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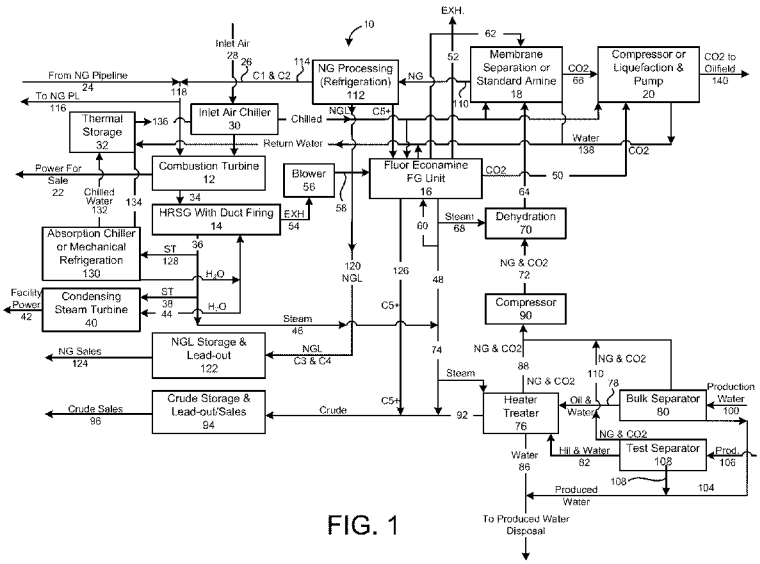


FIG. 1

(57) Abstract: A process for enhanced oil recovery includes the steps of producing steam in at least a first pressure range and a second pressure range, passing the steam of the first pressure range to a steam turbine (40) so as to produce power therefrom, passing the steam of the second pressure range to an amine capture system (16) such that carbon dioxide is delivered therefrom, and injecting the carbon dioxide from the amine capture system into a well (140) for enhanced oil recovery. Steam of a third pressure range can be passed to an absorption chiller (130) so as to cool a liquid therein. The first pressure range is greater than the second pressure range.

PROCESS FOR ENHANCED OIL RECOVERY USING CAPTURE OF CARBON DIOXIDE

FIELD OF THE INVENTION

[0001] The present invention relates to carbon dioxide injection for tertiary hydrocarbon recovery. More particularly, the present invention the relates to portable carbon dioxide generators that can be used for producing the carbon dioxide gas for injection into a hydrocarbon-bearing formation. The present invention also relates to systems and methods whereby steam of different pressures can be utilized to enhance the efficiency of the enhanced recovery process.

BACKGROUND OF THE INVENTION

[0002] The world's power demands are expected to rise 50% by 2030. With worldwide total of active coal plants over 50,000 and rising, the International Energy Agency estimates that fossil fuels will account for 85% of the energy market by 2030. Meanwhile, trillions of dollars worth of oil remain underground in apparently depleted wells.

[0003] The U.S. currently produces approximately 5.1 million barrels of oil per day. Most of the oil fields in the United States are declining in oil recovery productivity. It has been proven that carbon dioxide can be used for enhanced oil recovery so as to increase oil recovery productivity in the declining fields. The Department of Energy estimates that 89 billion barrels of "stranded" oil can be recovered using carbon dioxide for enhanced oil recovery.

[0004] There are tens of thousands of depleted oil and natural gas wells around the world, which collectively possess significant amounts of petroleum resources that cannot currently be extracted using conventional extraction techniques. For example, in a typical oil well, only about 30% of the underground oil is recovered during initial drilling. An additional approximately 20% may be accessed by "secondary recovery" techniques such as water flooding. In recent years, "tertiary recovery" techniques have been developed to recover additional oil from depleted wells. Such tertiary recovery techniques include thermal recovery, chemical injection, and gas injection. Using current methods, these tertiary techniques allow for an additional 20% or more of the original oil-in-place (OOIP) to be recovered.

[0005] Gas injection is one of the most common tertiary techniques. In particular, carbon dioxide injection into depleted oil wells has received considerable attention owing to its ability to mix with crude oil. Since the crude oil is miscible with carbon dioxide, the injection of carbon dioxide renders

the oil substantially less viscous and more readily extractable.

[0006] Carbon dioxide in quantities sufficiently large enough for commercial exploitation generally has come from three sources. One such source is the naturally occurring underground supply of carbon dioxide in areas such as Colorado, Wyoming, Mississippi, and other areas. A second source is that resulting from by-products of the operation of a primary process, such as the manufacture of ammonia or a hydrogen reformer. A third source is found in the exhaust gases from burning of various hydrocarbon fuels. One of the largest problems that is faced by carbon dioxide users is the problem of transportation from the place of production to the point of use.

[0007] Problems exist within the current carbon dioxide pipeline infrastructure in that extensions into potentially productive areas are costly and somewhat limited due to the availability of high purity carbon dioxide. Even in areas that have relatively close proximity to an existing carbon dioxide pipeline, extensions to potential producing areas are costly and time-consuming. The single greatest problem is the lack of commercial quantities of carbon dioxide in close proximity to the oil fields that are in need of this resource to produce the remaining the reserves that are recoverable by using the tertiary recovery methods. This problem is exacerbated when the field is remote to an existing carbon dioxide pipeline and/or is not of sufficient size to justify the costly extension of the pipeline infrastructure. Because an oilfield undergoing tertiary recovery will begin to recycle quantities of carbon dioxide that is recovered along with the tertiary oil, the need for carbon dioxide will diminish significantly over time. This necessitates the recovery of pipeline infrastructure capital costs quickly.

