating the slurry hydrocracking effluent comprises separating the slurry hydrocracking effluent to form the effluent vapor fraction and the effluent liquid fraction at a temperature of from 450°C to 470°C; and cooling the effluent vapor fraction comprises cooling the effluent vapor fraction to form the cooled stream at a temperature of from 260°C to 315°C. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the second embodiment in this paragraph further comprising fractionating the effluent liquid fraction and the liquid stream to obtain an unstabilized naphtha stream, wherein hydrotreating the vapor stream comprises hydrotreating the vapor stream and the unstabilized naphtha stream to form the distillate product. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the second embodiment in this paragraph further comprising stripping the effluent liquid fraction and the liquid stream to form a stripped liquid and a stripper vapor; recovering a diesel range component from the stripped liquid; and removing offgas and sour water from the stripper vapor to obtain an unstabilized naphtha stream, wherein hydrotreating the vapor stream comprises hydrotreating the vapor stream, the diesel range component, and the unstabilized naphtha stream to form the distillate product. An embodiment of the invention is one, any or all of prior embodiments in this paragraph up through the second embodiment in this paragraph further comprising stripping the effluent liquid fraction and the liquid stream to form a stripped liquid and a stripper vapor; fractionating the stripped liquid into a pitch range component, a heavy vacuum gas range component, a light vacuum gas range component, and a diesel range component; and removing offgas and sour water from the stripper vapor to obtain an unstabilized naphtha stream, wherein

hydrotreating the vapor stream comprises hydrotreating the vapor stream, the diesel range component, and the unstabilized naphtha stream to form the distillate product.

[0055] A third embodiment of the invention is an apparatus for processing a hydrocarbon stream, the apparatus comprising a slurry hydrocracking zone configured for hydrocracking the hydrocarbon stream to form a slurry hydrocracking effluent; a first separator operating at first temperature and configured to separate the slurry hydrocracking effluent into an effluent vapor fraction and an effluent liquid fraction; a second separator operating at a second temperature lower than the first temperature and configured to separate the effluent vapor fraction into a liquid stream and a vapor stream; and a hydrotreating zone configured for hydrotreating the vapor stream to form a product stream.

[0056] While at least one exemplary embodiment has been presented in the foregoing detailed description, it should be appreciated that a vast number of variations exist. It should also be appreciated that the exemplary embodiment or exemplary embodiments are only examples, and are not intended to limit the scope, applicability, or configuration of the claimed subject matter in any way. Rather, the foregoing detailed description will provide those skilled in the art with a convenient road map for implementing an exemplary embodiment or embodiments. It being understood that various changes may be made in the function and arrangement of elements described in an exemplary embodiment without departing from the scope set forth in the appended claims.

CLAIMS

1. A method for processing a hydrocarbon stream (15), the method comprising the steps of:

hydrocracking the hydrocarbon stream to form a hydrocracking effluent (25)
5 including vacuum gas oil range components;

removing the vacuum gas oil range components from the hydrocracking effluent to form a stream of vacuum gas oil range components (37, 57) and a processed hydrocracking effluent (53); and

hydrotreating the processed hydrocracking effluent to form a product stream (65).

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2. The method of claim 1 wherein removing the vacuum gas oil range components from the hydrocracking effluent comprises:

separating the hydrocracking effluent to form a vapor fraction (33) and a liquid fraction (37);

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cooling the vapor fraction to form a cooled stream (45); and

separating the cooled stream to form a liquid stream (57) and the processed hydrocracking effluent.

3. The method of claim 2 wherein:

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separating the hydrocracking effluent comprises separating the hydrocracking effluent to form the vapor fraction and the liquid fraction at a temperature of from 370°C to 500°C; and

cooling the vapor fraction comprises cooling the vapor fraction to form the cooled stream at a temperature of from 250°C to 350°C.

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4. The method of claim 2 wherein:

separating the hydrocracking effluent comprises separating the hydrocracking effluent to form the vapor fraction and the liquid fraction at a temperature of from 400°C to 470°C; and

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cooling the vapor fraction comprises cooling the vapor fraction to form the cooled stream at a temperature of from 260°C to 315°C.

5. The method of claim 2 further comprising removing naphtha range components and diesel range components (75) from the liquid stream and from the liquid fraction, wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent, the naphtha range components, and the diesel range components to form the product stream.

6. The method of claim 2 further comprising fractionating the liquid fraction and the liquid stream to obtain an unstabilized naphtha stream (75), wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent and the unstabilized naphtha stream to form the product stream.

7. The method of claim 2 further comprising:
stripping the liquid fraction (137) and the liquid stream (157) to form a stripped liquid (278) and a stripper vapor (264);
recovering diesel range components (286) from the stripped liquid; and
removing offgas (272) and sour water (274) from the stripper vapor to obtain an unstabilized naphtha stream (176), wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent, the diesel range components, and the unstabilized naphtha stream to form the product stream.

