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(54) Titre : PROCEDE DE CONVERSION D'HYDROCARBURES
(54) Title: HYDROCARBON CONVERSION PROCESS

(57) **Abrégé/Abstract:**

This invention provides an integrated process for converting a hydrocarbon feedstock having components boiling above about 100 °C into steam cracked products, which process comprises passing said feedstock to a hydrotreating zone at a pressure in the range of from about 400 psig to about 1,250 psig to effect substantially complete decomposition of organic sulfur and/or nitrogen compounds, passing the product from said hydrotreating zone to a steam cracking zone, and recovering therefrom hydrogen and C₁-C₄ hydrocarbons, steam cracked naphtha, steam cracked gas oil and steam cracked tar therefrom, wherein the amount of steam cracked tar produced is reduced by at least about 15 percent, basis the starting hydrocarbon feedstock which has not been subjected to hydrotreating.

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(21) International Application Number: PCT/US97/14437 (22) International Filing Date: 15 August 1997 (15.08.97) (30) Priority Data: <table border="0"> <tr> <td>60/027,859</td> <td>15 August 1996 (15.08.96)</td> <td>US</td> </tr> <tr> <td>60/034,612</td> <td>31 December 1996 (31.12.96)</td> <td>US</td> </tr> <tr> <td>08/848,438</td> <td>8 May 1997 (08.05.97)</td> <td>US</td> </tr> </table> (71) Applicant (for all designated States except US): EXXON CHEMICAL PATENTS INC. [US/US]; 5200 Bayway Drive, Baytown, TX 77520-5200 (US). (72) Inventors; and (75) Inventors/Applicants (for US only): BRADOW, Carl, W. [-/US]; 4115 North Webber Drive, Pearland, TX 77584 (US). GRENOBLE, Dane, C. [-/US]; 18201 Sandy Cove, Nassau Bay, TX 77058 (US). MILAM, Stanley, N. [-/US]; 710 Teetshorn, Houston, TX 77009 (US). WINQUIST, Bruce, H. [-/US]; 11202 Cold Spring Drive, Houston, TX 77043 (US). MURRAY, Brendan, D. [-/US]; 1118 Stoney Hill Drive, Houston, TX 77077 (US). FOLEY, Richard [-/US]; 5000 Montrose Boulevard #12H, Houston, TX 77006 (US).		60/027,859	15 August 1996 (15.08.96)	US	60/034,612	31 December 1996 (31.12.96)	US	08/848,438	8 May 1997 (08.05.97)	US	(74) Agents: RUSSELL, Linda, K.; Exxon Chemical Company, P.O. Box 2149, Baytown, TX 77522-2149 (US) et al. (81) Designated States: AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, CA, CH, CN, CU, CZ, DE, DK, EE, ES, FI, GB, GE, GH, HU, IL, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MD, MG, MK, MN, MW, MX, NO, NZ, PL, PT, RO, RU, SD, SE, SG, SI, SK, TJ, TM, TR, TT, UA, UG, US, UZ, VN, YU, ARIPO patent (GH, KE, LS, MW, SD, SZ, UG, ZW), Eurasian patent (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European patent (AT, BE, CH, DE, DK, ES, FI, FR, GB, GR, IE, IT, LU, MC, NL, PT, SE), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, ML, MR, NE, SN, TD, TG). Published <i>With international search report.</i>
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HYDROCARBON CONVERSION PROCESS

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Field of the Invention

10 This invention relates to a process for upgrading hydrocarbon feedstocks for subsequent use in steam cracking. In particular, this invention describes a process for upgrading hydrocarbon feedstocks for use in steam cracking by the application of hydrotreating and concomitant partial hydrogenation of the unsaturated and/or aromatic species found therein, and the resultant yield increase of hydrogen, C₁-C₄ hydrocarbons, steam cracked naphtha and steam cracked gas oil, and the concomitant decrease in the yield of steam cracked gas tar, upon steam cracking of the hydrotreated hydrocarbon feedstocks.

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Background of the Invention

20 Steam cracking is a process widely known in the petrochemical art. The primary intent of the process is the production of C₁-C₄ hydrocarbons, particularly ethylene, propylene, and butadiene, by thermal cracking of hydrocarbon feedstocks in the presence of steam at elevated temperatures. The steam cracking process in general has been well described in the publication entitled "Manufacturing Ethylene" by S. B. Zdonik et. al, Oil and Gas Journal Reprints 1966 - 1970. Typical liquid feedstocks for conventional steam crackers are straight run (virgin) and hydrotreated straight run (virgin) feedstocks ranging from light naphthas to vacuum gas oils. Gaseous feedstocks such as ethane, propane and butane are also commonly processed in the steam cracker.

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The selection of a feedstock for processing in the steam cracker is a function of several criteria including: (i)

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availability of the feedstock, (ii) cost of the feedstock and (iii) the yield slate derived by steam cracking of that feedstock. Feedstock availability and cost are predominantly a function of global supply and demand issues. On the other hand, the yield slate derived by steam cracking of a given feedstock is a function of the chemical characteristics of that feedstock. In general, the yield of high value C_1 - C_4 hydrocarbons, particularly ethylene, propylene and butadiene, is greatest when the steam cracker feedstocks are gaseous feedstocks such as ethane, propane and butane. The yield of high value steam cracked naphtha and low value steam cracked gas oil (SCGO) and particularly low value steam cracked tar (SCT) upon steam cracking of a straight run (virgin) or hydrotreated straight run (virgin) feedstocks increases as the boiling range of the feedstock increases. Thus, the steam cracking of liquid feedstocks such as naphthas, gas oils and vacuum gas oils generally results in a greater proportion of particularly low value steam cracked products, i.e., steam cracked tar. In addition, steam cracking facilities where naphthas and gas oils are processed require additional capital infrastructure in order to process the large volume of liquid co-products resulting from steam cracking of those feedstocks.

