USE OF SYNGAS FOR THE UPGRADING OF HEAVY CRUDE AT THE WELLHEAD

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ABSTRACT

The present system may be used to hydroprocess heavy crude oil at the wellhead, effectively lowering the viscosity and removing contaminants such as sulfur, nitrogen and metal contents. The hydrogen source for hydroprocessing is the separated hydrogen product from the methane produced from a syngas plant.
FIG. 1
FIG. 2
USE OF SYNGAS FOR THE UPGRADING OF HEAVY CRUDE AT THE WELLHEAD

TECHNICAL FIELD OF THE INVENTION

[0001] The present invention relates to a process for the preparation of synthesis gas, i.e., a mixture of carbon monoxide and hydrogen, from natural gas. More particularly, this invention relates to a method for maximizing the hydrogen production in syngas. Still more particularly, the present invention relates to upgrading crude oil at the wellhead to utilize co-produced natural gas and increase the ease of transportation of the crude by reducing the viscosity and sulfur, nitrogen, and other contaminants.

BACKGROUND OF THE INVENTION

[0002] Large quantities of methane, the main component of natural gas, are available in many areas of the world, and natural gas is predicted to outlast oil reserves by a significant margin. However, most natural gas is situated in areas that are geographically remote from population and industrial centers. The costs of compression, transportation, and storage make its use economically unattractive. To improve the economics of natural gas use, much research has focused on the use of methane as a starting material for the production of higher hydrocarbons and hydrocarbon liquids, which are more easily transported and thus more economical. The conversion of methane to hydrocarbons is typically carried out in two steps. In the first step, methane is converted into a mixture of carbon monoxide and hydrogen (i.e., synthesis gas or syngas). In a second step, the syngas is converted into hydrocarbons.

[0003] This first step, the preparation of synthesis gas from natural gas, is well known in the art and usually referred to as syngas conversion. The amount of hydrogen and carbon in syngas depends on the process technology, feedstock, and the operating conditions used in its manufacture. Synthesis gas can be made from a wide variety of feedstocks including natural gas, liquefied petroleum gas (LPG), oil, coal and petroleum coke. Processes for converting these materials to syngas are steam methane reforming, CO₂ reforming, auto thermal reforming and partial oxidation or gasification using either air or pure oxygen.

[0004] The ratio of hydrogen to carbon monoxide can range as low as 0.6 with CO₂ reforming of natural gas or partial oxidation of petroleum coke to as high as 6.5 with steam methane reforming. When hydrogen is the desired product, the reforming reaction can be followed by the well-known water gas shift reaction (WGS) shown in Equation 1.

\[
CO + H₂O \leftrightarrow CO₂ + H₂
\]  

[0005] The WGS essentially converts all the carbon monoxide in the raw syngas to carbon dioxide, thereby maximizing the quantity of hydrogen produced. The shift reaction can likewise be avoided and the quantity of carbon monoxide maximized by selecting a feedstock with a higher carbon to hydrogen ratio or recycling carbon dioxide through the process. Although carbon monoxide can be maximized, hydrogen cannot be eliminated and is an inevitable byproduct of the process.

[0006] Current industrial use of methane as a chemical feedstock proceeds by the initial conversion of methane to carbon monoxide and hydrogen by either steam reforming, which is the most widespread process, or by dry reforming. Steam reforming currently is the major process used commercially for the conversion of methane to synthesis gas, proceeding according to Equation 2.

\[
CH₄ + H₂O \leftrightarrow CO + 3H₂
\]

[0007] Although steam reforming has been practiced for over five decades, efforts to improve the energy efficiency and reduce the capital investment required for this technology continue.

[0008] The catalytic partial oxidation (CPOX) of hydrocarbons, e.g., natural gas or methane to syngas is also a process known in the art. While currently limited as an industrial process, partial oxidation has recently attracted much attention due to significant inherent advantages, such as the fact that significant heat is released during the process, in contrast to steam reforming processes.

