(57) Abrégé/Abstract:
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Title: SYSTEMS, METHODS, AND PROCESSES UTILIZED FOR TREATING SUBSURFACE FORMATIONS

Abstract: Systems, methods, and/or heaters for treating a subsurface formation are described herein. Some embodiments also generally relate to heaters that have novel components therein. Such heaters may be obtained by using the systems and methods described.

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SYSTEMS, METHODS, AND PROCESSES
UTILIZED FOR TREATING SUBSURFACE FORMATIONS

BACKGROUND

1. Field of the Invention

[0001] The present invention relates generally to methods and systems for production of hydrocarbons, hydrogen, and/or other products from various subsurface formations such as hydrocarbon containing formations.

2. Description of Related Art

[0002] Hydrocarbons obtained from subterranean formations are often used as energy resources, as feedstocks, and as consumer products. Concerns over depletion of available hydrocarbon resources and concerns over declining overall quality of produced hydrocarbons have led to development of processes for more efficient recovery, processing and/or use of available hydrocarbon resources. In situ processes may be used to remove hydrocarbon materials from subterranean formations. Chemical and/or physical properties of hydrocarbon material in a subterranean formation may need to be changed to allow hydrocarbon material to be more easily removed from the subterranean formation. The chemical and physical changes may include in situ reactions that produce removable fluids, composition changes, solubility changes, density changes, phase changes, and/or viscosity changes of the hydrocarbon material in the formation. A fluid may be, but is not limited to, a gas, a liquid, an emulsion, a slurry, and/or a stream of solid particles that has flow characteristics similar to liquid flow.

[0003] During some in situ processes, wax may be used to reduce vapors and/or to encapsulate contaminants in the ground. Wax may be used during remediation of wastes to encapsulate contaminated material. U.S. Patent Nos. 7,114,880 to Carter, and 5,879,110 to Carter describe methods for treatment of contaminants using wax during the remediation procedures.

[0004] In some embodiments, a casing or other pipe system may be placed or formed in a wellbore. U.S. Patent No. 4,572,299 issued to Van Egmond et al. describes spooling an electric heater into a well. In some embodiments, components of a piping system may be welded together. Quality of formed wells may be monitored by various techniques. In some embodiments, quality of welds may be inspected by a hybrid electromagnetic acoustic transmission technique known as EMAT. EMAT is described in U.S. Patent Nos. 5,652,389 to Schaps et al.; 5,760,307 to Latimer et al.; 5,777,229 to Geier et al.; and 6,155,117 to Stevens et al.

[0005] In some embodiments, an expandable tubular may be used in a wellbore. Expandable tubulars are described in U.S. Patent Nos. 5,366,012 to Lohbeck, and 6,354,373 to Vercaemer et al.
[0006] Heaters may be placed in wellbores to heat a formation during an in situ process. Examples of in situ processes utilizing downhole heaters are illustrated in U.S. Patent Nos. 2,634,961 to Ljungstrom; 2,732,195 to Ljungstrom; 2,780,450 to Ljungstrom; 2,789,805 to Ljungstrom; 2,923,535 to Ljungstrom; and 4,886,118 to Van Meurs et al.

[0007] Application of heat to oil shale formations is described in U.S. Patent Nos. 2,923,535 to Ljungstrom and 4,886,118 to Van Meurs et al. Heat may be applied to the oil shale formation to pyrolyze kerogen in the oil shale formation. The heat may also fracture the formation to increase permeability of the formation. The increased permeability may allow formation fluid to travel to a production well where the fluid is removed from the oil shale formation. In some processes disclosed by Ljungstrom, for example, an oxygen containing gaseous medium is introduced to a permeable stratum, preferably while still hot from a preheating step, to initiate combustion.

[0008] A heat source may be used to heat a subterranean formation. Electric heaters may be used to heat the subterranean formation by radiation and/or conduction. An electric heater may resistively heat an element. U.S. Patent No. 2,548,360 to Germain describes an electric heating element placed in a viscous oil in a wellbore. The heater element heats and thins the oil to allow the oil to be pumped from the wellbore. U.S. Patent No. 4,716,960 to Eastlund et al. describes electrically heating tubing of a petroleum well by passing a relatively low voltage current through the tubing to prevent formation of solids. U.S. Patent No. 5,065,818 to Van Egmond describes an electric heating element that is cemented into a wellbore without a casing surrounding the heating element.

[0009] U.S. Patent No. 6,023,554 to Vinegar et al. describes an electric heating element that is positioned in a casing. The heating element generates radiant energy that heats the casing. A granular solid fill material may be placed between the casing and the formation. The casing may conductively heat the fill material, which in turn conductively heats the formation.

[0010] U.S. Patent No. 4,570,715 to Van Meurs et al. describes an electric heating element. The heating element has an electrically conductive core, a surrounding layer of insulating material, and a surrounding metallic sheath. The conductive core may have a relatively low resistance at high temperatures. The insulating material may have electrical resistance, compressive strength, and heat conductivity properties that are relatively high at high temperatures. The insulating layer may inhibit arcing from the core to the metallic sheath. The metallic sheath may have tensile strength and creep resistance properties that are relatively high at high temperatures.


[0012] Obtaining permeability in an oil shale formation between injection and production wells tends to be difficult because oil shale is often substantially impermeable. Many methods have
attempted to link injection and production wells. These methods include: hydraulic fracturing such as methods investigated by Dow Chemical and Laramie Energy Research Center; electrical fracturing by methods investigated by Laramie Energy Research Center; acid leaching of limestone cavities by methods investigated by Dow Chemical; steam injection into permeable nahcolite zones to dissolve the nahcolite by methods investigated by Shell Oil and Equity Oil; fracturing with chemical explosives by methods investigated by Talley Energy Systems; fracturing with nuclear explosives by methods investigated by Project Bronco; and combinations of these methods. Many of these methods, however, have relatively high operating costs and lack sufficient injection capacity.

