

PROCESSES FOR HYDROCARBON CONVERSION**CROSS-REFERENCE TO RELATED APPLICATION**

[0001] This application claims priority to and the benefit of U.S. Provisional Application
5 No. 63/596,327 having a filing date of November 6, 2023, the disclosure of which is
incorporated herein by reference in its entirety.

FIELD

[0002] Embodiments disclosed herein generally relate to processes for hydrocarbon
conversion. More particularly, the processes relate to hydroprocessing a hydrocarbon feed that
10 includes a Group I lube extract.

BACKGROUND

[0003] Steam crackers are capable of steam cracking a wide range of feeds that can be
gaseous, e.g., a C₄- hydrocarbon feed, and/or liquid, e.g., a C₅+ hydrocarbon feed, at room
temperature. Steam cracker effluents include hydrocarbons that have been converted or
15 upgraded to higher value products, e.g., light olefins, such as ethylene and propylene. The
products are typically separated and processed in an effluent processing unit. In addition to the
higher value products, other relatively low value products such as steam cracker tar are also
produced. The steam cracker tar is typically blended with one or more other hydrocarbon
streams and sold as fuel oil. The steam cracker tar can be upgraded via hydroprocessing in a
20 hydroprocessing unit to reduce sulfur content and density to produce a low-sulfur fuel oil
boiling-range product that is suitable for use as a fuel oil or a blending constituent thereof.

[0004] The quantity of steam cracker tar in a steam cracker effluent produced by steam
cracking a liquid hydrocarbon feed is significantly greater than the quantity of steam cracker
tar produced by steam cracking a gaseous hydrocarbon feed. As such, when a hydroprocessing
25 unit is configured to process a steam cracker tar derived from steam cracking a liquid
hydrocarbon feed, such configuration can limit or prevent the steam cracker from processing a
gaseous hydrocarbon feed because the hydroprocessing unit requires a certain minimum
amount of steam cracker tar to be present in the steam cracker effluent.

[0005] There is a need, therefore, for improved processes and systems for increasing the
30 hydrocarbon feed flexibility for a steam cracker by improving the feed flexibility for the
hydroprocessing unit configured to process the steam cracker tar. This disclosure satisfies this
and other needs.

SUMMARY

[0006] Processes and systems for upgrading hydrocarbon(s) are provided. In some embodiments, the hydrocarbon upgrading process can include (I) feeding molecular hydrogen, a utility fluid, and a hydrocarbon feed into a first hydroprocessing stage. The hydrocarbon feed
5 can be or can include a Group I lube extract. The process can also include (II) conducting hydroprocessing in the first hydroprocessing stage to produce a first hydroprocessed effluent. The process can also include (III) separating from the first hydroprocessed effluent a mid-cut product and a bottoms product. The process can also include (IV) feeding molecular hydrogen and at least a portion of the bottoms product into a second hydroprocessing stage. The process
10 can also include (V) conducting hydroprocessing in the second hydroprocessing stage to produce a second hydroprocessed effluent. The process can also include (VI) recycling at least a portion of the mid-cut product to the first hydroprocessing stage as at least a portion of the utility fluid.

[0007] In other embodiments, a hydrocarbon upgrading process can include (I) heating a
15 hydrocarbon in a steam cracking furnace and combining the hydrocarbon with an aqueous fluid to produce a first mixture that can include hydrocarbon and steam. The heating can be carried out before, during, and/or after the hydrocarbon feed is combined with the aqueous fluid. The process can also include (II) steam cracking at least a portion of the first mixture to produce a steam cracker effluent. The process can also include (III) separating from the steam cracker
20 effluent a steam cracker tar product and an upgraded steam cracker effluent that can include ethylene and propylene. The process can also include (IV) feeding molecular hydrogen, at least a portion of the steam cracker tar product, and a hydrocarbon feed into a first hydroprocessing stage. The hydrocarbon feed can be or can include a Group I lube extract. The process can also include (V) conducting hydroprocessing in the first hydroprocessing stage
25 to produce a first hydroprocessed effluent. The process can also include (VI) separating from the first hydroprocessed effluent a mid-cut product and a bottoms product. The process can also include (VII) feeding molecular hydrogen and at least a portion of the bottoms product into a second hydroprocessing stage. The process can also include (VIII) conducting hydroprocessing in the second hydroprocessing stage to produce a second hydroprocessed
30 effluent. The process can also include (IX) recycling at least a portion of the mid-cut product to the first hydroprocessing stage as at least a portion of the utility fluid.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] The drawings described herein are for illustrative purposes only of selected embodiments and not all possible implementations and are not intended to limit the scope of the present disclosure. Like reference numerals shown throughout the drawings represent similar parts throughout the embodiments shown in the drawings.

[0009] FIG. 1 depicts a schematic of an illustrative process/system for upgrading a hydrocarbon feed that includes a Group I lube extract, according to one or more embodiments described.

[0010] FIG. 2 depicts a schematic of another illustrative process/system for upgrading a hydrocarbon feed that includes a Group I lube extract, according to one or more embodiments described.

[0011] FIG. 3 depicts a schematic of an illustrative process/system for upgrading a steam cracker tar and a hydrocarbon feed that includes a Group I lube extract, according to one or more embodiments described.

[0012] FIG. 4 depicts a schematic of another illustrative process/system for upgrading a steam cracker tar, a fluidized catalytic cracker main column bottoms product, and a hydrocarbon feed that includes a Group I lube extract, according to one or more embodiments described.

DETAILED DESCRIPTION

[0013] Various specific embodiments, versions and examples of the invention will now be described, including preferred embodiments and definitions that are adopted herein for purposes of understanding the claimed invention. While the following detailed description gives specific preferred embodiments, those skilled in the art will appreciate that these embodiments are exemplary only, and that the invention may be practiced in other ways. For purposes of determining infringement, the scope of the invention will refer to any one or more of the appended claims, including their equivalents, and elements or limitations that are equivalent to those that are recited. Any reference to the “invention” may refer to one or more, but not necessarily all, of the inventions defined by the claims.

[0014] In this disclosure, a process is described as including at least one “step.” It should be understood that each step is an action or operation that may be carried out once or multiple times in the process, in a continuous or discontinuous fashion. Unless specified to the contrary or the context clearly indicates otherwise, multiple steps in a process may be conducted sequentially in the order as they are listed, with or without overlapping with one or more other

steps, or in any other order, as the case may be. In addition, one or more or even all steps may be conducted simultaneously with regard to the same or different batch of material. For example, in a continuous process, while a first step in a process is being conducted with respect to a raw material just fed into the beginning of the process, a second step may be carried out simultaneously with respect to an intermediate material resulting from treating the raw materials fed into the process at an earlier time in the first step. Preferably, the steps are conducted in the order described.

[0015] Unless otherwise indicated, all numbers indicating quantities in this disclosure are to be understood as being modified by the term “about” in all instances. It should also be understood that the precise numerical values used in the specification and claims constitute specific embodiments. Efforts have been made to ensure the accuracy of the data in the examples. However, it should be understood that any measured data inherently contains a certain level of error due to the limitation of the technique and/or equipment used for making the measurement.

[0016] Certain embodiments and features are described herein using a set of numerical upper limits and a set of numerical lower limits. It should be appreciated that ranges including the combination of any two values, e.g., the combination of any lower value with any upper value, the combination of any two lower values, and/or the combination of any two upper values are contemplated unless otherwise indicated.

[0017] As used herein, the indefinite article “a” or “an” shall mean “at least one” unless specified to the contrary or the context clearly indicates otherwise. Thus, embodiments using “a steam cracking furnace” include embodiments where one, two, or more steam cracking furnaces can be used, unless specified to the contrary or the context clearly indicates that only one steam cracking furnace is used.

[0018] The term “hydrocarbon” as used herein means (i) any compound consisting of hydrogen and carbon atoms or (ii) any mixture of two or more such compounds in (i). The term “C_n hydrocarbon,” where n is a positive integer, means (i) any hydrocarbon compound comprising carbon atom(s) in its molecule at the total number of n, or (ii) any mixture of two or more such hydrocarbon compounds in (i). Thus, a C₂ hydrocarbon can be ethane, ethylene, acetylene, or mixtures of at least two of these compounds at any proportion. A “C_m to C_n hydrocarbon” or “C_m-C_n hydrocarbon,” where m and n are positive integers and m < n, means any of C_m, C_{m+1}, C_{m+2}, ..., C_{n-1}, C_n hydrocarbons, or any mixtures of two or more thereof. Thus, a “C₂ to C₃ hydrocarbon” or “C₂-C₃ hydrocarbon” can be any of ethane, ethylene, acetylene,

propane, propene, propyne, propadiene, cyclopropane, and any mixtures of two or more thereof at any proportion between and among the components. A “saturated C₂-C₃ hydrocarbon” can be ethane, propane, cyclopropane, or any mixture thereof of two or more thereof at any proportion. A “C_{n+} hydrocarbon” means (i) any hydrocarbon compound comprising carbon atom(s) in its molecule at the total number of at least n, or (ii) any mixture of two or more such hydrocarbon compounds in (i). A “C_{n-} hydrocarbon” means (i) any hydrocarbon compound comprising carbon atoms in its molecule at the total number of at most n, or (ii) any mixture of two or more such hydrocarbon compounds in (i). A “C_m hydrocarbon stream” means a hydrocarbon stream consisting essentially of C_m hydrocarbon(s). A “C_m-C_n hydrocarbon stream” means a hydrocarbon stream consisting essentially of C_m-C_n hydrocarbon(s).

[0019] The term “hydrocarbon feed” refers to a composition that includes a Group I lube extract. In some embodiments, in addition to the Group I lube extract, the hydrocarbon feed can also include any additional hydrocarbons such as heavy hydrocarbons, e.g., C₅₊ hydrocarbons and/or light hydrocarbons, e.g., C₄₋ hydrocarbons.

[0020] The term “aromatic” as used herein is to be understood in accordance with its art-recognized scope which includes alkyl substituted and unsubstituted mono- and poly-nuclear compounds.

[0021] As used herein, “wt%” means percentage by weight, “vol%” means percentage by volume, “mol%” means percentage by mole, “ppm” means parts per million, and “ppm wt” and “wppm” are used interchangeably to mean parts per million on a weight basis. All concentrations herein are expressed on the basis of the total amount of the composition in question, unless specified otherwise.

Overview of Processes/Systems for Upgrading Hydrocarbons

[0022] A hydrocarbon feed that includes one or more relatively high sulfur-containing hydrocarbons can be hydroprocessed in a first hydroprocessing stage in the presence of molecular hydrogen and a utility fluid to produce a first hydroprocessed effluent. The hydrocarbon feed can be or can include, but is not limited to, a Group I lube extract. In some embodiments, the hydrocarbon feed can also include, in addition to the Group I lube extract, a steam cracker tar. In other embodiments, the hydrocarbon feed can also include, in addition to the Group I lube extract, a fluidized catalytic cracker main column bottoms product. In still other embodiments, the hydrocarbon feed can also include, in addition to the Group I lube extract, a steam cracker tar and a fluidized catalytic cracker main column bottoms product. Accordingly, as used herein, the term “hydrocarbon feed” refers to a feed that includes a Group

lube extract and, optionally, one or more additional hydrocarbons, e.g., a steam cracker tar and/or a fluidized catalytic cracker main column bottoms product.

[0023] In some embodiments, the hydrocarbon feed, the molecular hydrogen, and the utility fluid can be mixed prior to introduction into the first hydroprocessing stage. In other
5 embodiments, the hydrocarbon feed and the utility fluid can be mixed prior to introduction into the first hydroprocessing stage and the molecular hydrogen and the mixture of the hydrocarbon feed and utility fluid can be introduced separately into the hydroprocessing stage. In still other
10 embodiments, the hydrocarbon feed, the molecular hydrogen, and the utility fluid can be separately introduced into and mixed within the first hydroprocessing stage. When the steam cracker effluent and/or the fluidized catalytic cracker main column bottoms product is also
introduced into the first hydroprocessing stage, such additional feed can be separately
introduced thereto or introduced as a mixture of at least one of the hydrocarbon feed, the utility
fluid, and the molecular hydrogen. In some embodiments, the hydrocarbon feed, the utility
fluid, and at least one of the steam cracker tar and the fluidized catalytic cracker main column
15 bottoms product can be combined to produce a mixture and the mixture and molecular
hydrogen can be introduced into the first hydroprocessing stage. In other embodiments, the
hydrocarbon feed, the utility fluid, the molecular hydrogen, and at least one of the steam cracker
tar and the fluidized catalytic cracker main column bottoms product can be combined to
produce a mixture and the mixture can be introduced into the first hydroprocessing stage.