[0009] In catalytic partial oxidation, natural gas is mixed with air, oxygen-enriched air, or oxygen, and introduced to a catalyst at elevated temperature and pressure. The partial oxidation of methane yields a syngas mixture with a H₂:CO ratio of 2:1, as shown in Equation 3.

\[
CH₄ + 1/2O₂ \leftrightarrow CO + 2H₂
\]

[0010] This ratio is more useful than the H₂:CO ratio from steam reforming for the downstream conversion of the syngas to chemicals such as methanol and to fuels. The partial oxidation is also exothermic, while the steam reforming reaction is strongly endothermic. Furthermore, oxidation reactions are typically much faster than reforming reactions. This allows the use of much smaller reactors for catalytic partial oxidation processes. The syngas in turn may be converted to hydrocarbon products, for example, fuels boiling in the middle distillate range, such as kerosene and diesel fuel, and hydrocarbon waxes by processes such as the Fischer-Tropsch Synthesis.

[0011] The selectivities of catalytic partial oxidation to the desired products, carbon monoxide and hydrogen, are controlled by several factors, but one of the most important of these factors is the choice of catalyst composition. Typically, catalyst compositions have included precious metals and/or rare earths. The large volumes of expensive catalysts needed by prior art catalytic partial oxidation processes have placed these processes generally outside the limits of economic justification.

[0012] For successful operation at commercial scale, the catalytic partial oxidation process must be able to achieve a high conversion of the methane feedstock at high gas hourly space velocities, and the selectivity of the process to the desired products of carbon monoxide and hydrogen must be high. Such high conversion and selectivity must be achieved without detrimental effects to the catalyst, such as the formation of carbon deposits ("coking") on the catalyst, which severely reduces catalyst performance.

[0013] Accordingly, the economic evaluation for selection of a syngas process depends upon the required hydrogen to carbon monoxide molar ratio, availability and cost of hydrocarbon feedstocks and catalysts, availability and cost of oxygen and carbon dioxide, the cost of utilities and credits available for export steam and sale of excess hydrogen or carbon monoxide coproduct. This analysis is complex and
highly site dependent. Typically, petrochemical applications of syngas require a ratio of hydrogen to carbon monoxide of either 1:1 or 2:1. Commercial processes for syngas yield much higher ratios; therefore, separation technology, by-product credits and production techniques that can adjust the hydrogen to carbon monoxide ratio are important aspects of syngas production.

Presently, heavy crude oil presents processing problems in refineries due to high viscosities, sulfur, nitrogen, and metal contents. Because of environmental requirements, steps are often taken at the refinery to upgrade these crude oils by reducing their viscosity and contaminants. Treatment strategies range from blending lighter crudes with heavier crudes to hydroprocessing. These strategies, though effective, are expensive because they require additional intermediates, such as hydrogen, to be produced. Therefore, there exists a need for a method of upgrading heavy crude oil with an already existing hydrogen source.

SUMMARY OF THE INVENTION

The present invention relates to hydrotreating at the wellhead, using hydrogen produced from methane through the syngas process. As defined herein, the term “hydrotreating” is intended to be synonymous with the term “hydroprocessing,” which involves the reaction of hydrocarbons at operating conditions with hydrogen, usually in the presence of a catalyst. Included within the processes intended to be encompassed by the term “hydrotreating” are hydrotreating, aromatic hydrogenation, ring-opening, and hydrorefining, or hydrodesulfurization, hydrodenitration, and hydrotreatment. As will be recognized, one common attribute of these processes, and the reactions being effected therein, is that they are all “hydrogen-consuming,” and are, therefore, exothermic in nature. Although hydrotreating may be applied to any hydrocarbon feedstock, it is particularly applicable, though less easily applicable, to heavier feedstocks such as residua, vacuum and atmospheric gas oils, coal and shale liquids, etc., since these feedstocks typically contain higher concentrations of less easily removed contaminants.

