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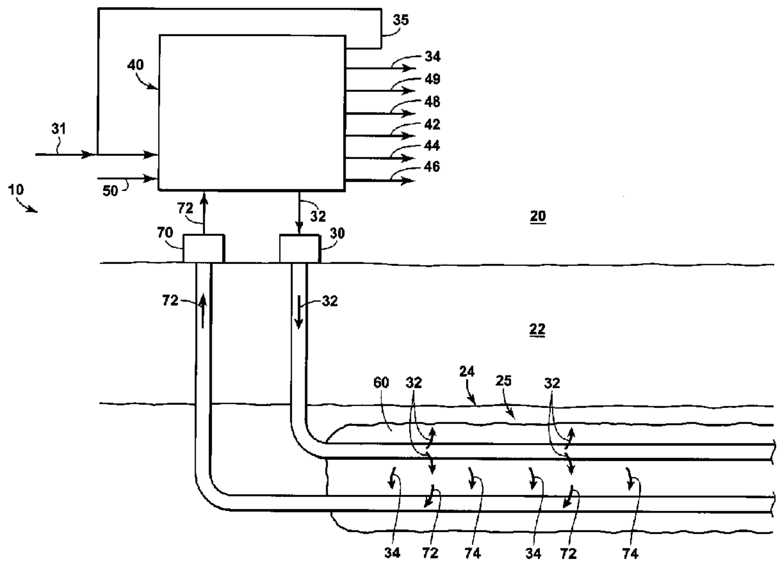
(54) Title: OPTIMIZATION OF GREENHOUSE GAS EMISSIONS IN A SOLVENT-BASED HEAVY OIL RECOVERY PROCESS



(57) Abrégé/Abstract:
The present disclosure comprises relating to the optimization, including preferably minimization, of greenhouse gas (GHG) emissions associated with the production of heavy oil from a subterranean reservoir in a solvent-based heavy oil recovery process. Optimization of GHG emissions is based on modifications to operating parameters associated with the process based on overall (or "total") GHG emissions intensity modeling based on the analysis of several key GHG emissions sources in the overall process as a function of the solvent fraction of the process injection fluid and/or the solvent composition of the process injection fluid. Solvent fractions and/or solvent compositions of the process injection fluid of the solvent-based heavy oil recovery process can then be adjusted or matched to a select range of solvent fractions and/or solvent compositions corresponding to the GHG emissions minima associated with the total GHG emissions intensity curves for the solvent-based heavy oil recovery process.

ABSTRACT

The present disclosure comprises relating to the optimization, including preferably minimization, of greenhouse gas (GHG) emissions associated with the production of heavy oil from a subterranean reservoir in a solvent-based heavy oil recovery process. Optimization of GHG emissions is based on modifications to operating parameters associated with the process based on overall (or "total") GHG emissions intensity modeling based on the analysis of several key GHG emissions sources in the overall process as a function of the solvent fraction of the process injection fluid and/or the solvent composition of the process injection fluid. Solvent fractions and/or solvent compositions of the process injection fluid of the solvent-based heavy oil recovery process can then be adjusted or matched to a select range of solvent fractions and/or solvent compositions corresponding to the GHG emissions minima associated with the total GHG emissions intensity curves for the solvent-based heavy oil recovery process.

OPTIMIZATION OF GREENHOUSE GAS EMISSIONS IN A SOLVENT-BASED HEAVY OIL RECOVERY PROCESS

BACKGROUND

Field of Disclosure

[0001] The present disclosure relates to the optimization, including preferably minimization, of greenhouse gas (GHG) emissions associated with the production of heavy oil from a subterranean reservoir in a solvent-based oil recovery process. Optimization of GHG emissions is based on modifications to operating parameters associated with the process based on overall GHG emissions modeling based on the analysis of several key GHG emissions sources in the overall process as a function of the solvent fraction of the injected fluid and/or solvent composition.

Description of Related Art

[0002] This section is intended to introduce various aspects of the art. This discussion is believed to facilitate a better understanding of particular aspects of the present techniques. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0003] Modern society is greatly dependent on the use of hydrocarbon resources for fuels and chemical feedstocks. Subterranean rock formations that can be termed "reservoirs" may contain resources such as hydrocarbons that can be recovered. Removing hydrocarbons from the subterranean reservoirs depends on numerous physical properties of the subterranean rock formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the subterranean rock formations, and the proportion of hydrocarbons present, among other things.

[0004] Easily produced sources of hydrocarbons are dwindling, leaving less conventional sources to satisfy future needs. As the costs of hydrocarbons increase, less conventional sources become more economical. One example of less conventional sources becoming more economical is that of oil sand production. The hydrocarbons produced from less conventional sources may have relatively high viscosities, for example, ranging from 1000 centipoise (cP) to 20 million cP with American Petroleum Institute (API) densities ranging from 8 degree (°) API, or lower, up to 20° API, or higher. The hydrocarbons recovered from less conventional sources may include heavy oil. However, the hydrocarbons produced from the less conventional sources may be difficult to recover using conventional techniques. For example, the heavy oil may be sufficiently viscous that economical production of the heavy oil from a subterranean formation (also referred to as a "subterranean reservoir" herein) is precluded.

[0005] Several conventional recovery processes, such as but not limited to thermal recovery processes, have been utilized to decrease the viscosity of the heavy oil. Decreasing the viscosity of the heavy oil may decrease a resistance of the heavy oil to flow and/or permit production of the heavy oil from the subterranean reservoir by piping, flowing, and/or pumping the heavy oil from the subterranean reservoir. While each of these recovery processes may be effective under certain conditions, each possess inherent limitations.

[0006] One of the conventional recovery processes utilizes steam injection. The steam injection may be utilized to heat the heavy oil to decrease the viscosity of the heavy oil. Water and/or steam may represent an effective heat transfer medium, but the pressure required to produce saturated steam at a desired temperature may limit the applicability of steam injection to high pressure operation and/or require a large amount of energy to heat the steam. Additionally, there are significant greenhouse gas (GHG) emissions relationships to the amount of heating required for the steam prior to injection.

[0007] Another of the conventional recovery processes utilizes cold and/or heated solvents. Cold and/or heated solvents may be injected into a subterranean reservoir as liquids and/or vapors to decrease the viscosity of heavy oil present within the subterranean reservoir. Traditionally, low molecular weight hydrocarbons (e.g., propane and/or butane) are injected into the subterranean reservoir as the cold and/or heated solvent. The injected solvent may dissolve the heavy oil, dilute the heavy oil, and/or transfer thermal energy to the heavy oil. Utilizing the cold and/or heated solvents may suffer from limited injection temperature and/or pressure operating ranges, and/or an inability to effectively decrease the viscosity of the heavy oil. In other recovery processes, the injected fluid may be substantially comprised of a hydrocarbon-based solvent and injected in a vaporized form. In hybrid steam-solvent recovery processes, the injected fluid is comprised of mixture of steam and solvent, in which the relative amount of steam to solvent, or "solvent fraction" of the injection fluid may be varied. The composition of the solvent may also be varied in the process.

[0008] However, in these solvent or steam-solvent (collectively "solvent-based") processes, a single solvent composition and/or a single solvent fraction is usually selected and maintained throughout the majority of the process. This is generally due to the lack of knowledge of changes that may be made in the process and the impact of process changes and/or operating parameter selections on the overall GHG emissions that are produced by the solvent-based hydrocarbon extraction process. Additionally, these operating parameters relationship to the overall GHG emissions produced may change over time, due to either internal factors, such as changes in the reservoir or well properties or operating conditions, or to external factors, such as the compositional selection and solvent fraction utilized as make-up solvents from sources separate to the reservoir operation or the impact of oil product produced from the reservoir. As such, without a comprehensive GHG emissions analysis of at least some of these reservoir variables and key performance indicators of the process, preferably performed over multiple periods of time, especially associated with changes in these internal and/or external factors, GHG emissions from the steam-solvent processes cannot be optimized, or preferably minimized, due use of non-optimal processing conditions.

[0009] A need therefore exists in the industry for improved technology, including technology for methods enabling the optimization of greenhouse gas (GHG) emissions from solvent-based (which includes steam-solvent) heavy oil recovery processes and associated systems. A need exists for a system of GHG emissions analysis of key emission sources as a function of the produced oil and modification of solvent fractions and/or solvent compositions in the injection fluids of the solvent-based heavy oil recovery processes/systems in order to optimize GHG emissions associated with the overall recovery process.

SUMMARY

[0010] It is an object of the present disclosure to provide systems and methods for the optimization of greenhouse gas (GHG) emissions from solvent-based heavy oil recovery systems based on the analysis of GHG emissions from individual sources of the overall solvent-based heavy oil recovery systems and processes.

[0011] In an embodiment herein is a method for optimizing GHG emissions from a solvent-based heavy oil recovery process for a subterranean reservoir, comprising:

a) determining a solvent having a first solvent composition to be modeled to be utilized as an injection fluid in the solvent-based heavy oil recovery process;

b) determining the GHG emissions for at least one key GHG emissions source of the solvent-based oil recovery process over a range of solvent fractions based on the first solvent composition;

c) selecting a range of solvent fractions near the solvent fractions associated with the GHG minimum emissions point;

d) selecting the solvent fraction of the injection fluid in the solvent-based heavy oil extraction process to be within the selected range of solvent fractions;

e) injecting the injection fluid containing the solvent and steam utilizing the selected solvent fraction into the subterranean reservoir.

[0012] In another embodiment herein the total GHG emissions intensity curve is based on the calculated GHG emissions intensity curve for at least one, more than one or all of the following key GHG emissions sources of the solvent-based heavy oil recovery process:

- the make-up solvent;
- the power demand;
- the solvent recovery unit (SRU); and
- the vaporization unit.

[0013] In another embodiment herein in step c), the selected range of solvent fractions is within +/- 20 vol% of the solvent fraction associated with the minimum GHG emissions intensity point.

[0014] In another embodiment herein in step c), the selected range of solvent fractions corresponds to a point on the total GHG emissions intensity curve that is within +/- 20% of the minimum GHG emissions intensity point.

[0015] The foregoing has broadly outlined the features of the present disclosure so that the detailed description that follows may be better understood. Additional features will also be described herein.

DESCRIPTION OF THE DRAWINGS

[0016] These and other features, aspects and advantages of the present disclosure will become apparent from the following description and the accompanying drawings, which are briefly discussed below.

[0017] Figure 1 is a simplified schematic representation of an example of a solvent-based heavy oil recovery system.

[0018] Figure 2 illustrates the normalized values of two (2) key performance indicators for an example early to mid-life subterranean reservoir operating in a solvent-based (steam-solvent) heavy oil recovery process as a function of the solvent fraction of the injection fluid.

[0019] Figure 3A illustrates a GHG emissions intensity curve of the make-up solvent component as a function of the solvent fraction of the injection fluid for an early to mid-life subterranean reservoir under exemplary solvent-based heavy oil recovery process conditions in accordance with the methods of the current disclosure.

[0020] Figure 3B illustrates a GHG emissions intensity curve of the power demand component as a function of the solvent fraction of the injection fluid for an early to mid-life subterranean reservoir under exemplary solvent-based heavy oil recovery process conditions in accordance with the methods of the current disclosure.

