

LOW EMISSION POWER GENERATION AND HYDROCARBON RECOVERY SYSTEMS AND METHODS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit under 35 U.S.C. §119(e) of pending U.S.
5 Provisional Application Serial No. 61/260,636, filed on 12 November 2009 and entitled
“Low Emission Power Generation and Hydrocarbon Recovery Systems and Methods,” the
entirety of which is incorporated herein by reference for all purposes.

[0002] Additionally, it is noted that this application relates to International Patent
Application No. PCT/US2009/038247 filed 25 March 2009, which, in turn, claims the benefit
10 of U. S. Provisional Application No. 61/072,292, filed 28 March 2008 and U. S. Provisional
Application No. 61/153,508, filed 18 February 2009.

FIELD

[0003] Embodiments of the invention relate to low emission power generation in a
hydrocarbon recovery processes. More particularly, embodiments of the invention relate to
15 methods and systems for utilizing nitrogen, oxygen, carbon dioxide, and/or hydrocarbon fuel
to generate power in a very low emission hydrocarbon recovery process.

TECHNOLOGY BACKGROUND

[0004] This section is intended to introduce various aspects of the art, which may be
associated with exemplary embodiments of the present invention. This discussion is believed
20 to assist in providing a framework to facilitate a better understanding of particular aspects of
the present invention. Accordingly, it should be understood that this section should be read
in this light, and not necessarily as admissions of prior art.

[0005] Many enhanced hydrocarbon recovery operations can be classified as one of the
following types: pressure maintenance and miscible flooding. In a pressure maintenance
25 operation, inert gasses such as nitrogen are injected into a primarily gaseous reservoir to
maintain at least a minimal pressure in the reservoir to prevent retrograde condensation and
improve total recovery. In a miscible flooding operation, miscible gasses such as carbon
dioxide are injected into a primarily liquidous reservoir to mix with the liquids, lowering their
viscosity and increasing pressure to improve the recovery rate.

[0006] Many oil producing countries are experiencing strong domestic growth in power demand and have an interest in enhanced oil recovery (EOR) to improve oil recovery from their reservoirs. Two common EOR techniques include nitrogen (N₂) injection for reservoir pressure maintenance and carbon dioxide (CO₂) injection for miscible flooding for EOR.

5 There is also a global concern regarding green house gas (GHG) emissions. This concern combined with the implementation of cap-and-trade policies in many countries make reducing CO₂ emissions a priority for these and other countries as well as the companies that operate hydrocarbon production systems therein.

[0007] Some approaches to lower CO₂ emissions include fuel de-carbonization or post-combustion capture. However, both of these solutions are expensive and reduce power generation efficiency, resulting in lower power production, increased fuel demand and increased cost of electricity to meet domestic power demand. Another approach is an oxyfuel gas turbine in a combined cycle (e.g. where exhaust heat from the gas turbine Brayton cycle is captured to make steam and produce additional power in a Rankine cycle). However, there are no commercially available gas turbines that can operate in such a cycle and the power required to produce high purity oxygen significantly reduces the overall efficiency of the process. Several studies have compared these processes and show some of the advantages of each approach. See, e.g. BOLLAND, OLAV, and UNDRUM, HENRIETTE, *Removal of CO₂ from Gas Turbine Power Plants: Evaluation of pre- and post-combustion methods*, SINTEF Group, found at <http://www.energy.sintef.no/publ/xergi/98/3/3art-8-engelsk.htm> (1998).

[0008] U.S. Pat. No. 4,344,486 (the '486 patent) discloses a process of adding substantially pure oxygen to the produced hydrocarbons and carbon dioxide from a liquid producing formation to produce heat or power and re-injecting the carbon dioxide for EOR. The '486 patent discloses separating hydrocarbon liquids from gaseous constituents in a production stream of a liquid producing formation, then mixing the gaseous constituents with substantially pure oxygen and combusting the mixture to produce heat and CO₂. The CO₂ is then injected into the same or a different liquid producing formation. This approach fails to teach or suggest a solution to the efficiency drag from the oxygen plant.

[0009] U.S. Pat. Pub. No. 2007/0237696 (the '696 publication) discloses essentially a combination of the oxy-fuel process and EOR as disclosed in the '486 patent. The '696 publication also requires a stand-alone oxygen plant or air separation plant, and fails to teach or suggest a working gas power turbine configuration.