Additionally, the term “catalytic partial oxidation”, or CPOX, when used in the context of the present syngas production methods, in addition to its usual meaning, can also refer to a net catalytic partial oxidation process, in which hydrocarbons (comprising mainly methane) and oxygen-containing gases (i.e. oxygen, oxygen-enriched air, air) are supplied as reactants and the resulting product stream is predominantly the partial oxidation products CO and H2, rather than the complete oxidation products CO2 and H2O. For example, the preferred catalysts serve in the short contact time process of the invention, which is described in more detail below, to yield a product gas mixture containing H2 and CO in a molar ratio of approximately 2:1. Although the primary reaction mechanism of the process is partial oxidation, other oxidation reactions may also occur in the reactor to a lesser or minor extent. As shown in Equation (2), the partial oxidation of methane yields H2 and CO in a molar ratio of 2:1.

As explained above, syngas technology can be shifted to produce larger amounts of hydrogen by varying the H2:CO ratio and additionally converting the remaining CO to CO2 and additional H2 using the water gas shift reaction. Utilization of the hydrogen from methane allows for a use of an otherwise wasted resource. Additionally, the produced CO2 from the water gas shift reaction can be injected into the formation as a CO2 flood.

In a preferred embodiment of the present invention, a method for upgrading heavy crude oils at the wellhead includes producing syngas in a syngas-producing process, separating the syngas into H2 and CO streams, and injecting the H2 stream into a hydroprocessing operation located at the wellhead. A hydroprocessing operation located at the wellhead is preferably within 100 miles of the wellhead, more preferably within 10 miles of the wellhead, and most preferably within a mile of the wellhead.

In an alternate embodiment of the present invention, a method for upgrading heavy crude oils at the wellhead includes producing syngas in a syngas-producing process, separating the syngas into H2 and CO streams, running the CO stream in the presence of a water feed through a water gas shift process to produce a water gas shift product of CO2 and additional H2, separating the water gas shift product into H2 and CO2 streams, and injecting the H2 streams into a hydroprocessing process located at the wellhead.

BRIEF DESCRIPTION OF THE DRAWINGS

For a more detailed understanding of the present invention, reference is now made to the accompanying figures, FIG. 1 and FIG. 2, which are schematic illustrations of first and second systems, respectively, constructed in accordance with the present invention.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

Because of the shrinking world supply of oils, oil processors are faced with the necessity of utilizing heavy feedstocks that are highly contaminated with sulfur, nitrogen and metal contents. In the processing of these feedstocks, it is very desirable to remove as much of the contaminants as early in the refining of these feedstocks as possible, so that downstream catalysts do not suffer build-up and consequent reduced activity. Removing contaminants also makes a higher quality final product that is less corrosive and less polluting when combusted.

Referring now to FIG. 1, one embodiment of the present system 100 preferably includes a syngas plant 10, a hydrogen separation unit 20, and a hydroprocessing plant 30. Methane and oxygen-containing gas stream 11 is fed into syngas plant 10 and reacts with a suitable catalyst to form a stream of hydrogen and carbon monoxide 12. Hydrogen and carbon monoxide stream 12 is fed into hydrogen separation unit 20, where it is separated into carbon monoxide export stream 13 and hydrogen stream 14. Hydrogen stream 14 is injected into hydroprocessing plant 30, located at the wellhead.

Referring now to FIG. 2, an alternate embodiment of the present system 200 preferably includes a syngas plant 10, a first hydrogen separation unit 20, a water gas shift reactor 40, a second hydrogen separation unit 50, and a hydroprocessing plant 30. In some embodiments, system 200 further includes a carbon dioxide compressor 60. Methane and oxygen stream 11 is fed into syngas plant 10 and
reacts with a suitable catalyst to form a stream of hydrogen and carbon monoxide. Hydrogen and carbon monoxide stream 12 is fed into first hydrogen separation unit 20, where it is separated into carbon monoxide stream 13 and hydrogen stream 14. Carbon monoxide stream 13 may either exit system 200 as export stream 13b or comprise carbon monoxide feed stream 13a for water gas shift reactor 40. In the latter embodiment, carbon monoxide stream 13a is recycled into water gas shift reactor with water feed 21 under water gas shift favorable conditions to produce hydrogen and carbon dioxide stream 22. Hydrogen and carbon dioxide stream 22 is fed into second hydrogen separation unit 50, where it is separated into carbon dioxide stream 23 and hydrogen stream 24. Hydrogen streams 14 and 24 are injected into hydroprocessing plant 30, located at the wellhead. Carbon dioxide stream 23 may either exit system 200 as export stream 23b or comprise carbon dioxide feed stream 23a for carbon dioxide compressor 60. The compressed CO₂ may then be injected into the wellhead to further upgrade the heavy oil.