[0021] Figure 3C illustrates a GHG emissions intensity curve of a vaporization unit component of a surface facility as a function of the solvent fraction of the injection fluid for an early to mid-life subterranean reservoir under exemplary solvent-based heavy oil recovery process conditions in accordance with the methods of the current disclosure.

[0022] Figure 3D illustrates a GHG emissions intensity curve of the solvent recovery unit (SRU) component of a surface facility as a function of the solvent fraction of the injection fluid for an early to mid-life subterranean reservoir under exemplary solvent-based heavy oil recovery process conditions in accordance with the methods of the current disclosure.

[0023] Figure 3E illustrates a total GHG emissions intensity curve derived from the data in Figures 3A-3D in accordance with the methods of the current disclosure.

[0024] Figure 4A illustrates a GHG emissions intensity curve of the make-up solvent component as a function of the solvent fraction of the injection fluid for a late-life subterranean

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reservoir under exemplary solvent-based heavy oil recovery process conditions in accordance with the methods of the current disclosure.

[0025] Figure 4B illustrates a GHG emissions intensity curve of the power demand component as a function of the solvent fraction of the injection fluid for a late-life subterranean reservoir under exemplary solvent-based heavy oil recovery process conditions in accordance with the methods of the current disclosure.

[0026] Figure 4C illustrates a GHG emissions intensity curve of a vaporization unit component of a surface facility as a function of the solvent fraction of the injection fluid for a late-life subterranean reservoir under exemplary solvent-based heavy oil recovery process conditions in accordance with the methods of the current disclosure.

[0027] Figure 4D illustrates a GHG emissions intensity curve of the solvent recovery unit (SRU) component of a surface facility as a function of the solvent fraction of the injection fluid for a late-life subterranean reservoir under exemplary solvent-based heavy oil recovery process conditions in accordance with the methods of the current disclosure.

[0028] Figure 4E illustrates a total GHG emissions intensity curve derived from the data in Figures 4A-4D in accordance with the methods of the current disclosure.

DETAILED DESCRIPTION

[0029] For the purpose of promoting an understanding of the principles of the disclosure, reference will now be made to the features illustrated in the drawings and specific language will be used to describe the same. It will nevertheless be understood that no limitation of the scope of the disclosure is thereby intended. Any alterations and further modifications, and any further applications of the principles of the disclosure as described herein, are contemplated as would normally occur to one skilled in the art to which the disclosure relates. It will be apparent to those skilled in the relevant art that some features that are not relevant to the present disclosure may not be shown in the drawings for the sake of clarity.

[0030] At the outset, for ease of reference, certain terms used in this application and their meanings as used in this context are set forth. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication of issued patent. Further, the present techniques are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments, and terms or processes that serve the same or a similar purpose are considered to be within the scope of the present disclosure.

[0031] A "hydrocarbon" is an organic compound that primarily includes the elements hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. Hydrocarbons generally refer to components found in heavy oil or in oil sands. However, the techniques described herein are not limited to heavy oils, but may also be used with any number of other subterranean reservoirs. Hydrocarbon compounds may be aliphatic or aromatic, and may be straight chained, branched, or partially or fully cyclic.

[0032] "Bitumen" is a naturally occurring heavy oil material. Generally, it is the hydrocarbon component found in oil sands. Bitumen can vary in composition depending upon the degree of loss of more volatile components. It can vary from a very viscous, tar-like, semi-solid material to solid forms. The hydrocarbon types found in bitumen can include aliphatics, aromatics, resins, and asphaltenes. A typical bitumen might be composed of:

19 weight (wt.)% aliphatics (which can range from 5 wt.% - 30 wt.%, or higher);

19 wt.% asphaltenes (which can range from 5 wt.% - 30 wt.%, or higher);

30 wt.% aromatics (which can range from 15 wt.% - 50 wt.%, or higher);

32 wt.% resins (which can range from 15 wt.% - 50 wt.%, or higher); and

some amount of sulfur (which can range in excess of 7 wt.%).

[0033] The percentage of the hydrocarbon types found in bitumen can vary. In addition bitumen can contain some water and nitrogen compounds ranging from less than 0.4 wt.% to in excess of 0.7 wt.%. The metals content, while small, may be removed to avoid contamination of synthetic crude oil. Nickel can vary from less than 75 ppm (parts per million) to more than 200 ppm. Vanadium can range from less than 200 ppm to more than 500 ppm.

[0034] The term "heavy oil" includes bitumen, as well as lighter materials that may be found in a sand or carbonate reservoir. "Heavy oil" includes oils that are classified by the American Petroleum Institute (API), as heavy oils, extra heavy oils, or bitumens. Thus the term "heavy oil" includes bitumen. Heavy oil may have a viscosity of about 1000 centipoise (cP) or more, 10,000 cP or more, 100,000 cP or more or 1,000,000 cP or more. In general, a heavy oil has an API gravity between 22.3° API (density of 920 kilograms per meter cubed (kg/m^3) or 0.920 grams per centimeter cubed (g/cm^3)) and 10.0° API (density of 1,000 kg/m^3 or 1 g/cm^3). An extra heavy oil, in general, has an API gravity of less than 10.0° API (density greater than 1,000 kg/m^3 or greater than 1 g/cm^3). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water, and bitumen. The recovery of heavy oils is based on the viscosity decrease of fluids with increasing temperature (such as utilizing steam) or with dilution (such as by increasing solvent concentration). Once the viscosity of the heavy oils is reduced, the heavy oil is mobilized and can be recovered via a production well. When utilized in a gravity drainage based recovery process, the reduced viscosity makes the drainage quicker and therefore directly contributes to the recovery rate. A heavy oil may include heavy end components and light end components.

[0035] The term "asphaltenes" or "asphaltene content" refers to pentane insolubles (or the amount of pentane insoluble in a sample) according to ASTM D3279. Other examples of standard ASTM asphaltene tests include ASTM test numbers D4055, D6560, and D7061.

[0036] "Heavy end components" in heavy oil may comprise a heavy viscous liquid or solid made up of heavy hydrocarbon molecules. Examples of heavy hydrocarbon molecules include, but are not limited to, molecules having greater than or equal to 30 carbon atoms (C_{30}+). The amount of molecules in the heavy hydrocarbon molecules may include any number within or bounded by the preceding range. The heavy viscous liquid or solid may be composed of molecules that, when separated from the heavy oil, have a higher density and viscosity than a density and viscosity of the heavy oil containing both heavy end components and light end components. For example, in Athabasca bitumen, about 70 weight (wt.) % of the bitumen contains C_{30}+ molecules with about 18 wt. % of the Athabasca bitumen being classified as asphaltenes. The heavy end components may include asphaltenes in the form of solids or viscous liquids.

[0037] "Light end components" in heavy oil may comprise those components in the heavy oil that have a lighter molecular weight than heavy end components. The light end components may include what can be considered to be medium end components. Examples of light end components and medium end components include, but are not limited to, light and medium hydrocarbon molecules having greater than or equal to 1 carbon atom and less than 30 carbon atoms. The amount of molecules in the light and medium end components may include any number within or bounded by the preceding range. The light end components and medium end components may be composed of molecules that have a lower density and viscosity than a density and viscosity of heavy end components from the heavy oil.

[0038] A "fluid" includes a gas or a liquid and may include, for example, a produced or native reservoir hydrocarbon, an injected mobilizing fluid, hot or cold water, or a mixture of these among other materials. "Vapor" refers to steam, wet steam, and mixtures of steam and wet steam, any of which could possibly be used with a solvent and other substances, and any material in the vapor phase.

[0039] An "injection fluid" or "injection mixture" as used herein is a fluid which is injected into subterranean reservoir through an injection well which is generally designed to assist in reducing the viscosity of hydrocarbons (e.g., bitumen) located in the subterranean reservoir. The injection fluid may reduce the viscosity of the hydrocarbons located in the subterranean reservoir due to heat, dilution (or solvency), or a combination thereof. Unless otherwise stated, the injection fluid may be a gas, a liquid, or a combination thereof. In embodiments, unless otherwise stated, an "injection fluid" may comprise steam, a solvent, or a combination thereof, whereas an "injection mixture" will comprise steam and a solvent.

[0040] "Facility" or "surface facility" is a tangible piece of physical equipment through which fluids, including recovered heavy oil, are either produced from a subterranean reservoir or injected into a subterranean reservoir, or equipment that can be used to control production or completion operations. In its broadest sense, the term facility is applied to any equipment that may be present along the flow path between a subterranean reservoir and its delivery outlets. Facilities may comprise production wells, injection wells, well tubulars, wellbore head equipment, gathering lines, manifolds, pumps, compressors, separators, surface flow lines, steam generation plants, processing plants, and delivery outlets. In some instances, the term "surface facility" is used to distinguish from those facilities other than wells.

[0041] "Pressure" is the force exerted per unit area by the gas on the walls of the volume. Pressure may be shown in this disclosure as pounds per square inch (psi), kilopascals (kPa) or megapascals (MPa). "Atmospheric pressure" refers to the local pressure of the air. "Absolute pressure" (psia) refers to the sum of the atmospheric pressure (14.7 psia at standard conditions) plus the gauge pressure. "Gauge pressure" (psig) refers to the pressure measured by a gauge, which indicates only the pressure exceeding the local atmospheric pressure (i.e., a gauge pressure of 0 psig corresponds to an absolute pressure of 14.7 psia). The term "vapor pressure" has the usual thermodynamic meaning. For a pure component in an enclosed system at a given pressure, the component vapor pressure is essentially equal to the total pressure in the system. Unless otherwise specified, the pressures in the present disclosure are absolute pressures.

[0042] A "subterranean reservoir" is a subsurface rock or sand reservoir from which a production fluid, or resource, can be harvested. A subterranean reservoir may interchangeably be referred to as a subterranean formation. The subterranean formation may include sand, granite, silica, carbonates, clays, and organic matter, such as bitumen, heavy oil (e.g., bitumen), oil, gas, or coal, among others. Subterranean reservoirs can vary in thickness from less than one foot (0.3048 meters (m)) to hundreds of feet (hundreds of meters). The resource is generally a hydrocarbon, such as a heavy oil impregnated into a sand bed.

[0043] "Thermal recovery processes" include any type of hydrocarbon recovery process that uses a heat source to enhance the recovery, for example, by lowering the viscosity of a hydrocarbon. The processes may use injected mobilizing fluids, such as but not limited to hot water, wet steam, dry steam, or solvents alone, or in any combination, to lower the viscosity of the hydrocarbon. Any of the thermal recovery processes may be used in concert with solvents. For example, thermal recovery processes may include cyclic steam stimulation (CSS), steam assisted gravity drainage (SAGD), steam flooding, in-situ combustion and other such processes.

[0044] "Solvent-based recovery processes", "solvent-based heavy oil recovery processes", or the like includes any type of hydrocarbon recovery process that uses a solvent, at least in part, to enhance the recovery of heavy oil, for example, by lowering a viscosity of the in-situ hydrocarbon through dilution. Solvent-based recovery processes may be used in combination with other recovery processes, such as, for example, thermal recovery processes. In solvent-based recovery processes, a solvent is injected into a subterranean reservoir. The solvent may be heated or unheated prior to injection, may be a vapor, liquid, or a combination, and may be injected with or without steam. Solvent-based recovery processes may include, but are not limited to, solvent assisted cyclic steam stimulation (SA-CSS), solvent assisted steam assisted

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gravity drainage (SA-SAGD), solvent assisted steam flood (SA-SF), vapor extraction process (VAPEX), heated vapor extraction process (H-VAPEX), cyclic solvent process (CSP), heated cyclic solvent process (H-CSP), solvent flooding, heated solvent flooding, liquid extraction process, heated liquid extraction process, solvent-based extraction recovery process (SEP), thermal solvent-based extraction recovery processes (TSEP), and any other such recovery process employing solvents either alone or in combination with steam. A solvent-based recovery process may be a thermal recovery process if the injection mixture is heated prior to injection into the subterranean reservoir. The solvent-based recovery process may employ gravity drainage.

