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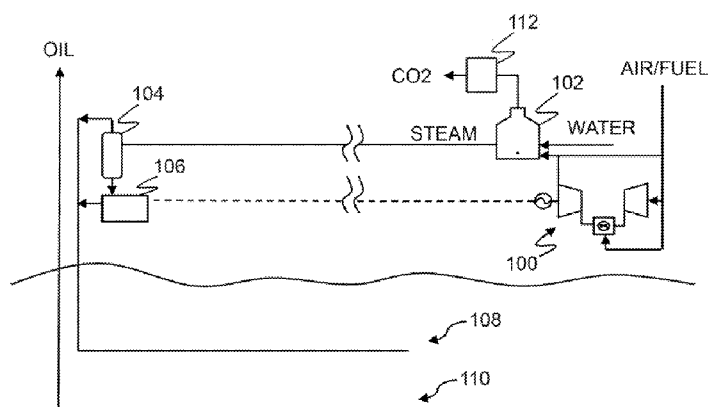


FIG. 1

(57) **Abstract:** Methods and systems relate to steam assisted oil recovery utilizing a fired boiler and an electric boiler, which may be disposed closer to an injection well than the fired boiler. A gas turbine produces electricity supplied to the electric boiler and flue gas exhaust that may input into the fired boiler. The electric boiler may vaporize condensate that forms from the steam generated in the fired boiler prior to being introduced into the injection well.

ELECTRIC AND FIRED STEAM GENERATION SYSTEMS

FIELD OF THE INVENTION

[0001] Embodiments of the invention relate to generating steam for steam assisted production of hydrocarbons with a fired boiler and an electric boiler.

BACKGROUND OF THE INVENTION

[0002] Recovery of heavy oil reserves often requires use of high quality steam to heat and mobilize the oil through processes such as steam assisted gravity drainage (SAGD). Energy intensive steam generators, such as once through steam generators (OTSGs), produce the steam often conveyed from a central processing facility to multiple wells for injection. For example, distances of up to ten kilometers may separate well pads from the steam generators.

[0003] Heat losses in steam lines and pressure let-down at such well pads results in condensation of about five percent of the steam. Prior approaches to compensate for the condensation at the well pads rely on oversizing the steam generators and water treatment systems. However, the oversizing adds to costs while providing an inefficient process.

[0004] The oil reserves recovered with the steam often exist in cold climates contributing to the heat losses. Temperature variations throughout a year create additional problems with determining desired steam demand since condensation levels may fluctuate. Further, the heat losses may limit how far the central processing facility may be from the well pads.

[0005] Therefore, a need exists for systems and methods that provide cost efficient injection quality steam at the well pad.

BRIEF SUMMARY OF THE DISCLOSURE

[0006] In one embodiment, a method of steam assisted oil recovery with dual steam generation includes producing electricity with an onsite gas turbine, generating steam with a fired boiler at a first location and conveying the steam to a second location resulting in a mixture formed of the steam and condensate caused by heat loss during the conveying. Upon separating the steam from the condensate in the mixture, an electric boiler powered by the electricity from the gas turbine heats the condensate to convert the

condensate back to a vapor phase combined with the steam separated from the condensate to provide a combined steam flow. The method further includes introducing the combined steam flow into a formation for the steam assisted oil recovery.

[0007] According to one embodiment, a method of steam assisted oil recovery with dual steam generation includes producing electricity with an onsite gas turbine, generating steam with both a fired boiler coupled to use a flue gas exhaust of the gas turbine as an oxidant feed for combustion in the fired boiler and an electric boiler powered by the electricity from the gas turbine. Introducing the steam from the fired boiler and the electric boiler into at least one injection well enables the steam assisted oil recovery.

[0008] For one embodiment, a system for steam assisted oil recovery with dual steam generation includes an onsite gas turbine to produce electricity, a fired boiler to generate steam at a first location and a steam conduit coupled to the fired boiler for conveying the steam to a second location. A separator couples to the steam conduit for dividing the steam from condensate formed by heat loss along the steam conduit and feeds the condensate to an electric boiler powered by the electricity from the gas turbine to heat and convert the condensate back to a vapor phase. An injection well couples to vapor outputs from the separator and the electric boiler for the steam assisted oil recovery.