8. The method of claim 2 further comprising:
stripping the liquid fraction (137) and the liquid stream (157) to form a stripped liquid (278) and a stripper vapor (264);
fractionating the stripped liquid into a pitch range component (296), a heavy vacuum gas range component (294), a light vacuum gas range component (292), and a diesel range component (286); and
removing offgas (272) and sour water (274) from the stripper vapor to obtain an unstabilized naphtha stream (176), wherein hydrotreating the processed hydrocracking effluent comprises hydrotreating the processed hydrocracking effluent, the diesel range component, and the unstabilized naphtha stream to form the product stream.

9. The method of claim 1 wherein removing the vacuum gas oil range components from the hydrocracking effluent comprises forming the processed hydrocracking effluent with no more than 1 wt% of the vacuum gas oil range components from the hydrocracking effluent.

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10. An apparatus (10) for processing a hydrocarbon stream (15), the apparatus comprising:

a slurry hydrocracking zone (20) configured for hydrocracking the hydrocarbon stream to form a slurry hydrocracking effluent (25);

10 a first separator (30) operating at first temperature and configured to separate the slurry hydrocracking effluent into an effluent vapor fraction (33) and an effluent liquid fraction (37);

a second separator (50) operating at a second temperature lower than the first temperature and configured to separate the effluent vapor fraction into a liquid stream (57) and a vapor stream (53); and

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a hydrotreating zone (60) configured for hydrotreating the vapor stream to form a product stream (65).

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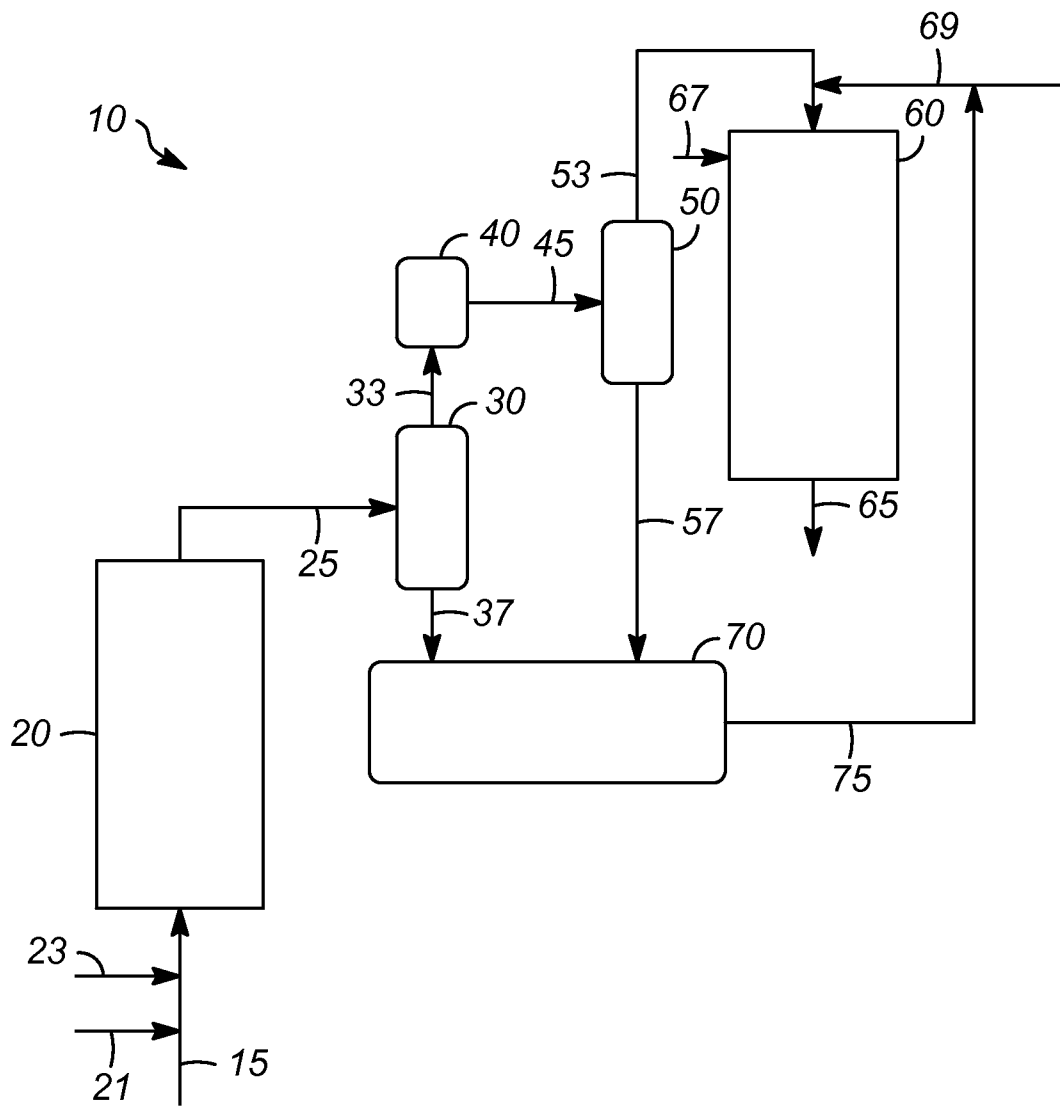