[0010] More recently International Patent Application no. US2009/038247 discloses a system that provides a solution to the efficiency drag from the oxygen plant and further provides an inert gas (nitrogen) injection for reservoir pressure maintenance. In the integrated system of US2009/038247, however, the net power produced is generally reduced
5 by the power consumption requirement of the process even at the improved efficiency.

[0011] As such, there is still a substantial need for a low emission, high efficiency hydrocarbon recovery process with increased power production.

SUMMARY

[0012] An integrated system is provided in at least one embodiment of the present
10 invention. The system includes an oxygen stream, a main control fuel stream, a main combustion unit, a first power generation system, and a second power generation system. The main combustion unit is configured to receive and combust the main control fuel stream and the oxygen stream to produce a gaseous combustion stream having carbon dioxide and water. The first power generation system is configured to receive the gaseous combustion
15 stream and produce at least a compressed gaseous substantially carbon dioxide stream. The second power generation system is configured to receive thermal energy from the gaseous combustion stream and convert the thermal energy into at least one unit of power.

[0013] A method for low emission hydrocarbon recovery with power production is also provided in at least one embodiment of the present invention. The method includes the steps
20 of generating a gaseous combustion stream having carbon dioxide and water; generating a compressed air stream; transferring heat from the gaseous combustion stream to the compressed air stream to form a cooled gaseous combustion stream and a heated compressed air stream; producing power, a water stream, and a carbon dioxide stream from the cooled gaseous combustion stream using a first power generation system; producing power from the
25 heated compressed air stream using a second power generation system; and injecting at least a portion of the carbon dioxide stream into a reservoir to increase hydrocarbon production.

BRIEF DESCRIPTION OF THE DRAWINGS

[0014] The foregoing and other advantages of the present disclosure may become apparent upon reviewing the following detailed description and drawings of non-limiting
30 examples of embodiments in which:

[0015] FIG. 1A illustrates an integrated systems for low emission power generation and hydrocarbon recovery according to an embodiment of the present disclosure;

[0016] FIG. 1B illustrates an integrated systems for low emission power generation and hydrocarbon recovery according to another embodiment of the present disclosure;

5 [0017] FIG. 1C illustrates an integrated systems for low emission power generation and hydrocarbon recovery according to yet another embodiment of the present disclosure;

[0018] FIG. 2A illustrates an integrated systems for low emission power generation and hydrocarbon recovery according to still yet another embodiment of the present disclosure;

[0019] FIG. 2B illustrates an integrated systems for low emission power generation and
10 hydrocarbon recovery according to yet another embodiment of the present disclosure; and

[0020] FIG. 3 illustrates a flow diagram of a method for low emission power generation and hydrocarbon recovery according to an embodiment of the present disclosure.

DETAILED DESCRIPTION

DEFINITIONS

15 [0021] Various terms as used herein are defined below. To the extent a term used in a claim is not defined below, it should be given the definition persons in the pertinent art have given that term.

[0022] As used herein, the "a" or "an" entity refers to one or more of that entity. As such, the terms "a" (or "an"), "one or more", and "at least one" can be used interchangeably
20 herein unless a limit is specifically stated.

[0023] As used herein, the terms "comprising," "comprises," and "comprise" are open-ended transition terms used to transition from a subject recited before the term to one or more elements recited after the term, where the element or elements listed after the transition term are not necessarily the only elements that make up of the subject.

25 [0024] As used herein, the terms "containing," "contains," and "contain" have the same open-ended meaning as "comprising," "comprises," and "comprise."

[0025] As used herein, the terms "having," "has," and "have" have the same open-ended meaning as "comprising," "comprises," and "comprise."

[0026] As used herein, the terms "including," "includes," and "include" have the same
30 open-ended meaning as "comprising," "comprises," and "comprise."