[0045] "Follow-up process" for the purpose of this specification is a process that may be utilized after a "Solvent-based recovery processes" in the later life (or "late life") stage of a subterranean reservoir and is defined as a switch to a different process which is directed to improving the recovery of the solvent remaining in the subterranean reservoir (while still also recovering heavy oil) that has been deposited into the subterranean reservoir by the solvent-based recovery process and has not been recovered. Examples of follow-up processes may include, but are not limited to, a steam assisted gravity drainage (SAGD) process, a solvent assisted cyclic steam stimulation (SA-CSS) process, a steam flood process, a solvent assisted steam flood (SA-SF) process, a solvent flood process, a heated vapor solvent flood process, a non-condensable gas (NCG) assisted steam process, a non-condensable gas (NCG) assisted solvent process, and a non-condensable gas (NCG) flood process.

[0046] "Transition criteria" for the purpose of this specification is the criteria utilized to switch from a "Solvent-based recovery process" to a "Follow-up process". The transition criteria may include a threshold fraction of the estimated original heavy oil in the subterranean reservoir that has been recovered. Examples of the threshold fraction include at least 10%, at least 20%, at least 30%, at least 40%, at least 50%, at least 60%, at least 70%, and/or at least 80% of the estimated original heavy oil in the subterranean reservoir.

[0047] "Greenhouse gas" or "GHG" for the purpose of this specification is carbon dioxide (CO_2). "Greenhouse gas emissions" or "GHG emissions" are the quantity of greenhouse gases that are emitted into the atmosphere by a process or process component as denoted herein. GHG emissions may also be expressed in a normalized value such as a total weight of GHG emissions per unit amount of produced oil.

[0048] "Solvent fraction" as utilized herein is the fraction by volume % (vol%) of a solvent (generally a hydrocarbon) in a mixture. Most notably, as used herein unless otherwise noted, the solvent fraction is the fractional amount (by vol%) of a solvent in a solvent-steam mixture at standard conditions.

[0049] "Make-up solvent" as used herein is the amount of new, additional solvent that is added to an injection fluid. Make-up solvent is generally expressed herein as the fraction (by vol%) of the total solvent injected (by injection rate) into the subterranean reservoir. The total solvent (or total solvent rate) is comprised of the recycled (or recovered) solvent and the makeup solvent. Since the amount of recycled (or recovered) solvent is generally less than the amount of total solvent, the make-up solvent is the amount of solvent added (by fraction of total solvent) to maintain a certain steam-to-solvent injection ratio in the injection fluid.

[0050] "Power demand" is the electricity use for the surface facility units such as pumps and compressors, which can be estimated based on total fluids in circulation for a recovery process.

[0051] "Solvent recovery unit" or "SRU" is the unit in a solvent-based extraction recovery processes which recovers solvent from the produced fluids (or a portion thereof) recovered from the subterranean reservoir and produces a recycled solvent that is reutilized in the injection fluid of the solvent-based extraction recovery process.

[0052] "Vaporization unit" is the portion of a solvent-based extraction recovery processes which vaporizes (which also includes partial vaporization) the injection fluid. In a steam-solvent process, the steam and solvent components may be vaporized separately as single components or after they have been combined in a mixture for use as an injection fluid.

[0053] "Produced oil" is the amount of oil produced (or "produced oil" herein) and includes all hydrocarbons produced from the reservoir, less the amount of recovered solvent from the reservoir.

[0054] "Oil Production Rate" (or "OPR") is the amount of oil produced (i.e., produced oil) from the reservoir per unit time. Herein the amount of oil produced (or "produced oil" herein) includes all hydrocarbons produced from the reservoir, less the amount of recovered solvent from the reservoir.

[0055] "Average Boiling Point", "average boiling point", or "ABP" is the temperature (in °C) at which 50 vol% of a substance or mixture boils (vaporizes) under standard atmospheric conditions. In the case of a solvent mixture as discussed herein, ABP of the solvent mixture is the temperature (in °C) at which 50 vol% of solvent mixture boils (vaporizes) under standard atmospheric conditions.

[0056] "Azeotrope" means the thermodynamic azeotrope as described further herein.

[0057] A "wellbore" is a hole in the subsurface made by drilling or inserting a conduit into the subsurface. A wellbore may have a substantially circular cross section or any other cross-sectional shape, such as an oval, a square, a rectangle, a triangle, or other regular or irregular shapes. The term "well," when referring to an opening in the formation or reservoir, may be used interchangeably with the term "wellbore." Further, multiple pipes may be inserted into a single wellbore, for example, as a liner configured to allow flow from an outer chamber to an inner chamber.

[0058] A "solvent extraction chamber" is a region of a subterranean reservoir containing heavy oil that forms around a well that is injecting solvent, which may additionally include other components such as steam or non-condensable gases (also termed herein as a "solvent injection mixture"), into the subterranean reservoir. The solvent extraction chamber has a temperature and a pressure that is generally at or close to a temperature and pressure of the solvent injection mixture injected into the subterranean reservoir. The solvent extraction chamber may form when heavy oil has, due to heat from the solvent injection mixture, dissolution within the solvent, combination with the solvent injection mixture components, and/or the action of gravity, at least partially mobilized through the pore spaces of the reservoir matrix. The mobilized heavy oil may be at least partially replaced in the pore spaces by solvent, thus forming the solvent chamber. The solvent chamber may contain liquid solvent, vapor solvent, condensed solvent, residual heavy oil, water, gas, non-condensable gas and/or a combination and/or mixture of them. In practice, layers in the subterranean reservoir containing heavy oil may not necessarily have pore spaces that contain 100 percent (%) heavy oil and may contain only 70 - 80 volume (vol.) % heavy oil with the remainder possibly being water. A water and/or gas containing layer in the subterranean reservoir may comprise 100% water and/or gas in the pore spaces, but generally contains 5 - 70 vol.% gas and 20 - 30 vol.% water with any remainder possibly being heavy oil.

[0059] A "vapor chamber" is a solvent extraction chamber that includes a vapor, or vaporous solvent. The vapor chamber may contain other gases including vapor water, and/or non-condensable gases. The vapor chamber may also contain vapor mixtures of water and solvent. The vapor chamber may also contain near-azeotropic or azeotropic vapor mixtures of water and solvent. Thus, when the solvent (or solvent injection mixture) is injected into the subterranean reservoir as a vapor, a vapor chamber may be formed around the well.

[0060] The terms "approximately," "about," "substantially," and similar terms are intended to have a broad meaning in harmony with the common and accepted usage by those of ordinary skill in the art to which the subject matter of this disclosure pertains. It should be understood by those of skill in the art who review this disclosure that these terms are intended to allow a description of certain features described and claimed without restricting the scope of these features to the precise numeral ranges provided. Accordingly, these terms should be interpreted as indicating that insubstantial or inconsequential modifications or alterations of the subject matter described and are considered to be within the scope of the disclosure. These terms when used in reference to a quantity or amount of a material, or a specific characteristic of the material, refer to an amount that is sufficient to provide an effect that the material or characteristic was intended to provide. The exact degree of deviation allowable may in some cases depend on the specific context.

[0061] The articles "the", "a" and "an" are not necessarily limited to mean only one, but rather are inclusive and open ended so as to include, optionally, multiple such elements.

[0062] As used herein, the phrase "at least one," in reference to a list of one or more entities should be understood to mean at least one entity selected from any one or more of the entity in the list of entities, but not necessarily including at least one of each and every entity specifically listed within the list of entities and not excluding any combinations of entities in the list of entities. This definition also allows that entities may optionally be present other than the entities specifically identified within the list of entities to which the phrase "at least one" refers, whether related or unrelated to those entities specifically identified. Thus, as a non-limiting example, "at least one of A and B" (or, equivalently, "at least one of A or B," or, equivalently "at least one of A and/or B") may refer, to at least one, optionally including more than one, A, with no B present (and optionally including entities other than B); to at least one, optionally including more than one, B, with no A present (and optionally including entities other than A);

to at least one, optionally including more than one, A, and at least one, optionally including more than one, B (and optionally including other entities). In other words, the phrases "at least one," "one or more," and "and/or" are open-ended expressions that are both conjunctive and disjunctive in operation. For example, each of the expressions "at least one of A, B and C," "at least one of A, B, or C," "one or more of A, B, and C," "one or more of A, B, or C" and "A, B, and/or C" may mean A alone, B alone, C alone, A and B together, A and C together, B and C together, A, B and C together, and optionally any of the above in combination with at least one other entity.

[0063] As used herein, the term "and/or" placed between a first entity and a second entity means one of (1) the first entity, (2) the second entity, and (3) the first entity and the second entity. Multiple entities listed with "and/or" should be construed in the same manner, i.e., "one or more" of the entities so conjoined. Other entities may optionally be present other than the entities specifically identified by the "and/or" clause, whether related or unrelated to those entities specifically identified. Thus, as a non-limiting example, a reference to "A and/or B," when used in conjunction with open-ended language such as "comprising" may refer to A only (optionally including entities other than B); to B only (optionally including entities other than A); to both A and B (optionally including other entities). These entities may refer to elements, actions, structures, steps, operations, values, and the like.

[0064] As used herein the terms "adapted" and "configured" mean that the element, component, or other subject matter is designed and/or intended to perform a given function. Thus, the use of the terms "adapted" and "configured" should not be construed to mean that a given element, component, or other subject matter is simply "capable of" performing a given function but that the element, component, and/or other subject matter is specifically selected, created, implemented, utilized, programmed, and/or designed for the purpose of performing the function. It is also within the scope of the present disclosure that elements, components, and/or other recited subject matter that is recited as being adapted to perform a particular function may additionally or alternatively be described as being configured to perform that function, and vice versa.

[0065] As used herein, the phrase, "for example," the phrase, "as an example," and/or simply the term "example," when used with reference to one or more components, features, details, structures, embodiments, and/or methods according to the present disclosure, are intended to convey that the described component, feature, detail, structure, embodiment, and/or method is an illustrative, non-exclusive example of components, features, details, structures, embodiments, and/or methods according to the present disclosure. Thus, the described component, feature, detail, structure, embodiment, and/or method is not intended to be limiting, required, or exclusive/exhaustive; and other components, features, details, structures, embodiments, and/or methods, including structurally and/or functionally similar and/or equivalent components, features, details, structures, embodiments, and/or methods, are also within the scope of the present disclosure. Any of the ranges disclosed may include any number within and/or bounded by the range given.

[0066] In the illustrative figures herein, in general, elements that are likely to be included are illustrated in solid lines, while elements that are optional may be illustrated in dashed lines. However, elements that are shown in solid lines may not be essential. Thus, an element shown in solid lines may be omitted without departing from the scope of the present disclosure.