[0024] In some embodiments, a mid-cut product and a bottoms product can be separated
20 from the first hydroprocessed effluent. In other embodiments, an overhead product that can
include molecular hydrogen and one or more C₁-C₄ hydrocarbons, the mid-cut product, and the
bottoms product can be separated from the first hydroprocessed effluent. In still other
embodiments, the overhead product, a light cut product that can include naphtha, the mid-cut
25 product, and the bottoms product can be separated from the first hydroprocessed effluent. In
some embodiments, at least a portion of the mid-cut product can be recycled to the first
hydroprocessing stage such that the mid-cut product can make-up at least a portion or all of the
utility fluid. In some embodiments, the overhead that includes molecular hydrogen can also
include hydrogen sulfide and/or other sulfur containing compounds. In such embodiment, at
30 least a portion of the sulfur containing compound(s) can be removed, e.g., via one or more
amine towers.

[0025] In some embodiments, a portion or all of the bottoms product separated from the
first hydroprocessed effluent can be used as a blending component to produce a low sulfur fuel

oil. In other embodiments, a portion or all of the bottoms product can be hydroprocessed in a second hydroprocessing stage in the presence of molecular hydrogen to produce a second hydroprocessed product. In some embodiments, the second hydroprocessed product can be used as a low sulfur fuel oil, e.g., a fuel oil containing ≤ 0.5 wt% sulfur, or a blending component thereof. In some embodiments, an overhead product rich in molecular hydrogen and a bottoms product lean in molecular hydrogen can be separated from the second hydroprocessed product. In some embodiments, at least a portion of the molecular hydrogen in the overhead product separated from the first hydroprocessed effluent and/or at least a portion of the molecular hydrogen separated from the second hydroprocessed product can be fed into the first hydroprocessing stage, fed into the second hydroprocessing stage, or a combination thereof.

Hydrocarbon Feeds

[0026] The Group I lube extract can include 3.5 wt%, 3.7 wt%, 4 wt%, 4.3 wt%, or 4.5 wt% to 5 wt%, 5.3 wt%, 5.5 wt%, 5.7 wt%, or 6 wt% of sulfur, based on the total weight of the Group I lube extract. The Group I lube extract can include 8 wt%, 8.3 wt%, 8.5 wt%, 8.7 wt%, 9 wt%, 9.3 wt%, 9.5 wt%, 9.7 wt%, or 10 wt% to 10.5 wt%, 10.7 wt%, 11 wt%, 11.3 wt%, 11.5 wt%, 11.7 wt%, or 12 wt% of hydrogen, based on the total weight of the Group I lube extract. The hydrogen content can be measured by proton nuclear magnetic resonance (NMR). For example, the hydrogen content can be measured according to ASTM D7171-05 or its equivalent. The sulfur content can be measured by X-ray fluorescence spectrometry. For example, the sulfur content can be measured according to ASTM D2622-21 or its equivalent. The Group I lube extract can have an API gravity in a range from 7.3°, 7.5°, 7.7°, 8°, 8.3°, 8.5°, or 8.7° to 9°, 9.3°, 9.5°, 9.7°, or 10°. The API gravity of the Group I lube extract and other hydrocarbon feeds can be measured at a temperature of 15.8°C according to ASTM D287-22. The Group I lube extract can have a solubility blending number (SBN) in a range from 93, 95, 100, 105, 110, 115, or 120 to 125, 130, 135, 140, 145, 150, or 155. The SBN of the Group I lube extract and other hydrocarbon feeds can be measured as described in U.S. Patent No. 5,871,634. The Group I lube extract can have density at 15°C in a range from 0.905 g/cm³, 0.910 g/cm³, 0.930 g/cm³, 0.950 g/cm³, 0.970 g/cm³, 0.990 g/cm³, or 1.000 g/cm³ to 1.005 g/cm³, 1.007 g/cm³, 1.009 g/cm³, 1.100 g/cm³, 1.105 g/cm³, 1.110 g/cm³, or 1.113 g/cm³. The density of the Group I lube extract and other hydrocarbon feeds can be determined by measuring the API and converting the API to density. In some embodiments, the Group I lube extract can include 3.5 wt% to 6 wt% of sulfur and from 8 wt% to 12 wt% of hydrogen, based

on the total weight of the Group I lube extract, can have an API gravity in a range from 7.3° to 10°, can have an SBN in a range from 93 to 155, and can have a density in a range from 0.905 g/cm³ to 1.113 g/cm³.

[0027] In some embodiments, the Group I lube extract can be produced by fractionating a crude oil or a fraction thereof in an atmospheric pressure pipestill (APS). One of the products recovered therefrom can be introduced into a lube vacuum pipestill (LVPS) to separate a lube molecule containing product that can be introduced into a lube extraction unit. The lube extraction unit can utilize any suitable solvent for extraction. In some embodiments, N-methyl pyrrolidone (NMP), furfural, and/or phenol can be used as the solvent for the extraction process. The products recovered from the lube extraction unit can include Group I lube extract as well as Group II lube extract.

[0028] In some embodiments, the Group I lube extract can be or can include, but is not limited to, a light neutral (LN) Group I lube extract, a heavy neutral (HN) Group I lube extract, a bright stock (BS) Group I lube extract, or a mixture thereof. In some embodiments, the light neutral Group I lube extract can include a greater amount of sulfur than the heavy neutral Group I lube extract and the heavy neutral Group I lube extract can include a greater amount of sulfur than the bright stock Group I lube extract. In some embodiments, the light neutral Group I lube extract can include a lower amount of hydrogen than the heavy neutral Group I lube extract and the heavy neutral Group I lube extract can include a lower amount of hydrogen than the bright stock Group I lube extract. In some embodiments, the bright stock Group I lube extract can have a greater API than the light neutral Group I lube extract and the light neutral Group I lube extract can have a greater API than the heavy neutral Group I lube extract. In some embodiments, the light neutral Group I lube extract can have a greater solubility blending number than the bright stock Group I lube extract and the bright stock Group I lube extract can have a greater solubility blending number than the heavy neutral Group I lube extract.

[0029] The light neutral Group I lube extract can include 3.9 wt%, 4 wt%, 4.3 wt%, 4.5 wt%, or 4.7 wt% to 5 wt%, 5.3 wt%, 5.5 wt%, 5.7 wt%, or 6 wt% of sulfur, based on the total weight of the light neutral Group I lube extract. The light neutral Group I lube extract can include 8 wt%, 8.3 wt%, 8.5 wt%, or 8.7 wt% to 9 wt%, 9.3 wt%, 9.5 wt%, 9.7 wt%, or 10 wt% of hydrogen, based on the total weight of the light neutral Group I lube extract. The light neutral Group I lube extract can have an API gravity in a range from 8°, 8.3°, 8.5°, or 8.7° to 9°, 9.3°, 9.5°, or 9.8°. The light neutral Group I lube extract can have a solubility blending number in a range from 125, 127, 130, 133, 135, 137, or 140 to 143, 145, 147, 150, 153, or

155. The light neutral Group I lube extract can have density at 15°C in a range from 0.905 g/cm³, 0.910 g/cm³, 0.930 g/cm³, 0.950 g/cm³, 0.970 g/cm³, 0.990 g/cm³, or 1.000 g/cm³ to 1.005 g/cm³, 1.007 g/cm³, 1.009 g/cm³, 1.100 g/cm³, 1.105 g/cm³, or 1.108 g/cm³. In some embodiments, the light neutral Group I lube extract can include 3.9 wt% to 6 wt% of sulfur and from 8 wt% to 10 wt% of hydrogen, based on the total weight of the light neutral Group I lube extract, can have an API gravity in a range from 8° to 9.8°, can have an SBN in a range from 125 to 155, and can have a density in a range from 0.905 g/cm³ to 1.108 g/cm³.

[0030] The heavy neutral Group I lube extract can include 3.7 wt%, 4 wt%, 4.3 wt%, 4.5 wt%, or 4.7 wt% to 5 wt%, 5.3 wt%, 5.5 wt%, or 5.7 wt% of sulfur, based on the total weight of the heavy neutral Group I lube extract. The heavy neutral Group I lube extract can include 8.8 wt%, 9 wt%, 9.3 wt%, or 9.5 wt% to 9.7 wt%, 10 wt%, 10.3 wt%, 10.5 wt%, or 10.8 wt% of hydrogen, based on the total weight of the heavy neutral Group I lube extract. The heavy neutral Group I lube extract can have an API gravity in a range from 7.3°, 7.5°, 7.7°, or 8° to 8.3°, 8.5°, 8.7°, or 9°. The heavy neutral Group I lube extract can have a solubility blending number in a range from 93, 95, 97, 100, 105, or 107 to 109, 111, 112, 113, or 115. The heavy neutral Group I lube extract can have density at 15°C in a range from 0.910 g/cm³, 0.920 g/cm³, 0.930 g/cm³, 0.950 g/cm³, or 0.970 g/cm³ to 0.990 g/cm³, 1.000 g/cm³, 1.010 g/cm³, 1.050 g/cm³, 1.100 g/cm³, 1.105 g/cm³, or 1.115 g/cm³. In some embodiments, the heavy neutral Group I lube extract can include 3.7 wt% to 5.7 wt% of sulfur and from 8.8 wt% to 10.8 wt% of hydrogen, based on the total weight of the heavy neutral Group I lube extract, can have an API gravity in a range from 7.3° to 9°, can have an SBN in a range from 93 to 115, and can have a density in a range from 0.910 g/cm³ to 1.115 g/cm³.

[0031] The bright stock Group I lube extract can include 3.6 wt%, 3.8 wt%, 4 wt%, 4.3 wt%, or 4.5 wt% to 4.7 wt%, 5 wt%, 5.3 wt%, or 5.5 wt% of sulfur, based on the total weight of the bright stock Group I lube extract. The bright stock Group I lube extract can include 9.5 wt%, 9.7 wt%, 10 wt%, or 10.3 wt% to 10.7 wt%, 11 wt%, 11.3 wt%, 11.5 wt%, or 11.7 wt% of hydrogen, based on the total weight of the heavy neutral Group I lube extract. The bright stock Group I lube extract can have an API gravity in a range from 8.1°, 8.3°, 8.5°, or 8.7° to 9°, 9.3°, 9.5°, 9.7°, or 10°. The bright stock Group I lube extract can have a solubility blending number in a range from 97, 100, 103, 105, 107, or 110 to 112, 114, 116, 118, or 119. The bright stock Group I lube extract can have density at 15°C in a range from 0.905 g/cm³, 0.910 g/cm³, 0.930 g/cm³, 0.950 g/cm³, or 0.970 g/cm³ to 0.990 g/cm³, 1.000 g/cm³, 1.010 g/cm³, 1.050 g/cm³, 1.100 g/cm³, 1.105 g/cm³, or 1.107 g/cm³. In some embodiments, the bright stock

Group I lube extract can include 3.6 wt% to 5.5 wt% of sulfur and from 9.5 wt% to 11.7 wt% of hydrogen, based on the total weight of the bright stock Group I lube extract, can have an API gravity in a range from 8.1° to 10°, can have an SBN in a range from 97 to 119, and can have a density in a range from 0.905 g/cm³ to 1.107 g/cm³.

- 5 [0032] The term “steam cracker tar” means (a) a mixture of hydrocarbons having one or more aromatic components and optionally (b) non-aromatic and/or non-hydrocarbon molecules, the mixture being produced via steam cracking a hydrocarbon within a radiant section of a steam cracking furnace. Certain steam cracker tars can have an initial boiling point $\geq 200^{\circ}\text{C}$. For certain steam cracker tars, ≥ 90 wt% of the steam cracker tar can have a boiling point at atmospheric pressure $\geq 290^{\circ}\text{C}$. Steam cracker tar can include, e.g., ≥ 50 wt%, ≥ 75 wt%, or ≥ 90 wt%, based on the weight of the steam cracker tar, of hydrocarbon molecules (including mixtures and aggregates thereof) having (i) one or more aromatic components, and (ii) a number of carbon atoms $\geq$ about 15. Steam cracker tar generally can include $\leq 1 \times 10^3$ ppmw of metal(s), based on the weight of the steam cracker tar, which is an amount of metal(s) that is far less than that found in crude oil (or crude oil components) of the same average viscosity.

- [0033] The steam cracker tar can include 3.3 wt%, 3.5 wt%, 3.7 wt%, or 4 wt% to 4.3 wt%, 4.5 wt%, 4.7 wt%, or 5 wt% of sulfur, based on the total weight of the steam cracker tar. The steam cracker tar can include 5.5 wt%, 5.7 wt%, 6 wt%, 6.3 wt%, or 6.5 wt% to 6.7 wt%, 7 wt%, 7.3 wt%, or 7.5 wt% of hydrogen, based on a total weight of the steam cracker tar. The steam cracker tar can have an API gravity in a range from -11°, -10.7°, -10.5°, -10.3°, -10°, or -9.7° to -9.5°, -9.3°, -9°, -8.7°, -8.5°, -8.3°, or -8°. The steam cracker tar can have a solubility blending number in a range from 180, 185, 190, 195, 200, 205, or 210 to 215, 220, 225, 230, 235, 240, 245, or 250. The steam cracker tar can have a density at 15°C in a range from 1.040 g/cm³, 1.070 g/cm³, 1.100 g/cm³, 1.150 g/cm³, or 1.170 g/cm³ to 1.200 g/cm³, 1.230 g/cm³, 1.250 g/cm³, or 1.271 g/cm³. In some embodiments, the steam cracker tar can include 3.3 wt% to 5 wt% of sulfur and 5.5 wt% to 7.5 wt% of hydrogen based on a total weight of the steam cracker tar, can have an API gravity in a range from -11° to -8°, can have a solubility blending number in a range from 180 to 250, and can have a density in a range from 1.040 g/cm³ to 1.271 g/cm³.