[0013] Large deposits of heavy hydrocarbons (heavy oil and/or tar) contained in relatively permeable formations (for example in tar sands) are found in North America, South America, Africa, and Asia. Tar can be surface-mined and upgraded to lighter hydrocarbons such as crude oil, naphtha, kerosene, and/or gas oil. Surface milling processes may further separate the bitumen from sand. The separated bitumen may be converted to light hydrocarbons using conventional refinery methods. Mining and upgrading tar sand is usually substantially more expensive than producing lighter hydrocarbons from conventional oil reservoirs.

[0014] In situ production of hydrocarbons from tar sand may be accomplished by heating and/or injecting a gas into the formation. U.S. Patent Nos. 5,211,230 to Ostapovich et al. and 5,339,897 to Leaute describe a horizontal production well located in an oil-bearing reservoir. A vertical conduit may be used to inject an oxidant gas into the reservoir for in situ combustion.

[0015] U.S. Patent No. 2,780,450 to Ljungstrom describes heating bituminous geological formations in situ to convert or crack a liquid tar-like substance into oils and gases.

[0016] U.S. Patent No. 4,597,441 to Ware et al. describes contacting oil, heat, and hydrogen simultaneously in a reservoir. Hydrogenation may enhance recovery of oil from the reservoir.

[0017] U.S. Patent No. 5,046,559 to Glandt and 5,060,726 to Glandt et al. describe preheating a portion of a tar sand formation between an injector well and a producer well. Steam may be injected from the injector well into the formation to produce hydrocarbons at the producer well.

[0018] As outlined above, there has been a significant amount of effort to develop methods and systems to economically produce hydrocarbons, hydrogen, and/or other products from hydrocarbon containing formations. At present, however, there are still many hydrocarbon containing formations from which hydrocarbons, hydrogen, and/or other products cannot be economically produced. Thus, there is still a need for improved methods and systems for production of hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations.
SUMMARY OF THE INVENTION

[0019] Embodiments described herein generally relate to systems, methods, and heaters for treating a subsurface formation. Embodiments described herein also generally relate to heaters that have novel components therein. Such heaters can be obtained by using the systems and methods described herein.

[0020] In certain embodiments, the invention provides one or more systems, methods, and/or heaters. In some embodiments, the systems, methods, and/or heaters are used for treating a subsurface formation.

[0021] In certain embodiments, a method for forming two or more wellbores in a subsurface formation includes forming a first wellbore in the formation; directionally drilling a second wellbore in a selected relationship relative to the first wellbore; providing at least one magnetic field in the second wellbore using one or more magnets in the second wellbore located on a drilling string used to drill the second wellbore; sensing at least one magnetic field in the first wellbore using at least two sensors in the first wellbore as the magnetic field passes by the at least two sensors while the second wellbore is being drilled; continuously assessing a position of the second wellbore relative to the first wellbore using the sensed magnetic field; and adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

[0022] In certain embodiments, a method for forming two or more wellbores in a subsurface formation includes forming at least a first wellbore in the formation; providing a current path and voltage signal to the first wellbore; directionally drilling a second wellbore in a selected relationship relative to the first wellbore; continuously sensing the voltage signal in the second wellbore; continuously assessing a position of the second wellbore relative to the first wellbore using the sensed voltage signal; and adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

[0023] In certain embodiments, a method for forming two or more wellbores in a subsurface formation includes forming a first wellbore in the formation; directionally drilling a second wellbore in a selected relationship relative to the first wellbore; providing an electromagnetic wave in the second wellbore; continuously sensing the electromagnetic wave in the first wellbore using at least one electromagnetic antenna; continuously assessing a position of the second wellbore relative to the first wellbore using the sensed electromagnetic wave; and adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

[0024] In certain embodiments, a method for forming two or more wellbores in a subsurface formation includes forming a first wellbore in the formation; directionally drilling a second
wellbore in a selected relationship relative to the first wellbore; transmitting a first
electromagnetic wave from a first transceiver in the first wellbore and sensing the first
electromagnetic wave using a second transceiver in the second wellbore; transmitting a second
electromagnetic wave from the second transceiver in the second wellbore and sensing the second
electromagnetic wave using the first transceiver in the first wellbore; continuously assessing a
position of the second wellbore relative to the first wellbore using the sensed first
electromagnetic wave and the sensed second electromagnetic wave; and adjusting the direction of
drilling of the second wellbore so that the second wellbore remains in the selected relationship
relative to the first wellbore.

[0025] In certain embodiments, a method for forming two or more wellbores in a subsurface
formation includes forming a plurality of first wellbores in the formation; providing a plurality of
electromagnetic waves in the first wellbores; directionally drilling one or more second wellbores
in a selected relationship relative to the first wellbores; continuously sensing the electromagnetic
waves in the first wellbores using at least one electromagnetic antenna in the second wellbores;
continuously assessing a position of the second wellbores relative to the first wellbores using the
sensed electromagnetic waves; and adjusting the direction of drilling of at least one of the second
wellbores so that the second wellbore remains in the selected relationship relative to the first
wellbores.

[0026] In certain embodiments, a method for forming two or more wellbores in a subsurface
formation includes forming a first wellbore in the formation; assessing a position of the first
wellbore; drilling a second wellbore in a selected relationship relative to the first wellbore;
continuously assessing a position of the second wellbore relative to the first wellbore; adjusting
the direction of drilling of the second wellbore so that the second wellbore remains in the
selected relationship relative to the first wellbore; drilling one or more additional wellbores in a
selected relationship to the second wellbore; continuously assessing a position of at least one of
the additional wellbores relative to the first wellbore and/or the second wellbore; and adjusting
the direction of drilling of the at least one of the additional wellbores so that the at least one of
the additional wellbores remains in the selected relationship relative to the second wellbore.