BRIEF DESCRIPTION OF THE DRAWINGS

[0009] A more complete understanding of the present invention and benefits thereof may be acquired by referring to the following description taken in conjunction with the accompanying drawings in which:

[0010] Figure 1 is a schematic of a production system for steam assisted oil recovery utilizing a fired boiler and an electric boiler disposed closer to an injection well than the fired boiler, according to one embodiment of the invention.

DETAILED DESCRIPTION

[0011] Turning now to the detailed description of the preferred arrangement or arrangements of the present invention, it should be understood that the inventive features and concepts may be manifested in other arrangements and that the scope of the invention

is not limited to the embodiments described or illustrated. The scope of the invention is intended only to be limited by the scope of the claims that follow.

[0012] Methods and systems relate to steam assisted oil recovery utilizing a fired boiler and an electric boiler, which may be disposed closer to an injection well than the fired boiler. A gas turbine produces electricity supplied to the electric boiler and flue gas exhaust that may input into the fired boiler. The electric boiler may vaporize condensate that forms from the steam generated in the fired boiler prior to being introduced into the injection well.

[0013] Figure 1 illustrates an exemplary system that includes a gas turbine 100, a fired boiler 102, a separator 104, an electric boiler 106, an injection well 108 and a production well 110. While illustrated in an exemplary SAGD configuration, other techniques, such as cyclic steam stimulation, solvent assisted SAGD, steam drive or huff and puff, may employ the steam generated as described herein. The injection well 108 extends in a horizontal direction and above the production well 110 also extending in the horizontal direction.

[0014] In operation, steam generated by the boilers 102, 106 enters a formation along the injection well 108 forming a steam chamber with heat transferred from the steam to oil or bitumen in the formation. The oil once heated becomes less viscous and mobile enough for flowing by gravity along with condensate of the steam to the production well 110. A mixture of the condensate and oil collected in the production well 110 flows to surface where the oil to be sold is removed from recovered water, which is recycled for generating additional steam to sustain steam injection.

[0015] The gas turbine 100 combusts fuel, such as natural gas, with an oxidant, such as air, to drive an electrical generator. In some embodiments, the gas turbine 100 operates at a central processing facility of an oil recovery site to at least generate electricity for the electric boiler 106. The gas turbine 100 may also provide other electricity requirements for the site.

[0016] The fired boiler 102, such as a once through steam generator, may also operate at the central processing facility and receives fuel and an oxidant supply for combustion at a burner to heat water that is input. At least part of the water converts to the steam that may have a quality of at least seventy-five percent and may be separated

from remaining liquid blowdown prior to being conveyed to the injection well 108. The pressure of the steam generated by the fired boiler 102 in some embodiments ranges from 5000 kilopascals (kPa) to 11,000 kPa and is selected depending on desired injection pressure with accounting for pressure losses when conveyed to the injection well 108.

[0017] For some embodiments, flue gas exhaust from the gas turbine 100 passes to the fired boiler 102 where the exhaust is used as at least part of the oxidant supply to the fired boiler 102. The gas turbine 100 operates at excess air input levels such that the exhaust may contain 12-15 volume percent oxygen, which may be high enough to support combustion in the fired boiler 102. Depending on power requirements and flow rates, the fired boiler 102 may use supplemental air to fully oxidize the fuel that may include hydrocarbons, such as coal, petroleum coke, asphaltenes, methane or natural gas.

[0018] The separator 104 located proximate the injection well 108 at a well pad couples to the fired boiler 102 via a steam conduit to receive a mixture of the steam from the fired boiler 102 and condensate resulting from pressure let-down and heat loss along the steam conduit. Outputs from the separator 104 divide the mixture to direct the steam (e.g., at 100 percent quality) into the injection well 108 and the condensate to the electric boiler 106. The separator 104 ensures desired quality of the steam is injected since the separator 104 may be within 100 meters of the injection well 108 compared to the central processing facility with the fired boiler 102 that may be greater than 100 meters or greater than 1 kilometer from the injection well 108.