[0008] Currently, carbon dioxide is present in low concentrations, such as within the flue gas from power generation facilities. These plants are found all over the United States and can be fired from a variety of hydrocarbon sources, including coal, fuel oil, biomass, and natural gas. Unfortunately, these facilities are most often located near large water sources due to their need to use this water for cooling during the power production process. In addition, generally, these are very large facilities with a long economic life. There are many oil fields that are not located within sufficiently close proximity to attempt to economically utilize a carbon capture technology and pipeline delivery method to provide the carbon dioxide to the oilfields that have this need.

[0009] In the past, various patents have issued relating to the production of carbon dioxide for

tertiary hydrocarbon recovery. For example, U.S. Patent No. 4,499,946, issued on February 19, 1985 to Martin et al., provides a portable, above-ground system and process for generating combustion gases and for injecting the purified nitrogen and carbon dioxide at controlled temperatures into a subterranean formation so as to enhance the recovery thereof. The system includes a high-pressure combustion reactor for sufficient generation of combustion gases at the required rates and at pressures up to about 8000 p.s.i. and temperatures up to about 4500 °F. The reactor is water-jacketed but lined with refractory material to minimize soot formation.

[0010] U.S. Patent No. 4,741,398, issued on May 3, 1988 to F. L. Goldsberry, shows a hydraulic accumulator-compressor vessel using geothermal brine under pressure as a piston to compress carbon dioxide-rich gas. This is used in a system having a plurality of gas separators in tandem to recover pipeline quality gas from geothermal brine. A first high pressure separator feeds gas to a membrane separator which separates low pressure waste gas from high pressure quality gas. A second separator produces low pressure waste gas. Waste gas from both separators is combined and fed into the vessel through a port at the top as the vessel is drained for another compression cycle.

[0011] U.S. Patent No. 4,824,447, issued on April 25, 1989 to F. L. Goldsberry, describes an enhanced oil recovery system which produces pipeline quality gas by using a high pressure separator/heat exchanger and a membrane separator. Waste gas is recovered from both the membrane separator and a low pressure separator in tandem with the high pressure separator. Liquid hydrocarbons are skimmed off the top of geothermal brine in the low pressure separator. High pressure brine from the geothermal well is used to drive a turbine/generator set before recovering waste gas in the first separator. Another turbine/generator set is provided in a supercritical binary power plant that uses propane as a working fluid in a closed cycle and uses exhaust heat from the combustion engine and geothermal energy of the brine in the separator/heat exchanger to heat the propane.

[0012] U.S. Patent No. 4,899,544, issued on February 13, 1990 to R. T. Boyd, discloses a cogeneration/carbon dioxide production process and plant. This system includes an internal combustion engine that drives an electrical generator. A waste heat recovery unit is provided through which hot exhaust gases from the engine are passed to recover thermal energy in a usable form. A means is provided for conveying exhaust gases coming out of the waste heat recovery unit

to a recovery unit where the carbon dioxide is extracted and made available as a saleable byproduct.

[0013] U.S. Patent No. 7,753,972, issued on July 13, 2010 to Zubrin et al., discloses a portable renewable energy system for enhanced oil recovery. This is a truck mobile system that reforms biomass into carbon dioxide and hydrogen. The gases are separated. The carbon dioxide is sequestered underground for enhanced oil recovery and the hydrogen used to generate several megawatts of carbon-free electricity.

[0014] U.S. Patent Publication No. 2008/0283247, published on November 20, 2008 to Zubrin et al., shows a portable, modular apparatus for recovering oil from an oil well and generating electric power. This system includes a chassis to support a fuel reformer, a gas separator, a power generator, and/or a compressor. The fuel reformer module is adapted to react a fuel source with water to generate a driver gas including a mixture of carbon dioxide gas and hydrogen gas. The gas separator module is operatively coupled to the reformer module and is adapted to separate at least a portion of the hydrogen gas from the rest of the driver gas. The power generator module is operatively coupled to the gas separator module and is adapted to generate electric power using a portion of the separated hydrogen gas. The compressor module is operatively connected to the reformer module and is adapted to compress a portion of the driver gas and to eject the driver gas at high pressure into the oil well for enhanced oil recovery.

[0015] U.S. Patent Publication No. 2009/0236093, published on September 24, 2009 to Zubrin et al., shows a method for extracting petroleum by using reformed gases. This method includes reforming a fuel source by reaction with water to generate driver gas and injecting the driver gas into the oil well. The reforming operation includes causing the combustion of a combustible material with ambient oxygen for the release of energy. A reforming reaction fuel and water is heated with the energy released from this heating process. This is at a temperature above that required for the reforming reaction in which the fuel and water sources are reformed into driver gas.

[0016] U.S. Patent Publication No. 2010/0314136, published on December 16, 2010 to Zubrin et al., discloses an in-situ apparatus for generating carbon dioxide gas at an oil site for use in enhanced oil recovery. The apparatus includes a steam generator adapted to boil and superheat water to generate a source of superheated steam, as well as a source of essentially pure oxygen. The apparatus also includes a steam reformer adapted to react a carbonaceous material with the superheated steam and

the pure oxygen, in an absence of air, to generate a driver gas made up of primarily carbon dioxide gas and hydrogen. A separator is adapted to separate at least a portion of the carbon dioxide gas from the rest of the driver gas to generate a carbon dioxide-rich driver gas and a hydrogen-rich fuel gas. A compressor is used for compressing the carbon dioxide-rich driver gas for use in enhanced oil recovery.