DESCRIPTION

[0027] In the following detailed description section, specific embodiments of the present invention are described in connection with preferred embodiments. However, to the extent that the following description is specific to a particular embodiment or a particular use of the present invention, this is intended to be for exemplary purposes only and simply provides a description of the exemplary embodiments. Accordingly, the invention is not limited to the specific embodiments described below, but rather, it includes all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

[0028] With reference to FIG. 1A, an integrated system 100 is shown for a low emission, high efficiency hydrocarbon recovery process with increased excess power production. In general, the system 100 comprises two power-producing cycles coupled together synergistically to reduce overall emissions; produce CO₂ for enhanced oil recovery (EOR) or sequestration; produce N₂ for EOR, sequestration, or sale; produce clean water that may be used for domestic purposes; and/or the like. More specifically, the system 100 includes a main combustion unit (e.g., an oxy-fuel combustor) 102 configured to receive a main control fuel stream 104 and an oxygen stream 106. In at least one embodiment the oxygen stream 106 is generated by an Air Separation Unit ("ASU") 110 that is configured to separate an air stream 112 into a substantially oxygen enriched component (e.g., oxygen stream 106) and a substantially nitrogen enriched component (e.g., nitrogen stream 114). The nitrogen stream 114 may be compressed via a compressor 120 to generate a nitrogen injection stream 122 for subsequent injection into a pressure maintenance reservoir 124. However, the nitrogen stream 114 may be used in any appropriate application and/or sold to satisfy the design criteria of a particular application. It should also be appreciated that the oxygen stream 106 and the main control fuel stream 104 may be generated and/or supplied by any appropriate mechanism to satisfy the design criteria of a particular application. Furthermore, one or more embodiments may implement an air stream, which itself contains oxygen, as the oxygen stream 106.

[0029] Similarly, the main control fuel stream 104 may be any appropriate fuel or mixture of fuels (e.g., natural gas, coal, hydrocarbon liquid, and/or any other suitable carbonaceous fuel) to satisfy the design criteria of a particular application. In general, the main combustion unit 102 exhausts a mixture including carbon dioxide (CO₂) and water (H₂O) as a gaseous combustion stream 130.

[0030] The gaseous combustion stream 130 may be passed through a heat exchanger 132. The heat exchanger 132 is generally configured to transfer thermal energy from the gaseous combustion stream 130 to a gas turbine 180. As will be described later in the present application, the heat exchanger (i.e., heat exchange unit) 132 forms the interface between two
5 power-producing cycles.

[0031] Having passed through the heat exchanger 132, the gaseous combustion stream 130 may be received by a first Heat Recovery Steam Generator (HRSG) 140. The first HRSG 140 generally includes a heat exchanger, such as a steam coil (not shown), in contact with the gaseous combustion stream 130 for generating steam 142. The steam 142 may be expanded
10 across a steam turbine 150 to generate power/work. The steam turbine discharge stream 152 may then be condensed (e.g., in first condenser 154) and/or chilled (e.g., in chiller 156) to produce a water stream 160. In at least one embodiment, the chiller 156 is configured to receive a make-up water stream 158. All or a portion of the water 160, such as streams 160' and 160'', may be circulated to an appropriate piece of equipment, such as the first 140 and/or
15 a second 162 HRSG, and/or applied to any appropriate use to satisfy the design criteria of a particular application.

[0032] The first HRSG 140 may pass the gaseous combustion stream 130 to a second condenser 164 for separation into a compressed gaseous substantially CO₂ stream 170 and a water stream 172. In at least one embodiment, a portion 170' of the cooled CO₂ stream 170
20 may be recirculated back to the main combustion unit 102 to moderate combustion temperatures. In at least one other embodiment, a second portion 170'' of the CO₂ stream 170 may be used in connection with EOR injection, sequestration, and/or any other suitable use. In yet another embodiment, exhaust gases 171 from at least one external source (not shown) may be mixed (i.e., combined) with the CO₂ stream 170 such that the exhaust gases 171 are
25 also used in connection with combustion temperature moderation, EOR injection, sequestration, and/or any other suitable use.

[0033] Returning now to the heat exchange unit 132, the heat exchanger 132 of the system 100 generally acts to transfer thermal energy from the gaseous combustion stream 130 to a gas turbine 180 based power generating process. The gas turbine 180 generally receives
30 an air stream, such as the air stream 112' which may be derived from the same source as air stream 112, and compresses the air stream, e.g. via compressor 182, to form a compressed turbine air stream 184. The heat exchanger 132 receives the compressed turbine air stream

184 and heats the air stream 184 via heat transfer between the gaseous combustion stream 130 and the stream 184. In the embodiment of FIG. 1A, the heated compressed turbine air stream 184' is then passed to a combustor (i.e., supplemental combustion unit) 186 that is coupled to an expander 190 for producing power/work from the combustor exhaust stream 184". In at least one embodiment the combustor 186 is configured to receive a fuel stream (i.e., supplemental control fuel stream) 188. The supplemental control fuel stream 188 may be any suitable fuel and/or fuel stream, such as but not limited to the main control fuel stream 104, to satisfy the design criteria of a particular application.