[0067] Figures 1 through 4E provide illustrative, non-exclusive examples of systems according to the present disclosure, components of systems, data that may be utilized to select a composition of a hydrocarbon solvent mixture and or a reservoir injection mixture that may be utilized with systems, and/or methods, according to the present disclosure, of operating and/or utilizing systems. Elements that serve a similar, or at least substantially similar, purpose are labeled with like numbers in each of Figures 1 through 4E, and these elements may not be discussed in detail herein with reference to each of Figures 1 through 4E. Similarly, all elements may not be labeled in each of Figures 1 through 4E, but associated reference numerals may be utilized for consistency. Elements, components, and/or features that are discussed herein with reference to one or more of Figures 1 through 4E may be included in and/or utilized with any of Figures 1 through 4E without departing from the scope of the present disclosure.

[0068] Figure 1 is a non-limiting schematic representation of a hydrocarbon production system **10** that may be utilized with, may be included in, and/or may include the systems and methods according to the present disclosure. Figure 1 is utilized only to assist in explaining the details of the present disclosure, and is not meant to be limiting in any manner, including any limitations on reservoir or well configurations, solvent or steam usage or requirements, or overall recovery system and/or oil processing requirements. For purposes of illustration, the hydrocarbon production system **10** may include an injection well **30** and a production well **70**

that extend within a subterranean reservoir **24** that is present within a subsurface region **22** and/or that extend between a surface region **20** and the subterranean reservoir **24**. Hydrocarbon production system **10** may include a surface facility **40**. Surface facility **40** may be configured to receive a reservoir heavy oil product stream **72** from production well **70**. A reservoir heavy oil product stream **72** may be produced from the subterranean reservoir **24**. Surface facility **40** may be configured to provide a reservoir injection mixture **32** to injection well **30**.

[0069] The reservoir injection mixture (or "injection fluid") **32** may be in liquid form, vapor form, or both. The reservoir injection mixture preferably is comprised of a steam and a solvent mixture. The solvent mixture is comprised of hydrocarbons. In preferred embodiments, the solvent mixture is substantially comprised of hydrocarbons, or even essentially comprised of hydrocarbons. In the preferred processes herein, the normal boiling point of the solvent mixture is selected such as to minimize the greenhouse gas (GHG) emissions of the oil recovery process based on one or more process key performance indicators.

[0070] When the reservoir injection mixture **32** comprises a vaporous hydrocarbon solvent mixture, the solvent-based recovery process may be referred to as, or may be, a vapor extraction process (VAPEX). Preferably, the reservoir injection mixture **32** includes steam and a solvent mixture. Preferably the solvent mixture is comprised essentially of hydrocarbons. In a preferred embodiment, the steam and solvent mixture is within 30%+/-, 20%+/-, or 10%+/- of the azeotropic solvent molar fraction of the steam and the solvent mixture as measured at the reservoir operating pressure. Alternatively, molar fraction of solvent mixture in the solvent and steam injection mixture is 70-100%, 80-100%, or 90 to 100% of the azeotropic solvent molar fraction of the steam and the solvent mixture as measured at the reservoir operating pressure. Alternatively, the molar fraction of solvent mixture in the solvent and steam injection mixture is 70-110% of the azeotropic solvent molar fraction of the steam and the solvent mixture as measured at the reservoir operating pressure. In another preferred embodiment, the reservoir injection mixture is comprised of at least 80% by weight of the steam and the solvent mixture. In other preferred embodiments, the reservoir injection mixture is comprised of at least 90% or 95% by weight of the steam and the solvent mixture, more preferably, is comprised essentially of the steam and the solvent mixture.

[0071] In preferred embodiments, at least 90%, at least 95%, or essentially all (by weight) of the reservoir injection mixture is injected into the subterranean reservoir in vapor form. In other embodiments, at least 5 wt%, 10 wt%, 20 wt%, 40 wt%, 60 wt%, 75 wt%, 85 wt%, 90 wt% , 95 wt% or 99 wt% of the reservoir injection mixture is hydrocarbon compounds.

[0072] When the solvent-based recovery process is performed using heated solvent, the solvent-based recovery process may be referred to as a high temperature solvent (and/or vapor) solvent-based recovery process. The heated solvent may be injected into the subterranean reservoir at an injection temperature and an injection pressure. The injection temperature may be at, or near, a saturation temperature for the heated solvent at the injection pressure. When more than one solvent is utilized, the extraction process may be referred to as a multi-solvent-based recovery process and/or a multi-component solvent-based recovery process, which, at elevated temperatures, may be referred to as a high temperature multi-component solvent-based recovery process, which may be a high temperature multi-component vapor extraction process.

[0073] Once provided to subterranean reservoir **24**, the reservoir injection mixture **32** may combine with the bituminous hydrocarbon deposit **25** within a solvent extraction chamber **60**, may dilute the bituminous hydrocarbon deposit **25**, may dissolve in the bituminous hydrocarbon deposit **25**, and/or may dissolve the bituminous hydrocarbon deposit **25**, thereby decreasing the viscosity of the bituminous hydrocarbon deposit. When reservoir injection mixture **32** is a vaporous hydrocarbon solvent mixture, solvent extraction chamber **60** may be referred to as a vapor chamber **60**. The vaporous hydrocarbon solvent mixture may condense within vapor chamber **60**. When reservoir injection mixture **32** condenses, the hydrocarbon solvent mixture may release latent heat (or latent heat of condensation), transfer thermal energy to the subterranean reservoir, and/or generate a condensate **34**. Condensation of the reservoir injection mixture **32** may heat a bituminous hydrocarbon deposit **25** that may be present within the subterranean reservoir, thereby decreasing a viscosity of the bituminous hydrocarbon deposit. In embodiments, the subterranean reservoir operating temperature may be 30-250°C or 80-150°C. In further embodiments, the subterranean reservoir operating pressure may be 5-95% of a fracture pressure of the reservoir, or 0.2 to 4 MPa, or 1 to 2.5 MPa. Conversely, the subterranean reservoir operating pressure may be equal to the pressure of a gas cap in the subterranean reservoir, the pressure of a gas zone within the subterranean reservoir, the pressure of a bottom water zone in the subterranean reservoir, or the pressure of a mobile water zone within the subterranean reservoir.

[0074] The bituminous hydrocarbon deposit **25** may include bitumen, gaseous hydrocarbons, asphaltenes, and/or water. The reservoir injection mixture **32** and/or condensate **34** also may combine with, mix with, be dissolved in, dissolve, and/or dilute bituminous hydrocarbon deposit **25**, further decreasing the viscosity of the bituminous hydrocarbon deposit.

[0075] The energy transfer between the reservoir injection mixture **32** and bituminous hydrocarbon deposit **25** and/or the mixing of reservoir injection mixture **32** and/or condensate **34** with bituminous hydrocarbon deposit **25** may generate reduced-viscosity hydrocarbons **74**, which may flow to production well **70**. The reduced-viscosity hydrocarbons **74** may flow to production well **70** due to gravity. After flowing to production well **70**, a reservoir product stream **72** containing heavy oil is produced from the subterranean reservoir. The reduced-viscosity hydrocarbons **74** may have a lower viscosity than the hydrocarbons within the subterranean reservoir **24** had before the reservoir injection mixture **32** was injected into the subterranean reservoir **24**. The reservoir product stream **72** may comprise reduced-viscosity hydrocarbons **74**, asphaltenes, gaseous hydrocarbons, water, reservoir injection mixture **32**, and/or condensate **34** in any suitable ratio and/or relative proportion.

[0076] Surface facility **40** may process the reservoir product stream **72** and/or may separate the reservoir product stream **72** into one or more component streams prior to the product hydrocarbon stream being conveyed from the surface facility **40**. Surface facility **40** may separate reservoir product stream **72** into a bitumen product stream **42**, a gaseous hydrocarbon product stream **44**, an asphaltene product stream **48**, a solvent mixture **35**, a separated surplus solvent stream **49**, and/or a water product stream **46**, which may include water. The bitumen product stream **42** may include bitumen and/or asphaltenes. The gaseous hydrocarbon product stream **44** may include gaseous hydrocarbons. The asphaltene product stream **48** may include asphaltenes. The separated surplus solvent stream **49** may include a portion of hydrocarbon solvent mixture **32** that was produced with the reservoir heavy oil product stream **72**. The surplus solvent stream **49** may be referred to as an undesired solvent stream, an unwanted solvent stream, and/or an excess solvent stream. Surplus solvent stream **49** may be generated as a result of adjustments to the solvent mixture composition. Surplus solvent stream **49** may be generated as a result of removing some of the solvents in the reservoir product stream **72** that are not wanted or desired to be in the solvent mixture **35** or the reservoir injection mixture

32. The surplus solvent stream **49** may be mixed as a diluting agent, blending agent, and/or viscosity-reducing agent with the bitumen product stream **42** to facilitate shipment by pipelines.

[0077] Surface facility **40** may generate a solvent mixture **35** from any suitable source. In most operations at least a portion of the solvent mixture **35** is recovered from the subterranean reservoir in a solvent recovery unit ("SRU"). The SRU (not separately shown) may be a subcomponent of the surface facility **40**. The solvent recovered from by the SRU is recycled to the solvent mixture **35** for reuse as a solvent in the solvent-based hydrocarbon recovery processes herein. The solvent mixture **35** may comprise hydrocarbons that have been produced by a source separate from the subterranean reservoir. For example, the solvent mixture may comprise a natural gas liquid, a natural gas condensate, a liquefied petroleum gas, or a crude oil refinery naphtha. Surface facility **40** may receive a supplemental solvent stream **31** and/or may supply at least a portion of the solvent mixture **35** recovered from the reservoir product stream **72** as a part of the reservoir injection stream **32** to injection well **30**. Surface facility **40** may separate at least a portion of gaseous hydrocarbon product stream **44**, solvent mixture **35**, and/or condensate **34** from the reservoir product stream **72**. Surface facility **40** may recycle and/or re-inject a portion of the gaseous hydrocarbon product stream **44**, separated solvent mixture **35**, and/or separated condensate **34** into injection well **30** as components of the reservoir injection mixture **32**. Additional steam **50** may be added to the surface facility **40** and/or injected directly as part of the reservoir injection stream **32**. The solvent mixture **35** may additionally include a supplemental solvent stream **31**. The composition of the supplemental solvent stream **31** may be similar in composition to the solvent mixture **35** wherein its main purpose is to add additional solvent to the solvent mixture **35** for the reservoir injection mixture **32**. Alternatively, the supplemental solvent stream **31** may be tailored to adjust the composition of the overall solvent mixture **35** for the reservoir injection mixture **32**, as well as additionally supply additional solvent to the overall process to make up for losses in the subterranean reservoir and/or losses due to the surface facility processing and solvent recovery.

[0078] In an embodiment, at least a portion of the reservoir product stream **72** is sent to a solvent recovery unit (SRU) (not separately shown, but may be a component of the surface facility **40**) which separates the product stream into the bitumen (or heavy oil) product stream **42** and the solvent mixture **35**, the latter of which may recycled for injection into the solvent-based oil recovery process. In other embodiments, the SRU may contain a single stage flash unit or a multistage flash unit which separates the product stream into the heavy oil product stream **42**, the recovered solvent mixture **35**, and the separated surplus solvent stream **49**. The flash unit may be a two-stage flash unit. In other embodiments, at least a portion of the reservoir product stream **72** may be sent to a separation unit comprising a multistage distillation unit which separates the product stream into the heavy oil product stream **42**, the solvent mixture **35**, and the separated surplus solvent stream **49**. In any of these embodiments, the operational variables of the single stage flash unit, the multistate flash unit, or the multistage distillation unit may be regulated to tailor the composition of the solvent mixture **35** to the recommend range of the solvent normal boiling point by the this disclosed method. The operational variables may include the flash temperature and pressure in each flash units. In preferred embodiments, the operational variables of the single stage flash unit, the multistate flash unit, or the multistage distillation unit are regulated to match the composition of the solvent mixture to an optimized normal boiling point range for the process.