[0027] In certain embodiments, a method for forming two or more wellbores in a subsurface
formation includes forming a first wellbore in the formation; directionally drilling a second
wellbore in a selected relationship relative to the first wellbore; providing an electromagnetic
field in the first wellbore using one or more magnets; continuously sensing the electromagnetic
field in the first wellbore using at least one electromagnetic field sensor positioned in the second
wellbore; continuously assessing a position of the second wellbore relative to the first wellbore
using the sensed electromagnetic field; and adjusting the direction of drilling of the second
wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

[0028] In certain embodiments, a method for forming two or more wellbores in a subsurface formation includes forming a first wellbore in the formation; directionally drilling a second wellbore in a selected relationship relative to the first wellbore; providing an electromagnetic field in the second wellbore using one or more magnets; continuously sensing the electromagnetic field in the second wellbore using at least one electromagnetic field sensor positioned in the first wellbore; continuously assessing a position of the second wellbore relative to the first wellbore using the sensed electromagnetic field; and adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

[0029] In certain embodiments, a method for forming a wellbore in a heated formation includes flowing liquid cooling fluid to a bottom hole assembly in a wellbore in a heated formation; and vaporizing at least a portion of the liquid cooling fluid at or near a region to be cooled, wherein vaporizing the liquid cooling fluid absorbs heat from the region to be cooled.

[0030] In certain embodiments, a method for forming a wellbore in a heated formation includes flowing a two-phase cooling fluid to a bottom hole assembly in a wellbore in the heated formation; vaporizing at least a portion of a liquid phase of the two-phase cooling fluid at or near a drill bit, wherein vaporizing the liquid phase cools the drill bit; and removing cuttings and the cooling fluid from the wellbore.

[0031] In certain embodiments, a system for forming a wellbore in a heated formation includes cooling fluid; a drill bit configured to form an opening in the heated formation; a drilling string coupled to the drill bit, the drilling string configured to transport drilling fluid to the drill bit and facilitate removal of drilling fluid and cuttings from the wellbore; a back pressure device coupled to the drilling pipe, the back pressure device configured to maintain a sufficiently high pressure on the cooling fluid flowing towards the drill bit so that at least a portion of the cooling fluid remains in a liquid phase, prior to the back pressure device; and wherein at least a portion of the cooling fluid is configured to vaporize after flowing through the back pressure device to provide cooling to a region.

[0032] In certain embodiments, a method for installing a horizontal or inclined subsurface heater includes placing a heating section of a heater in a horizontal or inclined section of a wellbore with an installation tool; uncoupling the tool from the heating section; and mechanically and electrically coupling a lead-in section of the heater to the heating section of the heater, wherein the lead-in section is located in an angled or vertical section of the wellbore.
[0033] In certain embodiments, a method for providing heat to a subsurface formation includes installing a heater comprising a heating section and a lead-in section into a wellbore in the subsurface formation, wherein the installation includes: placing the heating section of a heater in a horizontal or inclined section of the wellbore with an installation tool; uncoupling the tool from the heating section; mechanically and electrically coupling the lead-in section of the heater to the heating section of the heater, wherein the lead-in section is located in an angled or vertical section of the wellbore; providing electrical power to the heater; and providing heat to at least a portion of a subsurface formation from the heater.

[0034] In certain embodiments, a method for assessing one or more temperatures of an electrically powered subsurface heater includes assessing an impedance profile of the electrically powered subsurface heater while the heater is being operated in the subsurface; and analyzing the impedance profile with a frequency domain algorithm to assess one or more temperatures of the heater.

[0035] In certain embodiments, a method for forming a longitudinal subsurface heater includes longitudinally welding an electrically conductive sheath of an insulated conductor heater along at least one longitudinal strip of metal; and forming the longitudinal strip into a tubular around the insulated conductor heater with the insulated conductor heater welded along the inside surface of the tubular.

[0036] In certain embodiments, a method for forming a longitudinal subsurface heater includes longitudinally welding an electrically conductive sheath of an insulated conductor heater along an inside surface of a metal tubular.

[0037] In certain embodiments, a longitudinal subsurface heater includes an insulated conductor heater, including: an electrical conductor; an electrical insulator at least partially surrounding the electrical conductor; and an electrically conductive sheath at least partially surrounding the electrical insulator; a metal tubular at least partially surrounding the insulated conductor heater; and wherein the sheath of the insulated conductor heater is longitudinally welded along an inside surface of the metal tubular.

[0038] In certain embodiments, a heating system for a subsurface formation includes three substantially u-shaped heaters, first end portions of the heaters being electrically coupled to a single, three-phase wye transformer, second end portions of the heaters being electrically coupled to each other and/or to ground; wherein the three heaters enter the formation through a first common wellbore and exit the formation through a second common wellbore so that the magnetic fields of the three heaters at least partially cancel out in the common wellbores.

[0039] In certain embodiments, a heating system for a subsurface formation includes an elongated electrical conductor located in the subsurface formation, wherein the electrical
conductor extends between at least a first electrical contact and a second electrical contact; and a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

[0040] In certain embodiments, a heating system for a subsurface formation includes an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and a ferromagnetic conductor, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats.

[0041] In certain embodiments, a heating system for a subsurface formation includes an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; wherein the electrical conductor, when energized with time-varying electrical current, induces electrical current flow on the inside and outside surfaces of the ferromagnetic conductor such that the ferromagnetic conductor resistively heats.

[0042] In certain embodiments, a heating system for a subsurface formation includes an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats; and wherein the ferromagnetic conductor is configured to have little or no induced current flow at temperatures at and above a selected temperature.