What is more, the yield of the least desirable products of steam cracking, steam cracked tar, is generally even higher when low quality hydrogen deficient cracked feedstocks such as thermally cracked naphtha, thermally cracked gas oil, catalytically cracked naphtha, catalytically cracked gas oil, coker naphthas and coker gas oil are processed. The significantly increased yield of the low value steam cracked tar product relative to production of high value C_1 - C_4 hydrocarbon products obtained when processing the low quality hydrogen deficient cracked feedstocks is such that these feedstocks are rarely processed in steam crackers.

Catalytic hydrodesulfurization (sulfur removal), hydrodenitrification (nitrogen removal) and hydrogenation

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(olefins, diolefins and aromatics saturation) are well known in the petroleum refining art. Hydrodesulfurization, hydrodenitrification and partial hydrogenation have been applied to upgrading feedstocks for steam cracking as described by Zimmermann in U.S. Patent No. 4,619,757. This two stage approach employed base metal, bi-metallic catalysts on both non-acidic (alumina) and acidic (zeolite) supports.

Minderhoud et. al., U.S. Patent No. 4,960,505, described an approach for upgrading of kerosene and fuel oil feedstocks by first pre-treating the feedstock to effect hydrodesulfurization and hydrodenitrification to yield a liquid product with sulfur and nitrogen contaminants at levels of less than 1,000 and 50 ppm wt., respectively. Thereafter, the low impurity hydrocarbon stream was subjected to hydrogenation to yield a high cetane number fuel oil product.

Winqvist et. al., U.S. Patent No. 5,391,291, described an approach for upgrading of kerosene, fuel oil, and vacuum gas oil feedstocks by first pre-treating the feedstock to effect hydrodesulfurization and hydrodenitrification, and thereafter hydrogenation of the resultant liquid hydrocarbon fraction to yield a high cetane number fuel oil product.

It has been found that the present invention which comprises hydrotreating followed by steam cracking results in significant yield improvements for hydrogen, C_1 - C_4 hydrocarbons and steam cracked naphtha when applied to straight run (virgin) feedstocks; and results in high yields of hydrogen, C_1 - C_4 hydrocarbons and steam cracked naphtha and reduced yields of steam cracked tar when applied to low quality, hydrogen deficient, cracked feedstocks such as thermally cracked naphtha, thermally cracked kerosene, thermally cracked gas oil, catalytically cracked naphtha, catalytically cracked kerosene, catalytically cracked gas oil, coker naphthas, coker kerosene, coker gas oil, steam cracked naphthas and steam cracked gas oils. The ability of this process to treat low quality hydrogen deficient cracked feedstocks, such as steam cracked gas oil,

permits these heretofore undesirable feedstocks to be recycled to extinction through the combined feedstock upgrading and steam cracking system.

5 It has further been found that hydrogen, C₁-C₄ hydrocarbons and steam cracked naphtha can be produced in higher quantities in a process in which the effluent from at least one hydrotreating zone containing at least two hydrotreating catalysts is passed to a steam cracking zone. The effluents from the steam cracking zone are then passed to one or more
10 fractionating zones in which the effluents are separated into a fraction comprising hydrogen and C₁-C₄ hydrocarbons, a steam cracked naphtha fraction, a steam cracked gas oil fraction and a steam cracked tar fraction. The process of the present invention results in improved yields of the high value steam
15 cracked products, i.e., C₁-C₄ hydrocarbons, particularly ethylene, propylene, and butadiene, and steam cracked naphtha, particularly isoprene, cis-pentadiene, trans-pentadiene, cyclopentadiene, and benzene, and reduced yields of steam cracked tar.

20 Summary of the Invention

This invention provides an integrated process for converting a hydrocarbon feedstock having components boiling above 100°C into steam cracked products comprising hydrogen, C₁-C₄ hydrocarbons, steam cracked naphtha (boiling from C₅ to
25 220°C), steam cracked gas oil (boiling from 220°C to 275°C) and steam cracked tar (boiling above 275°C).

The process of the present invention therefore comprises: (i) passing the hydrocarbon feedstock through at least one hydrotreating zone wherein said feedstock is contacted
30 at an elevated temperature and at a pressure in the range of from about 400 psig (27 bar) to about 1,250 psig (85 bar) with a hydrogen source and at least two hydrotreating catalysts to effect substantially complete conversion of organic sulfur and/or nitrogen compounds contained therein to H₂S and NH₃,
35 respectively; (ii) passing the product from said hydrotreating zone to a product separation

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zone to remove gases and, if desired, light hydrocarbon fractions; (iii) passing the product from said separation zone to a steam cracking zone and thereafter; (iv) passing the product from said steam cracking zone to one or more product separation zones to separate the product into a fraction comprising hydrogen and C₁-C₄ hydrocarbons, a steam cracked naphtha fraction, a steam cracked gas oil fraction and a steam cracked tar fraction, wherein the yields of ethylene and propylene and butadiene in the H₂ and C₁-C₄ hydrocarbons fraction are each increased by at least about 5 percent, relative to the yields obtained when the untreated hydrocarbon feedstock is subjected to said steam cracking and product separation, the yield of isoprene, cis-pentadiene, trans-pentadiene, cyclopentadiene and benzene in the steam cracked naphtha fraction are each increased by at least about 10 percent, relative to when the untreated hydrocarbon feedstock is subjected to said steam cracking and product separation, the yield of steam cracked gas oil is increased by at least about 20 percent, relative to when the untreated hydrocarbon feedstock is subjected to said steam cracking and product separation, and the yield of steam cracked tar is reduced by at least about 15 percent, relative to when the untreated hydrocarbon feedstock is subjected to said steam cracking and product separation.