[0079] Conventional recovery processes that utilize an injected vapor stream to decrease the viscosity of hydrocarbons may utilize a pure (i.e., single-component), or at least substantially pure, injected vapor stream that comprises a light hydrocarbon, such as propane. In contrast, the systems and methods according to the present disclosure may utilize a solvent mixture **35**. The solvent mixture **35** may include a hydrocarbon fraction that comprises, consists of, or consists essentially of C_4 to C_{12} hydrocarbons, or C_5 to C_9 hydrocarbons. The solvent mixture **35** may include a hydrocarbon fraction that comprises, consists of, or consists essentially of at least one of alkanes, iso-alkanes, naphthenic hydrocarbons, aromatic hydrocarbons, and olefin hydrocarbons. Supplemental solvent stream **31** may be tailored to adjust the composition of the solvent mixture **35** to within the solvent specification as required herein for optimizing overall GHG emissions for the associated processes. As such, the supplemental solvent stream **31** may include a hydrocarbon fraction that comprises, consists of, or consists essentially of C_4 to C_{12} hydrocarbons, or C_5 to C_9 hydrocarbons. Additionally, or alternatively, the supplemental solvent stream **31** may include a hydrocarbon fraction that comprises, consists of, or consists essentially of at least one of alkanes, iso-alkanes, naphthenic hydrocarbons, aromatic hydrocarbons, and olefin hydrocarbons.

[0080] Theoretically, available solvents to use in present solvent-based oil recovery processes can range from light hydrocarbon mixtures such as natural gas liquids (NGLs) and liquefied petroleum gases (LPGs) to heavy fractions such as different refinery streams. The concept disclosed herein proposes a new methodology for selecting parameters of a solvent-based oil recovery process and determining an optimum range of solvent fraction to be utilized in the injection fluid and/or determining an optimum range of the potential injection solvent fraction and/or the average boiling point (ABP) in order to optimize (or minimize) total GHG emissions from the solvent-based hydrocarbon extraction process. This concept relies on: 1) determining at least one solvent composition to be modeled, 2) determining the GHG emissions for at least one key GHG emissions source over a range of solvent fractions based on the at least one solvent composition; 3) selecting a range of solvent fractions near the GHG minimum emissions point based on the at least one key GHG emissions sources; and 4) tailoring the solvent fraction of the injected fluid in the solvent-based hydrocarbon extraction process to be within a certain envelope from the GHG minimum emissions point. In other embodiments (as disclosed later herein), step 4) can be replaced by, or additionally include, tailoring the composition of the solvent fraction of the injected fluid in the solvent-based heavy oil extraction process to operate within a certain envelope from the GHG minimum emissions point.

[0081] Figure 2 helps illustrate an underlying concept of the present disclosure. Figure 2 illustrates the normalized values of two (2) key performance indicators for an exemplary early to mid-life subterranean reservoir operating in a solvent-based (steam-solvent) heavy oil recovery process plotted as a function of the solvent fraction of the injection fluid. As shown in Figure 2, for the modeled steam-solvent recovery processes, energy intensity ("energy intensity" = Excess energy delivered to the reservoir (Energy In – Energy Out) for producing a volume of oil) and solvent retention ("solvent retention" = retained vol% of solvent in the reservoir for producing a volume of oil) operate inversely of one another. The values of these two (2) key performance indicators as a function of volume fraction are shown as "normalized" values in Figure 2 (i.e., the values shown are actual values divided by their corresponding maximum values). The decreasing trend for energy intensity can be explained by reducing steam fraction and replacing it with hydrocarbon solvent which takes advantage of dilution in addition to heat to decrease the bitumen viscosity. To comprehend the solvent retention pattern, one needs to recognize the solvent-steam azeotropic point. Consider compositions with a solvent volume fraction less than the azeotropic amount. As the mixture loses heat at constant pressure, the vapor phase gets richer in solvent while the liquid phase consists primarily of water. Thus when tracing this path, little to no solvent condenses and the solvent remains primarily in the vapor phase. The majority of solvent retention incurs in the case and in the form of the solvent rich liquid phase condensation. So in order to minimize the solvent retention within the chamber, compositions with a solvent fraction lower than the azeotropic condition are desirable anywhere in the chamber.

[0082] In thermal recovery processes (such as the steam-solvent recovery processes discussed herein), the energy intensity for vaporization is proportional to the required amount of fuel utilized in the heaters for vaporization of the injection fluid and consequently proportional to GHG direct emission for the vaporization unit. As a result, the reduction in energy intensity with increased solvent content results in reduction in GHG direct emission. While SRU energy intake increases with solvent concentration, it is a minor contributor to direct GHG emission. Therefore, direct GHG emission intensity in a steam-solvent (or solvent-based) hydrocarbon recovery process is a strong function of the amount of solvent injected into the subterranean reservoir during the process.

[0083] In preferred embodiments, the key GHG emissions sources of the recovery process for determining the GHG emissions as a function of the solvent fraction in the processes as utilized herein are considered as: 1) the make-up solvent, 2) the power demand, 3) the solvent recovery unit (SRU), and 4) the vaporization unit. The make-up solvent and the power demand are considered parameters of the process which produce "indirect" GHG emissions. This is because, while these components are part of the overall GHG emissions for the process, the GHG emissions accounted for in these parameters (i.e., emissions sources) occurs outside of the direct operation of the surface facility (see element **40** of Figure 1), such as GHG emissions associated with the production and transportation of the makeup solvent and the GHG emissions associated with producing electricity for the power demand of the surface facilities. In contrast, the solvent recovery unit (SRU) and the vaporization unit are considered parameters of the process which produce "direct" GHG emissions, as most of the energy (and thus the associated GHG emissions) are produced in these units that are a part of the surface facility unit associated with the solvent-based hydrocarbon recovery processes herein.

[0084] Figures 3A-3D show the analytical modeling analysis and numerical simulation results illustrate this concept by plotting the indirect and direct GHG emissions intensities as a function of solvent fraction for the key GHG emissions sources. In each of these figures, the GHG for each source is normalized as a "GHG Emissions Intensity" in tonnes of CO2 emissions per barrel of produced oil. Figure 3A illustrates the GHG emissions intensity of the make-up solvent component as a function of the solvent fraction of the injection fluid for an early to mid-life subterranean reservoir under exemplary solvent-based hydrocarbon recovery process conditions in accordance with the methods of the current disclosure. Figure 3B illustrates the GHG emissions intensity of the power demand component as a function of the solvent fraction of the injection fluid for an early to mid-life subterranean reservoir under exemplary solvent-based hydrocarbon recovery process conditions in accordance with the methods of the current disclosure. Figure 3C illustrates the GHG emissions intensity of a vaporization unit component of a surface facility as a function of the solvent fraction of the injection fluid for an early to mid-life subterranean reservoir under exemplary solvent-based hydrocarbon recovery process conditions in accordance with the methods of the current disclosure. Figure 3D illustrates the GHG emissions intensity of the solvent recovery unit (SRU) component of a surface facility as a function of the solvent fraction of the injection fluid for an early to mid-life subterranean reservoir under exemplary solvent-based hydrocarbon recovery process conditions in accordance with the methods of the current disclosure.

[0085] Since all of these GHG emission components are plotted on a common normalized basis of GHG emissions intensity as a function of solvent fraction, a total GHG emissions intensity curve can be generated which is derived by adding four the GHG emission sources over the solvent concentration range. For a set solvent composition, there is an optimum range for solvent concentration of a solvent-steam recovery process at which the total GHG emission intensity is minimized. Figure 3E illustrates the total GHG emissions intensity curve derived from the data in Figures 3A-3D in accordance with the methods of the current disclosure. The data shown in these figures was based on a solvent composition of a diluent with a boiling point range near that of hexane.

[0086] While in practice, the accuracy of the total GHG emissions intensity curve is best derived by looking at a combination of the data from all four (4) key GHG emissions sources, it is noted that for rougher calculations/estimations, the total GHG emissions intensity curve may be derived from only one or more of the four (4) key GHG emissions sources. In particular it has been noted in this example herein that the make-up solvent component and the vaporization component of the calculations appear to be the most significant source components to the total GHG emissions intensity curve values. However, such relationships may change significantly based on specific well configurations, associated solvent-based processes and systems, as well as the "stage" or "life" of the subterranean reservoir system. As such, for example, an embodiment herein could include wherein the total GHG emissions intensity curve is derived only from the make-up solvent component and the vaporization component curves with the understanding that some accuracy in the total GHG emissions intensity values may be lacking.

[0087] In a similar manner, that while preferred, it is not necessary that the GHG emissions intensity calculations be performed over the entire range of solvent fractions. It is just necessary that the minimum GHG emissions intensity point be calculated as well as some amount of tolerance above and below this minimum that falls within a desired tolerance window be calculated.

[0088] In practice as disclosed herein, in preferred embodiments, a total GHG emissions intensity curve is generated for a set solvent composition and the minimum GHG emissions intensity point is determined. The solvent fraction is then selected from a desired tolerance window with respect to the minimum GHG emissions intensity point. This point will correspond to both 1) a minimum GHG emissions intensity point as defined by the total GHG emissions intensity curve, and 2) a corresponding solvent fraction. While the exact minima may not be practically achievable, in one embodiment, it is desired that the solvent fraction is adjusted or chosen for the solvent-based extraction process and such that it is within +/- 20 vol%, +/- 10 vol%, or +/- 5 vol% of solvent fraction associated with the minimum GHG emission intensity point. In other embodiments, it is desired that the solvent fraction is adjusted or chosen and such that it corresponds to a point on the total GHG emissions intensity curve that is within +/- 20%, +/- 10%, or +/- 5% of the minimum GHG emissions intensity point.

[0089] It should also be noted that the curves for the four (4) key GHG emissions sources may be run for different solvent compositions and multiple Total GHG Emissions Intensity curves be generated. The solvent composition with the lowest GHG emission intensity point may be chosen and the solvent composition be adjusted or chosen such that it is within a desired tolerance window with respect to the solvent composition with the lowest minimum GHG emissions intensity point. In this case, the solvent composition would be defined by the average boiling point (ABP) of the solvent composition. In embodiments herein, the average boiling point range for the optimum solvent composition may fall within 100 °C +/-, 75 °C +/-, 50 °C +/- , 25 °C +/-, or 5 °C +/- of the average boiling point of the solvent composition corresponding to the lowest minimum GHG emissions intensity point calculated from the multiple total GHG emissions intensity curves. The solvent fraction can then, optionally, be adjusted to fall within the tolerances discussed with respect to the total GHG emissions intensity curve associated with the lowest minimum GHG emissions intensity point calculated from the multiple total GHG emissions intensity curves as discussed prior.