[0043] In certain embodiments, a system for heating a hydrocarbon containing formation includes a first elongated electrical conductor located in the subsurface formation, wherein the
first electrical conductor extends between at least two electrical contacts; and a first ferromagnetic conductor, wherein the first ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the first electrical conductor; wherein the first electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the first ferromagnetic conductor such that the first ferromagnetic conductor resistively heats; a second elongated electrical conductor located in the subsurface formation, wherein the second electrical conductor extends between at least two electrical contacts; and a second ferromagnetic conductor, wherein the second ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the second electrical conductor; wherein the second electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the second ferromagnetic conductor such that the second ferromagnetic conductor resistively heats; and wherein the first and second ferromagnetic conductors are configured to provide heat to the formation such that heat from the ferromagnetic conductors is superpositioned in the formation.

[0044] In certain embodiments, a method for heating a hydrocarbon containing formation includes providing time-varying electrical current to an elongated electrical conductor located in the formation; inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats; allowing heat to transfer from the ferromagnetic conductor to at least a part of the formation; and mobilizing at least some hydrocarbons in the part of the formation.

[0045] In certain embodiments, a heating system for a subsurface formation includes a first wellbore extending into the subsurface formation; a second wellbore extending into the subsurface formation; and three or more heaters extending between the first wellbore and the second wellbore, at least one heater comprising: an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.
[0046] In certain embodiments, a heating system for a subsurface formation includes a first wellbore extending into the subsurface formation; a second wellbore extending into the subsurface formation; a third wellbore extending into the subsurface formation; a first heater located in the first wellbore, a second heater located in the second wellbore, and a third heater located in the third wellbore, at least one heater comprising: an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

[0047] In certain embodiments, a heating system for a subsurface formation includes an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; an insulation layer at least partially surrounding the electrical conductor; and a ferromagnetic sheath at least partially surrounding the insulation layer, the ferromagnetic sheath and the electrical conductor being configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic sheath, or vice versa; wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic sheath such that the ferromagnetic sheath resistively heats.

[0048] In certain embodiments, a heating system for a subsurface formation includes a first electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least a first electrical contact and a second electrical contact; a first insulation layer at least partially surrounding the first electrical conductor; a first ferromagnetic sheath at least partially surrounding the first insulation layer, the first ferromagnetic sheath and the first electrical conductor being configured in relation to each other such that electrical current does not flow from the first electrical conductor to the first ferromagnetic sheath, or vice versa; a second electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least the first electrical contact and the second electrical contact; a second insulation layer at least partially surrounding the second electrical conductor; a second ferromagnetic sheath at least partially surrounding the second insulation layer, the second ferromagnetic sheath and the second electrical conductor being configured in relation to each other such that electrical current does not flow from the second electrical conductor to the second ferromagnetic sheath, or vice versa; and a third insulation layer located between the first
ferromagnetic sheath and the second ferromagnetic sheath; wherein the first and second electrical conductors, when energized with time-varying electrical current, induce sufficient electrical current flow in the first and second ferromagnetic sheaths, respectively, such that the ferromagnetic sheaths resistively heat.

[0049] In certain embodiments, a heating system for a subsurface formation includes an electrical conductor extending into the subsurface formation; and a ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of an overburden section of the formation, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor comprises a plurality of straight, angled, or longitudinally spiral grooves or protrusions that increase the effective circumference of the ferromagnetic conduit; wherein the straight, angled, or longitudinally spiral grooves or protrusions are configured to inhibit or reduce induction resistance heating in the ferromagnetic conductor.

[0050] In certain embodiments, a heating system for a subsurface formation includes a ferromagnetic conductor extending into the subsurface formation, wherein the ferromagnetic conductor is configured to resistively heat when electrical current is applied to, or induced in, the ferromagnetic conductor; and a plurality of straight, angled, or spiral grooves or protrusions located on at least one surface of the ferromagnetic conductor, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conduit.

[0051] In certain embodiments, a method of treating a formation fluid includes providing formation fluid from a subsurface in situ heat treatment process; separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises carbon dioxide, hydrogen sulfide, hydrocarbons, hydrogen or mixtures thereof; separating molecular oxygen from air to form a molecular oxygen stream comprising molecular oxygen; combining the first gas stream with the molecular oxygen stream to form a combined stream comprising molecular oxygen and the first gas stream; and providing the combined stream to one or more downhole burners.

[0052] In certain embodiments, a system includes a separating unit configured to receive formation fluid from a subsurface in situ heat treatment process and separate the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises carbon dioxide, sulfur compounds, hydrocarbons, hydrogen, or mixtures thereof; a fuel conduit configured to receive the first gas stream and transport the first gas stream; an oxidizing fluid production system configured to apply current to water to form an oxidizing fluid; an oxidizing fluid conduit configured to receive the oxidizing fluid and transport the oxidizing fluid; and one
or more downhole burners in or near the formation or another formation and coupled to the fuel conduit and oxidizing fluid conduit, wherein at least one of the burners is configured to receive the first gas stream and/or the oxidizing fluid from the fuel and/or oxidizing fluid conduits and combust the first gas stream and/or the oxidizing fluid stream, thereby heating at least a portion of the formation or another formation.

[0053] In certain embodiments, a method of treating formation fluid includes providing formation fluid from a subsurface in situ heat treatment process; separating the formation fluid to produce a liquid stream and a gas stream, wherein the gas stream comprises hydrocarbons; providing the gas stream to a reformation unit; reforming the gas stream to produce a hydrogen gas stream; and providing at least a portion of the hydrogen in the hydrogen gas stream to one or more downhole burners in or near the formation or another formation.