[0034] It may be noted that heating the compressed turbine air stream 184 in the heat exchange unit 132 may significantly reduce the amount of the supplemental control fuel 188 required to produce a desired air inlet temperature at the expander 190. Accordingly, the reduction in the amount of the supplemental control fuel stream 188 generally provides a reduction in the amount of emissions created by the supplemental combustion unit 186. Specifically, at least one simulation predicts that two-thirds of the emissions may be eliminated by using the heat exchanger unit 132 to heat the compressed turbine air stream 184 prior to combustion.

[0035] The gas turbine exhaust 192 may then pass to the second HRSG 162 or any other suitable device to satisfy the design criteria of a particular application. In at least one embodiment the second HRSG 162 is coupled to the steam turbine 150 and passes steam 166 to the steam turbine 150. The steam 166 may be combined with or used in place of the steam 142 to generate power and form the steam turbine discharge stream 152. In addition, one or more embodiments of the present invention may include a Selective Catalytic Reduction device (SCR) 194 coupled to the second HRSG 162 for processing stack gas 196 prior to release.

[0036] In at least one embodiment, the water content in the gaseous combustion stream 130 may be reduced by operating the main combustion unit 102 at an elevated pressure, as compared with the water content present in the combustion stream 130 when the main combustion unit 102 is operated near (i.e., slightly above, at, or slightly below) atmospheric pressure. In such an embodiment, the ASU 110 may be configured to provide a high pressure oxygen stream 106 to the main combustion unit 102.

[0037] In at least one embodiment, a reduction in the water content may allow for the elimination and/or simplification of one or more subsequent processing steps, such as the

application of a dehydration unit (not shown). Similarly, operation of the main combustion unit 102 at an increased pressure may reduce the need to compress the generated CO₂ (e.g., the compressed gaseous substantially CO₂ stream 170). More specifically for subsequent use in, for example, EOR the amount of power required to compress the CO₂ derived from the combustion stream 130 to an appropriate reservoir injection level may be reduced by a factor of three. High pressure combustion equipment may also have a smaller physical footprint. In contrast, however, near atmospheric combustion generally avoids the need to compress the oxygen stream 106 and avoids the complications associated with high pressure combustion, such as the propensity to form soot.

[0038] Referring to FIG. 1B, a diagram illustrating another integrated system 100' that may be implemented in connection with the present invention is shown. In general the system 100' may be implemented similarly to the system 100 with the inclusion of a CO₂ reservoir 174 for injection of at least a portion of the compressed gaseous substantially CO₂ stream 170, such as stream 170'. As illustrated, a portion of the CO₂ stream 170, such as the stream 170'', may still be routed to the main combustion unit 102 for combustion temperature moderation. In addition or in the alternative, stream 170'' may be derived from (e.g., separated from) the fluids produced from reservoir 174. In at least one embodiment, the main control fuel stream 104 may be obtained from the CO₂ reservoir 174. Similarly, the supplemental control fuel stream 188 may be obtained from the pressure maintenance reservoir 124. It may be noted that the use of nitrogen in the fuel obtained from the pressure maintenance reservoir 124 may provide additional mass which may enhance the performance of the expander 190 and reduce the air compression requirement, thus increasing the net power of the gas turbine 180.

[0039] In at least one embodiment, the water stream 172 may be injected into a reservoir (e.g., 174) to enhance hydrocarbon recovery (e.g., EOR). In at least one other embodiment, the water stream 172 may be used in connection with well work, drilling, plant cooling, and/or steam systems. However, the water stream 172 may be implemented in connection with any appropriate use to satisfy the design criteria of a particular application. Furthermore, the water stream 172 may be characterized, or processed further such that it may be characterized, as low salinity water (i.e., water having total dissolved solids less than approximately 10,000 parts-per-million). Such low salinity water may be especially beneficial for reservoir water flooding as opposed to non-low salinity water. While the water stream 172 generally results from the process of combustion, water, such as low-salinity

water, may be produced using any appropriate process to satisfy the design criteria of a particular embodiment.