[0034] The steam cracking conditions in the radiant section of the steam cracking furnace can include, but are not limited to, one or more of: exposing a hydrocarbon introduced thereto to a temperature (as measured at a radiant outlet of the steam cracker) of $\geq 400^{\circ}\text{C}$, e.g., a

temperature of about 700°C, about 800°C, or about 900°C to about 950°C, about 1,000°C, or about 1050°C, a pressure of about 100 kPa-absolute to about 600 kPa-absolute, and/or a steam cracking residence time of about 0.01 seconds to about 5 seconds. Suitable steam crackers, product recovery configurations, other equipment, and process conditions can include those disclosed in U.S. Patent Nos.: 6,419,885; 7,560,019; 7,993,435; 8,105,479; 8,197,668; 8,882,991; 9,637,694; 9,777,227; U.S. Patent Application Publication Nos.: 2014/0061096; 2014/0357923; 2016/0376511; 2018/0170832; 2019/0016975; and WO Publication No.: WO 2018/111574; WO/2020/096972; WO/2020/096974; WO/2020/096977; and WO/2020/096979.

[0035] The fluidized catalytic cracker main column bottoms product can be separated from a fluidized catalytic cracker effluent. The fluidized catalytic cracker effluent can be produced by contacting a hydrocarbon in the presence of fluidized catalyst particles within a fluidized catalytic cracker. The fluidized catalytic cracker main column bottoms product can include 1.5 wt%, 1.7 wt%, 2 wt%, 2.3 wt%, 2.5 wt%, 2.7 wt%, or 3 wt% to 3.3 wt%, 3.5 wt%, 3.7 wt%, 4 wt%, 4.3 wt%, 4.5 wt%, 4.7 wt%, or 5 wt% of sulfur, based on the total weight of the fluidized catalytic cracker main column bottoms product. The fluidized catalytic cracker main column bottoms product can include 6.1 wt%, 6.3 wt%, 6.5 wt%, 6.7 wt%, 7 wt%, or 7.3 wt% to 7.5 wt%, 7.7 wt%, 8 wt%, 8.3 wt%, 8.5 wt%, or 8.8 wt% of hydrogen, based on the total weight of the fluidized catalytic cracker main column bottoms product. The fluidized catalytic cracker main column bottoms product can have an API gravity in a range from -11°, -10°, -9°, -8°, -7°, -6° or -5° to -4°, -3°, -2°, 1°, 0°, 1°, 2°, or 2.5°. The fluidized catalytic cracker main column bottoms product can have a solubility blending number in a range from 180, 185, 190, 195, 200, 205, or 210 to 215, 220, 225, 230, 235, 240, 245, or 250. The fluidized catalytic cracker main column bottoms product can have a density at 15°C in a range from 0.954 g/cm³, 0.970 g/cm³, 1.000 g/cm³, 1.050, or 1.100 g/cm³ to 1.150 g/cm³, 1.200 g/cm³, 1.230 g/cm³, or 1.243 g/cm³. In some embodiments, the fluidized catalytic cracker main column bottoms product can include 1.5 wt% to 5 wt% of sulfur and 6.1 wt% to 8.8 wt% of hydrogen based on a total weight of the fluidized catalytic cracker main column bottoms product, can have an API gravity in a range from -11° to 2.5°, can have a solubility blending number in a range from 180 to 250, and can have a density in a range from 0.954 g/cm³ to 1.243 g/cm³.

[0036] In the fluidized catalytic cracker, a hydrocarbon can be contacted with a plurality of fluidized catalyst particles for a contact time therein. The hydrocarbon can be injected through one or more feed nozzles into a reactor riser. Within this reactor riser, the hydrocarbon

can be contacted with a fluidized catalyst under cracking conditions thereby resulting in spent catalyst particles containing coke deposited thereon and a lower boiling product stream.

[0037] The fluidized catalyst can be or can include any one or more catalysts typically used in fluidized catalytic cracking processes. For example, the catalyst can include large-pore molecular sieve catalysts, medium-pore molecular sieve catalysts, or a mixture thereof. Large-pore molecular sieves generally include molecular sieve catalysts having an average pore diameter of about 0.7 nm or greater and are typically used to catalytically “crack” hydrocarbons. The large-pore molecular sieves and the medium-pore molecular sieves can have a crystalline tetrahedral framework oxide component. For example, the crystalline tetrahedral framework oxide component can include zeolites, tectosilicates, tetrahedral aluminophosphates (ALPOs) and tetrahedral silicoaluminophosphates (SAPOs). Conventional FCC catalyst can be used (including a mixture of large pore and shape-selective catalyst).

[0038] In some embodiments, the fluidized catalytic cracking conditions can include: temperatures from 535°C to 850°C or more; a hydrocarbon partial pressure from about 70 kPa-a to about 345 kPa-a; and a catalyst to feed (wt/wt) ratio from 2 to 10. In some embodiments, steam can be concurrently introduced with the feed into the reaction zone. In some embodiments, the steam, if present, can make up to about 5 wt% of the hydrocarbon introduced into the fluidized catalytic cracker. In some embodiments, the residence time in the reaction zone can be less than about 5 seconds, e.g., from about 2 to about 3 seconds. Suitable fluidized catalytic crackers, product recovery configurations, other equipment, and process conditions can include those disclosed in Handbook of Petroleum Refining Processes, 2d Ed., R.A. Meyers, 3.3-3.111, McGraw-Hill and U.S. Patent Application Publication No. 2011/0220549.297

Utility Fluid/Mid-Cut Product

[0039] In some embodiments, the utility fluid and the mid-cut product can have substantially the same or the same properties with respect to one another. In some embodiments, the utility fluid and/or the mid-cut product can include ≤ 1 wt%, ≤ 0.9 wt%, ≤ 0.8 wt%, ≤ 0.7 wt%, ≤ 0.6 wt%, ≤ 0.5 wt%, ≤ 0.4 wt%, ≤ 0.3 wt%, ≤ 0.2 wt%, ≤ 0.18 wt%, ≤ 0.16 wt%, ≤ 0.14 wt%, ≤ 0.12 wt%, ≤ 0.1 wt%, ≤ 0.08 wt%, ≤ 0.06 wt%, ≤ 0.04 wt%, ≤ 0.02 wt%, or ≤ 0.01 wt% of sulfur, based on the total weight of the utility fluid and/or the mid-cut product. In some embodiments, the utility fluid and/or the mid-cut product can be substantially free of sulfur. In other embodiments, the utility fluid and/or the mid-cut product can include ≥ 0.001 wt%, ≥ 0.002 , ≥ 0.004 , or ≥ 0.006 wt% up to 0.2 wt% of sulfur, based on the total weight

of the utility fluid and/or mid-cut product. In some embodiments, the utility fluid and/or the mid-cut product can include 8.7 wt%, 9 wt%, 9.3 wt%, 9.5 wt%, or 9.7 wt% to 10 wt%, 10.3 wt%, 10.5 wt%, 10.7 wt%, or 11 wt% of hydrogen, based on a total weight of the utility fluid and/or mid-cut product. The utility fluid and/or the mid-cut product can have an API gravity in a range from 8°, 8.3°, 8.5°, 8.7°, 9°, 9.3°, 9.5°, 9.7°, 10°, 10.3°, 10.5°, 10.7°, or 11° to 11.5°, 11.7°, 12°, 12.3°, 12.5°, 12.7°, 13°, 13.3°, 13.5°, 13.7°, or 14°. The utility fluid and/or the mid-cut product can have a solubility blending number in a range from 100, 105, 110, 115, 120, or 125 to 130, 133, 135, 137, or 140. The utility fluid and/or the mid-cut product can have a density at 15°C in a range from 0.871 g/cm³, 0.875 g/cm³, 0.880 g/cm³, 0.885 g/cm³, 0.890 g/cm³, 0.895 g/cm³, or 0.900 g/cm³ to 0.905 g/cm³, 0.910 g/cm³, 0.930 g/cm³, 0.950, 0.970 g/cm³, 1.000 g/cm³, 1.030 g/cm³, 1.050 g/cm³, or 1.065 g/cm³. In some embodiments, the utility fluid and/or the mid-cut product can include ≤ 0.2 wt% of sulfur and from 8.7 wt% to 11 wt% of hydrogen, based on the total weight of the utility fluid and/or the mid-cut product, can have an API gravity in a range from 8° to 14°, can have a solubility blending number in a range from 100 to 140, and can have a density in a range from 0.871 g/cm³ to 1.065 g/cm³.

[0040] The utility fluid and/or the mid-cut product can contain ring compounds in an amount ≥ 25 wt%, ≥ 30 wt%, ≥ 35 wt%, ≥ 40 wt%, ≥ 45 wt%, ≥ 50 wt %, ≥ 55 wt%, or ≥ 60 wt% to 65 wt%, 70 wt%, 80 wt%, 90 wt%, or more, based on the weight of the utility fluid and/or mid-cut product. In some embodiments, the ring compounds can be or can include one or more aromatic hydrocarbon(s) that can include one, two, three and/or four ring aromatic hydrocarbon compounds. In some embodiments, the utility fluid and/or the mid-cut product can include ≥ 15 wt% of 2-ring and/or 3-ring aromatics, based on the weight of the utility fluid and/or the mid-cut product, such as ≥ 20 wt%, or ≥ 25 wt%, or ≥ 40 wt%, or ≥ 50 wt%, or ≥ 55 wt%, or ≥ 60 wt% to 65 wt%, 70 wt%, 80 wt%, 90 wt%, or more.

[0041] In some embodiments, the utility fluid and/or the mid-cut product can have an ASTM D86-23 10% distillation point ≥ 60°C and a 90% distillation point ≤ 425°C, e.g., ≤ 400°C. In some embodiments, the utility fluid and/or the mid-cut product can have a true boiling point distribution with an initial boiling point ≥ 130°C, ≥ 150°C, or ≥ 177°C and a final boiling point ≤ 566°C, ≤ 430°C, or ≤ 425°C. True boiling point distributions (the distribution at atmospheric pressure) can be determined, e.g., by conventional methods such as the method of ASTM D7500-15 (2019). When the final boiling point is greater than that specified in the standard, the true boiling point distribution can be determined by extrapolation. A particular form of the utility fluid and/or the mid-cut product can have a true boiling point distribution

having an initial boiling point $\geq 130^{\circ}\text{C}$ and a final boiling point $\leq 566^{\circ}\text{C}$ and/or can include ≥ 15 wt% of two ring and/or three ring aromatic compounds.

[0042] The bottoms product separated from the first hydroprocessed effluent can include 0.3 wt%, 0.4 wt%, 0.5 wt%, or 0.6 wt% to 1 wt%, 1.5 wt%, 2 wt%, or 3 wt% of sulfur, based on the total weight of the bottoms product. The bottoms product can include 5.5 wt%, 6 wt%, 6.5 wt%, 7 wt%, or 7.5 wt% to 8 wt%, 8.5 wt%, 9 wt%, 9.5 wt%, or 10 wt% of hydrogen, based on a total weight of the bottoms product. The bottoms product can have an API gravity in a range from -6° , -5° , -4° , or -3.5° , to -3° , -2° , -1° , or 0° . The bottoms product can have a density at 15°C in a range from 0.950 g/cm^3 , 0.970 g/cm^3 , 1.000 g/cm^3 , 1.050 , or 1.100 g/cm^3 to 1.110 g/cm^3 , 1.150 g/cm^3 , 1.200 g/cm^3 , or 1.250 g/cm^3 . In some embodiments, the bottoms product can include 0.3 wt% to 3 wt% of sulfur and from 5.5 wt% to 10 wt% of hydrogen, based on the total weight of the bottoms product, can have an API gravity in a range from -6° to 0° , and can have a density in a range from 0.950 g/cm^3 to 1.250 g/cm^3 .