[0054] In certain embodiments, a method for treating a hydrocarbon containing formation includes providing heat input to a first section of the formation from one or more heat sources located in the first section; and producing fluids from the first section through a production well located at or near the center of the first section; wherein the heat sources are configured such that the average heat input per volume of formation in the first section increases with distance from the production well.

[0055] In certain embodiments, a method for treating a hydrocarbon containing formation includes providing heat input to a first section of the formation from one or more heat sources located in the first section; providing the heat input into the formation from the heat sources such that the heat input to the formation per volume of formation in a first volume of the first section is less than the heat input to the formation per volume of formation in a second volume of the first section and the heat input to the formation per volume of formation in the second volume is less than the heat input to the formation per volume of a third volume of the first section, wherein the first volume substantially surrounds a production well located at or near the center of the section, the second volume substantially surrounds the first volume, and the third volume substantially surrounds the second volume; and producing fluids from the first section through the production well.

[0056] In some embodiments, a method for treating a hydrocarbon containing formation includes providing heat to a first portion of the formation from a plurality of heaters in the first portion, at least two of the heaters being located in heater wells in the first portion; producing fluids through one or more production wells in a second portion of the formation, the second portion being at least partially substantially adjacent to the first portion; reducing or turning off the heat provided to the first portion after a selected time; providing an oxidizing fluid through one or more of the heater wells in the first portion; providing heat to the first portion and the second portion through
oxidation of at least some hydrocarbons in the first portion, and movement of fluid heated by such oxidation from the first portion to the second portion; and producing fluids through at least one of the production wells in the second portion, the produced fluids includes at least some oxidized hydrocarbons produced in the first portion.

[0057] In some embodiments, a method for treating a subsurface formation includes heating a first portion from one or more heaters located in the first portion; producing hydrocarbons from the first portion; reducing or turning off the heat provided to the first portion after a selected time; injecting an oxidizing fluid in the first portion to cause a temperature of the first portion to increase sufficiently to oxidize hydrocarbons in the first portion and a third portion, the third portion being substantially below the first portion; heating a second portion from heat transferred from the first portion and/or third portion and/or one or more heaters located in the second portion such that an average temperature in the second portion is at least about 100 °C, wherein the second portion is substantially adjacent to the first portion; allowing hydrocarbons to flow from the second portion into the first portion and/or third portion; reducing or discontinuing injection of the oxidizing fluid in the first portion; and producing additional hydrocarbons from the first portion of the formation, the additional hydrocarbons includes oxidized hydrocarbons from the first portion, at least some hydrocarbons from the second portion, at least some hydrocarbons from the third portion of the formation, or mixtures thereof, and wherein a temperature of the first portion is below 600 °C.

[0058] In some embodiments, a method for treating a subsurface formation includes producing hydrocarbons from a first portion and/or a third portion by an in situ heat treatment process, heating a second portion with one or more heaters to an average temperature of about 100 °C; the first portion and third portion being separated by the second portion; reducing or turning off the heat provided to the first portion after a selected time; injecting an oxidizing fluid in the first portion to cause a temperature of the first portion to increase sufficiently to oxidize hydrocarbons in the first portion; injecting and/or creating a drive fluid and/or an oxidizing fluid in the third portion to cause at least some hydrocarbons to move from the third portion through the second portion to the first portion of the hydrocarbon layer; reducing or discontinuing injection of the oxidizing fluid in the first portion; and producing additional hydrocarbons and/or syngas from the first portion of the formation, the additional hydrocarbons and/or syngas includes at least some hydrocarbons from the second and third portions of the formation.

[0059] In some embodiments, a method for treating a subsurface formation includes producing at least one third of hydrocarbons from a first portion by an in situ heat treatment process, wherein an average temperature of the first portion is less than 350 °C; injecting an oxidizing fluid in the first portion to cause the average temperature of the first portion to increase sufficiently to
oxidize hydrocarbons in the first portion and to raise the average temperature of the first portion to greater than 350 °C; and injecting a heavy hydrocarbon fluid in the first portion to from a diluent and/or drive fluid, the heavy hydrocarbon fluid includes one or more condensable hydrocarbons.

[0060] In certain embodiments, a method for treating a nahcolite containing subsurface formation includes solution mining a first nahcolite bed above a hydrocarbon containing layer using a plurality of first solution mining wells; solution mining a second nahcolite bed below the hydrocarbon containing layer using a plurality of second solution mining wells; converting at least one of the first solution mining wells into a production well; heating the hydrocarbon containing layer using a plurality of heaters; and producing formation fluid from at least one converted first solution mining well.

[0061] In certain embodiments, a method for treating a nahcolite containing subsurface formation includes solution mining a first nahcolite bed above a hydrocarbon containing layer using a plurality of first solution mining wells; solution mining a second nahcolite bed below the hydrocarbon containing layer using a plurality of second solution mining wells; converting at least one of the second solution mining wells into a production well; heating the hydrocarbon containing layer using a plurality of heaters; and producing formation fluid from at least one converted second solution mining well.

[0062] In certain embodiments, a method for treating a nahcolite containing subsurface formation includes solution mining a first nahcolite bed above a treatment area using one or more solution mining wells positioned in the first nahcolite bed; solution mining a second nahcolite bed below the treatment using one or more solution mining wells in the second nahcolite bed; providing heat to the treatment area from heaters; converting one or more of the solution mining wells used to solution mine the first nahcolite bed to production wells; producing formation fluid through at least one production well in the first nahcolite bed.