[0040] Referring to FIG. 1C, a diagram illustrating yet another system 100'' that may be implemented in connection with the present invention is shown. In general the system 100'' may be implemented similarly to the systems 100 and 100' with the inclusion of a reformer 142 configured to receive a reformer fuel stream 144, such as the fuel stream 104 or 188, and a steam stream 146, such as the stream 142 or 166, and generate a hydrogen fuel stream 148. In general, the hydrogen fuel stream 148 may be implemented in the system 100'' as the supplemental control fuel stream 188, and/or any other appropriate fuel stream. The use of hydrogen as a fuel generally eliminates or reduces the production of carbon dioxide in any resulting combustion stream. Thus the hydrogen fuel may be strategically or preferentially used in the combustion unit 186 of the Gas Turbine 180 to eliminate the carbon dioxide emissions that would otherwise result from using a carbonaceous fuel. This may be beneficial in attaining ultra-low emissions for system 100''. In at least one embodiment, at least a portion of the hydrogen fuel stream 148, such as the portion 148', may be diverted for subsequent sale. It may be noted that the hydrogen fuel stream may, in one or more embodiments, also be implemented as the main control fuel stream 104. However, it may be undesirable to eliminate the carbon dioxide from gaseous combustion stream 130 as the carbon dioxide is generally separated and subsequently used for reservoir injection. It is contemplated, however, that a portion of the hydrogen fuel stream 148 and/or reformer effluent separated from the hydrogen stream may be implemented (e.g., mixed) with the main control fuel stream 104 to obtain a desirable (i.e., meets the design criteria of a particular application) combustion unit performance (e.g., flame stability) and/or carbon dioxide reduction in gaseous combustion stream 130.

[0041] Referring, now, to FIG. 2A, an integrated system 200 is shown for a low emission, high efficiency hydrocarbon recovery process with excess power production. The system 200 may be implemented similarly to the systems 100, 100' and 100'' with the exception that the supplemental combustion unit 186 is omitted. Accordingly, the heated compressed turbine air stream 184' is passed directly to the expander 190. Elimination of the supplemental combustion unit 186 and the associated combustion exhaust may be beneficial, for example, in reaching ultra-low emissions. In such an embodiment, the heated compressed turbine air stream 184' may reach the expander 190 at a temperature substantially less than the preferred (e.g., maximum) operating inlet temperature, as specified by a manufacturer, of

the expander 190. The reduced temperature generally reduces the overall power generated by the system 200 in exchange for a reduction in the complexity of the system 200 and reduced emissions. In contrast, inclusion of the supplemental combustion unit 186 generally provides the expander 190 with an air stream 184'' at a temperature substantially equal to the preferred (e.g., maximum) operating inlet temperature of the expander 190. The inclusion of the supplemental combustion unit 186 generally yields additional power but may also complicate the design of the system 200 and increase emissions associated with system 200. It may be noted that use of a ceramic heat exchanger for element 132 may provide sufficient heat transfer such that the heated compressed turbine air 184' reaches the expander 190 substantially at the preferred operating (e.g., maximum) inlet temperature of the expander 190. The additional heat may yield additional power while elimination of the supplemental combustion unit 186 may provide a reduction in the overall emissions of the system 200 (e.g., those emissions associated with the supplemental combustion unit 186). It may also be noted that elimination of the supplemental combustion unit 186 generally eliminates the need for the SCR 194.

[0042] Referring to FIG. 2B, a diagram illustrating another integrated system 200' that may be implemented in connection with the present invention is shown. In general the system 200' may be implemented similarly to the system 200 with the inclusion of a CO₂ reservoir 174 for injection of at least a portion of the compressed gaseous substantially CO₂ stream 170, such as stream 170'. As illustrated, a portion of the CO₂ stream 170, such as the stream 170'', may be routed to the main combustion unit 102 for combustion temperature moderation. In addition or in the alternative, stream 170'' may be derived from (e.g., separated from) the fluids produced from reservoir 174. In at least one embodiment, the main control fuel stream 104 may be obtained from the CO₂ reservoir 174. Again, as with systems 100, 100', 100'' and 200, the nitrogen stream 114 from an associated ASU 110 may be compressed via a compressor 120 to generate a nitrogen injection stream 122. The nitrogen stream 122 may be used for subsequent injection into a pressure maintenance reservoir 124, or the nitrogen stream 114/122 may be used in any appropriate application and/or sold to satisfy the design criteria of a particular application.