[0019] The electric boiler 106 heats the condensate and may be located at the well pad and within 100 meters of the injection well 108. The condensate thereby converts back to steam for output by the electric boiler 106. The steam from the electric boiler 106 combines with the steam output from the separator 104 prior to introduction into the injection well 108.

[0020] Provided remote location, typical lack of fuel supply and limited space at the well pad, the electric boiler 106 benefits from not requiring fuel lines, combustion air blowers and stacks. Further, the electric boiler 106 provides efficient conversion of the condensate into the steam since substantially all input electrical energy transfers to the condensate. Combustion-based steam generation in contrast to the electric boiler 106

fails to benefit from near boiling temperatures (e.g., 300° C) of the condensate since such high preheat leads to higher flue gas exit temperatures, thereby reducing efficiency.

[0021] The gas turbine 100 electrical power output increases with decreasing air inlet temperature due to the higher density of the inlet air. For example, the gas turbine 100 provides twenty percent more power output at -18° C than at 15° C. As ambient air temperature decreases, heat losses in the steam conduit between the fired boiler 102 at the central processing facility and the separator 104 at the well pad increase resulting in more condensation losses. Relative higher loads on the electric boiler 106 thus coincide with when the gas turbine 100, since located onsite and exposed to like temperatures, generates additional power during colder periods. Expense of producing such additional power during the colder periods requires no additional capital costs.

[0022] Further, generating the steam at the well pad extends possible distance between the well pad and the central processing facility since not limited by such heat loss along the steam conduit. For some embodiments, well pads closer to the central processing facility may rely on the fired boiler 102 alone for generation of the steam to be injected without utilizing the electric boiler 106 that is only employed for well pads having a relative further distance from the central processing facility. The electric boiler 106 may be selected for example to convert the condensate to steam at well pads greater than five kilometers from the central processing facility or that have at least five percent of the steam condensed upon reaching such well pads while condensate from other well pads is recycled or otherwise used remote therefrom.

[0023] Some embodiments may employ the electric boiler 106 input with electricity from the gas turbine 100 and water conveyed in liquid form from the central processing facility instead of the separator 104 coupled to the fired boiler 102. The water may pass to electric well pad boilers (such as the electric boiler 106) for one or more well pads forming a distal pad set further from the central processing facility than one or more well pads forming a proximal pad set, which is provided with steam that is from the central processing facility and may be the mixture of wet steam as described herein upon reaching even the proximal pad set. The fired boiler 102 at the central processing facility thus alone or in combination with the electric boiler 106 may supply steam requirements

for the proximal pad set while well pad electric boilers alone may generate all steam required for the distal pad set.

[0024] In some embodiments, flue gas exiting the fired boiler 102 contains 2-4 volume percent oxygen and 8-10 volume percent carbon dioxide. These concentrations may facilitate implementing a carbon dioxide recovery unit 112 if desired or necessary to meet government regulations. For example, an amine-based scrubbing unit, a hybrid adsorption/cryogenic capture unit, or a hybrid membrane/cryogenic capture unit may strip the carbon dioxide from the flue gas of the fired boiler 102 and provide a suitable output for sequestration.

[0025] Carbon dioxide capture from stand-alone gas turbines proves difficult because of relative lower carbon dioxide levels and higher oxygen levels, which have an adverse effect on carbon dioxide recovery units. However, the carbon dioxide produced in the gas turbine 100 passes along with the carbon dioxide from the fired boiler 102 for subsequent capture. Further, the gas turbine 100 operates in simple cycle mode, which is lower in capital cost than alternate power generation options such as natural gas combined cycle (NGCC) plants that require additional equipment such as a heat recovery steam generator (HRSG), steam turbines, a condenser, a cooling system and a water treatment system.

[0026] In closing, it should be noted that the discussion of any reference is not an admission that it is prior art to the present invention, especially any reference that may have a publication date after the priority date of this application. At the same time, each and every claim below is hereby incorporated into this detailed description or specification as additional embodiments of the present invention.