[0063] In some embodiments, a method of treating a gas stream, includes, in a first cryogenic zone, cryogenically separating a first gas stream to form a second gas stream and a third stream, wherein a majority of the second gas stream includes methane and/or molecular hydrogen and a majority of the third stream includes one or more carbon oxides, hydrocarbons having a carbon number of at least 2, one or more sulfur compounds, or mixtures thereof; and in a second cryogenic zone, cryogenically contacting the third stream with a carbon dioxide stream to form a fourth stream and a fifth stream, wherein a majority of the fourth stream includes one or more of the carbon oxides and hydrocarbons having a carbon number of at least 2, and a majority of the fifth stream includes hydrocarbons having a carbon number of at least 3 and one or more of the sulfur compounds.
[0064] In some embodiments, a system of treating a gas stream includes a first cryogenic separation zone configured receive a first gas stream and to cryogenically separate the first gas stream to form a second gas stream and a third gas stream, wherein the second gas stream includes methane and/or molecular hydrogen and the third gas stream includes one or more carbon oxides, hydrocarbons having a carbon number of at least 2, one or more sulfur compounds, or mixtures thereof; a second cryogenic separation zone configured to receive the third gas stream and carbon dioxide and wherein the second cryogenic separation unit is configured to cryogenically separate the third gas stream to form a fourth stream and fifth stream, wherein a majority of the fourth stream includes one or more of the carbon oxides and hydrocarbons having a carbon number of at least 2, and a majority of the fifth stream includes hydrocarbons having a carbon number of at least 3 and one or more of the sulfur compounds.

[0065] In some embodiments, a method of treating a formation fluid includes separating formation fluid from a subsurface in situ heat treatment process to form a liquid stream and a first gas stream, wherein the first gas stream includes one or more carbon oxides, one or more sulfur compounds, hydrocarbons and/or molecular hydrogen; in a first cryogenic zone, cryogenically separating the first gas stream to form a second gas stream and a third stream, wherein a majority of the second gas stream includes methane and/or molecular hydrogen, and the third stream includes hydrocarbons having a carbon number of at least 2, one or more sulfur compounds, one or more carbon oxides, or mixtures thereof; and in a second cryogenic zone, cryogenically separating the third gas stream to form a fourth stream and a fifth stream, wherein a majority the fourth stream includes one or more carbon oxides and hydrocarbons having a carbon number of at most 2; and a majority of the fifth stream includes hydrocarbons having a carbon number of at least 3 and/or one or more sulfur compounds.

[0066] In certain embodiments, a variable voltage transformer includes a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding; a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage; a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage; and wherein an electrical load is configured to be coupled to the multistep load tap changer to provide electrical power to the load with a selected voltage, the multistep load tap changer is configured to tap a selected voltage step in order to provide the selected voltage to the electrical load.
[0067] In some embodiments, a variable voltage transformer system for providing power to a three-phase electrical load includes a first variable voltage transformer coupled to a first leg of three-phase electrical load; a second variable voltage transformer coupled to a second leg of three-phase electrical load; a third variable voltage transformer coupled to a third leg of three-phase electrical load. Each of the first, second, and third variable voltage transformers include a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding; a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage; a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage. The corresponding leg of the three-phase electrical load is configured to be coupled to the multistep load tap changer to provide electrical power to the load with a selected voltage. The multistep load tap changer is configured to tap a selected voltage step in order to provide the selected voltage to the corresponding leg.

[0068] In some embodiments, a method of controlling voltage provided to one or more electric heaters includes providing electrical power to the first heater with a selected voltage using a variable voltage transformer, wherein the variable voltage transformer includes: a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding; a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage; a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the selected voltage to the first heater; assessing change in electrical resistance of the first heater over a selected period of time; and adjusting the selected voltage provided to the first heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the selected voltage is changed in response to the change in the electrical resistance of the first heater.

[0069] In some embodiments, a method of controlling voltage provided to one or more electric heaters includes providing electrical power to the first heater with a selected voltage using a variable voltage transformer, wherein the variable voltage transformer includes: a primary winding configured to be coupled to a voltage power source that provides a first voltage across
the primary winding; a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage; a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the selected voltage to the first heater; assessing an electrical resistance of the first heater; providing electrical power at the first selected voltage until the electrical resistance of the first heater reaches a selected value; assessing the electrical resistance of the first heater over a selected period of time, and assessing if there is a change in the electrical resistance of the first heater at the second selected voltage over the selected period of time; and adjusting the second selected voltage provided to the first heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the second selected voltage is changed in response to the change in the electrical resistance of the first heater.

[0070] In some embodiments, a method of controlling voltage provided to one or more electric heaters includes providing electrical power to the first heater with a selected voltage using a variable voltage transformer, wherein the variable voltage transformer includes: a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding; a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage; a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the selected voltage to the first heater; assessing an electrical resistance of the first heater at the selected voltage; and cycling the selected voltage provided to the first heater by switching the selected voltage step tapped by the multistep load tap changer between at least two voltage steps such that the selected voltage is cycled between at least two voltages after a selected amount of time at each of the at least two voltages.

[0071] In certain embodiments, a method of heating a portion of a subsurface formation includes drawing fuel on a fuel carrier through an opening formed in the formation; supplying oxidant to the fuel at one or more locations in the opening; and combusting the fuel with the oxidant to provide heat to the formation.
In certain embodiments, a system for heating a portion of a subsurface formation includes an opening formed in the formation; a conveyor positioned in the opening; fuel carriers coupled to the conveyor, wherein at least one fuel carrier is configured to hold fuel to be combusted in the opening; and one or more oxidant conduits positioned in the opening configured to supply oxidant to at least one fuel carrier at one or more locations in the opening.

In further embodiments, features from specific embodiments may be combined with features from other embodiments. For example, features from one embodiment may be combined with features from any of the other embodiments.

In further embodiments, treating a subsurface formation is performed using any of the methods, systems, or heaters described herein.

In further embodiments, additional features may be added to the specific embodiments described herein.