[0017] U.S. Patent Publication No. 2011/0067410, published on March 24, 2011 to Zubrin et al., teaches a reformation power plant that generates clean electricity from carbonaceous material and high pressure carbon dioxide. The reformation power plant utilizes a reformation process that reforms carbonaceous fuel with super-heated steam into a high-pressure gaseous mixture that is rich in carbon dioxide and hydrogen. This high-pressure gas exchanges excess heat with the incoming steam from a boiler and continues onward to a condenser. Once cooled, the high-pressure gas goes through a methanol separator, after which the carbon dioxide-rich gas is sequestered underground or is re-used. The remaining hydrogen-rich gas is combusted through a gas turbine. The gas turbine provides power to a generator and also regenerative heat for the boiler. The generator converts mechanical energy into electricity, which is transferred to the electric grid.

[0018] It is an object of the present invention to provide a system for use in hydrocarbon recovery that places a high purity carbon dioxide source close to the hydrocarbon-bearing formation.

[0019] It is another object of the present invention to provide a system for producing carbon dioxide and hydrocarbon recovery which is portable.

[0020] It is still another object of the present invention to provide a system for producing carbon dioxide for use in hydrocarbon recovery that can be permitted as a minor emission source.

[0021] It is still a further object of the present invention to provide a system for producing carbon dioxide for use in hydrocarbon recovery which can be delivered in short order to a desired location.

[0022] It is a further object of the present invention to provide a system for producing carbon dioxide for use in hydrocarbon recovery which allows power to be sold into the power grid.

[0023] It is still another object of the present invention to provide a system for producing carbon dioxide for use in hydrocarbon recovery that is environmentally beneficial.

[0024] It is still a further object of the present invention to provide a system for producing carbon dioxide for use in hydrocarbon recovery which minimizes site work and field construction costs and

equipment.

[0025] It is still a further object of the present invention to provide a system that will minimize water requirements for the enhanced hydrocarbon recovery.

[0026] These and other objects and advantages of the present invention will become apparent from a reading of the attached specification and appended claims.

BRIEF SUMMARY OF THE INVENTION

[0027] The present invention is a process for enhanced oil recovery from a well in which the process includes the steps of: (1) producing steam in at least a first pressure range and a second pressure range; (2) passing the steam of the first pressure range to a steam turbine so as to produce power therefrom; (3) passing the steam of the second pressure range to an amine capture system such that carbon dioxide is delivered therefrom; and (4) injecting the carbon dioxide from the amine capture system into a well for enhanced oil recovery.

[0028] In the present invention, the step of producing steam further includes producing steam in a third pressure range. The third pressure range is passed to an absorption chiller so as to cool a liquid therein. The steam of the first pressure range has a pressure range greater than the pressure of the steam of the second pressure range. The pressure of the steam is of the second pressure range is greater than the pressure of the steam in the third pressure range. The first pressure range will have a pressure greater than 500 p.s.i.g. The steam of the second pressure range will have a pressure of between 150 and 200 p.s.i.g. The steam of the third pressure range will be less than 25 p.s.i.g.

[0029] The steam of the second pressure range can be used of variety of purposes. In particular, the steam of the second pressure range can be passed to a dehydration unit so as to dry the natural gas passing therethrough. Additionally, the steam of the second pressure range can be passed to a heater treater. Initially, oil and water are pumped from the well into the heater treater. The pumped oil and water are heated in the heater treater with the passed steam of the second pressure range. Water is separated from the pumped oil and water in the heater treater.

[0030] In the present invention, the step of producing steam includes the steps of operating a heat recovery steam generator so as to produce the steam and to produce an exhaust. The exhaust is delivered the exhaust to the amine capture system. The carbon dioxide is separated from the exhaust by the amine capture system. The energy is initially produced by a combustion turbine. The

combustion turbine is operated so as to provide power to the heat recovery steam generator.

[0031] In the present invention, the step of injecting the carbon dioxide includes the steps of compressing the carbon dioxide to a pressure of up to 2000 p.s.i.g. The compressed carbon dioxide is injected into the well.

[0032] The use of the combustion turbine in conjunction with the heat recovery steam generator provides power for sale and use in the project and steam for additional power. The heat recovery steam generator allows for the generation of steam at various steam pressures. Within the present invention, it is contemplated that the heat recovery steam generator will generate steam in at least two, and most likely, three different pressure ranges. By a using a heat recovery steam generator with multiple steam pressures, the exhaust temperature (containing the carbon dioxide to be captured) can be greatly lowered. This, in turn, increases the retention of the enhanced amine solution.

[0033] The high pressure steam (in excess of 500 p.s.i.g.) will be utilized to generate additional power through the use of a condensing steam turbine. The turbine condenses the steam that is produced and is used to generate additional power. The steam is converted back to water for reintroduction to the heat recovery steam generator. This serves to generate additional power without the necessity of the large volumes of water required in many installations, or the capital costs and electrical requirements of the air cooling.

[0034] The medium pressure steam (approximately 150 - 200 p.s.i.g.) will be utilized to provide the heat of the regeneration of the enhanced amine in the carbon dioxide capture system as well as for the regeneration of glycol in the gas dehydration system. The medium pressure steam can also be used for the regeneration of the standard amine in the facility that is used to separate recycle gas coming from the oil field into its natural gas and carbon dioxide components.