Mixture

[0043] In some embodiments, the mixture of the hydrocarbon feed, i.e., the Group I lube extract and, optionally, the steam cracker tar and/or the fluidized catalytic cracker main column bottoms product, and the utility fluid and/or the mid-cut product can include the utility fluid and/or mid-cut product in an amount sufficient to provide the mixture thereof with a viscosity that is sufficiently low for the mixture to be conveyed to hydroprocessing, e.g., a 50°C kinematic viscosity of the mixture can be in a range from 1 cSt to ≤ 500 cSt, as measured by ASTM D445-21e2. In some embodiments, the mixture of the hydrocarbon feed and the utility fluid and/or mid-cut product can include from 20 wt%, 25 wt%, 30 wt%, 35 wt%, 40 wt%, 45 wt%, or 50 wt% to 60 wt%, 65 wt%, 70 wt%, 75 wt%, 80 wt%, 85 wt%, 90 wt%, or 95 wt% of the hydrocarbon feed and from 5 wt%, 10 wt%, 15 wt%, 20 wt%, 25 wt%, 30 wt%, 35 wt%, 40 wt%, 45 wt%, or 50 wt% to 60 wt%, 65 wt%, 70 wt%, 75 wt%, 80 wt%, 85 wt%, 90 wt%, or 95 wt% of the utility fluid and/or mid-cut product, based on the total weight of the mixture. In some embodiments, the mixture of the hydrocarbon feed and the utility fluid and/or the mid-cut product can include from 30 wt% to 50 wt% of the utility fluid and/or mid-cut product and from 70 wt% to 50 wt% of the hydrocarbon feed, based on the total weight of the mixture. In other embodiments, the mixture of the hydrocarbon feed and the utility fluid and/or mid-cut product can include from 35 wt% to 45 wt% of the utility fluid and/or mid-cut product and from 65 wt% to 55 wt% of the hydrocarbon feed, based on the total weight of the mixture.

[0044] In some embodiments, the mixture of the hydrocarbon feed, e.g., the Group I lube extract and, optionally, the steam cracker tar and/or the fluidized catalytic cracker main column bottoms product, and the utility fluid and/or the mid-cut product can include 1.8 wt%, 1.9 wt%, 2 wt%, 2.1 wt%, or 2.2 wt% to 2.4 wt%, 2.5 wt%, 2.7 wt%, 2.9 wt%, or 3.1 wt% of sulfur, based on the total weight of the mixture. In some embodiments, the mixture of the hydrocarbon feed and the utility fluid and/or the mid-cut product can include 6.8 wt%, 7 wt%, 7.3 wt%, 7.5 wt%, 7.7 wt%, or 8 wt% to 8.3 wt%, 8.5 wt%, 8.7 wt%, 9 wt%, or 9.2 wt% of hydrogen, based on the total weight of the mixture. In some embodiments, the mixture of the hydrocarbon feed and the utility fluid and/or the mid-cut product can have a solubility blending number in a range from 160, 165, 170, 173, 175, 177, or 180 to 183, 185, 187, 190, 193, 195, 197, or 200. In some embodiments, the mixture of the hydrocarbon feed and the utility fluid and/or the mid-cut product can have a solubility blending number ≤ 200 , ≤ 195 , or ≤ 190 and ≥ 170 , ≥ 173 , ≥ 175 , or ≥ 177 . In some embodiments, the mixture of the hydrocarbon feed and the utility fluid and/or the mid-cut product can have a density at 15°C in a range from 0.950 g/cm³, 0.970 g/cm³, or 0.990 g/cm³ to 1.000 g/cm³, 1.020 g/cm³, 1.030 g/cm³, 1.050 g/cm³, or 1.100 g/cm³.

[0045] In some embodiments, the hydrocarbon feed or at least a portion thereof can be subjected to a heat soaking process. The heat soaking process can reduce the reactivity of the hydrocarbon(s) in the hydrocarbon feed. For example, when the hydrocarbon feed includes a steam cracker tar and/or a fluidized catalytic cracker main column bottoms, such components can be subjected to a heat soaking step prior to, during, or after being combined with the other component(s) of the hydrocarbon feed, i.e., the Group I lube extract and any additional hydrocarbons that can be present in the hydrocarbon feed.

[0046] In some embodiments, the heat soaking process can be conducted at a temperature in a range from 200°C, 210°C, 215°C, 230°C, or 245°C to 260°C, 275°C, 290°C, or 300°C. In some embodiments, the heat soaking process can be conducted for a time period in a range from 1 minute, 2 minutes, 5 minutes, or 10 minutes to 15 minutes, 20 minutes, 25 minutes, or 30 minutes. In some embodiments, the heat soaking process can be carried out in one or more tar drums and related piping. In other embodiments, the heat soaking process can be carried out at least in part in one or more soaker drums and/or in vessels, conduits, and other equipment (e.g. fractionators, water-quench towers, indirect condensers) associated with, e.g., (i) separating the steam cracker tar and/or fluidized catalytic cracker main column bottoms product and/or (ii) conveying such hydrocarbons to the first hydroprocessing stage. The location of the heat soaking process is not critical. The heat soaking process can be carried out

at any convenient location, e.g., after separation of the steam cracker tar and/or the fluidized catalytic cracker main column bottoms product from the steam cracker effluent and/or the fluidized catalytic cracker effluent, respectively, and before hydroprocessing in the first hydroprocessing stage, such as downstream of a tar drum and upstream of mixing the thermally treated tar and/or fluidized catalytic main column bottoms product with utility fluid/mid-cut product and the Group I lube extract.

[0047] In some embodiments, the utility fluid and/or the mid-cut product can be combined with the hydrocarbon feed during the heat soaking process. In other embodiments, the utility fluid and/or mid-cut product can be mixed with the hydrocarbon feed after a heat soaking process step has been applied to the hydrocarbon feed or a portion thereof, e.g., the steam cracker tar and/or the fluidized catalytic cracker main column bottoms product.

[0048] In some embodiments, particularly when the hydrocarbon feed includes a steam cracker tar, the hydrocarbon feed or the mixture of the hydrocarbon feed and the utility fluid and/or mid-cut product can be subjected to a solids-removal step. In some embodiments, when the hydrocarbon feed include the steam cracker tar and/or the fluidized catalytic main column bottoms product, the steam cracker tar and/or the fluidized catalytic main column bottoms product can be subjected to the solids-removal step and can then be combined with the additional components of the hydrocarbon feed, i.e., the Group I lube extract and any additional hydrocarbons that can be present in the hydrocarbon feed. The solids removal step can include any suitable process or system capable of removing solids from the feed, e.g., centrifugation, filtration, or the like. In some embodiments, the solids removal step can include filtration followed by centrifugation.

First Hydroprocessing Stage

[0049] In some embodiments, the first hydroprocessing stage can be conducted at a temperature in a range from 200°C, 225°C, 250°C, 260°C, 280°C, or 300°C to 325°C, 350°C, 375°C, 400°C, 410°C, or 425°C. In some embodiments, the first hydroprocessing stage can be conducted at a weight hourly space velocity (WHSV) in a range from 0.6 hr⁻¹, 0.8 hr⁻¹, 1 hr⁻¹, 1.5 hr⁻¹, or 2 hr⁻¹ to 3 hr⁻¹, 4 hr⁻¹, 5 hr⁻¹, 6 hr⁻¹, 7 hr⁻¹, 8 hr⁻¹, 9 hr⁻¹, or 10 hr⁻¹, or more. In some embodiments, the first hydroprocessing stage can be conducted at a total pressure in a range from 4 MPa, 5 MPa, 6 MPa, 7 MPa, or 8 MPa to 10 MPa, 11 MPa, 12 MPa, 13 MPa, 14 MPa, 15 MPa, or more. In some embodiments, the first hydroprocessing stage can include a molecular hydrogen supply rate in a range from 150 standard cubic meters of molecular hydrogen per cubic meter of the hydrocarbon feed (S m³/m³), 175 S m³/m³, 200 S m³/m³, 250

S m³/m³, 275 S m³/m³, 300 S m³/m³, 325 S m³/m³, or 350 S m³/m³ to 375 S m³/m³, 400 S m³/m³, 450 S m³/m³, 500 S m³/m³, 550 S m³/m³, 600 S m³/m³, 700 S m³/m³, 800 S m³/m³, 900 S m³/m³, or 1,000 S m³/m³.

[0050] The first hydroprocessing stage can include processing the mixture of the hydrocarbon feed and the molecular hydrogen in the presence of a catalytically effective amount of at least one catalyst having activity for hydrocarbon hydroprocessing. In some embodiments, conventional hydroprocessing catalysts can be utilized for hydroprocessing in the first hydroprocessing stage, such as those specified for use in resid and/or heavy oil hydroprocessing, but the invention is not limited thereto. Suitable catalysts for use in the first hydroprocessing stage can include bulk metallic catalysts and supported catalysts e.g., catalysts supported on alumina and/or silica. The metals can be in elemental form or in the form of a compound. In some embodiments, the catalyst can include at least one metal from any of Groups 5 to 10 of the Periodic Table of the Elements (tabulated as the Periodic Chart of the Elements, The Merck Index, Merck & Co., Inc., 1996). Examples of such catalytic metals can be or can include, but are not limited to, vanadium, chromium, molybdenum, tungsten, manganese, technetium, rhenium, iron, cobalt, nickel, ruthenium, palladium, rhodium, osmium, iridium, platinum, or mixtures thereof. In some embodiments, the catalyst can include the conventional RT-621 catalyst.

[0051] In some embodiments, the catalyst can have a total amount of Groups 5 to 10 metals per gram of catalyst of at least 0.0001 g, at least 0.001 g, at least 0.01 g, in which grams are calculated on an elemental basis. For example, the catalyst can include a total amount of Group 5 to 10 metals in a range of from 0.0001 g, 0.001 g, 0.005 g, 0.01 g, or 0.05 g to 0.08 g, 0.1 g, 0.2 g, or 0.3. In some embodiments, the catalyst can also include at least one Group 15 element. An example of a preferred Group 15 element is phosphorus. When a Group 15 element is utilized, the catalyst can include a total amount of elements of Group 15 in a range of from 0.000001 g, 0.00001 g, 0.0001 g, or 0.0005 g, to 0.001 g, 0.03 g, 0.06 g, or 0.08 g, in which grams are calculated on an elemental basis. In some embodiments, the first stage hydroprocessing can be carried out in the presence of the catalyst(s) located in at least one catalyst bed. In some embodiments, two, three, or more catalyst beds can be connected in series, optionally with intercooling.

[0052] In some embodiments, the first hydroprocessing stage can include one, two, three, or more units. In some embodiments, the first hydroprocessing stage can include, in sequence, one or more guard bed reactors, one or more pre-treaters downstream of the guard bed

reactor(s), and one or more main first hydroprocessing reactors downstream of the pre-treater(s). In some embodiments, the hydrocarbon feed, the molecular hydrogen, and the utility fluid and/or mid-cut product can be introduced as a mixture, separately, or a combination of a mixture and separate feeds, e.g., a mixture of the hydrocarbon feed and the utility fluid and/or mid-cut product and a molecular hydrogen feed can be introduced into the guard bed reactor.

[0053] The guard bed reactor can include one or more catalysts and can be operated under relatively mild hydroprocessing conditions to reduce the reactivity of the hydrocarbon feed. In some embodiments, the guard bed reactor can include one or more materials configured to trap solid particulates such as coke that may be present in the hydrocarbon feed. The effluent from the guard bed reactor can pass through an outlet and into the pre-treater for further hydroprocessing under somewhat harsher conditions and optionally with a more active catalyst. The effluent from the pre-treater can pass to a main hydroprocessing reactor for further hydroprocessing under yet more severe conditions to obtain the first hydroprocessed product.

[0054] In some embodiments, the guard bed reactor(s) can be operated at a temperature in a range from 240°C, 250°C, 255°C, or 260°C to 265°C, 270°C, 275°C, 280°C, or 290°C. In some embodiments, the guard bed reactor(s) can be operated at a WHSV in a range from 3 hr⁻¹, 3.5 hr⁻¹, 4 hr⁻¹, or 4.5 hr⁻¹ to 5 hr⁻¹, 5.5 hr⁻¹, 6 hr⁻¹, 7 hr⁻¹, 8 hr⁻¹, 9 hr⁻¹, or 10 hr⁻¹. In some embodiments, the guard bed reactor(s) can be operated at a total pressure in a range from 6 MPa, 6.5 MPa, 7 MPa, or 8 MPa to 9 MPa, 10 MPa, 11 MPa, or 12 MPa. In some embodiments, the guard bed reactor(s) can include one or more upstream catalyst beds that can include at least one catalyst having de-metallization activity, e.g., relatively large-pore catalyst(s) to capture metals in the hydrocarbon feed. In some embodiments, one or more catalyst beds located further downstream in the guard bed reactor(s) can contain at least one catalyst having activity for olefin saturation, e.g., catalyst(s) containing Ni and/or Mo.