Description of the Preferred Embodiments

As used in this specification, the term "C₁-C₄ hydrocarbons" refers to methane, ethane, ethylene, acetylene, propane, propylene, propadiene, methylacetylene, butane, isobutane, isobutylene, butene-1, cis-butene-2, trans-butene-2, butadiene, and C₄-acetylenes. As used in this specification, the term "steam cracked naphtha" refers to products boiling between C₅ and 220°C, including isoprene, cis-pentadiene, trans-pentadiene, cyclopentadiene, methylcyclopentadiene, and benzene.

The hydrocarbon feedstock in the process of the present invention typically comprises a hydrocarbon fraction having a major proportion, i.e., greater than about 95 percent,

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of its components boiling above about 100°C, preferably above about 150°C or higher. Suitable feedstocks of this type include straight run (virgin) naphtha, cracked naphthas (e.g. catalytically cracked, steam cracked, and coker naphthas and the like), straight run (virgin) kerosene, cracked kerosenes (e.g. catalytically cracked, steam cracked, and coker kerosenes and the like), straight run (virgin) gas oils (e.g. atmospheric and vacuum gas oil and the like), cracked gas oils (e.g. coker and catalytically cracked light and heavy gas oils, steam cracked gas oils and the like) visbreaker oil, deasphalted oil, thermal cracker cycle oil, synthetic gas oils and coal liquids. Normally the feedstock will have an extended boiling range, e.g., up to 650°C or higher, but may be of more limited ranges with certain feedstocks. In general, the feedstocks will have a boiling range between about 150°C and about 650°C.

In the hydrotreating zone, the hydrocarbon feedstock and a hydrogen source are contacted with at least two hydrotreating catalysts to effect substantially complete decomposition of organic sulfur and/or nitrogen compounds in the feedstock, i.e., organic sulfur levels below about 100 parts per million, preferably below about 50 parts per million, and more preferably below about 25 parts per million, and organic nitrogen levels below about 15 parts per million, preferably below about 5 parts per million, and more preferably below about 3 parts per million. The source of hydrogen will typically be hydrogen-containing mixtures of gases which normally contain about 70 volume percent to about 100 volume percent hydrogen.

In one embodiment, the hydrotreating zone contains two hydrotreating catalysts in a stacked bed or layered arrangement. When a stacked bed catalyst configuration is utilized, the first hydrotreating catalyst typically comprises one or more Group VIB and/or Group VIII (Periodic Table of the Elements) metal compounds supported on an amorphous carrier such as alumina, silica-alumina, silica, zirconia or titania. Examples of such metals comprise nickel, cobalt, molybdenum and tungsten. The

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5 first hydrotreating catalyst is preferably an oxide and/or
sulfide of a Group VIII metal, preferably cobalt or nickel,
mixed with an oxide and/or a sulfide of a Group VIB metal,
preferably molybdenum or tungsten, supported on alumina or
silica-alumina. The second hydrotreating catalyst typically
comprises one or more Group VIB and/or Group VIII metal
components supported on an acidic porous support. From Group
10 VIB, molybdenum, tungsten and mixtures thereof are preferred.
From Group VIII, cobalt, nickel and mixtures thereof are
preferred. Preferably, both Group VIB and Group VIII metals are
present. In a particularly preferred embodiment, the
hydrotreating component of the second hydrotreating catalyst is
nickel and/or cobalt combined with tungsten and/or molybdenum
with nickel/tungsten or nickel/molybdenum being particularly
15 preferred. With respect to the second hydrotreating catalyst,
the Group VIB and Group VIII metals are supported on an acidic
carrier, such as, for example, silica-alumina, or a large pore
molecular sieve, i.e. zeolites such as zeolite Y, particularly,
ultrastable zeolite Y (zeolite USY), or other dealuminated
20 zeolite Y. Mixtures of the porous amorphous inorganic oxide
carriers and the molecular sieves can also be used. Typically,
both the first and second hydrotreating catalysts in the stacked
bed arrangement are sulfided prior to use.

25 The hydrotreating zone is typically operated at
temperatures in the range of from about 200°C to about 550°C,
preferably from about 250°C to about 500°C, and more preferably
from about 275°C to about 425°C. The pressure in the
hydrotreating zone is generally in the range of from about 400
psig to about 1,250 psig, preferably from about 400 psig to
30 about 1,000 psig, and more preferably from about 400 psig to
about 750 psig. Liquid hourly space velocities (LHSV) will
typically be in the range of from about 0.1 to about 10,
preferably from about 0.5 to about 5 volumes of liquid
hydrocarbon per hour per volume of catalyst, and hydrogen to oil
35 ratios will be in the range of from about 500 to about 10,000

standard cubic feet of hydrogen per barrel of feed (SCF/BBL) (about .089 to about 2.0 standard cubic meters per liter of feed (m^3/l)), preferably from about 1,000 to about 5,000 SCF/BBL (about 0.18 to about 1.00 m^3/l), most preferably from about
5 2,000 to about 3,000 SCF/BBL (about .35 to about .53 m^3/l).