[0035] The low pressure steam (up to approximately 25 p.s.i.g.) will be used to provide the heat required for the absorption chillers that are used to cool turbine inlet air and to cool the regenerated enhanced amine and normal amine before injection into the respective contactor vessels. A portion of this steam, or possibly even hot water being returned from the absorption chillers, will be utilized to heat the inlet oil and water in the heater-treater on the inlet side of the central oil field production facilities. If optimization would indicate that a portion of the steam can provide all or a portion of

the refrigeration for the natural gas processing, then the steam can be utilized as part of the natural gas liquids separation facility.

[0036] The enhanced oil recovery projects are long term developments. Typically, they would require carbon dioxide for many years. The production outcomes are predictable. An oil field central processing facility has to be in service for the same period of time and would require two externally provided inputs, heat and power. Given the reservoir and oil characteristics, a reservoir simulation model can be created and the outputs of that model can be utilized to design the central facility equipment. Through the use of the heat from the combustion turbine, the overall efficiency of the process is greatly improved.

[0037] A standard oil field central processing facility will have a gas flame-driven heat source for the amine plant, the heater-treater and the gas dehydrator. Each of these pieces of equipment has its own safety and emissions issues. The integrated design of the present invention allows a single source of heat and emissions to be the combustion turbine. In this facility, the insulated steam and return lines will travel to and from each individual piece of equipment taking heat and returning water to the process with minimal losses.

[0038] There has been and will continue to be a push to increase the energy efficiency of processes wherever they are located. Unfortunately, one of the areas that has historically been one of the most wasteful users of energy has been the energy industry itself. The present invention generates heat, savings for the oil-gas-water separation and the heater-treater, gas-water separation in the dehydrator, natural gas-carbon dioxide separation in the amine and enhanced amine processes, and savings for the absorption chilling refrigeration process. Studies have indicated that this integrated process generates an approximately 16% reduction in the use of external energy in the central processing and also a similar reduction in emissions. This 16% energy savings does not take into consideration the heat that is required to regenerate the enhanced amine that captures the carbon dioxide in the first place. If the energy required for this process was provided, separate and apart from the heat recovery steam generator, it would require an increase of approximately 42% in the external fuel, and subsequent emissions requirements. The integrated process of the present invention provides an effective method of generating carbon dioxide for enhanced oil recovery directly at an oil field location while, at the same time, providing all the necessary heat and power required to run all of the

associated oil field processes in the most efficient manner possible.

[0039] This foregoing Section is intended to describe, in generality, the preferred embodiment of the present invention. It is understood that modifications to the process of the present invention can be made within the scope of the present invention. As such, this Section should not to be construed, in any way, as limiting of the broad scope of the present invention. The present invention should only be limited by the following claims and their legal equivalents.

BRIEF DESCRIPTION OF THE DRAWINGS

[0040] FIGURE 1 is a block diagram showing the process of the enhanced oil recovery of the present invention.

DETAILED DESCRIPTION OF THE INVENTION

[0041] Referring to FIGURE 1, there is shown the process 10 for enhanced oil recovery. The process 10 of the present invention includes a combustion turbine 12, a heat recovery steam generator 14, amine capture systems 16 and 18, and a compressor 20.

[0042] The combustion turbine 12 is a natural gas-powered combustion turbine which utilizes natural gas as the fuel source. The combustion turbine 12 includes a generator suitable for generating electrical energy. The combustion turbine 12 is connected by line 22 to the electrical grid or to suitable batteries. As such, the electrical energy produced by the combustion turbine 12 can be connected to the electrical grid so that electrical energy from the combustion turbine 12 can be sold to the utilities. The combustion turbine 12 is connected to a natural gas pipeline 24 and/or to the natural gas line 26 which emanates from the process 10. Inlet air to the combustion turbine 12 is provided along inlet air line 28. The inlet air passing through line 28 is delivered to an inlet air chiller 30. The inlet air chiller cools the inlet to a cooler temperature so that the output of the combustion turbine 12 remains more constant. For example, in hot weather, the combustion turbine 12 will operate less efficiently. The inlet air chiller 30 will serve to cool the inlet air to approximately 60°F prior to passing to the combustion turbine 12. The inlet air 30 will sit above the turbine. As such, water will fall out from the inlet air chiller 30. This chilled water can then be provided to the thermal storage 32 or for other make-up water needs.

[0043] The exhaust from the combustion turbine 12 is delivered to the heat recovery steam generator 14. The heat recovery steam generator 14 causes the hot exhaust 34 from the combustion turbine

12 to pass therethrough such that the heat recovery steam generator 14 will extract residual heat from the hot exhaust 34 and produce steam for the process of the present invention. The heat recovery steam generator 14 will also lower the exhaust temperature before the exhaust gases pass into the amine capture systems 16 and/or 18. Importantly, the heat recovery steam generator 14 will produce a great deal of steam. In particular, the heat recovery steam generator 14 will produce steam of a first pressure range, a second pressure range, and a third pressure range. Line 36 shows the steam output from the heat recovery steam generator 14. It can be seen that the steam of the first pressure range 38 will pass to a condensing steam turbine 40. The first pressure range of the steam passing from line 36 into line 38 will be greater than 500 p.s.i.g. As such, the steam will have sufficient power so as to properly operate the condensing steam turbine.