[0024] In some embodiments, system 200 may include a syngas plant 10, a hydrogen separation unit 20, a water gas shift reactor 40, and a hydroprocessing plant 30. In these embodiments, the hydrogen separation unit separates both the hydrogen-carbon monoxide and the hydrogen-carbon dioxide streams into a hydrogen stream and a carbon monoxide-carbon dioxide stream. A carbon dioxide removal process such as membrane separation or an amine system may be utilized to separate the carbon monoxide from the carbon dioxide.

[0025] In some embodiments, the methane from the methane and oxygen-containing stream is associated gas. Associated gas is herein defined as gas co-produced from the same oil field or same wellhead being treated. In other embodiments, the methane from the methane and oxygen-containing stream is supplied via pipeline from other sources.

[0026] Process of Producing Syngas

[0027] A feed stream comprising a hydrocarbon feedstock and an oxygen-containing gas is contacted with a suitable syngas catalysts in a reaction zone maintained at partial oxidation-promoting conditions of temperature, pressure and flowrate, effective to produce an effluent stream comprising carbon monoxide and hydrogen. Preferably a millisecond contact time reactor is employed. The hydrocarbon feedstock may be any gaseous hydrocarbon having a low boiling point, such as methane, natural gas, associated gas, or other sources of light hydrocarbons having from 1 to 5 carbon atoms. The hydrocarbon feedstock may be a gas arising from naturally occurring reserves of methane which contain carbon dioxide. Preferably, the feed comprises at least 50% by volume methane, more preferably at least 75% by volume, and most preferably at least 80% by volume methane.

[0028] The hydrocarbon feedstock is in the gaseous phase when contacting the catalyst. The hydrocarbon feedstock is contacted with the catalyst as a mixture with an oxygen-containing gas, preferably pure oxygen. The oxygen-containing gas may also comprise steam and/or CO₂, in addition to oxygen. Alternatively, the hydrocarbon feedstock is contacted with the catalyst as a mixture with a gas comprising steam and/or CO₂.

[0029] Preferably, the methane-containing feed and the oxygen-containing gas are mixed in such amounts to give a carbon (i.e., carbon in methane) to oxygen (i.e., atomic oxygen) ratio from about 1.25:1 to about 3.3:1, more preferably, from about 1.3:1 to about 2.2:1, and most preferably from about 1.5:1 to about 2.2:1, especially the stoichiometric ratio of 2:1.

[0030] The process is operated at atmospheric or superatmospheric pressures, the latter being preferred. The pressures may be from about 100 kPa to about 12,500 kPa, preferably from about 130 kPa to about 10,000 kPa.

[0031] The process is preferably operated at catalyst temperatures of from about 600°C to about 1,200°C, preferably from about 700°C to about 1,100°C. The hydrocarbon feedstock and the oxygen-containing gas are preferably pre-heated before contact with the catalyst.

[0032] It will be understood that the selection of a catalyst or catalyst system requires many technical and economic considerations. The process of selecting a precious metal catalyst can be broken down into components. Key catalyst properties include high activity, high selectivity, high recycle capability and filterability. Catalyst performance is determined mainly by the precious metal component. A metal is chosen based both on its ability to complete the desired reaction and its inability to complete an unwanted reaction. Typical catalysts used in CPOX include metals from Group 6B, 7B, & 8B of the periodic table associated with promoters from Groups 1B through 8B, Groups 1A through 5A, and metals from the Lanthanide group.

[0033] Generally, catalysts are supported on a carrier material or support. The catalyst support may be any of a variety of materials that a catalytically active material is coated on. The catalyst support preferably allows for a high degree of metal dispersion. The choice of support is largely determined by the nature of the reaction system. The support catalyst is preferably stable under reaction and regeneration conditions. Further, it preferably does not adversely react with solvent, reactants, or reaction products.