These conditions are adjusted to achieve substantially complete desulfurization and denitrification, i.e., organic sulfur levels below about 100 parts per million, preferably below about 50 parts per million, and more preferably below about 25 parts per
10 million, and organic nitrogen levels below about 15 parts per million, preferably below about 5 parts per million, and more preferably below about 3 parts per million.

Alternatively, the hydrotreating step may be carried out utilizing two or more hydrotreating zones. For example, in
15 one embodiment, the hydrotreating step can be carried out in the manner described below in which two zones, a first hydrotreating zone and a second hydrotreating zone, are used.

In the first hydrotreating zone, the hydrocarbon feedstock and a hydrogen source are contacted with a first
20 hydrotreating catalyst. The source of hydrogen will typically be hydrogen-containing mixtures of gases which normally contain about 70 volume percent to about 100 volume percent hydrogen. The first hydrotreating catalyst will typically include one or more Group VIB and/or Group VIII metal compounds on an amorphous
25 carrier such as alumina, silica-alumina, silica, zirconia or titania. Examples of such metals comprise nickel, cobalt, molybdenum and tungsten. The first hydrotreating catalyst is preferably an oxide and/or sulfide of a Group VIII metal, preferably cobalt or nickel, mixed with an oxide and/or a
30 sulfide of a Group VIB metal, preferably molybdenum or tungsten, supported on alumina or silica-alumina. The catalysts are preferably in sulfided form.

The first hydrotreating zone is generally operated at temperatures in the range of from about 200°C to about 550°C,
35 preferably from about 250°C to about 500°C, and more preferably from about 275°C to about 425°C. The pressure in the first hydrotreating zone is generally in the range of from about 27

bar to about 85 bar, preferably from about 27 bar to about 63 bar, and more preferably from about 27 bar to about 51 bar. Liquid hourly space velocities (LHSV) will typically be in the range of from about 0.2 to about 2, preferably from about 0.5 to about 1 volumes of liquid hydrocarbon per hour per volume of catalyst, and hydrogen to oil ratios will be in the range of from about 500 to about 10,000 standard cubic feet of hydrogen per barrel of feed (SCF/BBL) (about $.089 \text{ m}^3/\ell$ to about $2.0 \text{ m}^3/\ell$), preferably from about 1,000 to about 5,000 SCF/BBL (about 0.18 to about $1.0 \text{ m}^3/\ell$), most preferably from about 2,000 to about 3,000 SCF/BBL about $.35$ to about $.53 \text{ m}^3/\ell$). These conditions are adjusted to achieve the desired degree of desulfurization and denitrification. Typically, it is desirable in the first hydrotreating zone to reduce the organic sulfur level to below about 500 parts per million, preferably below about 200 parts per million, and the organic nitrogen level to below about 50 parts per million, preferably below about 25 parts per million.

The product from the first hydrotreating zone may then, optionally, be passed to a means whereby ammonia and hydrogen sulfide are removed from the hydrocarbon product by conventional means. The hydrocarbon product from the first hydrotreating zone is then sent to a second hydrotreating zone.

Optionally, the hydrocarbon product may also be passed to a fractionating zone prior to being sent to the second hydrotreating zone if removal of light hydrocarbon fractions is desired.

In the second hydrotreating zone, the product from the first hydrotreating zone and a hydrogen source, typically hydrogen, about 70 volume percent to about 100 volume percent, in admixture with other gases, are contacted with at least one second hydrotreating catalyst. The operating conditions normally used in the second hydrotreating reaction zone include a temperature in the range of from about 200°C to about 550°C , preferably from about 250°C to about 500°C , and more preferably, from about 275°C to about 425°C , a liquid hourly space velocity

(LHSV) of about 0.1 to about 10 volumes of liquid hydrocarbon per hour per volume of catalyst, preferably an LHSV of about 0.5 to about 5, and a total pressure within the range of about 27 bar to about 85 bar, preferably from about 27 bar to about 68 bar, and more preferably from about 27 bar to about 51 bar. The hydrogen circulation rate is generally in the range of from about 500 to about 10,000 standard cubic feet per barrel (SCF/BBL) (about .089 to about 2.0 m³/l), preferably from about 1,000 to 5,000 SCF/BBL (about 0.18 to about 1.0 m³/l), and more preferably from about 2,000 to 3,000 SCF/BBL (about .35 to about .53 m³/l). These conditions are adjusted to achieve substantially complete desulfurization and denitrification. Typically, it is desirable that the hydrotreated product obtained from the hydrotreating zone or zones have an organic sulfur level below about 100 parts per million, preferably below about 50 parts per million, and more preferably below about 25 parts per million, and an organic nitrogen level below about 15 parts per million, preferably below about 5 parts per million and more preferably below about 3 parts per million. It is understood that the severity of the operating conditions is decreased as the volume of the feedstock and/or the level of nitrogen and sulfur contaminants to the second hydrotreating zone is decreased. For example, if product gases, including H₂S and NH₃ (ammonia), and, optionally, light hydrocarbon fractions are removed after the first hydrotreating zone, then the temperature in the second hydrotreating zone will be lower, or alternatively, the LHSV in the second hydrotreating zone will be higher.

The catalysts typically utilized in the second hydrotreating zone comprise an active metals component supported on an acidic porous support. The active metal component, "the hydrotreating component", of the second hydrotreating catalyst is selected from a Group VIB and/or a Group VIII metal component. From Group VIB, molybdenum, tungsten and mixtures thereof are preferred. From Group VIII, cobalt, nickel and mixtures thereof are preferred. Preferably, both Group VIB and Group VIII metals are present. In a particularly preferred

embodiment, the hydrotreating component is nickel and/or cobalt combined with tungsten and/or molybdenum with nickel/tungsten or nickel/molybdenum being particularly preferred. The components are typically present in the sulfide form.