[0044] The steam turbine 40 is a device that extracts thermal energy from pressurized steam and uses it to carry out mechanical work on a rotating output shaft. Since the steam turbine 40 utilizes rotary motion, it is particularly suited to be used to drive an electrical generator. The steam turbine is in the form of a heat engine that derives most of its improvement in thermodynamic efficiency through the use of multiple stages in the expansion of the steam. Ultimately, the electrical power for the process 10 of the present invention can be provided as an output 42 of the condensing steam turbine. The steam 38 of the first pressure range is returned back to the heat recovery steam generator 14 along line 44 as water.

[0045] The heat recovery steam generator 14 also passes the steam along line 36 so as to produce steam of a second pressure so as to be delivered along line 46. The steam of the second pressure, as passed along line 46, will be in the range of between 150 p.s.i.g. and 200 p.s.i.g. Suitable valving systems, known in the art, can serve to properly deliver the desired pressure of steam along the respective lines. The steam of the second pressure range can be utilized for a variety of purposes. The steam passing along line 46 can then pass to line for delivery to the amine capture system 16. In particular, the amine capture system 16 is a Fluor Econamine FG Unit.

[0046] The Fluor Econamine FG Unit which forms the amine capture system 16 is an amine-based technology for a large-scale, post-combustion carbon dioxide capture. The Econamine FG Plus technology is one of the first and one of the most widely applied commercial solutions that has been proven in operating environments to remove carbon dioxide from high oxygen content flue gases.

The amine capture system 16 utilizes a solvent formulation that is specially designed to recover carbon dioxide from low-pressure, oxygen-containing streams, such as boilers and reformer stack gas and gas-turbine flue-gas streams. The carbon dioxide recovered by the amine capture system 16 can be tailored to meet the end user's specifications. In particular, the amine capture system 16 utilizes a particular type of amine that captures carbon dioxide without degrading in the presence or oxygen.

[0047] The steam passing along 18 is used to provide heat. In this amine capture system, the amine will enter the contactor tower and trickle downward while the exhaust gases flow upwardly. As such, the amine will contact the exhaust gases and retain the carbon dioxide. The amine and carbon dioxide is then delivered to a boiler (heated by the steam 48) such that the carbon dioxide will boil out of the amine then be delivered outwardly along line 50 in the system 10. Exhaust gases pass from the amine capture system 16 along line 52.

[0048] The exhaust from the heat recovery steam generator 14 is passed along line 54 to a blower 56. The blower 56 is in the nature of a fan. As such, the exhaust 56 can provide further heat for the amine capture system 16. The exhaust, as passed by the blower 56, will contain additional carbon dioxide that can be removed through the use of the amine capture system 16. The higher velocity exhaust gas from line 58 is delivered by blower 56 along line 58 as an input into the amine capture system 16.

[0049] The steam of the second pressure can further be delivered along lines 60 and 62 to the amine capture system 18. The amine capture system 18 is a membrane separator or a standard amine contactor. The membrane separator or standard amine contactor as used as part of the amine capture system 18 serves to remove the carbon dioxide from the natural gas and carbon dioxide mixture as passes as an input along 64 to the amine capture system 18. The carbon dioxide output is passed along line 66 to the compressor 20. The amine capture system 18 serves to receive the solution containing carbon dioxide. The steam from the heat recovery steam generator 14 is delivered along lines 60 and 62 as heat to the amine capture system 18. As such, this heat is used so as to strip the carbon dioxide from the solution. As a result, the low pressure carbon dioxide will pass outwardly of the amine capture system 18 along line 66 to the carbon dioxide compressor 20. The carbon dioxide that passes along line 66 is a low-pressure, high-purity carbon dioxide.

[0050] The amine capture system 18 utilizes the steam of the second pressure range, as passed along line 48, directly to the amine capture system 18. Additionally, the amine capture system 18 can also utilize steam that is produced from the amine capture system 16. As such, the steam that is part of the output of the amine capture system 16 can be further utilized within the system 10 of the present invention.

[0051] The steam of the second pressure can also be used to facilitate the drying of the natural gas and carbon dioxide that has been produced from the well. In particular, steam of the second pressure range passes along line 68 into the dehydration unit 70. The dehydration unit 70 utilizes triethylene glycol to remove water from the mixture of carbon dioxide and natural gas that passes as an input along line 72 to the dehydration unit 70. The dehydration unit 70 takes the water out of the carbon dioxide and natural gas mixture. As such, only a dry gas mixture of the natural gas and carbon dioxide will pass along line 64 as an input to the amine capture system 18.

[0052] The steam of the second pressure can further pass along line 74 as a steam input to the heater treater 76. The heater treater 76 is a vessel that is commonly used in the oil field. In particular, the heater treater 76 receives an oil and water mixture from line 78 from a bulk separator 80. Additionally, the heater treater 76 can further receive oil and water along line 82 from the test separator 84. As a result, the heater treater 76 will contain a mixture of oil and water therein. In normal application, water will settle within the heater treater while oil will flow toward the top. By the application of the steam of the second pressure range from the heat recovery steam generator 14, the temperature of the oil and water mixture within the heater treater 76 is elevated. As such, this will enhance the separation process. Ultimately, water will pass outwardly of the heater treater 76 along line 86 for disposal. The natural gas and carbon dioxide will flow outwardly of the heater treater 76 along line 88 to a compressor 90. The crude oil that is separated from the water in heater treater 76 is passed along line 92 to crude storage vessel 94. Ultimately, the crude oil that is received within the storage vessel 94 can be provided as a salable product along line 96.