[0055] In some embodiments, all of the molecular hydrogen introduced into the first hydroprocessing stage can be introduced into the guard bed reactor(s) and unreacted molecular hydrogen can flow from the guard bed reactor(s) and into the pre-treater(s) and so on. In other embodiments, a first portion of the molecular hydrogen introduced into the first hydroprocessing stage can be introduced into the guard bed reactor(s), and the remaining amount of the molecular hydrogen introduced into the first hydroprocessing stage can be introduced into the pre-treater(s) and unreacted molecular hydrogen in the pre-treater effluent can flow into the main first hydroprocessing reactor(s). In still embodiments, a first portion of

the molecular hydrogen introduced into the first hydroprocessing stage can be introduced into the guard bed reactor(s), a second portion of the molecular hydrogen introduced into the first hydroprocessing stage can be introduced into the pre-treater(s), and a third portion of the molecular hydrogen introduced into the first hydroprocessing stage can be introduced into the main first hydroprocessing reactor(s).

[0056] In some embodiments, the pre-treater(s) can be operated at a temperature in a range from 255°C, 260°C, 265°C, 270°C, or 275°C to 280°C, 285°C, 290°C, 295°C, 300°C, 305°C, or 310°C. In some embodiments, the pre-treater(s) can be operated at a WHSV in a range from 1 hr⁻¹, 1.5 hr⁻¹, 2 hr⁻¹, or 2.5 hr⁻¹ to 3 hr⁻¹, 3.5 hr⁻¹, 4 hr⁻¹, 4.5 hr⁻¹, or 5 hr⁻¹. In some embodiments, the pre-treater(s) can be operated at a total pressure in a range from 6 MPa, 6.5 MPa, 7 MPa, or 8 MPa to 9 MPa, 10 MPa, 11 MPa, 12 MPa, 13 MPa, 14 MPa, or 15 MPa. Suitable catalysts for use in the pre-treater(s) can include bulk metallic catalysts and supported catalysts e.g., catalysts supported on alumina and/or silica. The metals can be in elemental form or in the form of a compound. In some embodiments, the catalyst can include at least one metal from any of Groups 5 to 10 of the Periodic Table of the Elements (tabulated as the Periodic Chart of the Elements, The Merck Index, Merck & Co., Inc., 1996). Examples of such catalytic metals can be or can include, but are not limited to, vanadium, chromium, molybdenum, tungsten, manganese, technetium, rhenium, iron, cobalt, nickel, ruthenium, palladium, rhodium, osmium, iridium, platinum, or mixtures thereof. In some embodiments, the catalyst can include the conventional RT-621 catalyst.

[0057] In some embodiments, the main hydroprocessing reactor(s) can be operated at a temperature in a range from 365°C, 370°C, 375°C, 380°C, 390°C, or 400°C to 405°C, 410°C, 415°C, or 420°C. In some embodiments, the main hydroprocessing reactor(s) can be operated at a WHSV in a range from 0.4 hr⁻¹, 0.6 hr⁻¹, 0.7 hr⁻¹ to 0.9 hr⁻¹, 1 hr⁻¹, 1.3 hr⁻¹, or 1.5 hr⁻¹, e.g., about 0.8 hr⁻¹. Suitable catalysts for use in the main hydroprocessing reactor(s) can include bulk metallic catalysts and supported catalysts e.g., catalysts supported on alumina and/or silica. The metals can be in elemental form or in the form of a compound. In some embodiments, the catalyst can include at least one metal from any of Groups 5 to 10 of the Periodic Table of the Elements (tabulated as the Periodic Chart of the Elements, The Merck Index, Merck & Co., Inc., 1996). Examples of such catalytic metals can be or can include, but are not limited to, vanadium, chromium, molybdenum, tungsten, manganese, technetium, rhenium, iron, cobalt, nickel, ruthenium, palladium, rhodium, osmium, iridium, platinum, or

mixtures thereof. In some embodiments, the catalyst can include the conventional RT-621 catalyst.

[0058] In some embodiments, the main hydroprocessing reactor(s) can be operated at a temperature greater than the pre-treater(s) and the pre-treater(s) can be operated at a temperature greater than the guard bed reactor(s). In some embodiments, the main hydroprocessing reactor(s) can be operated at a WHSV that can be less than the pre-treater(s) and the guard bed reactor(s) can be operated at a WHSV that can be less than the pre-treater(s). In other embodiments, the guard bed reactor(s) can be operated at a WHSV that can be greater than the pre-treater(s) and the pre-treater(s) can be operated at a WHSV that can be greater than the main hydroprocessing reactor(s). In some embodiments, suitable first hydroprocessing stages can include those described in WO Publication Nos. WO2018/111576A1 and WO2018/111577A1.

Separation Stage

[0059] The first hydroprocessed effluent can be separated via one or more separation stages or units. In some embodiments, the first hydroprocessed effluent can be introduced into a fractionator or distillation column and the mid-cut product and the bottoms product can be recovered or otherwise obtained therefrom. In some embodiments, the overhead product that includes molecular hydrogen and the light cut that can include naphtha can also be recovered from the fractionator or distillation column. In other embodiments, the first hydroprocessed effluent can be introduced into a first fractionator or distillation tower and an overhead product that includes molecular hydrogen and an intermediate bottoms product that includes liquid hydrocarbons can be recovered therefrom. In such embodiments, the intermediate bottoms product can be introduced into a second fractionator or distillation tower from which the light cut that includes naphtha, the mid-cut product, and the bottoms product can be recovered or otherwise obtained therefrom. In some embodiments, suitable separation stages for separating the first hydroprocessed effluent into the plurality of products can include those described in WO Publication Nos. WO2018/111576A1 and/or WO2018/111577A1.

Second Hydroprocessing Stage

[0060] In some embodiments, the second hydroprocessing stage can be conducted at a temperature in a range from 350°C, 375°C, or 400°C to 410°C, 420°C, 425°C, 440°C, or 450°C. In some embodiments, the second hydroprocessing stage can be conducted at a weight hourly space velocity (WHSV) in a range from 0.1 hr⁻¹, 0.2 hr⁻¹, 0.3 hr⁻¹, or 0.4 hr⁻¹ to 0.5 hr⁻¹, 0.6 hr⁻¹, 0.7 hr⁻¹, 0.8 hr⁻¹, 0.9 hr⁻¹, or 1 hr⁻¹. In some embodiments, the second hydroprocessing

stage can be conducted at a lower WHSV than the first hydroprocessing stage. Said another way, in some embodiments, the first hydroprocessing stage can be conducted at a greater WHSV than the second hydroprocessing stage.

[0061] In some embodiments, the second hydroprocessing stage can be conducted at a total pressure in a range from 4 MPa, 5 MPa, 6 MPa, 7 MPa, or 8 MPa to 10 MPa, 11 MPa, 12 MPa, 13 MPa, 14 MPa, 15 MPa, or more. In some embodiments, the second hydroprocessing stage can include a molecular hydrogen supply rate in a range from 150 S m³/m³, 250 S m³/m³, 350 S m³/m³, 450 S m³/m³, 500 S m³/m³, 535 S m³/m³, 575 S m³/m³, or 600 S m³/m³ to 800 S m³/m³, 900 S m³/m³, 1,065 S m³/m³, 1,100 S m³/m³, 1,150 S m³/m³, 1,250 S m³/m³, 1,350 S m³/m³, or 1,500 S m³/m³.

[0062] The second hydroprocessing stage can include processing the bottoms product and the molecular hydrogen in the presence of a catalytically effective amount of at least one catalyst having activity for hydrocarbon hydroprocessing. In some embodiments, a portion of the mid-cut product and/or other utility fluid can be mixed with the bottoms product. In other embodiments, the bottoms product can be hydroprocessed in the second hydroprocessing stage in the absence or substantial absence of any utility fluid and/or mid-cut product.

[0063] In some embodiments, conventional hydroprocessing catalysts can be utilized for hydroprocessing in the second hydroprocessing stage, such as those specified for use in resid and/or heavy oil hydroprocessing, but the invention is not limited thereto. Suitable catalysts for use in the first hydroprocessing stage can include bulk metallic catalysts and supported catalysts, e.g., catalysts supported on alumina and/or silica. The metals can be in elemental form or in the form of a compound. In some embodiments, the catalyst can include at least one metal from any of Groups 5 to 10 of the Periodic Table of the Elements (tabulated as the Periodic Chart of the Elements, The Merck Index, Merck & Co., Inc., 1996). Examples of such catalytic metals can be or can include, but are not limited to, vanadium, chromium, molybdenum, tungsten, manganese, technetium, rhenium, iron, cobalt, nickel, ruthenium, palladium, rhodium, osmium, iridium, platinum, or mixtures thereof. In some embodiments, the catalyst can include the conventional RT-621 catalyst.

[0064] In some embodiments, the catalyst can have a total amount of Groups 5 to 10 metals per gram of catalyst of at least 0.0001 g, at least 0.001 g, at least 0.01 g, in which grams are calculated on an elemental basis. For example, the catalyst can include a total amount of Group 5 to 10 metals in a range of from 0.0001 g, 0.001 g, 0.005 g, 0.01 g, or 0.05 g to 0.08 g, 0.1 g, 0.2 g, or 0.3. In some embodiments, the catalyst can also include at least one Group 15 element.

An example of a preferred Group 15 element is phosphorus. When a Group 15 element is utilized, the catalyst can include a total amount of elements of Group 15 in a range of from 0.000001 g, 0.00001 g, 0.0001 g, or 0.0005 g, to 0.001 g, 0.03 g, 0.06 g, or 0.08 g, in which grams are calculated on an elemental basis. In some embodiments, the first stage hydroprocessing can be carried out in the presence of the catalyst(s) located in at least one catalyst bed. In some embodiments, two, three, or more catalyst beds can be connected in series, optionally with intercooling. In some embodiments, suitable second hydroprocessing stages can include those described in WO Publication Nos. WO2018/111576A1 and WO2018/111577A1.

5 [0065] In some embodiments, the second hydroprocessed effluent can include ≤ 0.5 wt%, ≤ 0.4 wt%, ≤ 0.3 wt%, ≤ 0.2 wt%, or ≤ 0.1 wt% of sulfur, based on a total weight of the second hydroprocessed effluent. In some embodiments, the second hydroprocessed effluent can include 6.5 wt%, 7 wt%, 7.5 wt%, or 8 wt% to 8.5 wt%, 9 wt%, or 10 wt% of hydrogen, based on the total weight of the second hydroprocessed effluent. In some embodiments, the second hydroprocessed effluent can have a solubility blending number in a range from 170, 175, 180, 185, 190, or 195 to 200, 210, 220, 230, 240, or 250. In some embodiments, the second hydroprocessed product can have a 15°C density in a range from 0.990 g/cm³, 1.000 g/cm³, or 1.050 g/cm³ to 1.060 g/cm³, 1.080 g/cm³, or 1.100 g/cm³. In some embodiments, the second hydroprocessed effluent can include ≤ 0.5 wt% of sulfur and from 6.5 wt% to 10 wt% of hydrogen, based on the total weight of the second hydroprocessed effluent, can have an API gravity in a range from -4° to 10°, can have an SBN in a range from 170 to 250, and can have a density in a range from 0.990 g/cm³ to 1.100 g/cm³. It should be understood that, as further described below with reference to FIGS. 3 and 4, the second hydroprocessed effluent properties can be for a second hydroprocessed effluent that has undergone a separation process to remove at least a portion of gaseous components such as molecular hydrogen and sulfur-containing compounds, e.g., hydrogen sulfide, therefrom.

15 [0066] In some embodiments, the second hydroprocessed effluent or a fraction thereof can be useful as a diluent (e.g., a flux) for heavy hydrocarbons, especially those of relatively high viscosity. Optionally, all or a portion of the second hydroprocessed effluent can substitute for more expensive, conventional diluents. Non-limiting examples of blendstocks suitable for blending with the second hydroprocessed effluent or a fraction thereof can include one or more of bunker fuel, burner oil, heavy fuel oil, e.g., No. 5 and No. 6 fuel oil, high-sulfur fuel oil, low-sulfur fuel oil, regular-sulfur fuel oil, gas oil as can be obtained from the distillation of

crude oil, crude oil components, and hydrocarbons derived from crude oil (e.g., coker gas oil), and the like. For example, the second hydroprocessed effluent or a fraction thereof can be used as a blending component to produce a fuel oil composition that can include ≤ 0.5 wt% of sulfur.

[0067] Referring now to Figures 1-4, the hydrocarbon upgrading process/system is described in more detail. FIG. 1 depicts a schematic of an illustrative process/system 101 for upgrading a hydrocarbon feed in line 1003 obtained from a hydrocarbon feed source 1001 that includes a Group I lube extract, according to one or more embodiments. In some embodiments, the hydrocarbon feed via line 1003, a utility fluid via line 1007 that can be obtained from one or more utility fluid sources 1005, and molecular hydrogen via line 1009 can be introduced into a first hydroprocessing stage 1011. As explained below, in some embodiments, the utility fluid source 1005 can be optional and, therefore, not required, due to recycling a mid-cut product via lines 1019 and 1027 recovered from a separation stage 1017. As shown, the hydrocarbon feed via line 1003, the utility fluid via line 1007, and the molecular hydrogen via line 1009 can be introduced separately into and mixed within the first hydroprocessing stage 1011. In other embodiments, however, two, e.g., the hydrocarbon feed in line 1003 and the utility fluid in line 1007 and/or the mid-cut product in line 1027 can be mixed prior to introduction into the first hydroprocessing stage 1011, or all three of the hydrocarbon feed in line 1003, the molecular hydrogen in line 1009, and the utility fluid in line 1007 and/or the mid-cut product in line 1027 can be mixed prior to introduction into the first hydroprocessing stage 1011.