[0090] The processes described herein can be done at multiple stages in the life of the well. The following example with respect to Figures 4A-4E illustrates how, although the analyses and processes previously described remains the same, due to a changes in the conditions of the subterranean reservoir over time, the results of GHG emissions intensity analysis may change. Figures 4A-4D show the GHG emissions intensity curves for a subterranean reservoir in a late-life stage of operation. In the last phase ("late-life") of a solvent-based hydrocarbon extraction process, late-life solvent recovery strategies (e.g. blow down or wind down) are typically utilized to minimize solvent retention in the reservoir. Figures 4A-4D illustrate the GHG emissions intensity curves derived from the analytical modeling analysis and numerical simulation results of the four (4) key GHG emissions sources described prior.

[0091] Figure 4A illustrates the GHG emissions intensity of the make-up solvent component as a function of the solvent fraction of the injection fluid in the late-life phase in accordance with the methods of the current disclosure. Figure 4B illustrates the GHG emissions intensity of the power demand component as a function of the solvent fraction of the injection fluid in the late-life phase in accordance with the methods of the current disclosure. Figure 4C illustrates the GHG emissions intensity of the vaporization unit component as a function of the solvent fraction of the injection fluid in the late-life phase in accordance with the methods of the current disclosure. Figured 4D illustrates the GHG emissions intensity of the solvent recovery unit (SRU) component as a function of the solvent fraction of the injection fluid in the late-life phase in accordance with the methods of the current disclosure. Similar to Figure 3E, Figure 4E illustrates the total GHG emissions intensity curve derived from the data in Figures 4A-4D in accordance with the methods of the current disclosure. As can be seen, from Figures 4A-4D, the total GHG emissions intensity (Figure 4E) is mainly driven by direct

GHG emissions of vaporization given that indirect GHG emissions of make-up solvent now minimized in this late stage operation. It can further be seen how the minima of the total GHG emissions intensity has changed in this analysis from about 65% solvent fraction in early life (Figure 3E) to about 70% solvent fraction in late life (Figure 4E) of the subterranean solvent-based extraction processes. The data shown in Figures 4A-4E was based on the solvent composition as modeled in Figures 3A-3E.

[0092] As the examples in Figures 3A-3E and 4A-4E illustrate, the methods herein can be used to optimize solvent-based heavy oil recovery process in early-life or mid-life of a subterranean reservoir, but also can additionally be utilized to determine which of possible late-life "follow-up processes" should be selected and transitioned to optimize or even minimize GHG emissions. Examples of follow-up processes may include, but are not limited to, a steam assisted gravity drainage (SAGD) process, a solvent assisted cyclic steam stimulation (SA-CSS) process, a steam flood process, a solvent assisted steam flood (SA-SF) process, a solvent flood process, a heated vapor solvent flood process, a non-condensable gas (NCG) assisted steam process, a non-condensable gas (NCG) assisted solvent process, and a non-condensable gas (NCG) flood process. The methods herein can be utilized to determine which of possible late-life "follow-up processes" that are solvent-based may be selected and transitioned to from a solvent-based heavy oil recovery process. Examples of follow-up solvent-based processes to which the GHG emissions analyses disclosed here can apply include, but are not limited to, a solvent assisted cyclic steam stimulation (SA-CSS) process, a solvent assisted steam flood (SA-SF) process, a solvent flood process, a heated vapor solvent flood process, and a non-condensable gas (NCG) assisted solvent process. In preferred embodiments herein, the transitioning may occur when a transition criteria is reached in the operation of the subterranean reservoir. The transition criteria may include a threshold fraction of the estimated original heavy oil in the subterranean reservoir that has been recovered. Examples of the threshold fraction include at least 10%, at least 20%, at least 30%, at least 40%, at least 50%, at least 60%, at least 70%, and/or at least 80% of the estimated original heavy oil in the subterranean reservoir.

[0093] In the present disclosure, several examples have been discussed and/or presented in the context of flow diagrams, or flow charts, in which the methods are shown and described as a series of blocks, or steps. Unless specifically set forth in the accompanying description, the

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order of the blocks may vary from the illustrated order in the flow diagram, including with two or more of the blocks (or steps) occurring in a different order and/or concurrently.

Industrial Applicability

[0094] The systems and methods disclosed in the present disclosure are applicable to the oil and gas industry.

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CLAIMS

1. A method for optimizing GHG emissions from a solvent-based heavy oil recovery process for a subterranean reservoir, comprising:

a) determining a solvent having a first solvent composition to be modeled to be utilized as an injection fluid in the solvent-based heavy oil recovery process;

b) determining the GHG emissions for at least one key GHG emissions source of the solvent-based oil recovery process over a range of solvent fractions based on the first solvent composition;

c) selecting a range of solvent fractions near the solvent fractions associated with the GHG minimum emissions point;

d) selecting the solvent fraction of the injection fluid in the solvent-based heavy oil extraction process to be within the selected range of solvent fractions;

e) injecting the injection fluid containing the solvent and steam utilizing the selected solvent fraction into the subterranean reservoir.

2. The method of claim 1, further comprising recovering a product stream comprising heavy oil from the subterranean reservoir.

3. The method of claim 2, wherein the product stream comprises bitumen.

4. The method of any one of claims 1-3, wherein further comprising recovering a recovered solvent stream from the subterranean reservoir.

5. The method of claim 2, wherein at least a portion of the solvent in the injection fluid comprises at least a portion of the recovered solvent stream.

6. The method of any one of claims 1-5, wherein the solvent-based oil recovery process is a gravity drainage process.

7. The method of any one of claims 1-6, wherein the solvent and steam are injected in the vapor phase.

8. The method of any one of claims 1-7, wherein a total GHG emissions intensity curve is generated for the range of solvent fractions based on the first solvent composition.

9. The method of any one of claims 1-8, wherein the range of solvent fractions is 0% to 100%.

10. The method of any one of claims 8-9, wherein the total GHG emissions intensity curve is based on the calculated GHG emissions intensity curve for at least one of the following key GHG emissions sources of the solvent-based heavy oil recovery process:

- the make-up solvent;
- the power demand;
- the solvent recovery unit (SRU); and
- the vaporization unit.

11. The method of claim 10, wherein:

the make-up solvent calculated GHG emissions intensity curve and the power demand calculated GHG emissions intensity curve are indirect GHG emissions source curves;

the solvent recovery unit (SRU) calculated GHG emissions intensity curve and the vaporization unit calculated GHG emissions intensity curve are direct GHG emissions source curves; and the total GHG emissions intensity curve is based on the calculated GHG emissions intensity curves of at least one indirect GHG emissions source curve and at least one direct GHG emissions source curve.

12. The method of claim 11, wherein the at least one indirect GHG emissions source curve is the solvent recovery unit (SRU) calculated GHG emissions intensity curve and the at least one direct GHG emissions source curve is the vaporization unit calculated GHG emissions intensity curve.

13. The method of any one of claims 8-12, wherein the total GHG emissions intensity curve is based on the calculated GHG emissions intensity curve for all of the following key GHG emissions sources of the solvent-based heavy oil recovery process:

- the make-up solvent;
- the power demand;
- the solvent recovery unit (SRU); and
- the vaporization unit.

14. The method of any one of claims 1-13, wherein in step c), the selected range of solvent fractions is within +/- 20 vol% of the solvent fraction associated with the minimum GHG emissions intensity point.

15. The method of any one of claims 8-13, wherein in step c), the selected range of solvent fractions corresponds to a point on the total GHG emissions intensity curve that is within +/- 20% of the minimum GHG emissions intensity point.

16. The method of any one of claims 1-7, further comprising wherein:

- in step a), at least one additional solvent having an at least one additional solvent composition different from the first solvent composition is utilized;

- in step b), a first set of GHG emissions for the at least one key GHG emissions source of the solvent-based oil recovery process over a range of solvent fractions are determined based on the first solvent composition; and at least one additional set of GHG emissions for the at least one key GHG emissions source of the solvent-based oil recovery process over a range of solvent fractions are determined based on the at least one solvent composition; and

- in step c), the GHG minimum emissions point is selected based on the lowest value of the GHG minimum emissions point between first set of GHG emissions and the at least one additional set of GHG emissions; and;

- in steps c)- e), the composition of the solvent and the solvent fractions are based on the solvent and solvent fractions associated with the set of GHG emissions with the lowest GHG minimum emissions point.

17. The method of claim 16, wherein a total GHG emissions intensity curve is generated for the range of solvent fractions based on the first set of GHG emissions and a total GHG emissions intensity curve is generated for the range of solvent fractions based on the at least one additional set of GHG emissions.

18. The method of claim 17, wherein the solvent in the injection fluid is selected such that the average boiling point range of the solvent is within 100 °C of the average boiling point of the solvent composition corresponding to the lowest minimum GHG emissions intensity point calculated from the total GHG emissions intensity curves.

19. The method of any one of claims 16-18, wherein the range of solvent fractions is 0% to 100%.

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20. The method of any one of claims 17-19, wherein the total GHG emissions intensity curves are based on the calculated GHG emissions intensity curves for at least one of the following key GHG emissions sources of the solvent-based heavy oil recovery process:

- the make-up solvent;
- the power demand;
- the solvent recovery unit (SRU); and
- the vaporization unit.

21. The method of claim 20, wherein:

the make-up solvent calculated GHG emissions intensity curves and the power demand calculated GHG emissions intensity curves are indirect GHG emissions source curves;

the solvent recovery unit (SRU) calculated GHG emissions intensity curves and the vaporization unit calculated GHG emissions intensity curves are direct GHG emissions source curves; and

the total GHG emissions intensity curves are based on the calculated GHG emissions intensity curves of at least one indirect GHG emissions source curves and at least one direct GHG emissions source curves.

22. The method of claim 21, wherein the at least one indirect GHG emissions source curves are the solvent recovery unit (SRU) calculated GHG emissions intensity curves and the at least one direct GHG emissions source curves are the vaporization unit calculated GHG emissions intensity curves.

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23. The method of any one of claims 17-22, wherein the total GHG emissions intensity curves are based on the calculated GHG emissions intensity curves for all of the following key GHG emissions sources of the solvent-based heavy oil recovery process:

- the make-up solvent;
- the power demand;
- the solvent recovery unit (SRU); and
- the vaporization unit.

24. The method of any one of claims 16-23, wherein in step c), the selected range of solvent fractions is within +/- 20 vol% of the solvent fraction associated with the minimum GHG emissions intensity point.

25. The method of any one of claims 16-23, wherein in step c), the selected range of solvent fractions corresponds to a point on the total GHG emissions intensity curve that is within +/- 20% of the minimum GHG emissions intensity point.

26. The method of any one of claims 1-25, wherein the method is performed prior to selecting a follow-up process and transitioning from the solvent-based heavy oil recovery process to a follow-up process.

27. The method of claim 26, wherein the transitioning is based on a transition criteria which includes determining that a threshold fraction of the estimated original heavy oil in the subterranean reservoir has been recovered.

28. The method of claim 27, wherein threshold fraction is selected from:

- at least 10%;
- at least 20%;
- at least 30%;
- at least 40%;

- at least 50%;
- at least 60%;
- at least 70%; and
- at least 80%.