[0034] Suitable supports include activated carbon, alumina, silica, silica-alumina, silicon carbide, carbon black, TiO₂, ZrO₂, CaCO₃, and BaSO₄, or stabilized forms of the aforementioned materials. Preferably, the catalytically active material is supported on either zirconia, stabilized zirconia, or alumina.

[0035] It will be understood that alternative choices of support may be made without departing from the preferred embodiments of the present invention by one of ordinary skill in the art. A support preferably favorably influences any of the catalyst activity, selectivity, recycling, refining, material handling reproducibility and the like. Properties of a support include surface area, pore volume, pore size, distribution, particle size, attrition resistance, acidity, basicity, impurity levels, and the ability to promote metal-support interactions. Metal dispersion increases with surface support area. Support porosity influences metal dispersion and distribution, metal sintering resistance, and intraparticle diffusion of reactants, products and poisons. Smaller support particle size increases catalytic activity but decreases filterability. The support preferably has desirable mechanical properties, attrition resistance and hardness. For example, an attrition resistant support allows for multiple catalyst recy-
clinging and rapid filtration. Further, support impurities preferably are inert. Alternatively, the support may contain promoters that enhance catalyst selectivity.

[0036] The catalysts used may be prepared by any of the methods known to those skilled in the art. By way of illustration and not limitation, such methods include impregnating the catalytically active compounds or precursors onto a support, extruding one or more catalytically active compounds or precursors together with support material to prepare catalyst extrudates, and/or precipitating the catalytically active compounds or precursors onto a support. Accordingly, supported catalysts may be used in the form of powders, particles, pellets, monoliths, honeycombs, packed beds, foams, and aerogels.

[0037] The hydrocarbon feedstock and the oxygen-containing gas may be passed over the catalyst at any of a variety of space velocities. Space velocities for the process (weight hourly space velocity), stated as normal liters of gas per kilogram of catalyst per hour, are from about 20,000 to about 100,000,000 NL/kg/h, preferably from about 50,000 to about 50,000,000 NL/kg/h. It is preferred that the residence time on the catalyst is about 10 milliseconds or less. Although, for ease in comparing with other syngas production systems, space velocities at standard conditions have been used to describe the present invention, it is well recognized in the art that residence times is the inverse of space velocity and that the disclosure of high space velocities equates to low residence times on the catalyst. Under these operating conditions a flow rate of reactant gases is preferably maintained sufficient to ensure a residence time of no more than 10 milliseconds with respect to each portion of reactant gas in contact with the catalyst. The product gas mixture emerging from the reactor is harvested and directly routed into hydrogen separation unit.

[0038] Process of Separating Hydrogen from Syngas/WGS Product

[0039] A preferred method for hydrogen separation employs pressure swing adsorption. At a high pressure, solid molecular sieves can absorb a greater quantity of certain gaseous components than others and absorb some compounds more strongly than others. For example, hydrogen is adsorbed less strongly than carbon monoxide and carbon dioxide, and the strength of adsorption of carbon monoxide and carbon dioxide increases with increasing molecular weight. As a result, at elevated pressures, hydrocarbons and other impurities are absorbed from a hydrogen-rich stream and most of the hydrogen passes through the system, leaving the impurities behind. Very high purity hydrogen can be produced this way. The hydrogen-rich stream can then be piped to a hydroprocessing unit. When the pressure on the system is reduced, the impurities adsorbed at high pressure are released from the solid adsorbent and purged.