[0043] TABLE 1, below, provides a simulated performance comparison between the systems 200 and 200' and a conventional Natural Gas Combined Cycle (NGCC).

TABLE 1 Example Performance Comparison

	NGCC with Carbon Capture	System of FIGs. 2A-B
Gas Turbine Power (MW)	361	370
Steam Turbine Generator Power (MW)	206	365
Auxiliary Loads (MW)	114	112
Net Power (MW)	453	622
Fuel Usage (mmscfd)	86.6	120.8
CO ₂ Produced (mmscfd)	85.7	119.9
Heat Rate	7968	8096
LHV efficiency	42.8	42.1

[0044] Referring to FIG. 3, a flow diagram of a method 300 for low emission hydrocarbon recovery with power generation according to one embodiment is shown. The method 300 may be advantageously implemented in connection with the system 100, 100', 100'', 200 and/or 200' described previously in connection with FIGs. 1A-1C, FIGs. 2A-2B, and/or any appropriate system to meet the design criteria of a particular application. The method 300 generally includes a plurality of blocks or steps (e.g., 302, 304, 306, etc.) that may be performed serially. As will be appreciated by one of ordinary skill in the art, the order of the steps shown in FIG. 3 is exemplary and the order of one or more steps may be modified within the spirit and scope of the present invention. Additionally, the steps of the method 300 may be performed in at least one non-serial (or non-sequential) order, and one or more steps may be omitted to satisfy the design criteria of a particular application.

[0045] Block 302 is an entry point into the method 300. At block 304 a gaseous combustion stream (e.g., 130) and a compressed air stream (e.g. 184) may be generated. In at least one embodiment an oxygen stream (e.g., 106) from an ASU (e.g., 110) is implemented in conjunction with a combustion unit (e.g., 102) and a fuel stream (e.g., 104) to generate the gaseous combustion stream. In such an embodiment, the gaseous combustion stream generally includes carbon dioxide and water. The carbon dioxide along with nitrogen generated as a byproduct in the ASU may be compressed and/or injected into a reservoir (e.g., 124, 174) to facilitate hydrocarbon production. However, the gaseous combustion stream and/or the compressed air stream may be generated using any appropriate mechanism to satisfy the design criteria of a particular application.

[0046] At block 306 heat is transferred from the gaseous combustion stream to the compressed air stream. The heat transfer generally results in a cooled gaseous combustion stream and a heated compressed air stream. In at least one embodiment the heat is transferred

using a heat exchange unit (e.g., 132) which may be any appropriate material and/or device capable of exchanging heat at high temperatures such as ceramic matrix composites (CMC), ceramic air-to-air heat exchangers, compact plate-fin ceramic recuperators and other metallic alloys such as Inconel for low pressure application and various oxide dispersion strengthened (ODS) alloys. Various coatings, such as Thermal Barrier Coatings (TBCs) and Environmental Barrier Coatings (EBCs) may also be used for these applications. Specific examples of potentially suitable heat exchange units are Heatric (a Division of Meggitt Corporation) high-temperature heat exchangers (PCHE, FPHE, H²X) made from diffusion-bonding process and using specialty alloys such as Inconel 617 to enable operation at very high process temperatures. However, the heat may be transferred using any appropriate device and/or material to satisfy the design requirements of a particular application.

[0047] At block 308 a first power generation system which, in at least one embodiment, may include a HRSG (e.g., 140), a steam turbine (e.g., 150), a first condenser (e.g., 154), a chiller (e.g., 156), and/or a second condenser (e.g., 164) is generally implemented to receive the cooled gaseous combustion stream and produce at least one unit of power/work, a water stream (e.g., 160, 172) and/or a compressed gaseous substantially CO₂ stream (e.g., 170).