29. The method of any one of claims 26-28, wherein the follow-up process is selected from:
    - a steam assisted gravity drainage (SAGD) process;
    - a solvent assisted cyclic steam stimulation (SA-CSS) process;
    - a steam flood process;
    - a solvent assisted steam flood (SA-SF) process;
    - a solvent flood process;
    - a heated vapor solvent flood process;
    - a non-condensable gas (NCG) assisted steam process;
    - a non-condensable gas (NCG) assisted solvent process; and
    - a non-condensable gas (NCG) flood process.

30. The method of any one of claims 26-28, wherein the follow-up process is a second solvent-based heavy oil recovery process and is selected from:
    - a solvent assisted cyclic steam stimulation (SA-CSS) process;
    - a solvent assisted steam flood (SA-SF) process;
    - a solvent flood process;
    - a non-condensable gas (NCG) assisted solvent process; and
    - a heated vapor solvent flood process.

31. The method of claim 30, wherein the method as applied to the solvent-based heavy oil recovery process in any one of claims 1-25 is further applied to the follow-up process prior to the selecting the follow-up process and the transitioning from the solvent-based heavy oil recovery process to the follow-up process.

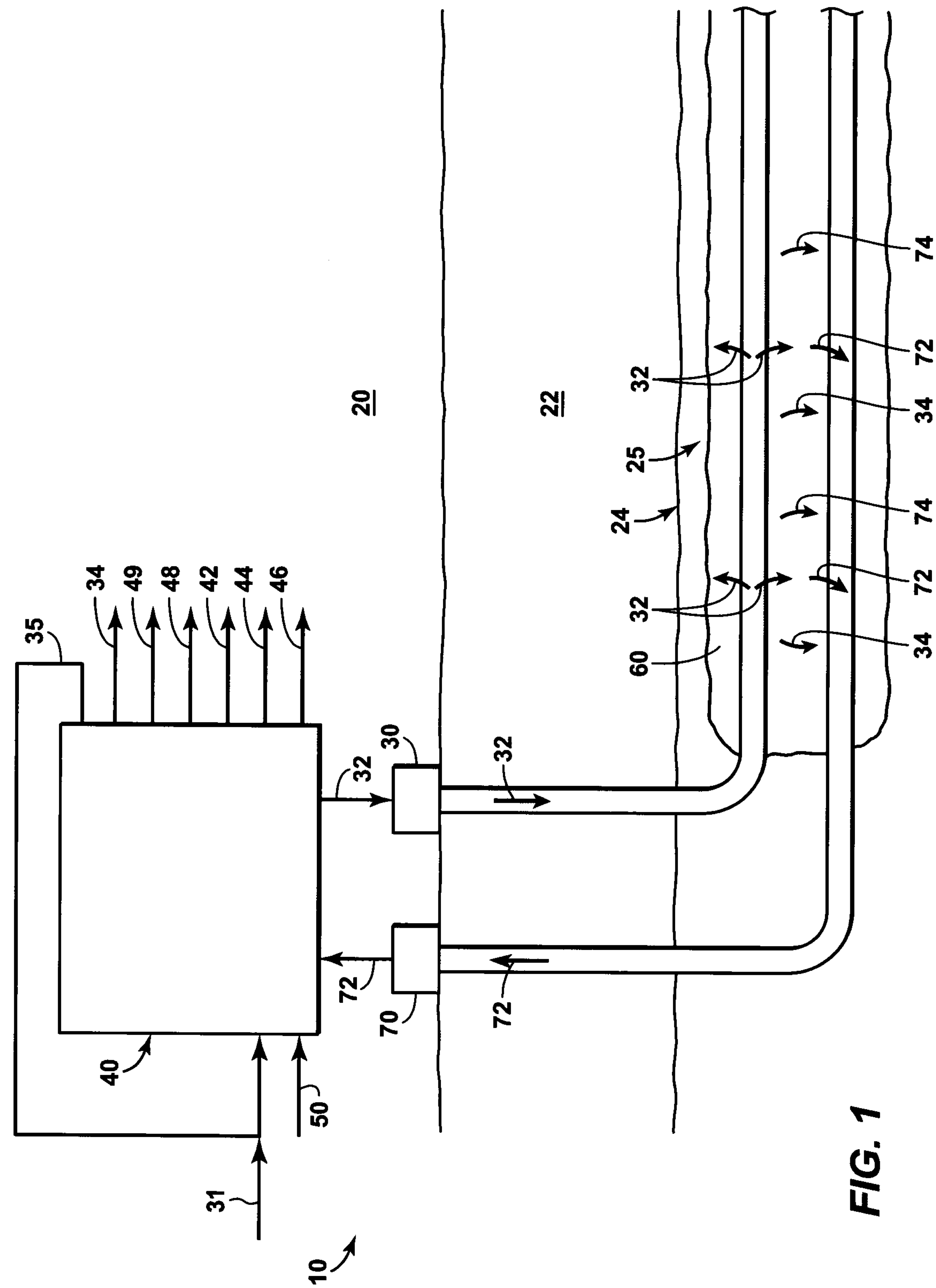


FIG. 1

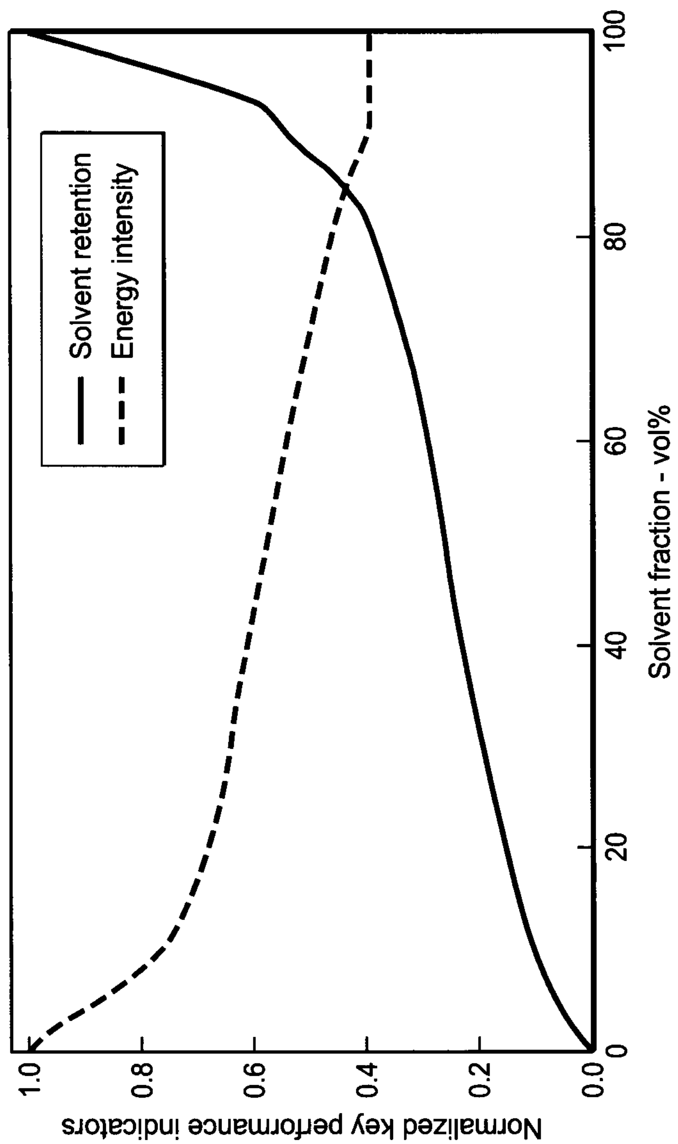

Solvent retention
Energy intensity
Normalized key performance indicators
1.0
0.8
0.6
0.4
0.2
0.0
0
20
40
60
80
100
Solvent fraction - vol%