**BRIEF DESCRIPTION OF THE DRAWINGS**

Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description and upon reference to the accompanying drawings in which:

FIG. 1 shows a schematic view of an embodiment of a portion of an in situ heat treatment system for treating a hydrocarbon containing formation.

FIG. 2 depicts a schematic representation of an embodiment of a system for treating in situ heat treatment process gas.

FIG. 3 depicts a schematic representation of an embodiment of a system for treating in situ heat treatment process gas.

FIG. 4 depicts a schematic representation of an embodiment of a system for treating in situ heat treatment process gas.

FIG. 5 depicts a schematic representation of an embodiment of a system for treating in situ heat treatment process gas.

FIG. 6 depicts a schematic representation of an embodiment of a system for treating in situ heat treatment process gas.

FIG. 7 depicts a schematic representation of an embodiment of a system for treating the mixture produced from an in situ heat treatment process.

FIG. 8 depicts a schematic representation of an embodiment of a system for treating a liquid stream produced from an in situ heat treatment process.

FIG. 9 depicts a schematic representation of an embodiment of a system for forming and transporting tubing to a treatment area.
[0086] FIG. 10 depicts an embodiment of a drilling string with dual motors on a bottom hole assembly.

[0087] FIG. 11 depicts time versus rpm (revolutions per minute) for a conventional steerable motor bottom hole assembly during a drill bit direction change.

[0088] FIG. 12 depicts time versus rpm for a dual motor bottom hole assembly during a drill bit direction change.

[0089] FIG. 13 depicts an embodiment of a drilling string with a non-rotating sensor.

[0090] FIG. 14 depicts an embodiment for assessing a position of a first wellbore relative to a second wellbore using multiple magnets.

[0091] FIG. 15 depicts an embodiment for assessing a position of a first wellbore relative to a second wellbore using a continuous pulsed signal.

[0092] FIG. 16 depicts an embodiment for assessing a position of a first wellbore relative to a second wellbore using a radio ranging signal.

[0093] FIG. 17 depicts an embodiment for assessing a position of a plurality of first wellbores relative to a plurality of second wellbores using radio ranging signals.

[0094] FIG. 18 depicts a top view representation of an embodiment for forming a plurality of wellbores in a formation.

[0095] FIGS. 19 and 20 depict an embodiment for assessing a position of a first wellbore relative to a second wellbore using a heater assembly as a current conductor.

[0096] FIGS. 21 and 22 depict an embodiment for assessing a position of a first wellbore relative to a second wellbore using two heater assemblies as current conductors.

[0097] FIG. 23 depicts an embodiment of an umbilical positioning control system employing a magnetic gradiometer system and wellbore to wellbore wireless telemetry system.

[0098] FIG. 24 depicts an embodiment of an umbilical positioning control system employing a magnetic gradiometer system in an existing wellbore.

[0099] FIG. 25 depicts an embodiment of an umbilical positioning control system employing a combination of systems being used in a first stage of deployment.

[0100] FIG. 26 depicts an embodiment of an umbilical positioning control system employing a combination of systems being used in a second stage of deployment.

[0101] FIG. 27 depicts two examples of the relationship between power received and distance based upon two different formations with different resistivities.

[0102] FIG. 28A depicts an embodiment of a drilling string including cutting structures positioned along the drilling string.

[0103] FIG. 28B depicts an embodiment of a drilling string including cutting structures positioned along the drilling string.
[0104] FIG. 28C depicts an embodiment of a drilling string including cutting structures positioned along the drilling string.
[0105] FIG. 29 depicts an embodiment of a drill bit including upward cutting structures.
[0106] FIG. 30 depicts an embodiment of a tubular including cutting structures positioned in a wellbore.
[0107] FIG. 31 depicts a cross-sectional representation of fluid flow in the drilling string of a wellbore with no control of vaporization of the fluid.
[0108] FIG. 32 depicts a partial cross-sectional representation of a system for drilling with controlled vaporization of drilling fluid to cool the drilling bit.
[0109] FIG. 33 depicts a partial cross-sectional representation of a system for cooling a downhole region that utilizes triple walled drilling string used and cooling fluid.
[0110] FIG. 34 depicts a partial cross-sectional representation of a reverse circulation flow scheme that uses cooling fluid, wherein the cooling fluid returns with the drilling fluid and cuttings.
[0111] FIG. 35 depicts a schematic of a rack and pinion drilling system.
[0112] FIGS. 36A through 36D depict schematics of an embodiment for a continuous drilling sequence.
[0113] FIG. 37 depicts a schematic of an embodiment of circulating sleeves.
[0114] FIG. 38 depicts schematics of an embodiment of a circulating sleeve with valves.
[0115] FIG. 39 depicts an embodiment of a bottom hole assembly for use with particle jet drilling.
[0116] FIG. 40 depicts a rotating jet head with multiple nozzles for use during particle jet drilling.
[0117] FIG. 41 depicts a rotating jet head with a single nozzle for use during particle jet drilling.
[0118] FIG. 42 depicts a non-rotating jet head for use during particle jet drilling.
[0119] FIG. 43 depicts a bottom hole assembly that uses an electric orienter to change the direction of wellbore formation.
[0120] FIG. 44 depicts a bottom hole assembly that uses directional jets to change the direction of wellbore formation.
[0121] FIG. 45 depicts a bottom hole assembly the uses a tractor system to change the direction of wellbore formation.
[0122] FIG. 46 depicts a perspective representation of a robot used to move the bottom hole assembly in a wellbore.
[0123] FIG. 47 depicts a representation of the robot positioned against the bottom hole assembly.
[0124] FIG. 48 depicts a schematic representation of a first group of barrier wells used to form a first barrier and a second group of barrier wells used to form a second barrier.

[0125] FIG. 49 depicts an embodiment of a freeze well for a circulated liquid refrigeration system, wherein a cutaway view of the freeze well is represented below ground surface.