[0068] The mixture of the hydrocarbon feed, utility fluid, and molecular hydrogen can be heated and contacted with one or more catalysts 1013 within the first hydroprocessing stage 1011 to produce a first hydroprocessed effluent that can be recovered via line 1015. The first hydroprocessed effluent via line 1015 can be introduced into a separation stage 1017. In some embodiments, a mid-cut product via line 1019 and a bottoms product via line 1021 can be recovered from the separation stage 1017. In other embodiments, the mid-cut product via line 1019, the bottoms product via line 1021, and an overhead product via line 1023 that can include molecular hydrogen can be recovered from the separation stage 1017. In still other embodiments, the mid-cut product via line 1019, the bottoms product via line 1021, the overhead product via line 1023, and a light cut product that can include naphtha via line 1025 can be recovered from the separation stage 1017.

[0069] In some embodiments, at least a portion of the mid-cut product in line 1019 can be recycled via line 1027 to the first hydroprocessing stage 1011, e.g., via mixing with the

hydrocarbon feed in line 1003. In some embodiments, at least a portion of the mid-cut product in line 1019 can be removed from the process/system 101 via line 1029. As noted above, the utility fluid source 1005 can be optional and not present because the mid-cut product that can be recycled via line 1019 and 1027 to the first hydroprocessing stage 1011 can make up all of the utility fluid that can be combined with the hydrocarbon feed in line 1003, whether prior to and/or after introducing the hydrocarbon feed 1003 into the first hydroprocessing stage 1011.

[0070] In some embodiments, at least a portion of the bottoms product via line 1021 and molecular hydrogen via line 1031 can be introduced into a second hydroprocessing stage 1033. A mixture of the bottoms product and molecular hydrogen can be heated and contacted with one or more catalysts 1035 within the second hydroprocessing stage 1033 to produce a second hydroprocessed effluent that can be recovered via line 1037.

[0071] In some embodiments, when the overhead in line 1023 is recovered from the separation stage 1017, at least a portion of the overhead via line 1023 can be introduced into one or more upgrading units 1039, *e.g.*, one or more amine towers. For example, fresh amine via line 1041 can be introduced to the upgrading unit 1039 and a rich amine via line 1043 can be recovered therefrom. A regenerated treat gas, which can be or can include molecular hydrogen, via line 1045 can also be recovered from the upgrading unit 1039. In some embodiments, at least a portion of the regenerated treat gas in line 1045 can be recycled via lines 1047 and 1049 to the first hydroprocessing stage 1011 and/or via lines 1047 and 1051 to the second hydroprocessing stage 1033. In some embodiments, at least a portion of the regenerated treat gas in line 1045 can be removed via line 1053 from the process/system 101.

[0072] FIG. 2 depicts a schematic of another illustrative process/system 201 for upgrading the hydrocarbon feed in line 1003 that includes a Group I lube extract, according to one or more embodiments. In some embodiments, the hydrocarbon feed via line 1003, molecular hydrogen via line 1009, and the utility fluid via line 1007 and/or the mid-cut product via lines 1019 and 1027 can be introduced into a first hydroprocessing stage 2000. In some embodiments, the molecular hydrogen in line 1009 can be obtained from a molecular hydrogen source 2002 and/or recycled via lines 1045 and 1047 from the one or more upgrading units 1039 as described above with reference to FIG. 1.

[0073] As shown, first hydroprocessing stage 2000 can include one or more guard bed reactors 2001, one or more pre-treaters 2007, and one or more main hydroprocessing reactors 2013. The guard bed reactor(s) 2001 can include one or more catalysts 2003, the pre-treater(s) 2007 can include one or more catalysts 2009, and the main hydroprocessing reactor(s) 2013

can include one or more catalysts 2015. In some embodiments, the composition of the catalysts 2003, 2009, and 2015 can be the same or different with respect to one another. In some embodiments, the guard bed reactor 2001, the pre-treater 2007, and/or the main hydroprocessing reactor 2013 can include one, two, three, or more different catalysts therein.

- 5 For example, in some embodiments, the one or more catalysts 2003 in the guard bed reactor(s) 2001 can include a layer of relatively low-reactivity hydroprocessing catalyst, a layer of hydrodemetallization catalyst, and a layer of a relatively high-activity catalyst, e.g., a catalyst that can include Ni, Co, or a combination or mixture thereof.

[0074] A guard bed reactor effluent via line 2005 can be introduced into the pre-treater 10 2007. A pre-treater effluent via line 2011 can be introduced into the main hydroprocessing reactor(s) 2013. A first hydroprocessed effluent via line 2017 can be recovered from the first hydroprocessing stage 2000 and introduced into the separation stage 1017 and further processed as described above with reference to FIG. 1. As noted above, in some embodiments, the first hydroprocessing stage 2000 that includes the guard bed reactor(s) 2001, the pre- 15 treater(s) 2007, and the main hydroprocessing reactor(s) 2013 can be as discussed and described in WO Publication Nos. WO2018/111576A1 and WO2018/111577A1.

[0075] In some embodiments, at least a portion of the mid-cut product in line 1019 can be recycled via line 1027 to the first hydroprocessing stage 2000, e.g., by mixing with the hydrocarbon feed in line 1003. In some embodiments, at least a portion of the regenerated treat 20 gas in line 1045 can be recycled via line 1047 to the guard bed reactor(s) 2001, recycled via lines 1047 and 2019 to the pre-treater(s) 2007, and/or can be recycled via lines 1047 and 2021 to the main hydroprocessing reactor 2013.

[0076] FIG. 3 depicts a schematic of an illustrative process/system 301 for upgrading a steam cracker tar in line 3023 and a hydrocarbon feed in line 1003 that includes a Group I lube 25 extract, according to one or more embodiments. A steam cracker hydrocarbon feed or simply "hydrocarbon" via line 3001 can be heated in a convection section 3007 of a steam cracker furnace 3005 to produce a heated hydrocarbon via line 3009. The hydrocarbon in line 3001 can be combined with an aqueous fluid in line 3003 to produce a first mixture that can include hydrocarbon and steam. The heating of the hydrocarbon in line 3001 can be carried out before, 30 during, and/or after the hydrocarbon is combined with the aqueous fluid. At least a portion of the heated hydrocarbon via line 3009 can be introduced into and steam cracked within a radiant section 3011 of the steam cracker furnace 3005 to produce a steam cracker effluent via line 3013.

[0077] In some embodiments, the hydrocarbon in line 3001 that can be mixed, blended, combined, or otherwise contacted with water, steam, or a mixture thereof and heated to produce the heated mixture can include any one or more of a number of hydrocarbons. In other embodiments, the hydrocarbon can include one or more C₄- hydrocarbons. In some
5 embodiments, the hydrocarbon can include one or more C₅+ hydrocarbons. In other embodiments, the hydrocarbon can include a mixture of one or more C₄- hydrocarbons and one or more C₅+ hydrocarbons. Feeds or hydrocarbons that include C₄- hydrocarbons can include one or more feeds thereto that are gaseous at room temperature, e.g., ethane, propane, and/or butane. Feeds or hydrocarbons that include C₅+ hydrocarbons that can be mixed, blended,
10 combined, or otherwise contacted with the water and/or steam and heated to produce the heated mixture can be or include, but is not limited to, raw crude oil, steam cracked gas oils and residues, gas oils, heating oil, jet fuel, diesel, kerosene, gasoline, coker naphtha, steam cracked naphtha, catalytically cracked naphtha, hydrocrackate, reformate, raffinate reformate, Fischer-Tropsch liquids, Fischer-Tropsch gases, natural gasoline, distillate, virgin naphtha,
15 atmospheric pipestill bottoms, vacuum pipestill streams such as vacuum pipestill bottoms and wide boiling range vacuum pipestill naphtha to gas oil condensates, heavy non-virgin hydrocarbons from refineries, vacuum gas oils, heavy gas oil, naphtha contaminated with crude, atmospheric residue, heavy residue, C₄/residue admixture, naphtha/residue admixture, hydrocarbon gases/residue admixture, hydrogen/residue admixtures, waxy residues, gas
20 oil/residue admixture, or any mixture thereof.

[0078] In some embodiments, the heated mixture that includes the hydrocarbon(s) and the aqueous fluid in line 3009 can include about 10 wt%, about 20 wt%, or about 30 wt% to about 70 wt%, about 80 wt%, about 90 wt%, or about 95 wt% of the aqueous fluid, based on a combined weight of the hydrocarbon(s) and the aqueous fluid. In some embodiments, the
25 heated mixture in line 3009 can be at a temperature in a range from 330°C, 340°C, 400°C, 405°C, 410°C, 425°C, or 450°C to 475°C, 500°C, 525°C, 550°C, 565°C, or 585°C.

[0079] The steam cracker effluent via line 3013 can be introduced into and separated within a steam cracker primary fractionator 3015 into a plurality of products, e.g., an overhead via line 3017, a steam cracker gas oil (“SCGO”) side stream via line 3019, a steam cracker quench
30 oil (“SCQO”) via line 3021, and a steam cracker tar (“SCT”) stream via line 3023. In some embodiments, illustrative primary fractionators can include those disclosed in U.S. Patent No. 8,083,931, and U.S. Patent Application Publication No. 2014/0357923. In some embodiments, the steam cracker effluent in line 3013 can be cooled via indirect heat exchange, direct heat

exchange via contact with a quench medium, or a combination thereof prior to introduction into the steam cracker primary fractionator 3015.

[0080] In some embodiments, at least a portion of the steam cracker tar in line 3023 can be combined with the utility fluid in line 1007 obtained from the utility fluid source 1005 and the hydrocarbon feed in line 1003 obtained from the hydrocarbon feed source 1001 that can include the Group I lube extract to produce a second mixture in line 3023 that includes the steam cracker tar, the utility fluid, and the hydrocarbon feed. In other embodiments, the mid-cut product in line 1027 can be combined with the steam cracker tar and the hydrocarbon feed to produce the second mixture in line 3023, as described above with reference to FIGS. 1 and 2. In still other embodiments, the steam cracker tar in line 3023 can be combined with the utility fluid in line 1007, the mid-cut product in line 1027, and the hydrocarbon feed in line 1003 to produce the second mixture. In some embodiments, a fluidized catalytic cracker main column bottoms product in line 3031 obtained from a fluidized catalytic cracker primary fractionator 3029 can also be combined with the steam cracker tar, the hydrocarbon feed, and at least one of the utility fluid and the mid-cut product to produce the second mixture.

[0081] In some embodiments, molecular hydrogen via line 1009 and the second mixture that includes the steam cracker tar, the hydrocarbon feed, and at least one of the utility fluid and the mid-cut product via line 3023 can be into the first hydroprocessing stage 1011 to produce the first hydroprocessed effluent via line 1015, as described above with reference to FIG. 1. In other embodiments, molecular hydrogen via line 1009 and the second mixture that includes the steam cracker tar, the hydrocarbon feed, and at least one of the utility fluid and the mid-cut product via line 3023 can be introduced into the first hydroprocessing stage 2000 to produce the first hydroprocessed effluent via line 1015, as described above with reference to FIG. 2.

[0082] The first hydroprocessed effluent via line 1015 can be introduced into the separation stage 1017 to recover at least the mid-cut product via line 1019 and the bottoms product via line 1021 and, optionally, the overhead via line 1023 and/or the light cut via line 1025, as described above with reference to FIGS. 1 and 2. In some embodiments, at least a portion of the bottoms product via line 1021 and molecular hydrogen via line 1031 can be fed into the second hydroprocessing stage 1033 to produce the second hydroprocessed effluent via line 1037. In some embodiments, at least a portion of the mid-cut product via lines 1019 and 1027 can be recycled to the first hydroprocessing stage 1011 as at least a portion of the utility fluid.

[0083] In some embodiments, the second hydroprocessed effluent via line 1037 can be introduced into a separation stage 3041 to recover at least an overhead product via line 3043 that can include molecular hydrogen and a bottoms product via line 3045. The bottoms product in line 3045, as disclosed herein, can also be referred to as the “second hydroprocessed effluent” and can have the properties described above with reference to the second hydroprocessed effluent. The overhead in line 3043 includes gaseous components, e.g., molecular hydrogen and sulfur-containing compounds such as hydrogen sulfide and do not contribute to the properties of the second hydroprocessed effluent as described herein. In other words, the second hydroprocessed effluent described herein refers to the product after separating at least the overhead in line 3043 such that at least a portion of the sulfur-containing compound(s) present in the second hydroprocessed effluent immediately upon exiting the second hydroprocessing stage 1033 has been removed therefrom. The overhead via line 3043 can be introduced into the one or more upgrading units 1039, e.g., one or more amine towers, to provide additional molecular hydrogen via line 1045 that can be recycled via lines 1047 and 1049 to the first hydroprocessing stage 1011 and/or via lines 1047 and 1051 to the second hydroprocessing stage 1033.