[0053] The compressor 90 receives the mixture of natural gas and carbon dioxide from the heater treater 76 and builds up the pressure of the gas. Typically, natural gas and carbon dioxide will have a pressure of approximately 75 p.s.i.g. from the field. The compressor 90 will enhance the pressure of the natural gas and carbon dioxide mixture to between 600 and 700 p.s.i. As such, the compressed

mixture of natural gas and carbon dioxide can flow into the dehydration unit 70 along line 72.

[0054] As can be seen in FIGURE 1, the bulk separator 80 receives production fluids from the well along line 100. As such, the production well fluids will typically include natural gas, carbon dioxide, water and oil. The bulk separator 80 serves to pass the separated natural gas and carbon dioxide mixture along line 102 for delivery to the compressor 90 and/or into the line 88 from the heater treater 76. The oil and water mixture from the bulk separator 80 passes along line 78 as an input to the vessel at the heater treater 76. The water from the bulk separator will pass along line 104 for disposal.

[0055] The test separator 84 receives production fluid along line 106. The test separator operates on each well separately. The test separator 84 can determine how much carbon dioxide is associated with the oil. The test separator 84 will then pass the oil and water mixture the heater treater 76 along line 82. The test separator 84 will further transmit the produced water along line 108 for disposal. Additionally, the natural gas and carbon dioxide mixture from the test separator 84 is delivered along line 110 to the compressor 90. As such, the natural gas and carbon dioxide mixture from the heater treater 76, from the bulk separator 80, and from the test separator 84 will flow for use in the system 10 of the present invention.

[0056] In FIGURE 1, it can be seen that the amine capture system 18 serves to separate the carbon dioxide from the natural gas. As stated previously, the carbon dioxide will flow outwardly of the amine capture system 18 along line 66 to the compressor 20. The natural gas, as separated from the carbon dioxide, will flow along line 110 to a natural gas processing system 112. The natural gas processing system 112 utilizes refrigeration so as to separate the various components of the natural gas. In particular, the methane and ethane will flow outwardly of the natural gas processing system 112 along line 114. The methane or ethane that passes along line 114 can be delivered to the natural gas pipeline 116. Alternatively, the natural gas that passes in the line 114 can be utilized as the fuel for the combustion turbine 12. As such, this natural gas would flow along line 118 as a fuel input to the combustion turbine 12.

[0057] The natural gas processing system 112 will further pass natural gas liquids along line 120 to a natural gas liquid storage and loadout facility 122. The natural gas liquids can include propane and butane. As such, the gas will need to be pressurized for delivery. Ultimately, any natural gas liquids

that are in the natural gas storage and loadout facility 122 can be delivered along line 124 for sale.

[0058] The natural gas processing system 112 can deliver pentanes and hexanes along line 126 for mixture with the crude passing in line 92. As such, these heavy natural gas components can be delivered as part of the crude product from the system 10.

[0059] The heat recovery steam generator 14 further produces steam of a third pressure range. This third pressure range will be in the order of less than 25 p.s.i.g. The steam of the second pressure range is delivered along line 128 to an absorption chiller 130. The cooling provided by the absorption chiller 130 can also be provided by a mechanical refrigeration unit. The steam passing in line 128 is used to provide the energy to the absorption chiller 130. The absorption chiller 130 can produce chilled water for delivery to the thermal storage 32 along line 132. The absorption chiller 130 will receive water, for chilling, along line 134 from the thermal storage 32.

[0060] The thermal storage 32 is in the nature of a tank. Typically, the water within the tank of the thermal storage 32 will contain glycol so as to avoid any freezing. The glycol will facilitate the ability to cool the water on a hot day while keeping the water from freezing on extremely cold days. The thermal storage 32 will further level out the refrigeration load of the system. Ultimately, warm water from the thermal storage 32 will pass for cooling to the absorption chiller 130. The thermal storage 32 serves to deliver chilled water along line 136 to the inlet air chiller 30, to the amine capture system 16, to the amine capture system 18 and to the compressor 20. Ultimately, after the chilled water has been utilized by these components, the water will return along line 138 back to the thermal storage 32. It is also possible that the chilled water flowing from the thermal storage 32 can also be used to facilitate the refrigeration of the natural gas in the natural gas processing system 112.

[0061] The compressor 20 serves to deliver the compressed carbon dioxide along line 140 to the well. The carbon dioxide that is compressed by the compressor 20 is received from the amine capture system 18. The compressor 20 will serve to compress the carbon dioxide to a pressure of approximately 2000 p.s.i.g. As such, this compressed carbon dioxide can be utilized for tertiary oil recovery in the well.

[0062] The foregoing disclosure and description of the invention is illustrative and explanatory thereof. Various changes in the details of the illustrated construction and the steps of the described method can be made within the scope of the present invention without departing from the true spirit

of the invention. The present invention should only be limited by the following claims and their legal equivalents.

CLAIMS

I claim:

1. A process for enhanced oil recovery from a well, the process comprising:

producing steam in at least a first pressure range and a second pressure range;

passing the steam of the first pressure range to a steam turbine so as to produce power therefrom;

passing the steam of the second pressure range to an amine capture system such that carbon dioxide is delivered therefrom; and

injecting the carbon dioxide from said amine capture system into a well for enhanced oil recovery.