[0027] Although the systems and processes described herein have been described in detail, it should be understood that various changes, substitutions, and alterations can be made without departing from the scope of the invention as defined by the following claims. Those skilled in the art may be able to study the preferred embodiments and identify other ways to practice the invention that are not exactly as described herein. It is the intent of the inventors that variations and equivalents of the invention are within the scope of the claims while the description, abstract and drawings are not to be used to

limit the scope of the invention. The invention is specifically intended to be as broad as the claims below and their equivalents.

CLAIMS

1. A method of steam assisted oil recovery with dual steam generation, comprising:
producing electricity with an onsite gas turbine;
generating steam with both a fired boiler and an electric boiler powered by the electricity from the gas turbine; and
introducing the steam from the fired boiler and the electric boiler into at least one injection well for the steam assisted oil recovery.
2. The method according to claim 1, wherein the gas fired boiler is coupled to use a flue gas exhaust of the gas turbine as an oxidant feed for combustion in the fired boiler.
3. The method according to claim 1, wherein the fired boiler alone supplies steam requirements for one or more well pads forming a proximal pad set closer to the fired boiler than one or more well pads forming a distal pad set that includes the electric boiler.
4. The method according to claim 1, wherein the fired boiler is at least 0.5 kilometers (e.g. between 0.5km and 10km) from the electric boiler.
5. The method according to claim 1, comprising:
generating steam with the fired boiler at a first location;
conveying the steam to a second location resulting in a mixture formed of the steam and condensate caused by heat loss during the conveying;
separating the steam from the condensate in the mixture;
heating the condensate in the electric boiler to convert the condensate back to a vapor phase combined with the steam separated from the condensate to provide a combined steam flow; and
introducing the combined steam flow into a formation for the steam assisted oil recovery.

6. The method according to claim 5, wherein the fired boiler is coupled to use a flue gas exhaust of the gas turbine as an oxidant feed for combustion in the fired boiler.
7. The method according to claim 5, further comprising capturing carbon dioxide from a flue gas exhaust of the fired boiler.
8. The method according to claim 5, wherein the fired boiler is coupled to use a flue gas exhaust of the gas turbine as an oxidant feed for combustion in the fired boiler and carbon dioxide is captured from combustion products of the fired boiler.
9. The method according to claim 5, wherein the electric boiler is disposed within 100 meters of where the combined steam flow is introduced into a well and the fired boiler is located further than 100, such as between 100 meters and 10,000, meters from the well.
10. The method according to claim 5, wherein the fired boiler is a once through steam generator.
11. The method according to claim 5, wherein the condensate enters the electric boiler at a temperature of at least 300° C, such as between 300° C and 1,000° C.
12. The method according to claim 5, wherein the fired boiler at the first location is at least 0.5 kilometers (such as between 0.5km and 10km) from the second location and the electric boiler.
13. The method according to claim 5, wherein the steam assisted oil recovery is a steam assisted gravity drainage process.

14. A system for performing a method of steam assisted oil recovery with dual steam generation according to any preceding claim, comprising:

an onsite gas turbine to produce electricity;

a fired boiler to generate steam at a first location, optionally wherein the fired boiler is a once through steam generator;

a steam conduit coupled to the fired boiler for conveying the steam to a second location;

a separator coupled to the steam conduit for dividing the steam from condensate formed by heat loss along the steam conduit;

an electric boiler powered by the electricity from the gas turbine to heat and convert the condensate back to a vapor phase; and

an injection well coupled to vapor outputs from the separator and the electric boiler for the steam assisted oil recovery.

15. The system according to claim 14, further comprising a recovery unit to capture carbon dioxide from a flue gas exhaust of the fired boiler.