FIG. 1

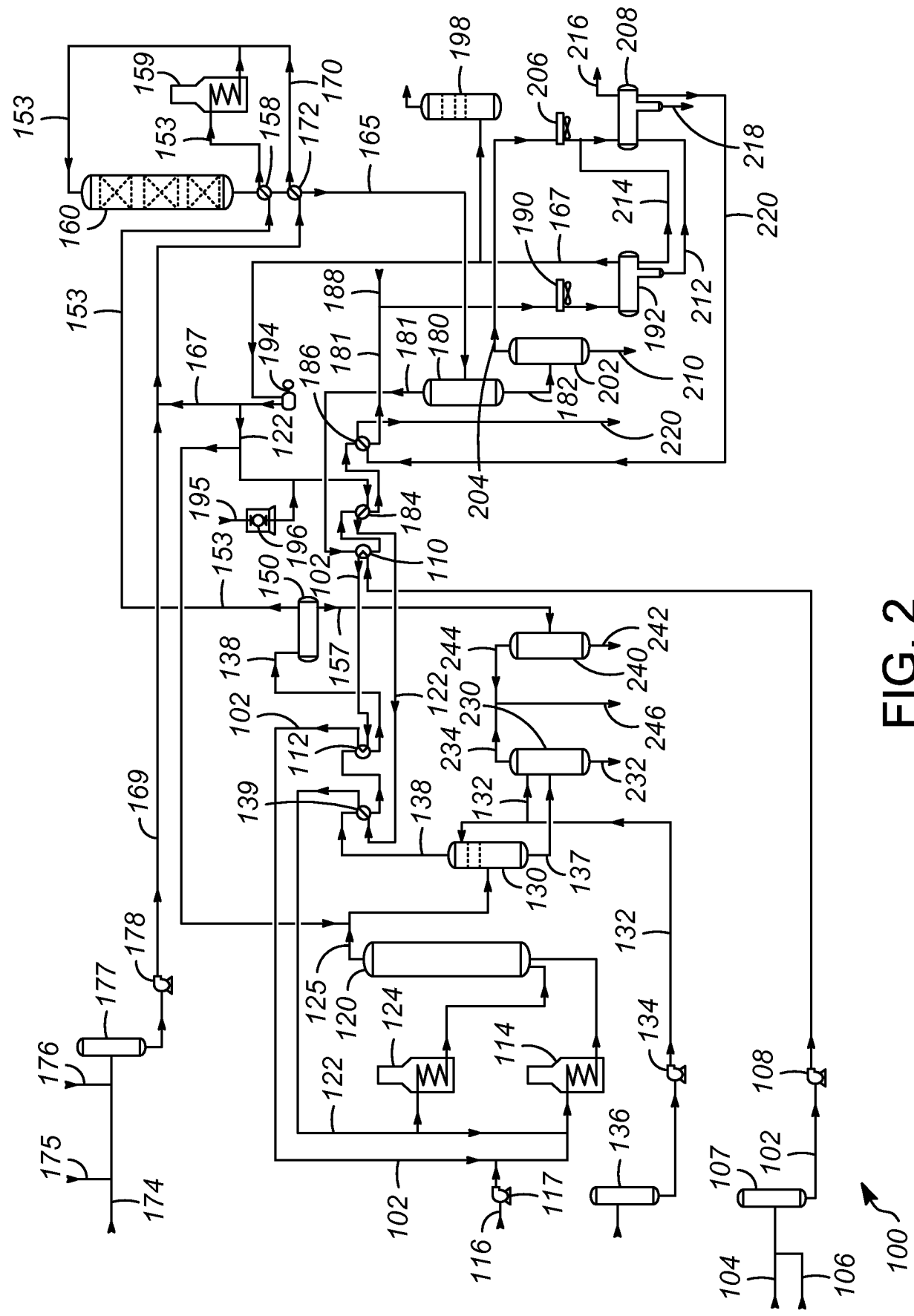


FIG. 2

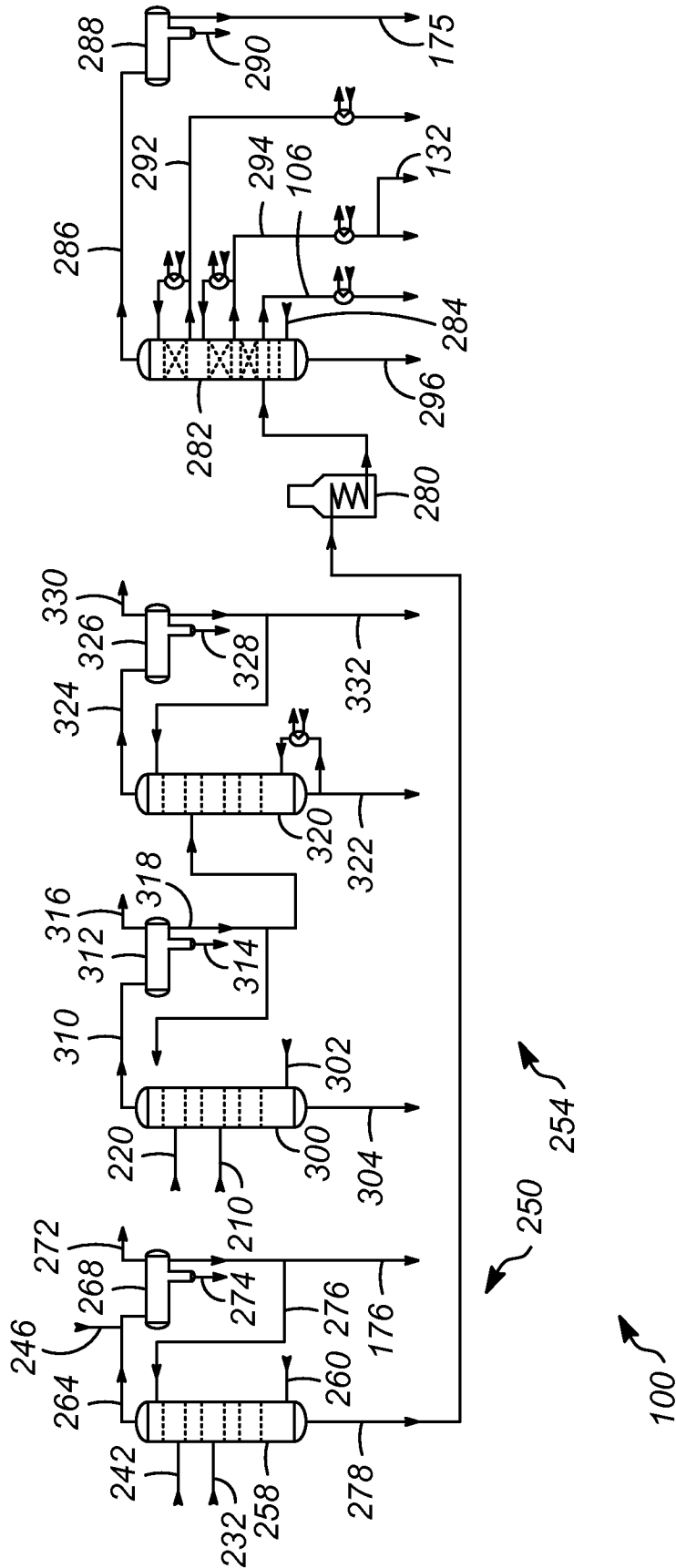


FIG. 3

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US 2015/033726

A. CLASSIFICATION OF SUBJECT MATTER
C10G 65/12 (2006.01)
C10G 47/26 (2006.01)

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 65/12, 47/26

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)

PatSearch (RUPTO internal), Esp@cenet, EAPATIS, Google, Information Retrieval System of FIPS

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2009/0127161 A1 (ROBERT S. HAZMANN et al.) 21.05.2009, fig. 1, 2, [0018]	1
Y		2-4, 10
A		5-9
Y	US 6066679 A (EXXON RESEARCH AND ENGINEERING COMPANY) 23.05.2000, col. 7, line 66-col. 8, line 30	2-4, 10
A	US 6660157 B2 (PETROCHINA COMPANY LIMITED et al.) 09.12.2003	1-10
A	US 5026472 A (UOP) 25.06.1991	1-10



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents:	"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"A" document defining the general state of the art which is not considered to be of particular relevance	"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"E" earlier document but published on or after the international filing date	"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)	"&" document member of the same patent family
"O" document referring to an oral disclosure, use, exhibition or other means	
"P" document published prior to the international filing date but later than the priority date claimed	

Date of the actual completion of the international search

17 July 2015 (17.07.2015)

Date of mailing of the international search report

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