[0040] Process of Upgrading Heavy Oil

[0041] In some embodiments of the present invention, hydrodesulfurization is the preferred process for removing undesirable compounds. In hydrodesulfurization, oil is combined with high-purity hydrogen, vaporized, and then passed over a catalyst such as tungsten, nickel, or a mixture of cobalt and molybdenum oxides supported on a carrier material such as alumina. Hydrodesulfurization is performed according to methods known to one of ordinary skill in the art. A general description of major considerations involved in performing hydrodesulfurization, and more generally hydrorefining, is given by W. S. Bland and R. L. Davidson. *Petroleum Processing Handbook*, Chapter 3 (1967). Operating temperatures are usually between 260° C and 425° C (500° F and 800° F) at pressures of 14 to 70 kilopounds per square centimeter (200 to 1,000 pounds per square inch). Operating conditions are set to facilitate the desired level of sulfur removal without promoting any change to the other properties of the oil.

[0042] The sulfur in the oil is converted to hydrogen sulfide, which is removed from the circulating hydrogen stream by absorption in a solution such as diethanolamine. The solution can then be heated to remove the sulfide and reused. The hydrogen sulfide recovered is useful for manufacturing elemental sulfur of high purity.

[0043] Hydrodenitification, a common process for removing nitrogen compounds and hydrodemetalation, a common process for removing metal contents, generally follow the same requirements as hydrodesulfurization.

[0044] CO₂ Flooding

[0045] According to some embodiments of the present invention, the CO product stream is fed into a water gas shift plant in the presence of water and operated at water gas shift favorable conditions. After the CO product has gone through the WGS, there will be CO₂ remaining. This CO₂ can be used to additionally upgrade the heavy oil; it is known to inject carbon dioxide, either alone or in conjunction with natural gas, either at high pressure or containing sufficient petroleum gases in the vapor phase to perform tertiary oil recovery. The carbon dioxide can greatly improve tertiary recovery, but the effort is not economical unless very large quantities of carbon dioxide are available at a reasonable price. Conventionally, most of the successful projects of this type depend on tapping and transporting (by pipeline) carbon dioxide from underground reservoirs. However, because CO₂ is a biproduct of our desired method to maximize hydrogen content, the cost is essentially the cost of separation of the hydrogen from the CO₂.

[0046] While the preferred embodiments of the invention have been shown and described, modifications thereof can be made by one skilled in the art without departing from the spirit and teachings of the invention. The embodiments described herein are exemplary only, and are not intended to be limiting. For example, while CPOX is preferably employed to produce syngas, any syngas-producing technology such as autothermal reforming (ATR) and steam reforming could be utilized. Many variations and modifications of the invention disclosed herein are possible and are within the scope of the invention. Accordingly, the scope of protection is not limited by the description set out above, but is only limited by the claims which follow, that scope including all equivalents of the subject matter of the claims. The disclosures of all patents, patent applications, and publications cited herein are incorporated by reference.
What is claimed is:

1. A method for upgrading heavy crude oils at the wellhead comprising:
   producing syngas in a syngas-producing process;
   separating the syngas into $\text{H}_2$ and $\text{CO}$ streams; and
   injecting the $\text{H}_2$ stream into a hydroprocessing operation
   located at the wellhead.

2. The method according to claim 1 wherein the syngas-producing operation
   is of a type selected from the group consisting of CPOX (catalytic partial oxidation), ATR (auto-
   thermal reforming), and steam reforming processes.

3. The method according to claim 2 wherein the syngas-
   producing process is CPOX.

4. The method according to claim 3 wherein a methane-
   containing gas and oxygen-containing gas feed is supplied to the
   CPOX process.

5. The method according to claim 4 wherein the methane-
   containing gas is associated gas co-produced from the oil well.

6. The method according to claim 4 wherein the methane-
   containing gas is supplied via pipeline from other sources.

7. The method according to claim 1 wherein a hydrogen
   separation process separates the syngas into $\text{H}_2$ and CO
   streams and optionally co-existing nitrogen streams.

8. The method according to claim 7 wherein the hydrogen
   separation process employs membrane separation technology.

9. The method according to claim 1 wherein the hydroprocessing
   operation is of a type selected from the group consisting of hydrogenation, hydrocracking, hydrodenitro-
   genation, hydrodemetalization, and hydrodesulfurization
   processes.