5 The Group VIB and Group VIII metals are supported on an acidic carrier. Two main classes of carriers known in the art are typically utilized: (a) silica-alumina, and (b) the large pore molecular sieves, i.e. zeolites such as Zeolite Y, Mordenite, Zeolite Beta and the like. Mixtures of the porous
10 amorphous inorganic oxide carriers and the molecular sieves are also used. The term "silica-alumina" refers to non-zeolitic aluminosilicates.

15 The most preferred support comprises a zeolite Y, preferably a dealuminated zeolite Y such as an ultrastable zeolite Y (zeolite USY). The ultrastable zeolites used herein are well known to those skilled in the art. They are also exemplified in U.S. Patent Nos. 3,293,192 and 3,449,070. They

are generally prepared from sodium zeolite Y by dealumination.

20 The zeolite is composited with a binder selected from alumina, silica, silica-alumina and mixtures thereof. Preferably the binder is alumina, preferably a gamma alumina binder or a precursor thereto, such as an alumina hydrogel, aluminum trihydroxide, aluminum oxyhydroxide or pseudoboehmite.

25 The Group VIB/Group VIII second hydrotreating catalysts are preferably sulfided prior to use in the second hydrotreating zone. Typically, the catalysts are sulfided by heating the catalysts to elevated temperatures (e.g., 200-400°C) in the presence of hydrogen and sulfur or a sulfur-containing
30 material.

 The product from the final hydrotreating zone is then passed to a steam cracking, i.e., pyrolysis, zone. Prior to being sent to the steam cracking zone, however, if desired, the hydrocarbon product from the final hydrotreating zone may be

passed to a fractionating zone for removal of product gases, and light hydrocarbon fractions.

5 In the steam cracking zone, the product from the hydrotreating zone and steam are heated to cracking temperatures. The operating conditions of the steam cracking zone normally include a coil outlet temperature greater than about 700°C, in particular between about 700°C and 925°C, and preferably between about 750°C and about 900°C, with steam present at a steam to hydrocarbon weight ratio in the range of
10 from about 0.1:1 to about 2.0:1. The coil outlet pressure in the steam cracking zone is typically in the range of from about 0 bar to about 5 bar, preferably in the range of from about 0 bar to about 4 bar. The residence time for the cracking reaction is typically in the range of from about 0.01 second to
15 about 5 seconds and preferably in the range of from about 0.1 second to about 1 second.

After the starting hydrocarbon feed has been subjected to a hydrotreating step and a steam cracking step, the effluent from the steam cracking step may be sent to one or more
20 fractionating zones wherein the effluent is separated into a fraction comprising hydrogen and C₁-C₄ hydrocarbons, a steam cracked naphtha fraction boiling from C₅ to about 220°C, a steam cracked gas oil fraction boiling in the range of from about 220°C to about 275°C and a steam cracked tar fraction boiling
25 above about 275°C. The amount of the undesirable steam cracked product, i.e., steam cracked tar, obtained utilizing the process of the present invention is greatly reduced. The yield of steam cracked tar is reduced by at least about 15 percent, relative to that obtained when the untreated hydrocarbon feedstock is
30 subjected to steam cracking and product separation.

The process according to the present invention may be carried out in any suitable equipment. The hydrotreating zone or zones in the present invention typically comprise one or more vertical reactors containing at least one catalyst bed and are
35 equipped with a means of injecting a hydrogen source into the

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reactors. A fixed bed hydrotreating reactor system wherein the feedstock is passed over one or more stationary beds of catalyst in each zone is particularly preferred.

5 The ranges and limitations provided in the instant specification and claims are those which are believed to particularly point out and distinctly claim the instant invention. It is, however, understood that other ranges and limitations that perform substantially the same function in substantially the same manner to obtain the same or
10 substantially the same result are intended to be within the scope of the instant invention as defined by the instant specification and claims.

The invention will now be described by the following examples which are illustrative and are not intended to be
15 construed as limiting the scope of the invention.

Illustrative Embodiment 1

Example 1 and Comparative Example 1-A below were each carried out using a 100% Heavy Atmospheric Gas Oil (HAGO) feedstock having the properties shown in Table 1 below. Example
20 1 illustrates the process of the present invention. Comparative Example 1-A illustrates HAGO which has not been subjected to hydrotreating prior to steam cracking.

Example 1

Example 1 describes the process of the present
25 invention using a 100% Heavy Atmospheric Gas Oil (HAGO) feed having the properties shown in Table 1 below was hydrotreated using two hydrotreating catalysts in a stacked bed system as follows.

A commercial alumina supported nickel/molybdenum catalyst, available under the name of KF-756 from Akzo Chemicals Inc., U.S.A., was used as the first hydrotreating catalyst (catalyst A) while a commercial zeolite nickel/tungsten catalyst, available under the name of Z-763 from Zeolyst International, was used as the second hydrotreating catalyst
30 (catalyst B).
35

Catalysts A and B catalysts were operated as a "stacked bed" wherein the HAGO and hydrogen contacted catalyst A first and thereafter catalyst B, with the volume ratio of the catalysts (A:B) being 1:1. The HAGO was hydrotreated at 360°C (675°F), 39.8 bar total unit pressure, an overall LHSV of 0.5 hr⁻¹ and a hydrogen flow rate of 3,000 SCF/BBL (0.53 m³/l).