[0048] At block 310 the heated compressed air stream may, if desired to satisfy a design criteria, be heated even further via a supplemental combustion unit (e.g., 186). In at least one embodiment a reformer unit (e.g., 142) may be implemented to generate hydrogen for subsequent use as a fuel stream (e.g., supplemental control fuel stream 188) to the supplemental combustion unit. In such an embodiment, the gaseous combustion stream of the supplemental combustion unit may be substantially devoid of carbon dioxide. As such, use of a reformer unit may provide a significant reduction in undesirable combustion related emissions.

[0049] At block 312 a second power generation system which may, for example, comprise a conventional Natural Gas Combined Cycle (NGCC) process modified for full air extraction, may be implemented to generate at least one unit of power/work. In at least one embodiment, the second power generation system may include a gas turbine (e.g., 180) a HRSG (e.g., 162), a steam turbine (e.g., 150), a first condenser (e.g., 154), a chiller (e.g., 156), and/or a SCR (e.g., 194) as illustrated, for example, in the exemplary integrated system 100 of FIG. 1A and/or 200 of FIG. 2A.

[0050] At block 314 at least a portion of any generated carbon dioxide stream (e.g., 170'') may be injected into a reservoir to increase hydrocarbon production (e.g., EOR). Similarly, at least a portion of the nitrogen produced (e.g., 114) may be injected into a reservoir to increase hydrocarbon production (e.g., through pressure maintenance).

- 5 [0051] At block 316 at least a portion of any generated carbon dioxide stream (e.g., 170') may be re-circulated to a suitable device such as a combustion unit to, for example, moderate combustion temperatures. Block 318 generally represents an exit point out of the method 300.

- 10 [0052] As may be appreciated, then, the disclosed system and methods generally provide a low emission, high efficiency hydrocarbon recovery process with increased power production. Furthermore, in one or more embodiments, the main combustor (e.g., 102) may be designed to handle low BTU-fuel with high CO₂ contamination such as would typically be found in the gas of an EOR project after CO₂ breakthrough. In one or more such embodiments, hydrogen may be added to the low BTU-fuel to assist with flame stability.

- 15 [0053] While the present invention may be susceptible to various modifications and alternative forms, the exemplary embodiments discussed above have been shown only by way of example. However, it should again be understood that the invention is not intended to be limited to the particular embodiments disclosed herein. Indeed, the present invention includes all alternatives, modifications, and equivalents falling within the true spirit and
20 scope of the appended claims.

CLAIMS

1. An integrated system, comprising:

a main combustion unit configured to receive and combust a main control fuel stream and an oxygen stream to produce a gaseous combustion stream having carbon dioxide and water;

a first power generation system configured to receive the gaseous combustion stream and produce at least a compressed gaseous substantially carbon dioxide stream;

a second power generation system configured to receive thermal energy from the gaseous combustion stream and convert the thermal energy into at least one unit of power;

a heat exchange unit configured to receive the gaseous combustion stream, extract the thermal energy from the gaseous combustion stream, and transfer the thermal energy to the second power generation system;

wherein the heat exchange unit transfers the thermal energy to a compressed turbine air stream of the second power generation system to form a heated compressed turbine air stream; and

an air separation unit configured to generate the oxygen stream and to generate a nitrogen stream,

wherein at least a portion of the nitrogen stream is injected into a pressure maintenance reservoir, and

at least a portion of the compressed gaseous substantially carbon dioxide stream is injected into a hydrocarbon reservoir.

2. The system of claim 1 wherein the second power generation system further includes a supplemental combustion unit configured to receive the heated compressed turbine air stream, receive a supplemental control fuel stream, and combust the heated compressed turbine air stream with the supplemental control fuel stream to form a combustor exhaust stream.

3. The system of claim 2 further including an expander for receiving the combustor exhaust stream, wherein the supplemental combustion unit is configured to provide the combustor exhaust stream to the expander at a temperature substantially equal to a preferred operating inlet temperature of the expander.