2. The process of Claim 1, the step of producing steam further comprising:

producing steam in a third pressure range; and

passing the steam of the third pressure range to an absorption chiller so as to cool a liquid therein.

3. The process of Claim 2, said first pressure range having a pressure greater than a pressure of said second pressure range, said second pressure range having a pressure greater than a pressure of said third pressure range.

4. The process of Claim 1, passing the steam of the second pressure range to a dehydration unit so as to dry the natural gas passing therethrough.

5. The process of Claim 1, further comprising:

passing the steam of the second pressure range to a heater treater;

pumping oil and water from the well into said heater treater;

heating the pumped oil and water in the heater treater with passed steam of the second pressure range; and

separating water from the heated pumped oil and water in the heater treater.

6. The process of Claim 1, the step of producing steam comprising:

operating a heat recovery steam generator so as to produce the steam and to produce an exhaust;

delivering the exhaust to the amine capture system; and

separating carbon dioxide from the exhaust by said amine capture system.

7. The process of Claim 6, further comprising:

producing energy from a combustion turbine; and

operating said combustion turbine so as to provide power to said heat recovery steam generator.

8. The process of Claim 1, the step of injecting comprising:

compressing the carbon dioxide to a pressure of up to 2000 p.s.i.g.; and

injecting the compressed carbon dioxide into the well.

9. A process for enhanced oil recovery from a well, the process comprising:

producing steam in at least two pressure ranges;

passing the steam of one pressure range to an amine capture system such that carbon dioxide is delivered therefrom;

passing steam of the other pressure range to an absorption chiller so as to cool a liquid therein;

passing the cooled liquid to said amine capture system; and

injecting the carbon dioxide from the amine capture system into a well for enhanced oil recovery.

10. The process of Claim 9, further comprising:

producing steam of another pressure range; and

passing the steam of said another pressure range to a steam turbine so as to produce power therefrom.

11. The process of Claim 9, further comprising:

operating a heat recovery steam generator so as to produce the steam of the at least two pressure range.

12. The process of Claim 9, the steps of passing the steam comprising:

selectively moving steam of said one pressure range to said amine capture system and steam of the other pressure range to said absorption chiller.

13. The process of Claim 9, further comprising:

passing the steam of the one pressure range to a dehydration unit so as to dry natural gas passing therethrough.

14. The process of Claim 9, further comprising:

passing the steam of the one pressure range to a heater treater;

pumping oil and water from the well into said heater treater;

heating the pumped oil and water in the heater treater with passed steam of said one pressure range; and

separating the oil from the heated pumped oil and water in the heater treater.

15. The process of Claim 9, the step of producing steam comprising:

operating a heat recovery steam generator so as to produce the steam and to produce an exhaust;

delivering the exhaust to the amine capture system; and

separating carbon dioxide from the exhaust by said amine capture system.

16. The process of Claim 15, further comprising:

producing energy from a combustion turbine; and

operating said combustion turbine so as to provide power to said heat recovery steam generator.

17. A process for enhanced oil recovery from a well, the process comprising:

producing steam from a heat recovery steam generator;

passing the steam from the heat recovery steam generator to an amine capture system;

delivering a mixture of carbon dioxide and natural gas to said amine capture system;

operating said amine capture system such that carbon dioxide and natural gas are passed separately therefrom; and

injecting the carbon dioxide from said amine capture system into the well for enhanced oil recovery.

18. The process of Claim 17, further comprising:

producing steam of another pressure from said heat recovery steam generator;

passing said steam of another pressure to an absorption chiller so as to cool a liquid therein; and

introducing the cooled liquid to said amine capture system so as to cool the amine therein.

19. The process of Claim 17, further comprising:

producing steam of a further pressure from said heat recovery steam generator;

passing the steam of the further pressure to a steam turbine so as to drive said steam turbine; and

producing power from said steam turbine.

20. The process of Claim 17, further comprising:

operating said heat recovery steam generator so as to produce the steam and an exhaust;

delivering the exhaust to said amine capture system; and

separating carbon dioxide from the exhaust by said amine capture system.

injecting the carbon dioxide from said amine capture system into a well for enhanced oil recovery.