FIG. 2

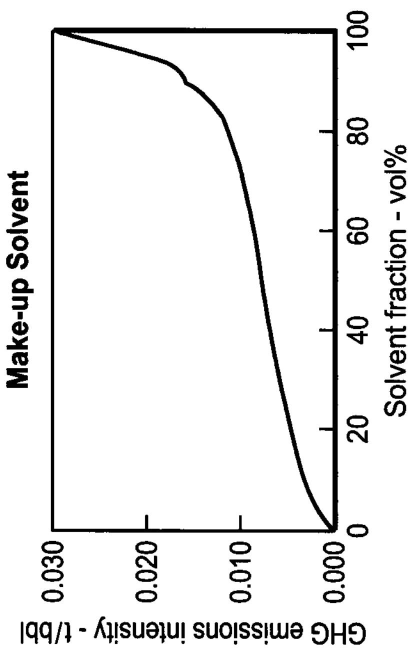


FIG. 3A

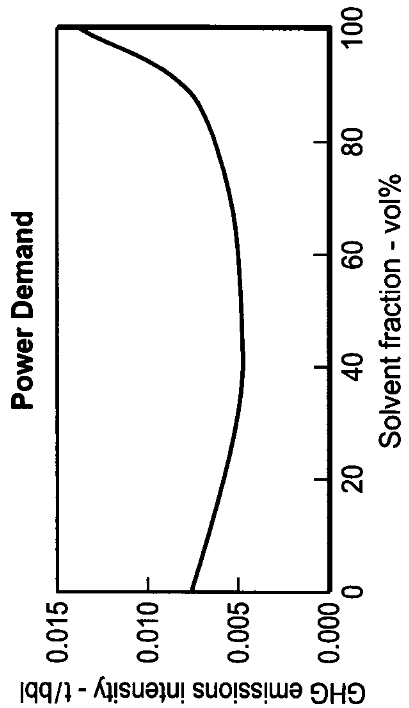


FIG. 3B

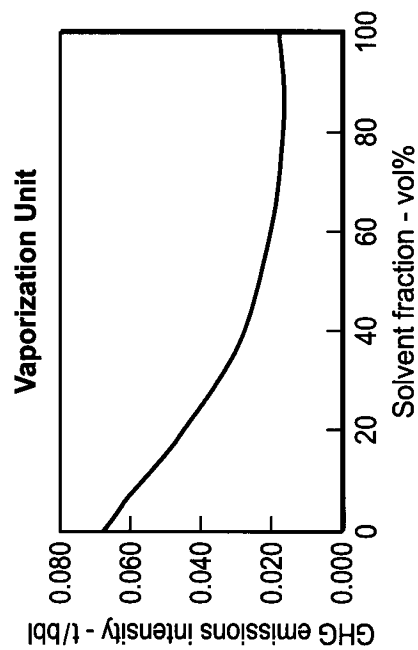


FIG. 3C

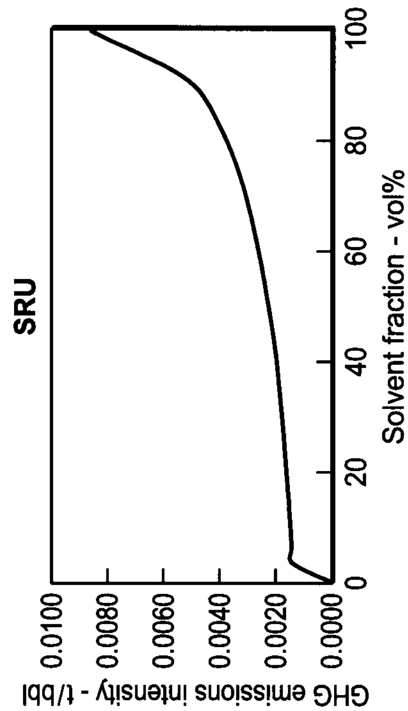
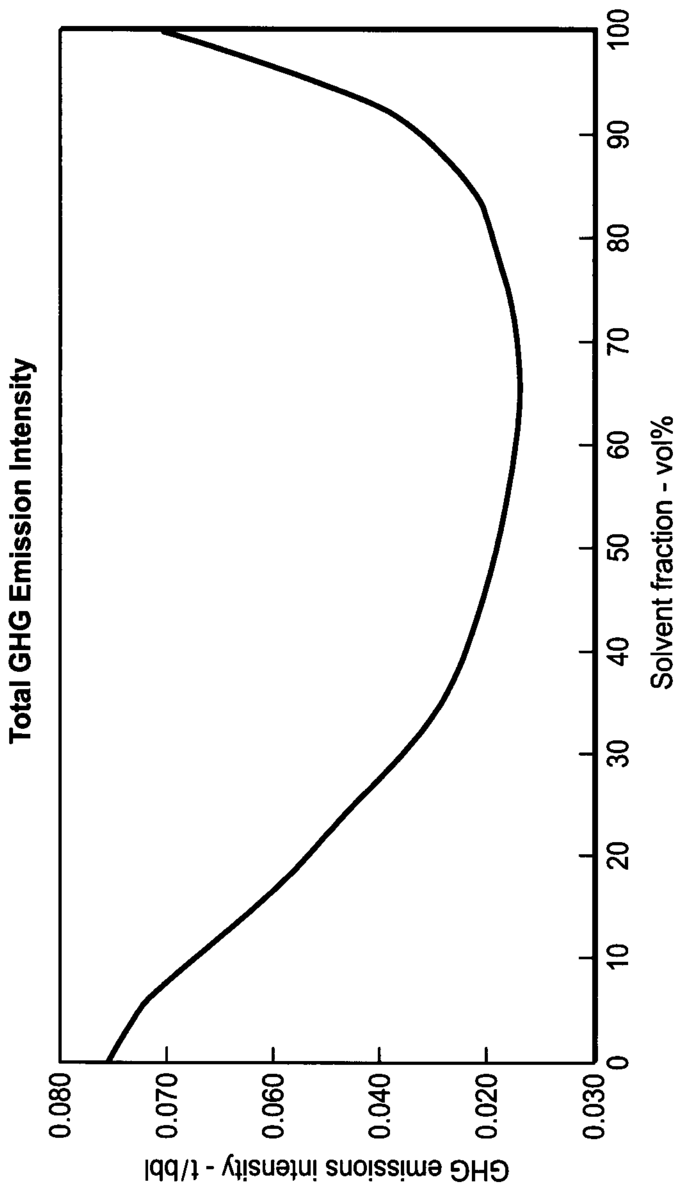


FIG. 3D



Total GHG Emission Intensity
GHG emissions intensity - t/bbl
0.080
0.070
0.060
0.040
0.020
0.030
Solvent fraction - vol%
0
10
20
30
40
50
60
70
80
90
100

FIG. 3E

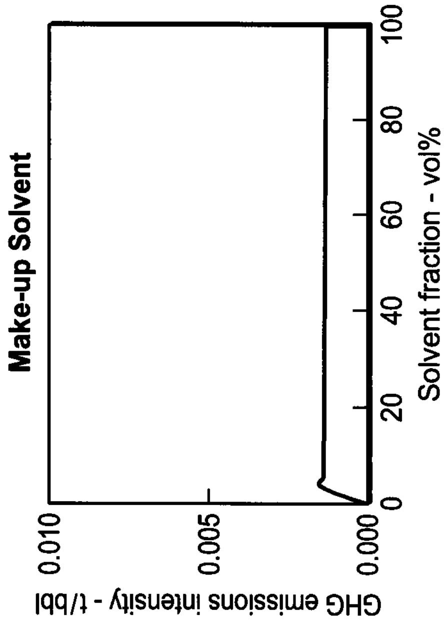


FIG. 4A

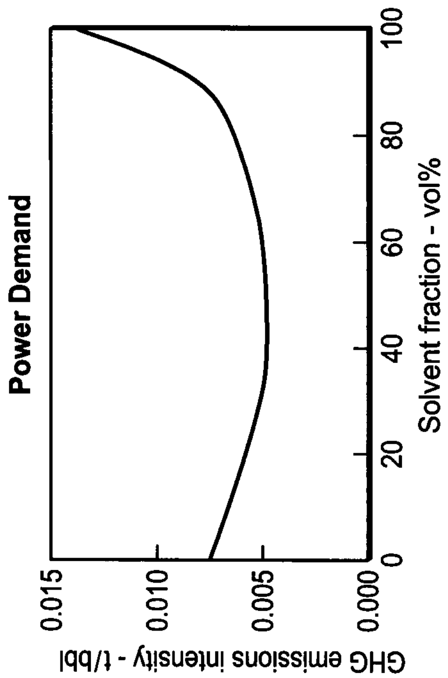


FIG. 4B

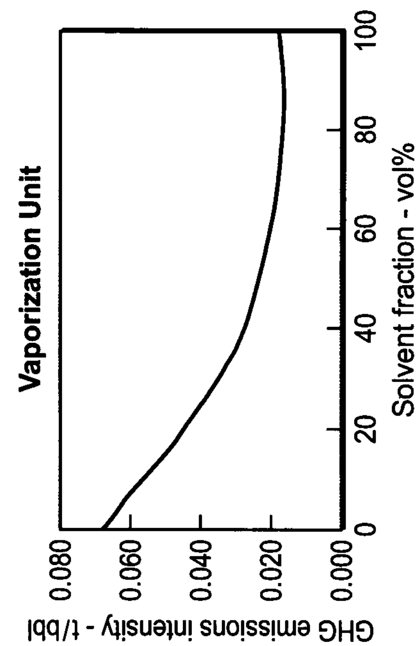


FIG. 4C

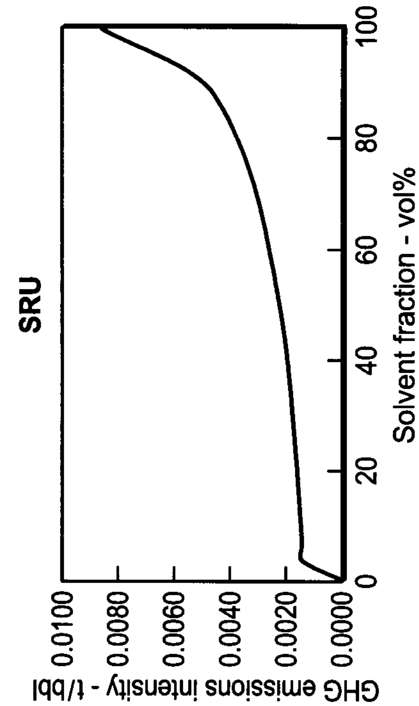


FIG. 4D

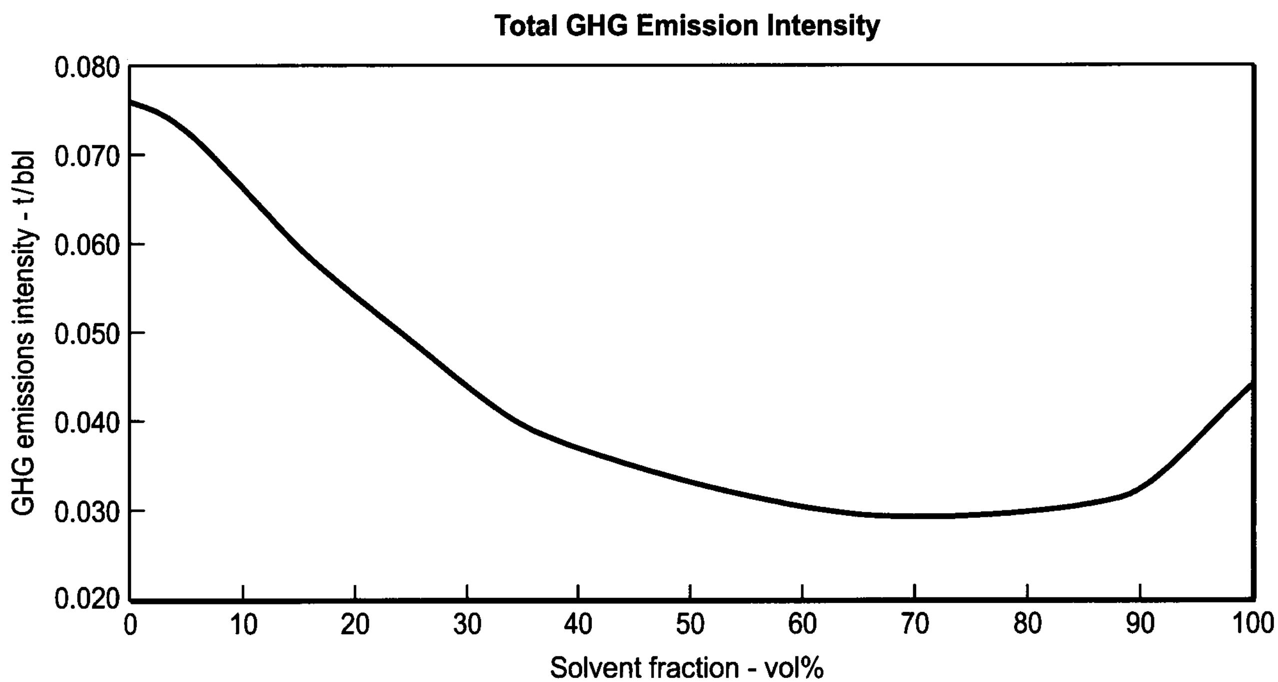
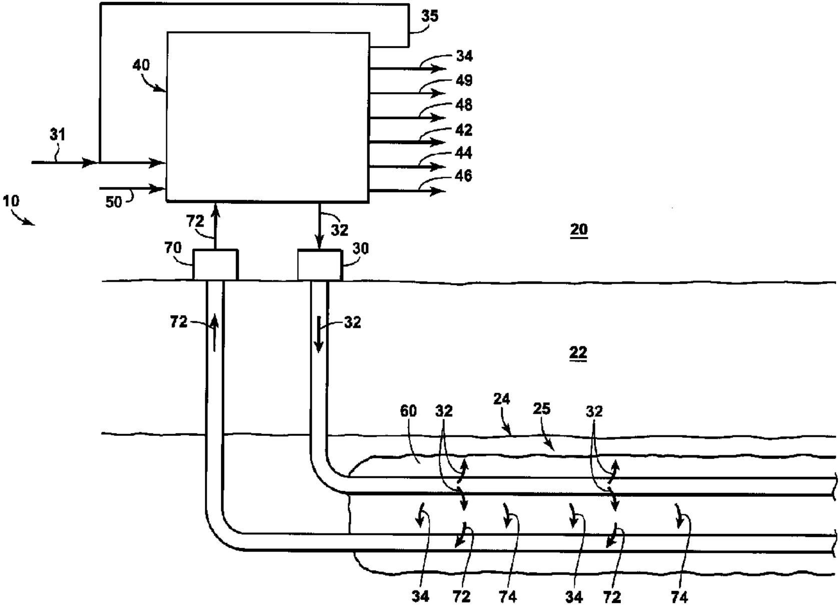

Total GHG Emission Intensity
GHG emissions intensity - t/bbl
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0
10
20
30
40
50
60
70
80
90
100
Solvent fraction - vol%

FIG. 4E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