[0084] It has been discovered that by combining the hydrocarbon feed in line 1003 with the steam cracker effluent, the composition of the hydrocarbon in line 3001 can be significantly varied. For example, if the steam cracker 3005 has been designed to primarily process a C₅+ hydrocarbon feed, the first hydroprocessing stage 1011, the separator 1017, and the second hydroprocessing stage 1033 will generally be designed to operate with a certain quantity of steam cracker tar being processed therein. By combining the hydrocarbon feed in line 1003 with the steam cracker tar in line 3023, the composition of the hydrocarbon in line 3001 can be adjusted to provide feed flexibility while the first hydroprocessing stage 1011, the separator 1017, and the second hydroprocessing stage 1033 can continue to operate as originally designed due to the increased volume introduced thereto due to the addition of the hydrocarbon feed in line 1003.

[0085] FIG. 4 depicts a schematic of another illustrative process/system 401 for upgrading a steam cracker tar in line 4029 and/or 4033 and a hydrocarbon feed in line 1003 that includes a Group I lube extract, according to one or more embodiments. A steam cracker hydrocarbon feed or simply “hydrocarbon” via line 4001 can be heated in a convection section 4007 of a steam cracker furnace 4005 to produce a heated hydrocarbon via line 4009. In some embodiments, the hydrocarbon in line 4001 can preferably include the one or more C₅+

hydrocarbons described above. In some embodiments, at least a portion of the hydrocarbon in line 4001 can include one or more C₄- hydrocarbons.

[0086] The hydrocarbon in line 4001 can be combined with an aqueous fluid in line 4003 to produce a first mixture that can include hydrocarbon and steam. The heating of the hydrocarbon in line 4001 can be carried out before, during, and/or after the hydrocarbon is combined with the aqueous fluid in line 4003. At least a portion of the heated hydrocarbon via line 4009 can be introduced into a separator 4011, which can be referred to as a flash drum, a knockout drum, or other separator, to produce a vapor phase product via line 4013 and a liquid phase product via line 4015. In some embodiments, the separator 4011 can be or include the separators and/or other equipment disclosed in U.S. Patent Nos. 7,138,047; 7,090,765; 7,097,758; 7,820,035; 7,311,746; 7,220,887; 7,244,871; 7,247,765; 7,351,872; 7,297,833; 7,488,459; 7,312,371; 6,632,351; 7,578,929; and 7,235,705.

[0087] In some embodiments, the heated mixture that includes the hydrocarbon(s) and the aqueous fluid in line 4009 can include about 10 wt%, about 20 wt%, or about 30 wt% to about 70 wt%, about 80 wt%, about 90 wt%, or about 95 wt% of the aqueous fluid, based on a combined weight of the hydrocarbon(s) and the aqueous fluid. In some embodiments, the heated mixture in line 4009 can be at a temperature in arrange from 330°C, 340°C, 400°C, 405°C, 410°C, 425°C, or 450°C to 475°C, 500°C, 525°C, 550°C, 565°C, or 585°C. In some embodiments, the liquid phase product in line 4015 can include hydrocarbons having a minimum boiling point $\geq$ 350°C, e.g., in a range of 400°C, 425°C, 450°C, or 475°C to 500°C, 525°C, 550°C, or 570°C, as measured according to ASTM D6352-19e1 or ASTM D2887-22e1. Those skilled in the art will appreciate that should an indicated boiling point fall outside the range specified in one or more of these standards, it can be determined by extrapolation.

[0088] At least a portion of the vapor phase product via line 4013 can be introduced into a radiant section 4017 of the steam cracker furnace 4005 and steam cracked therein to produce a steam cracker effluent via line 4019. The steam cracker effluent via line 4019 can be introduced into and separated within a steam cracker primary fractionator 4021 into a plurality of products, e.g., an overhead via line 4023, a steam cracker gas oil ("SCGO") via line 4025, a steam cracker quench oil ("SCQO") via line 4027, and a steam cracker tar ("SCT") via line 4029. In some embodiments, illustrative primary fractionators can include those disclosed in U.S. Patent No. 8,083,931, and U.S. Patent Application Publication No. 2014/0357923. In some embodiments, the steam cracker effluent in line 4019 can be cooled to produce a cooled steam cracker effluent prior to introducing the steam cracker effluent into the steam cracker

primary fractionator 4021. In some embodiments, the steam cracker effluent in line 4019 can be cooled by direct contact with one or more quench mediums and/or by indirect heat exchange with one or more quench mediums.

[0089] In some embodiments, at least a portion of the steam cracker tar in line 4029 can be introduced into a solids removal unit 4031 to produce a solids-lean steam cracker tar via line 4033 and a solids rich product via line 4035. In some embodiments, the solids removal unit 4031 can include one or more filters, one or more centrifuges, or a combination thereof. In some embodiments, a first quantity of the steam cracker tar in line 4029 can be introduced into the solids removal unit 4031 and a second quantity of the steam cracker tar in line 4029 can bypass the solids removal unit 4031 and can be combined with the solids-lean stream cracker tar in line 4033. It should be understood that the solids removal unit 4031 can be optional as the composition of the steam cracker tar in line 4029 can vary based, at least in part, on the particular composition of the hydrocarbon feed in 4001.

[0090] In some embodiments, at least a portion of the steam cracker tar in line 4033 can be combined with the utility fluid in line 1007 obtained from the utility fluid source 1005 and the hydrocarbon feed in line 1003 obtained from the hydrocarbon feed source 1001 that can include the Group I lube extract to produce a second mixture in line 4033 that includes the steam cracker tar, the utility fluid, and the hydrocarbon feed. In other embodiments, the mid-cut product in line 1027 can be combined with the steam cracker tar and the hydrocarbon feed to produce the second mixture in line 4033, as described above with reference to FIGS. 1 and 2. In still other embodiments, the steam cracker tar in line 4033 can be combined with the utility fluid in line 1007, the mid-cut product in line 1027, and the hydrocarbon feed in line 1003 to produce the second mixture in line 4033. In still other embodiments, the steam cracker tar in line 4033, the mid-cut product in line 1027, and the hydrocarbon feed in line 1007 can be combined to produce the second mixture in line 4033. In other embodiments, molecular hydrogen via line 1009 and the second mixture that includes the steam cracker tar, the hydrocarbon feed, and at least one of the utility fluid and the mid-cut product via line 4033 can be introduced into the first hydroprocessing stage 2000 to produce the first hydroprocessed effluent via line 1015, as described above with reference to FIG. 2.

[0091] In some embodiments, at least a portion of the liquid phase product via line 4015 can be introduced into a fluidized catalytic cracker 4041 to produce a fluidized catalytic cracker effluent via line 4043. The fluidized catalytic cracker effluent via line 4043 can be introduced into and separated within a fluidized catalytic cracker primary fractionator 4045 into a plurality

of products, e.g., a C₄ overhead (namely C₁, C₂, C₃, and C₄ hydrocarbons, and typically including H₂S) via line 4047, naphtha via line 4049, a cycle oil via line 4051, and a fluidized catalytic cracker main column bottoms product via line 4053. The fluidized catalytic cracker 4041 can include additional equipment that is typically used in such a process, e.g., a separator such as a cyclone separator for separating fluidized catalyst particles from the fluidized catalytic cracker effluent. It should also be understood that the fluidized catalytic cracker 4041 can also include additional separators such as a catalyst fines separator configured to remove entrained catalyst particles from the fluidized catalytic cracker main column bottoms product or other product(s) separated therefrom.

[0092] In some embodiments, at least a portion of the fluidized catalytic cracker main column bottoms product via line 4053 can be combined with the steam cracker tar in line 4033, the hydrocarbon feed in line 1003, and at least one of the utility fluid in line 1007 and the mid-cut product in line 1027 to produce the second mixture in line 4033. The second mixture via line 4033 that includes the steam cracker tar, the hydrocarbon feed from line 1003, and the utility fluid from line 1007 and/or the mid-cut product from line 1027, and, optionally, the fluidized catalytic cracker main column bottoms product from line 4053 and molecular hydrogen via line 1009 can be introduced into the first hydroprocessing stage 1033 to produce the first hydroprocessed effluent via line 1015. In other embodiments, the second mixture in line 4033 can include the hydrocarbon feed in line 1003, the fluidized catalytic cracker main column bottoms product in line 4053, and the utility fluid in line 1007 and/or the mid-cut in line 1027 and can be free of the steam cracker tar.

[0093] The first hydroprocessed effluent via line 1015 can be introduced into the separation stage 1017 to recover at least the mid-cut product via line 1019 and the bottoms product via line 1021 and, optionally, the overhead via line 1023 and/or the light cut via line 1025, as described above with reference to FIGS. 1 and 2. In some embodiments, at least a portion of the bottoms product via line 1021 and molecular hydrogen via line 1031 can be fed into the second hydroprocessing stage 1033 to produce the second hydroprocessed effluent via line 1037. In some embodiments, at least a portion of the mid-cut product via lines 1019 and 1027 can be recycled to the first hydroprocessing stage 1011 as at least a portion of the utility fluid. In some embodiments, at least a portion of the overhead in line 1023 can be introduced into the one or more upgrading units 1039 and molecular hydrogen via lines 1047 and 1049 and/or via lines 1047 and 1051 can be recycled to the first hydroprocessing stage 1011 and/or the second hydroprocessing stage 1033, respectively.

[0094] In some embodiments, the second hydroprocessed effluent via line 1037 can be introduced into the separation stage 3041 to recover at least the overhead product via line 3043 that can include molecular hydrogen and the bottoms product via line 3045, as described above with reference to FIG. 3. The overhead via line 3043 can be introduced into the one or more upgrading units 1039, *e.g.*, one or more amine towers, to provide additional molecular hydrogen via line 1045 that can be recycled via lines 1047 and 1049 and/or via lines 1047 and 1051 to the first hydroprocessing stage 1011 and/or the second hydroprocessing stage 1033, respectively.

Examples:

10 [0095] The foregoing discussion can be further described with reference to the following non-limiting examples.

Example 1

[0096] Three feed mixtures that included a mid-cut product and different Group I lube extracts were prepared. Each mixture included 60 wt% of the Group I lube extract and 40 wt% of the mid-cut product (MC). The Group I lube extracts were a light neutral Group I lube extract (LN), a heavy neutral Group I lube extract (HN), and a bright stock Group I lube extract (BS). The Group I lube extracts, the mid-cut product, and the mixtures thereof (LN/MC, HN/MC, and BS/MC) had the properties shown in Table 1.

Table 1: Properties of the Group I Lube Extracts and the Mid-cut Product				
	LN	HN	BS	MC
Sulfur, wt%	4.95	4.7	4.56	0.038
Hydrogen, wt%	8.9	9.8	10.6	10
API	8.9	8.2	9.1	14.5
Density, g/cm ³	1.007	1.012	1.005	0.968
SBN	141	104	108	123

20 [0097] Each feed was hydroprocessed with a CoMo/Al₂O₃ catalyst at 0.8h⁻¹ WHSV, 534 S m³/m³ (3,000 scf of molecular hydrogen per barrel of feed (SCFB)), and 8.3 MPa-gauge (1,200 psi-gauge) total pressure. The sulfur conversion and hydrogen consumption determined at 360°C, 370°C, 380°C, 390°C, and 400°C. The sulfur conversion rate when each mixture was hydroprocessed is shown in Table 2.

25

Table 2: Sulfur Conversion (%)			
Temp. (°C)	LN/MC	HN/MC	BS/MC
360	90	87	87
370	95	93	92
380	97	96	95
390	99	98	97
400	99	99	98

[0098] The hydrogen consumption rate when each mixture was hydroprocessed is shown in Table 3.

Table 3: Hydrogen Consumption (S m ³ /m ³ , Group I lube extract basis)			
Temp. (°C)	LN/MC	HN/MC	BS/MC
360	247	209	214
370	267	231	230
380	289	253	249
390	302	267	271
400	307	271	276

5

[0099] As shown in Tables 2 and 3, sulfur conversion and hydrogen consumption increased as the hydroprocessing temperature increased. The boiling point distribution for the LN/MC, HN/MC, and BS/MC mixtures (feed) and after hydroprocessing at a temperature of 360°C, 370°C, 380°C, 390°C, and 400°C were also measured. The boiling point distributions for the LN/MC, HN/MC, and BS/MC mixtures after hydroprocessing showed an approximate 10% increase in the amount of mid-cut product for all three mixtures.