The hydrotreated product was then passed to the steam cracking zone where it was contacted with steam at a temperature of 745 to 765°C, a pressure of 0.88 to 1.73 bar, and a steam to hydrocarbon weight ratio of 0.3:1 to 0.45:1. The residence time in the steam cracker was 0.4 to 0.6 seconds. The steam cracked product was then sent to a fractionating zone to quantify total hydrogen (H₂) and C₁-C₄ hydrocarbons, steam cracked naphtha (SCN), steam cracked gas oil (SCGO), and steam cracked tar (SCT). The steam cracking results are presented in Table 3 below.

Comparative Example 1-A

A 100% Heavy Atmospheric Gas Oil (HAGO) feed was treated in the same manner as forth in Example 1 above, except that it was not subjected to hydrotreating prior to steam cracking. The steam cracking results are presented in Table 3 below.

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TABLE 1

Properties of HAGO Feed (Comp. Ex. 1-A) and
Hydrotreated HAGO (Ex. 1)

	HAGO Feed (1-A)	Hydrotreated HAGO (Ex. 1)
5		
wt. % H	12.76	13.47
ppm wt. S	12,400	41
ppm wt. N	426	1
Density, G/cm ³ @ 15°C	0.8773	0.8242
	Simulated Distillation, D-2887 (ASTM), °C	
10		
IBP	99	37
5%	200	99
10%	238	124
30%	304	200
50%	341	261
15		
70%	374	337
90%	421	389
95%	443	413
FBP	491	485

HAGO feed (Comparative Example 1-A) and hydrotreated
HAGO (Example 1) were analyzed by GC-MS in order to determine
the structural types of the hydrocarbons present. These results
are shown in Table 2 below. The results clearly show that the
process of the present invention (Example 1) is effective at
reducing the aromatic content of hydrocarbon feed streams with
a concomitant rise in the quantity of both
paraffins/isoparaffins and naphthenes.

TABLE 2

Molecular Structural Types Observed in HAGO, HT-HAGO,
Hydrotreated HAGO and Distilled Saturated HT-HAGO

	HAGO (1-A)	Hydrotreated HAGO (Ex. 1)
30		
Relative Abundance of Various Molecular Types, Vol. %		
Paraffins/Isoparaffins	27.69	28.70
Naphthenes	38.87	41.29
35		
Aromatics	33.46	30.00

TABLE 3

**Laboratory Steam Cracking Yields for Gaseous
Products, Naphtha, Gas Oil, and Tar**

	Product Yield, wt. % Based on Feedstock	HAGO (1-A)	Hydrotreated HAGO (Ex. 1)
5	Total H ₂ and C ₁ -C ₄ Hydrocarbons	48.73	52.66
	Total Others, C ₅ and Greater	51.27	47.34
10	SCN, C ₅ -220°C (430°F)	23.54	29.50
	SCGO, 220-275°C (430-525°F)	4.83	6.06
	SCT, 275°C (526°F) and Above	22.90	11.78
	Total	100.0	100.0
	<u>Selected Gaseous Products</u>		
15	Hydrogen	0.39	0.46
	Methane	7.64	8.02
	Ethane	4.03	3.91
	Ethylene	14.39	16.54
	Acetylene	0.06	0.07
20	Propane	0.72	0.62
	Propylene	12.06	12.80
	Propadiene & Methylacetylene	0.18	0.18
	Butane & Isobutane	0.13	0.16
	Isobutylene	1.88	2.16
25	Butene-1	2.21	2.72
	Butadiene-1,3	3.32	3.74
	Butene-2 (cis & trans)	1.25	1.27
	C ₄ acetylenes	0.01	0.01
	<u>Selected Liquid Products</u>		
30	Isoprene	0.89	1.08
	Pentadiene (cis & trans)	0.74	0.95
	Cyclopentadiene	1.19	1.48
	Methylcyclopentadiene	0.81	1.06
	Benzene	3.35	3.88

35 As can be seen in Table 3 above, the yield of each of the particularly valuable steam cracked mono- and diolefin products in the H₂ and C₁-C₄ hydrocarbons fraction, i.e., ethylene, propylene, and butadiene, is increased by at least about 6.0 percent, the yield of each of the valuable steam

cracked diolefin and aromatic products in the steam cracked naphtha fraction, i.e., isoprene, cis-pentadiene, trans-pentadiene, cyclopentadiene, and benzene, is increased by at least about 15 percent, the yield of the steam cracked gas oil product is increased by about 25 percent and the yield of the low value steam cracked tar product is decreased by about 48 percent when the process of the present invention comprising hydrotreating and steam cracking (Example 1) is utilized relative to the yields obtained when the untreated hydrocarbon feed alone is subjected to steam cracking (Comparative Example 1-A).

Illustrative Embodiment 2

Example 2 and Comparative Example 2-A below were each carried out using a 100% Catalytically Cracked Naphtha (CCN) feedstock having the properties shown in Table 4 below. Example 2 illustrates the process of the present invention. Comparative Example 2-A is illustrative of CCN which has not been subjected to hydrotreating prior to steam cracking.

Example 2

Example 2 describes the process of the present invention using a 100% Catalytically Cracked Naphtha (CCN) feed.

A commercial alumina supported nickel/molybdenum catalyst (1/20" trilobe), available under the name of C-411 from Criterion Catalyst Company, was used as the first hydrotreating catalyst (catalyst A) while a commercial prototype hydroprocessing catalyst (1/8" cylinder), available under the name of HC-10 from Linde AG was used as the second hydrotreating catalyst (catalyst B).