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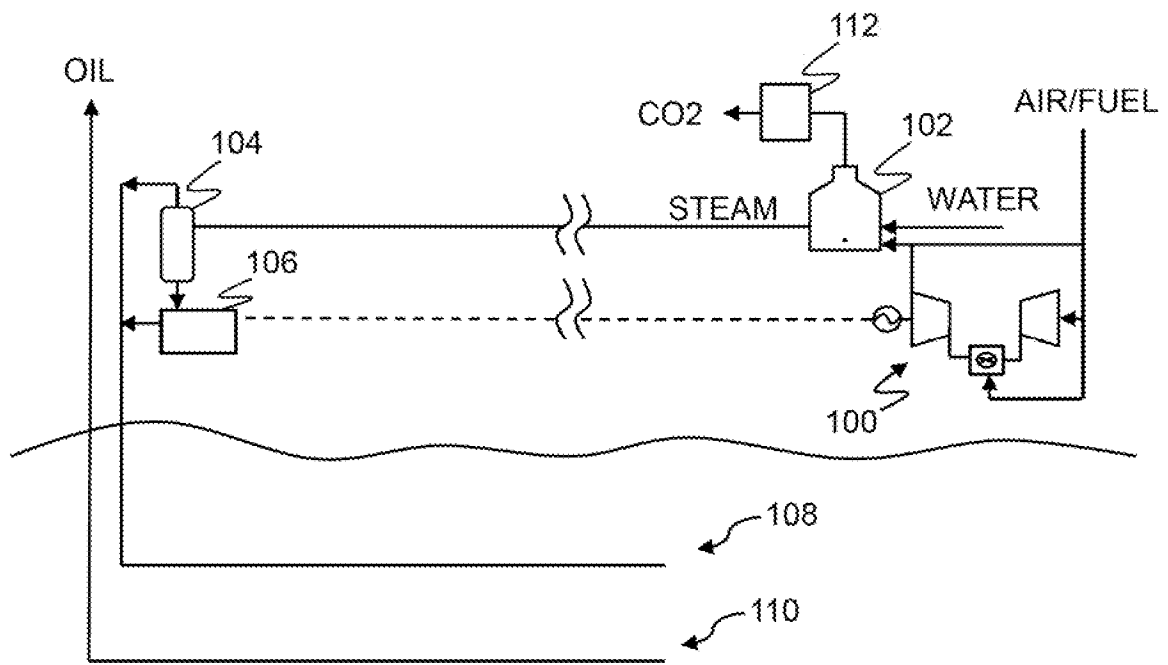


FIG. 1

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US14/47203

A. CLASSIFICATION OF SUBJECT MATTER

IPC(8) - E21B 43/24 (2014.01)

CPC - E21B 43/2406

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)

IPC(8) Classification(s): E21B 43/20, 43/24, 43/241, 43/243 (2014.01)

CPC Classification(s): E21B 43/24, 43/013, 43/2406; Y02C 10/04; F01K 17/04; Y02E 20/14; USPC Classification(s): 166/272.3, 303

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

MicroPatent (US Granted, US Applications, EP-A, EP-B, WO, JP, DE-G, DE-A, DE-T, DE-U, GB-A, FR-A); Google; Google Scholar; ProQuest; IP.com; keywords: steam, oil, bitumen, recover, extract, production, turbine, electricity, gravity, carbon dioxide, flue, boiler, heater

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X --- Y	US 2012/0138293 A1 (KAMINSKY RD et al.) June 7, 2012; paragraphs [0009], [0071], [0077], [0083], [0085]-[0089], [0095], [0097], [0098], [0116], [0117], [0173]	1, 3, 4 --- 2, 5-10, 12-13, 14/1-14/10, 14/12-14/13, 15/14/1-15/14/10, 15/14/12-15/14/13
Y	US 2012/0222426 A1 (MACADAM S) September 6, 2012; abstract, paragraphs [0025], [0032]	2, 6-8, 14/2, 14/6, 14/7, 14/8, 15/14/1-15/14/10, 15/14/12-15/14/13
Y	US 2007/0199300 A1 (MACADAM S et al.) August 30, 2007; paragraphs [0009], [0044], [0045], [0108]	5-10, 12-13, 14/1-14/10, 14/12-14/13, 15/14/1-15/14/10, 15/14/12-15/14/13
A	US 6,200,128 B1 (KOBAYASHI H) March 13, 2001; entire document	1-13, 14/1-14/13, 15/14/1-15/14/13
A	US 2002/0170846 A1 (DAVIS SM et al.) November 21, 2002; entire document	1-13, 14/1-14/13, 15/14/1-15/14/13

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

* 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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"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

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