10. The method according to claim 9 wherein the hydroprocessing
    operation is hydrodesulfurization.

11. A method for upgrading heavy crude oils at the wellhead comprising:
    producing syngas in a syngas-producing process;
    separating the syngas into $\text{H}_2$ and CO streams;
    running the CO stream in the presence of a water feed
    through a water gas shift process to produce a water gas
    shift product comprising $\text{CO}_2$ and additional $\text{H}_2$;
    separating the water gas shift product into $\text{H}_2$ and $\text{CO}_2$
    streams; and
    injecting the $\text{H}_2$ streams into a hydroprocessing operation
    located at the wellhead.

12. The method according to claim 11 wherein the syngas-
    producing process is of a type selected from the group
    consisting of CPOX (catalytic partial oxidation), ATR (auto-
    thermal reforming), and steam reforming processes.

13. The method according to claim 12 wherein the syngas-
    producing process is CPOX.

14. The method according to claim 13 wherein a methane-
    containing gas and oxygen-containing gas feed is supplied to
    the CPOX process.

15. The process according to claim 14 wherein the methane-
    containing gas is associated gas co-produced from the oil well.

16. The process according to claim 14 wherein the methane-
    containing gas is supplied via pipeline from other sources.

17. The method according to claim 11 wherein a hydrogen
    separation process separates the syngas into $\text{H}_2$ and CO
    streams and optionally co-existing nitrogen streams.

18. The method according to claim 17 wherein the hydrogen
    separation process employs membrane separation technology.

19. The method according to claim 11 wherein the hydroprocessing
    process is of a type selected from the group consisting of hydrogenation, hydrocracking, hydrodenitro-
    genation, hydrodemetalization, and hydrodesulfurization
    processes.

20. The method according to claim 19 wherein the hydroprocessing
    process comprises a hydrodesulfurization process.

21. The method according to claim 19 further comprising
    feeding the product $\text{CO}_2$ into a carbon dioxide compressor.

22. The method according to claim 21 wherein the compressed
    $\text{CO}_2$ is injected into the formation via injection wells
    to facilitate movement of the crude oil to the producing
    wellhead.

23. A method for upgrading heavy crude oils at the wellhead comprising:
    producing syngas in a syngas-producing process running
    at CPOX favorable conditions with a methane-containing
    gas and oxygen-containing gas feed;
    separating the syngas into $\text{H}_2$ and CO streams; and
    injecting the $\text{H}_2$ stream into a hydroprocessing operation
    located at the wellhead.

24. A method for upgrading heavy crude oils at the wellhead comprising:
    producing syngas in a syngas-producing process running
    at CPOX favorable conditions with a methane-containing
    gas and oxygen-containing gas feed;
    separating the syngas into $\text{H}_2$ and CO streams;
    running the CO stream in the presence of a water feed
    through a water gas shift process to produce a water gas
    shift product comprising $\text{CO}_2$ and additional $\text{H}_2$;
    separating the water gas shift product into $\text{H}_2$ and $\text{CO}_2$
    streams; and
    injecting the $\text{H}_2$ streams into a hydroprocessing operation
    located at the wellhead.

25. A system for upgrading heavy crude oils at the wellhead comprising:
    providing a syngas-producing process running at CPOX
    favorable conditions with a methane-containing gas
    and oxygen-containing gas feed to produce syngas;
    providing a hydrogen separation process, wherein the
    syngas is separated into $\text{H}_2$ and CO streams; and
    providing a hydroprocessing process located at the
    wellhead, wherein the $\text{H}_2$ stream is injected.

26. A system for upgrading heavy crude oils at the wellhead comprising:
    providing a syngas-producing process running at CPOX
    favorable conditions with a methane-containing gas
    and oxygen-containing gas feed to produce syngas;
providing a first hydrogen separation process, wherein the syngas is separated into H₂ and CO streams;

providing a water gas shift process with a water feed and a recycle means for running the CO stream to the water gas shift process, wherein the water gas shift process produces a water gas shift product comprising additional H₂ and CO₂;

providing a second hydrogen separation process, wherein the water gas shift product is separated into additional H₂ and CO₂ streams; and

providing a hydroprocessing process located at the wellhead, wherein the H₂ streams are injected.

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