The catalysts A and B were operated in the hydrotreating zone as a "stacked bed" wherein the feedstock and hydrogen were contacted with catalyst A first and thereafter with catalyst B; the volume ratio of the catalysts (A:B) in the hydrotreating zone was 2:1. The feed stock was hydrotreated at 370°C (700°F), 40.8 bar total unit pressure, an overall LHSV of 0.33 hr⁻¹ and a hydrogen flow rate of 2,900 SCF/BBL (0.52 m³/l).

Hydrotreating of the CCN feed consumed 860 SCF/BBL (0.15 m³/l) of hydrogen and resulted in the production of 0.9 percent by weight of light gases (methane, ethane, propane and butane) and 2.5 percent by weight of liquid hydrocarbon boiling between C₅ and 150°C (300°F).

The hydrotreated CCN was then passed to the steam cracking zone where it was contacted with steam at a temperature of 790 to 805°C, a pressure of between 1.22 to 1.39 bar, and a steam to hydrocarbon weight ratio of 0.3:1 to 0.45:1. The residence time in the steam cracker was 0.4 to 0.6 seconds. The steam cracked product was then sent to a fractionating zone to quantify total hydrogen (H₂) and C₁ -C₄) hydrocarbons, steam cracked naphtha (SCN), steam cracked gas oil (SCGO), and steam cracked tar (SCT). The steam cracking results are presented in Table 6 below.

Comparative Example 2-A

A 100% Catalytically Cracked Naphtha (CCN) feed was treated in the same manner as set forth in Example 2 above, except that it was not subjected to hydrotreating prior to steam cracking. The steam cracking results are presented in Table 6 below.

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TABLE 4

Properties of CCN Feed (Comp. Ex. 2-A) and Hydrotreated CCN (Ex. 2)

		CCN Feed (2-A)	Hydrotreated CCN (Ex. 2)
5	wt. % C	89.15	88.31
	wt. % H	10.31	11.78
	ppm wt. S	4,130	2
	ppm wt. N	217	<1
	Density, g/cm ³ @15°C	0.9071	0.8714
Simulated Distillation, D-2887 (ASTM), °C			
10	IBP	189	75
	5%	202	161
	10%	205	183
	30%	212	204
	50%	221	212
15	70%	230	223
	90%	236	235
	95%	242	244
	FBP	376	341

CCN Feed (Comparative Example 2-A) and the hydrotreated CCN (Example 2) were analyzed by GC-MS in order to determine the structural types of the hydrocarbons present. These results are shown in Table 5 below. As can be seen in Table 5, the process of the present invention (Example 2) is effective at reducing the aromatic content of hydrocarbon feed streams with a concomitant rise in the quantity of both paraffins/isoparaffins and naphthenes.

TABLE 5

Molecular Structural Types Observed in CCN Feed (Comp. Ex. 2-A) and Hydrotreated CCN (Ex. 2)

	Relative Abundance of Various Molecular Types, Vol. %	CCN Feed (2-A)	Hydrotreated CCN (Ex. 2)
30	Paraffins/Isoparaffins	7.97	10.92
	Naphthenes	5.19	26.79
	Aromatics	86.83	62.27

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TABLE 6

Laboratory Steam Cracking Yields for Gaseous Products
Naphtha, Gas Oil, and Tar

5	Product Yield wt. % Based on Feedstock	CCN Feed (2-A)	Hydrotreated CCN (Ex. 2)
	Total H ₂ and C ₁ -C ₄ Hydrocarbons	27.67	33.32
	Total Others C ₅ and Greater	72.33	66.68
	SCN, C ₅ -220°C (430°F)	40.85	35.79
	SCGO, 220-275°C(430-525°F)	7.75	12.00
10	SCT, 275°C (526°F) and Above	23.73	18.89
	Total	100.00	100.00
	<u>Selected Gaseous Products</u>		
	Hydrogen	0.65	0.74
	Methane	8.03	9.58
15	Ethane	1.91	2.66
	Ethylene	9.09	10.81
	Acetylene	0.08	0.09
	Propane	0.07	0.07
	Propylene	4.79	5.81
20	Propadiene & Methylacetylene	0.08	0.08
	Butane & Isobutane	0.03	0.02
	Isobutylene	0.87	0.91
	Butene-1	0.25	0.27
	Butadiene-1,3	1.28	1.53
25	Butene-2 (cis & trans)	0.32	0.43
	C ₄ acetylenes	0.00	0.00
	<u>Selected Liquid Products</u>		
	Isoprene	0.00	0.35
	Pentadiene (cis & trans)	0.13	0.15
30	Cyclopentadiene	0.49	0.80
	methylcyclopentadiene	0.10	0.00
	Benzene	2.79	4.03

As can be seen in Table 6 above, the yield of each of the particularly valuable steam cracked mono- and diolefin products in the H₂ and C₁-C₄ hydrocarbons fraction, i.e., ethylene, propylene, and butadiene, is increased by at least about 18 percent, the yield of each of the valuable steam cracked diolefin and aromatic products in the steam cracked naphtha fraction, i.e., isoprene, cis-pentadiene, trans-pentadiene, cyclopentadiene, and benzene, is increased by at

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least about 15 percent, the yield of the steam cracked gas oil product is increased by about 54 percent and the yield of the low value steam cracked tar product is decreased by about 20 percent when the process of the present invention comprising hydrotreating and steam cracking (Example 2) is utilized relative to the yields obtained when the untreated hydrocarbon feed alone is subjected to steam cracking (Comparative Example 2-A).