Example II

[00100] A mixture of the mid-cut product used in Example I, a steam cracker tar, and another light neutral Group I lube extract was hydroprocessed. The mixture included 48 wt% of the steam cracker tar, 12 wt% of the LN Group I lube extract, and 40 wt% of the mid-cut product. A 60/40 mixture of only the steam cracker tar and the mid-cut product was also hydroprocessed in the same hydroprocessing arrangement before and after the mixture of the mid-cut product used in Example I, a steam cracker tar, and another light neutral Group I lube extract was hydroprocessed. The properties of the LN Group I lube extract, steam cracker tar, mid-cut product, and the mixture thereof are shown in Table 5.

20

Table 5: Properties				
	LN Group I Lube Extract	Tar	Mid-cut	Mixture
Sulfur, wt%	4.71	4.22	0.038	2.58
Hydrogen, wt%	9.869	6.625	9.959	8.34
API	9.0	-9.1	14.5	7.7
SBN	140	225	123	180
Density, g/cm ³	1.006	1.155	0.968	1.016

[00101] In order to identify the classes of molecules and the boiling point distribution in the LN Group I lube extract and probe potential fouling promoters, the boiling range was estimated by simulated distillation (“SimDis”) according to ASTM D2887-18 and two-dimensional gas chromatography (2D-GC) analysis was performed. The SimDis plots showed a narrower boiling point distribution for the LN Group I lube extract compared to the steam cracker tar, spanning 343°C to 538°C. The LN Group I lube extract was a lighter stream compared to the steam cracker tar and, as such, the mixed feed density was slightly lower (1.016 g/cm³) as compared to a mixed feed that included 60 wt% of the steam cracker tar and 40 wt% of the mid-cut product (1.030 g/cm³). The 2D-GC data indicated the presence of saturates (paraffins) in an amount of about 9.12 wt%.

[00102] The mixture of the LN Group I lube extract, steam cracker tar, and mid-cut product was hydroprocessed for a month under the following conditions. The hydroprocessing stage included a pre-heater that heated the mixture to a temperature of 250°C, processed the heated mixture through a guard bed operated at a temperature of 260°C at a 1.2 hr⁻¹ WHSV to produce a guard bed effluent, processed the guard bed effluent in a pre-treater at a temperature of 362°C at a 2.4 hr⁻¹ WHSF to produce a pre-treated mixture, that was then processed in a main hydroprocessing reactor at a temperature in a range from 375°C to 390°C at a 0.8 hr⁻¹ WHSV. The total hydrogen flow was 534 S m³/m³ (3,000 SCFB), LN Group I lube extract and steam cracker tar basis. The hydrogen pressure was 8,274 kPa-gauge. The amount of hydrogen was distributed as follows: 25% was introduced into the guard bed reactor, 40% was introduced into the pre-treater, and 35% was introduced into the main hydroprocessing reactor. The catalyst used in the guard bed reactor and the pre-treater was a sulfided catalyst that included molybdenum oxide and nickel-molybdenum oxide on alumina and the catalyst used in the main

hydroprocessing reactor was a sulfided catalyst that included cobalt molybdenum oxide on alumina.

[00103] It was found that during introduction of the mixture that included the LN Group I lube extract, steam cracker tar, and mid-cut product both the hydrodesulfurization activity (sulfur conversion) and the solubility blending number of the mid-cut product recovered from the hydroprocessed effluent remained consistent and similar to the mixture that included only the steam cracker tar and the mid-cut product.

[00104] During the one month run of the mixture that included the LN Group I lube extract, steam cracker tar, and mid-cut product, three mid-cut products were obtained and the solubility blending number for each mid-cut product was tested. All three mid-cut products had a solubility number of 120 or greater.

[00105] The relative catalyst activity (RCA) during the hydroprocessing was compared before (steam cracker tar and mid-cut only feed) and during (the mixture of the LN Group I lube extract, steam cracker tar, and mid-cut product) to map the catalyst deactivation trend with and without the LN Group I lube extract present in the feed to the hydroprocessing reactor. An offset in RCA was observed, but such offset was an artifact of changes in the feed properties and the drop in relative activity remained almost the same, which indicated there was no significant impact of the LN Group I lube extract on the catalyst deactivation rate.

[00106] Various terms have been defined above. To the extent a term used in a claim is not defined above, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent. Furthermore, all patents, patent application publications, test procedures, and other documents cited in this application are fully incorporated by reference herein to the extent such disclosure is not inconsistent with this application and for all jurisdictions in which such incorporation is permitted.

[00107] While the foregoing is directed to embodiments of the present invention, other and further embodiments of the invention may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.

CLAIMS:

What is claimed is:

1. A hydrocarbon upgrading process, comprising:
 - (I) feeding molecular hydrogen, a utility fluid, and a hydrocarbon feed comprising a
5 Group I lube extract into a first hydroprocessing stage;
 - (II) conducting hydroprocessing in the first hydroprocessing stage to produce a first hydroprocessed effluent;
 - (III) separating from the first hydroprocessed effluent a mid-cut product and a bottoms product;
 - 10 (IV) feeding molecular hydrogen and at least a portion of the bottoms product into a second hydroprocessing stage;
 - (V) conducting hydroprocessing in the second hydroprocessing stage to produce a second hydroprocessed effluent; and
 - (VI) recycling at least a portion of the mid-cut product to the first hydroprocessing stage
15 as at least a portion of the utility fluid.
2. The process of claim 1, wherein the mid-cut product comprises ≤ 0.5 wt% of sulfur and 8.7 wt% to 11 wt% of hydrogen based on a total weight of the mid-cut product, has an API gravity in a range from 8° to 14° , an SBN in a range from 100 to 140, and a density in a range
20 from 0.871 g/cm^3 to 1.065 g/cm^3 .
3. The process of claim 1 or claim 2, wherein the Group I lube extract comprises 3.5 wt% to 6 wt% of sulfur and 8 wt% to 12 wt% of hydrogen based on a total weight of the Group I lube extract, has an API gravity in a range from 7.3° to 10° , an SBN in a range from 93 to 155,
25 and a density in a range from 0.905 g/cm^3 to 1.113 g/cm^3 .
4. The process of any one of claims 1 to 3, wherein the hydrocarbon feed in step (I) further comprises a steam cracker tar.
- 30 5. The process of claim 4, wherein the steam cracker tar comprises 3.3 wt% to 5 wt% of sulfur and 5.5 wt% to 7.5 wt% of hydrogen based on a total weight of the steam cracker tar, has an API gravity in a range from -11° to -8° , an SBN in a range from 180 to 250, and a density in a range from 1.040 g/cm^3 to 1.271 g/cm^3 .

6. The process of claim 4 or claim 5, further comprising:
providing a particle-containing steam cracker tar comprising solid particles therein; and
removing at least a portion of the solid particles from the particle-containing steam cracker tar
5 to obtain the steam cracker tar.
7. The process of any one of claims 1 to 6, wherein the hydrocarbon feed in step (I) further
comprises a fluidized catalytic cracker main column bottoms product.
- 10 8. The process of claim 7, wherein the fluidized catalytic cracker main column bottoms
product comprises 1.5 wt% to 5 wt% of sulfur and 6.1 wt% to 8.8 wt% of hydrogen based on
a total weight of the fluidized catalytic cracker main column bottoms product, has an API
gravity in a range from -11° to 2.5°, an SBN in a range from 180 to 250, and a density in a
range from 0.954 g/cm³ to 1.243 g/cm³.
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9. The process of any one of claims 1 to 3, wherein the hydrocarbon feed in step (I)
consists essentially of the Group I lube extract.
10. The process of any one of claims 1 to 8, wherein the hydroprocessing in step (V) is
20 conducted at a higher temperature than the hydroprocessing in step (II).
11. The process of any one of claims 1 to 10, wherein the hydroprocessing in step (II) is
conducted at a greater weight hourly space velocity than the hydroprocessing in step (V).
- 25 12. The process of any one of claims 1 to 11, wherein step (III) further comprises separating
an overhead product comprising molecular hydrogen from the first hydroprocessed effluent,
and wherein at least a portion of the molecular hydrogen separated in step (III) is recycled to
step (I), fed into the second hydroprocessing stage in step (IV), or a combination thereof.
- 30 13. The process of any one of claims 1 to 12, wherein step (III) further comprises separating
from the first hydroprocessed effluent a light cut comprising naphtha.

14. The process of any of claims 1 to 13, wherein the first hydroprocessing stage comprises, in sequence, a guard bed reactor, a pre-treater downstream of the guard bed reactor, and a main first hydroprocessing reactor downstream of the pre-treater.

5 15. A hydrocarbon upgrading process, comprising:

(I) heating a hydrocarbon in a steam cracking furnace and combining the hydrocarbon with an aqueous fluid to produce a first mixture comprising hydrocarbon and steam, wherein the heating is carried out before, during, and/or after the hydrocarbon feed is combined with the aqueous fluid;

10 (II) steam cracking at least a portion of the first mixture to produce a steam cracker effluent;

(III) separating from the steam cracker effluent a steam cracker tar product and an upgraded steam cracker effluent comprising ethylene and propylene;

15 (IV) feeding molecular hydrogen, at least a portion of the steam cracker tar product, and a hydrocarbon feed comprising a Group I lube extract into a first hydroprocessing stage;

(V) conducting hydroprocessing in the first hydroprocessing stage to produce a first hydroprocessed effluent;

(VI) separating from the first hydroprocessed effluent a mid-cut product and a bottoms product;

20 (VII) feeding molecular hydrogen and at least a portion of the bottoms product into a second hydroprocessing stage;

(VIII) conducting hydroprocessing in the second hydroprocessing stage to produce a second hydroprocessed effluent; and

25 (IX) recycling at least a portion of the mid-cut product to the first hydroprocessing stage as at least a portion of the utility fluid.

16. The process of claim 15, wherein the Group I lube extract comprises 3.5 wt% to 6 wt% of sulfur and 8 wt% to 12 wt% of hydrogen based on a total weight of the Group I lube extract, and has an API gravity in a range from 7.3° to 10°, an SBN in a range from 93 to 155, and a
30 density in a range from 0.905 g/cm³ to 1.113 g/cm³.

17. The process of claim 15 or claim 16, wherein the mid-cut product comprises ≤ 0.5 wt% sulfur and 8.7 wt% to 11 wt% of hydrogen based on a total weight of the mid-cut product, has

an API gravity in a range from 8° to 14°, an SBN in a range from 100 to 140, and a density in a range from 0.871 g/cm³ to 1.065 g/cm³.

18. The process of any one of claims 15 to 17, wherein the steam cracker tar comprises 3.3 wt% to 5 wt% of sulfur and 5.5 wt% to 7.5 wt% of hydrogen based on a total weight of the steam cracker tar, has an API gravity in a range from -11° to -8°, an SBN in a range from 180 to 250, and a density in a range from 1.040 g/cm³ to 1.271 g/cm³.

19. The process of any one of claims 15 to 18, step (IV) further comprises feeding a fluidized catalytic cracker main column bottoms product with the at least a portion of the steam cracker tar product, the utility fluid, and the hydrocarbon feed into the first hydroprocessing stage.

20. The process of claim 19, wherein the fluidized catalytic cracker main column bottoms product comprises 1.5 wt% to 5 wt% of sulfur and 6.1 wt% to 8.8 wt% of hydrogen based on a total weight of the fluidized catalytic cracker main column bottoms product, has an API gravity in a range from -11° to 2.5°, an SBN in a range from 180 to 250, and a density in a range from 0.954 g/cm³ to 1.243 g/cm³.

21. The process of claim 19 or claim 20, further comprising:

(Ia) separating from the first mixture a vapor phase product and a liquid phase product, wherein at least a portion of the vapor phase product is steam cracked in step (II) to produce the steam cracker effluent;

(X) catalytically cracking at least a portion of the liquid phase product in a fluidized catalytic cracker to produce a fluidized catalytic cracker effluent; and

(XI) separating the fluidized catalytic cracker main column bottoms product from the fluidized catalytic cracker effluent, wherein at least a portion of the separated fluidized catalytic cracker main column bottoms is fed into the first hydroprocessing stage in step (IV).

22. The process of any one of claims 15 to 21, wherein the hydroprocessing in step (VIII) is conducted at a higher temperature than the hydroprocessing in step (V).

23. The process of any one of claims 15 to 22, wherein the hydroprocessing in step (V) is conducted at a greater weight hourly space velocity than the hydroprocessing in step (VIII).
24. The process of any one of claims 15 to 23, wherein step (VI) further comprises
5 separating an overhead product comprising molecular hydrogen from the first hydroprocessed effluent, and wherein at least a portion of the molecular hydrogen separated in step (VI) is recycled to step (IV), fed into the second hydroprocessing stage in step (VII), or a combination thereof.
- 10 25. The process of any one of claims 15 to 24, further comprising (IV_a) combining the at least a portion of the steam cracker tar product with the utility fluid and the hydrocarbon feed to produce a second mixture, wherein the second mixture is fed into the first hydroprocessing stage.