4. The system of claim 2 further including an expander for receiving the combustor exhaust stream, wherein the supplemental combustion unit is configured to provide the combustor exhaust stream to the expander at a temperature less than a preferred operating inlet temperature of the expander.
5. The system of claim 2 wherein the main control fuel stream and the supplemental control fuel stream are supplied by a single shared fuel source.
6. The system of claim 2 further including a reformer configured to receive steam and a reaction fuel source and further configured to generate hydrogen, wherein at least a portion of the hydrogen is used for the supplemental control fuel stream.
7. The system of claim 6 wherein another portion of the hydrogen is captured for resale.
8. The system of claim 1 further including a reformer configured to receive steam and a reaction fuel source and further configured to generate hydrogen, wherein at least a portion of reformer products, the hydrogen, or both is used for the main control fuel stream.
9. The system of claim 1 wherein the oxygen stream is pressurized prior to combustion in the main combustion unit.
10. The system of claim 1 wherein the pressure of the oxygen stream is substantially equal to atmospheric pressure when the oxygen stream is received by the main combustion unit.
11. The system of claim 1 wherein the second power generation system includes a supplemental combustion unit configured to receive a supplemental control fuel stream and the supplemental control fuel stream is produced from the pressure maintenance reservoir.
12. The system of claim 1 wherein at least a portion of the compressed gaseous substantially carbon dioxide stream is recirculated back to the main combustion unit.

13. The system of claim 12 wherein an exhaust gas from at least one external source is mixed with the compressed gaseous substantially carbon dioxide stream.
14. The system of claim 1 wherein the main control fuel stream is produced from the hydrocarbon reservoir.
15. The system of claim 1 wherein an exhaust gas from at least one external source is mixed with the compressed gaseous substantially carbon dioxide stream.
16. The system of claim 1 wherein the second power generation system includes:
a compressor configured to receive an air source and generate a compressed turbine air stream;
and
an expander configured to receive the heated compressed turbine air stream and generate a gas turbine exhaust.
17. The system of claim 1 wherein the heat exchange unit is a ceramic heat exchanger and the heated compressed turbine air stream is at a temperature substantially equal to a preferred operating inlet temperature of the expander.
18. The system of claim 16 wherein the heated compressed turbine air stream is at a temperature substantially less than a preferred operating inlet temperature of the expander.
19. The system of claim 16 further including a supplemental combustion unit configured to receive the heated compressed turbine air stream from the heat exchange unit, and increase the temperature of the heated compressed turbine air stream through combustion of a supplemental control fuel stream.
20. The system of claim 1 wherein a water stream is produced from the water of the gaseous combustion stream and the water stream is injected into a reservoir to enhance hydrocarbon recovery.
21. The system of claim 20 wherein the water stream is a low-salinity water stream.

22. The system of claim 1 wherein a water stream is produced from the water of the gaseous combustion stream and the water stream is used in connection with at least one of well work, drilling, plant cooling, and a steam system.

23. The system of claim 1 wherein the oxygen stream comprises air.

24. A method for low emission hydrocarbon recovery with power production, the method comprising the steps of:

generating a gaseous combustion stream having carbon dioxide and water;

generating a compressed air stream;

transferring heat from the gaseous combustion stream to the compressed air stream to form a cooled gaseous combustion stream and a heated compressed air stream;

producing power, a water stream, and a carbon dioxide stream from the cooled gaseous combustion stream using a first power generation system;

producing power from the heated compressed air stream using a second power generation system, wherein the producing power using the second power generation system includes

using a heat exchange unit that receives the gaseous combustion stream to extract the thermal energy from the gaseous combustion stream, and

transferring the thermal energy to a compressed turbine air stream of the second power generation system to form a heated compressed turbine air stream;

injecting at least a portion of the carbon dioxide stream into a hydrocarbon reservoir to increase hydrocarbon production; and

injecting at least a portion of a nitrogen stream into a pressure maintenance reservoir.

25. The method of claim 24 further including the step of increasing the temperature of the heated compressed air stream prior to producing power from the second power generation system.

26. The method of claim 25 wherein the temperature of the heated compressed air stream is increased using a supplemental combustion unit.

27. The method of claim 26 wherein the supplemental combustion unit is configured to receive and combust a hydrogen fuel source produced by a reformer.
28. The method of claim 24 wherein the gaseous combustion stream having carbon dioxide and water is generated by a main combustion unit combusting a mixture of oxygen and fuel.
29. The method of claim 28 wherein the oxygen is generated by an Air Separation Unit.
30. The method of claim 28 wherein the oxygen is provided as air.
31. The method of claim 28 further including the step of re-circulating at least a portion of the carbon dioxide stream to the main combustion unit to moderate combustion temperature in the main combustion unit.
32. The method of claim 1, wherein the hydrocarbon reservoir and the pressure maintenance reservoir are different.