WHAT IS CLAIMED IS:

1. An integrated process for converting a cracked or uncracked hydrocarbon feedstock having components boiling above about 100°C into steam cracked products, which process comprises:

10 a) passing said hydrocarbon feedstock in the presence of a hydrogen source and two hydrotreating catalysts at least one of said hydrotreating catalysts being supported on an acidic zeolite molecular sieve, through a hydrotreating zone at an elevated temperature and a pressure from about 27 bar and about 85 bar to effect substantially complete decomposition of organic sulfur and/or nitrogen compounds contained therein;

15

b) passing the product from said hydrotreating zone to a steam cracking zone wherein said product is contacted with steam at temperatures greater than about 700°C; and

20

c) recovering hydrogen and C₁ -C₄ hydrocarbons, steam cracked naphtha, steam cracked gas oil and steam cracked tar therefrom, wherein the amount of steam cracked tar produced is reduced by at least about 15 percent, based on the starting hydrocarbon feedstock which has not been subjected to hydrotreating.

25

2. The process of claim 1 wherein said hydrocarbon feedstock has components boiling from about 150°C to about 650°C.

3. The process of claim 1 wherein said hydrotreating zone in step a) contains a first hydrotreating catalyst comprising a component selected from the group consisting of Group VIB metals, oxides and sulfides; Group VIII metals, oxides and sulfides; and mixtures thereof, supported on an amorphous carrier, and a second hydrotreating catalyst comprising a Group VIB component selected from the group consisting of tungsten, molybdenum and mixtures thereof, a Group VIII component selected from the group consisting of nickel, cobalt and mixtures thereof, and said acidic zeolite molecular sieve has a pore diameter greater than about six angstroms and is admixed with an inorganic oxide binder selected

30

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from the group consisting of alumina, silica, silica-alumina and mixtures thereof.

4. The process of claim 3 wherein said first hydrotreating catalyst and said second hydrotreating catalyst are arranged in said hydrotreating zone in a stacked bed configuration.

5. The process of claim 1 wherein said hydrotreating zone in step a) is operated at a temperature from about 200°C to about 550°C and a pressure from about 27 bar to about 68 bar.

10 6. The process of claim 1 wherein said hydrotreating zone in step a) is operated at a temperature from about 200°C to about 550°C and a pressure from about 27 bar to about 51 bar.

7. The process of claim 1 wherein said steam cracking zone in step b) is operated at a temperature greater than 15 about 700°C and a coil outlet pressure from about 0 bar to about 5 bar.

8. The process of claim 1 wherein said steam cracking zone in step b) is operated at a temperature from about 700°C to about 925°C and a coil outlet pressure from about 0 bar to 20 about 4 bar.

9. An integrated process for converting a cracked or uncracked hydrocarbon feedstock having components boiling above about 100°C into steam cracked products, which process comprises:

25 a) passing said hydrocarbon feedstock in the presence of a hydrogen source and a first hydrotreating catalyst through a first hydrotreating zone at an elevated temperature and a pressure from about 27 bar to about 85 bar to reduce the levels of organic sulfur and/or 30 nitrogen compounds contained therein,

b) passing the product from said first hydrotreating zone to a second hydrotreating zone wherein said product is contacted at a pressure of from about 27 bar to about 85 bar and a temperature from about 200°C to about 35 550°C with a hydrogen source and a second hydrotreating catalyst comprising one or more hydrogenating components selected from the group consisting of Group VIB metals, oxides, sulfides, Group VIII metals,

- oxides, sulfides and mixtures thereof supported on an acidic zeolite molecular sieve, to effect substantially complete decomposition of organic sulfur and/or nitrogen compounds contained in the product from the first hydrotreating zone,
- 5 c) passing the product from said second hydrotreating zone to a steam cracking zone wherein said product is contacted with steam at temperatures greater than about 700°C, and
- 10 d) recovering hydrogen and C₁-C₄ hydrocarbons, steam cracked naphtha, steam cracked gas oils and steam cracked tar therefrom, wherein the amount of steam cracked tar produced is reduced by at least about 15 percent, based on the starting hydrocarbon feedstock which
- 15 has not been subjected to hydrotreating.

10. The process of claim 9 wherein said hydrocarbon feedstock has components boiling from about 150°C to about 650°C.

11. The process of claim 10 wherein said first hydrotreating catalyst in step a) comprises a component selected from the group consisting of Group VIB metals, oxides and sulfides; Group VIII metals, oxides and sulfides; and mixtures thereof, supported on an amorphous carrier.

12. The process of claim 9 wherein said first hydrotreating zone in step a) is operated at a temperature from about 200°C to about 550°C and a pressure from about 27 bar to about 68 bar.

13. The process of claim 9 wherein said second hydrotreating catalyst in step b) comprises a Group VIB component selected from the group consisting of tungsten, molybdenum and mixtures thereof, a Group VIII component selected from the group consisting of nickel, cobalt and mixtures thereof, said molecular sieve has a pore diameter greater than about six angstroms and said molecular sieve is admixed with an inorganic oxide binder selected from the group consisting of alumina, silica, silica-alumina and mixtures thereof.

14. The process of claim 13 wherein the Group VIII component is nickel, the Group VIB component is selected from the group consisting of molybdenum, tungsten and mixtures thereof, the molecular sieve is zeolite Y and the binder is alumina.

15. The process of claim 9 wherein said second hydrotreating zone in step b) is operated at a temperature from about 200°C to about 550°C and a pressure from about 27 bar to about 68 bar.

5 16. The process of claim 9 wherein said steam cracking zone in step c) is operated at a temperature greater than about 700°C and a coil outlet pressure ranging from about 0 bar to about 5 bar.

10 17. The process of claim 9 wherein said steam cracking zone in step c) is operated at a temperature from about 700°C to about 925°C and a coil outlet pressure from about 0 bar to about 4 bar.