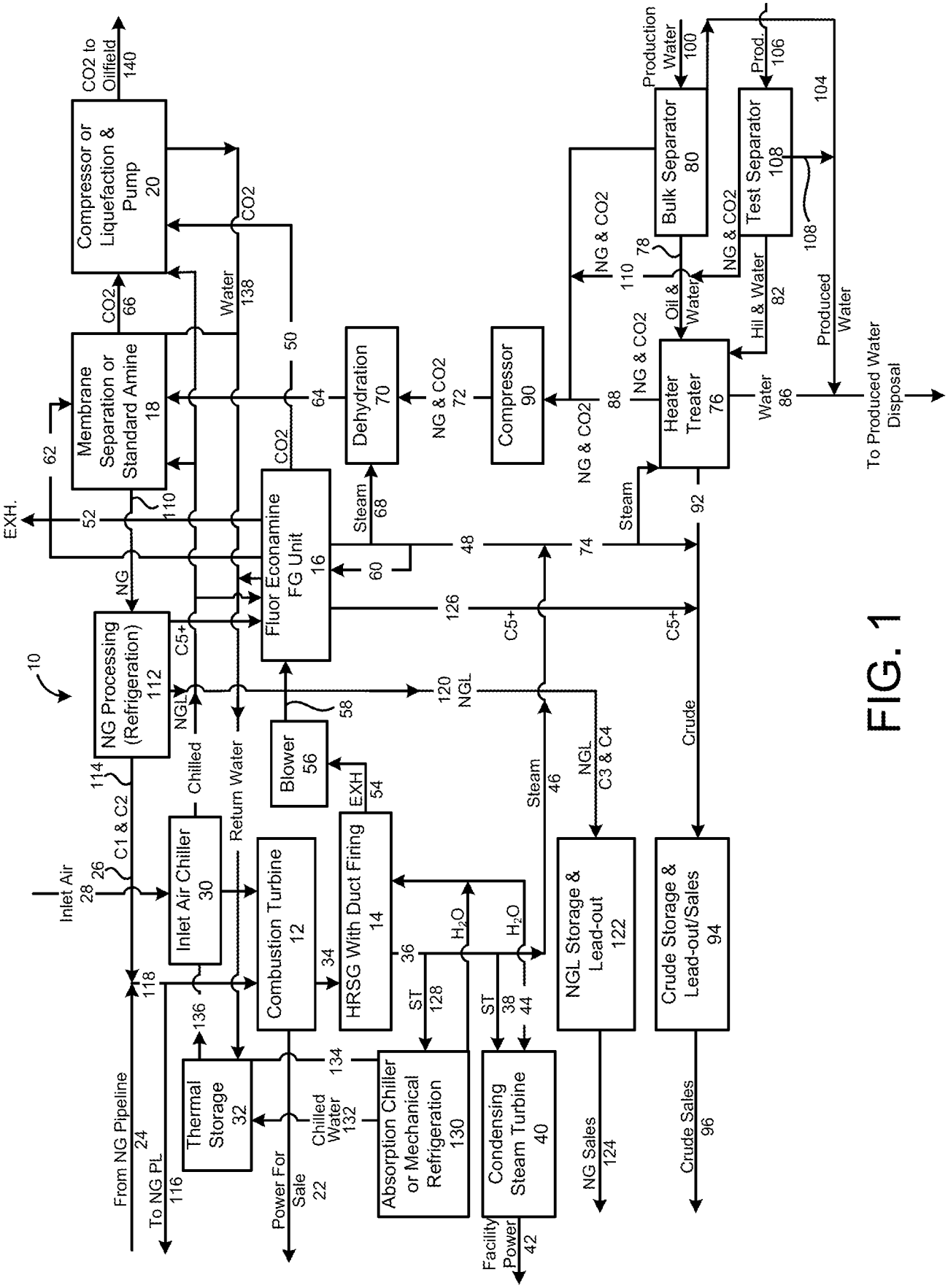

10
Inlet Air
28
26
C1 & C2
114
Inlet Air Chiller 30
Chilled
Return Water
136
Thermal Storage 32
118
From NG Pipeline 24
To NG PL 116
Power For Sale 22
Chilled Water 132
134
Absorption Chiller or Mechanical Refrigeration 130
Combustion Turbine 12
34
HRSG With Duct Firing 14
36
ST 128
ST 38
44
Condensing Steam Turbine 40
Facility Power 42
H2O
H2O
Blower 56
EXH 54
58
NG Processing (Refrigeration) 112
NGL
C5+
NG
Membrane Separation or Standard Amine 18
62
CO2
66
Compressor or Liquefaction & Pump 20
CO2 to Oilfield 140
Water 138
CO2
50
EXH.
52
110
Fluor Econamine FG Unit 16
CO2
64
Dehydration 70
NG & CO2 72
Steam 68
60
48
126
120 NGL
Steam 46
NGL C3 & C4
NGL Storage & Lead-out 122
NG Sales 124
Compressor 90
NG & CO2 88
74
C5+
Crude
Crude Storage & Lead-out/Sales 94
Crude Sales 96
Steam
92
Heater Treater 76
NG & CO2
Water 86
To Produced Water Disposal
Produced Water
Hil & Water 82
Oil & Water
78
Bulk Separator 80
NG & CO2 110
Production Water 100
Test Separator 108
NG & CO2
Prod. 106
104
108

FIG. 1

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2014/043086

A. CLASSIFICATION OF SUBJECT MATTER

E21B 43/16(2006.01)i, F01D 15/10(2006.01)i, E21B 43/34(2006.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 43/16; E21B 43/24; F02C 7/00; E21B 43/22; E21B 43/26; F02C 6/00; F01D 15/10; E21B 43/34

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & keywords: oil recovery, carbon dioxide, steam, exhaust, dehydration, heater treater, amine capture system

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2013-0036748 A1 (LEWIS, MICHAEL J.) 14 February 2013 See paragraphs [0042]-[0046], claim 1, and figure 1.	1-3,6-12,15-20
A		4-5,13-14
Y	US 2010-0206565 A1 (EMBRY et al.) 19 August 2010 See paragraphs [0015],[0018]-[0024], claim 8, and figure 1.	1-3,6-12,15-16,19
Y	US 2012-0090325 A1 (LEWIS, MICHAEL J.) 19 April 2012 See paragraphs [0046]-[0047] and figure 1.	7,16
Y	US 2009-0194280 A1 (GIL et al.) 06 August 2009 See paragraphs [0061]-[0062] and figure 1.	17-20
A	US 2010-0243248 A1 (GOLOMB et al.) 30 September 2010 See paragraphs [0029],[0091],[0094] and figure 7.	1-20

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
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"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents,such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.
PCT/US2014/043086

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		WO 2008-070035 A3	16/10/2008