[0126] FIG. 50 depicts a representation of a portion of a freeze well embodiment.

[0127] FIG. 51 depicts an embodiment of a wellbore for introducing wax into a formation to form a wax barrier.

[0128] FIG. 52A depicts a representation of a wellbore drilled to an intermediate depth in a formation.

[0129] FIG. 52B depicts a representation of the wellbore drilled to the final depth in the formation.

[0130] FIGS. 53, 54, and 55 depict cross-sectional representations of an embodiment of a temperature limited heater with an outer conductor having a ferromagnetic section and a non-ferromagnetic section.

[0131] FIGS. 56, 57, 58, and 59 depict cross-sectional representations of an embodiment of a temperature limited heater with an outer conductor having a ferromagnetic section and a non-ferromagnetic section placed inside a sheath.

[0132] FIGS. 60A and 60B depict cross-sectional representations of an embodiment of a temperature limited heater.

[0133] FIGS. 61A and 61B depict cross-sectional representations of an embodiment of a temperature limited heater.


[0135] FIGS. 63A and 63B depict cross-sectional representations of an embodiment of a temperature limited heater.

[0136] FIGS. 64A and 64B depict cross-sectional representations of an embodiment of a temperature limited heater.

[0137] FIG. 65 depicts a cross-sectional representation of an embodiment of a composite conductor with a support member.

[0138] FIG. 66 depicts a cross-sectional representation of an embodiment of a composite conductor with a support member separating the conductors.

[0139] FIG. 67 depicts a cross-sectional representation of an embodiment of a composite conductor surrounding a support member.

[0140] FIG. 68 depicts a cross-sectional representation of an embodiment of a composite conductor surrounding a conduit support member.
FIG. 69 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit heat source.

FIG. 70 depicts a cross-sectional representation of an embodiment of a removable conductor-in-conduit heat source.

FIG. 71 depicts a cross-sectional representation of an embodiment of a temperature limited heater in which the support member provides a majority of the heat output below the Curie temperature of the ferromagnetic conductor.

FIGS. 72 and 73 depict cross-sectional representations of embodiments of temperature limited heaters in which the jacket provides a majority of the heat output below the Curie temperature of the ferromagnetic conductor.

FIGS. 74A and 74B depict cross-sectional representations of an embodiment of a temperature limited heater component used in an insulated conductor heater.

FIG. 75 depicts a top view representation of three insulated conductors in a conduit.

FIG. 76 depicts an embodiment of three-phase wye transformer coupled to a plurality of heaters.

FIG. 77 depicts a side view representation of an end section of three insulated conductors in a conduit.

FIG. 78 depicts an embodiment of a heater with three insulated cores in a conduit.

FIG. 79 depicts an embodiment of a heater with three insulated conductors and an insulated return conductor in a conduit.

FIG. 80 depicts a cross-sectional representation of an embodiment of three insulated conductors banded together.

FIG. 81 depicts a cross-sectional representation of an embodiment of three insulated conductors banded together with a support member between the insulated conductors.

FIG. 82 depicts outer tubing partially unspooled from a coiled tubing rig.

FIG. 83 depicts a heater being pushed into outer tubing partially unspooled from a coiled tubing rig.

FIG. 84 depicts a heater being fully inserted into outer tubing with a drilling guide coupled to the end of the heater.

FIG. 85 depicts a heater, outer tubing, and drilling guide spooled onto a coiled tubing rig.

FIG. 86 depicts a coiled tubing rig being used to install a heater and outer tubing into an opening using a drilling guide.

FIG. 87 depicts a heater and outer tubing installed in an opening.

FIG. 88 depicts outer tubing being removed from an opening while leaving a heater installed in the opening.
[0160] FIG. 89 depicts outer tubing used to provide a packing material into an opening.
[0161] FIG. 90 depicts outer tubing being spooled onto a coiled tubing rig after packing material is provided into an opening.
[0162] FIG. 91 depicts outer tubing spooled onto a coiled tubing rig with a heater installed in an opening.
[0163] FIG. 92 depicts a heater installed in an opening with a wellhead.
[0164] FIG. 93 depicts an embodiment of an insulated conductor in a conduit with liquid between the insulated conductor and the conduit.
[0165] FIG. 94 depicts an embodiment of an insulated conductor heater in a conduit with a conductive liquid between the insulated conductor and the conduit.
[0166] FIG. 95 depicts an embodiment of an insulated conductor in a conduit with liquid between the insulated conductor and the conduit, where a portion of the conduit and the insulated conductor are oriented horizontally in the formation.
[0167] FIG. 96 depicts a cross-sectional representation of a ribbed conduit.
[0168] FIG. 97 depicts a perspective representation of a portion of a ribbed conduit.
[0169] FIG. 98 depicts an embodiment of a portion of an insulated conductor in a bottom portion of an open wellbore with a liquid between the insulated conductor and the formation.
[0170] FIG. 99 depicts a schematic cross-sectional representation of a portion of a formation with heat pipes positioned adjacent to a substantially horizontal portion of a heat source.
[0171] FIG. 100 depicts a perspective cut-out representation of a portion of a heat pipe embodiment with the heat pipe located radially around an oxidizer assembly.
[0172] FIG. 101 depicts a cross-sectional representation of an angled heat pipe embodiment with an oxidizer assembly located near a lowermost portion of the heat pipe.
[0173] FIG. 102 depicts a perspective cut-out representation of a portion of a heat pipe embodiment with an oxidizer located at the bottom of the heat pipe.
[0174] FIG. 103 depicts a cross-sectional representation of an angled heat pipe embodiment with an oxidizer located at the bottom of the heat pipe.
[0175] FIG. 104 depicts a perspective cut-out representation of a portion of a heat pipe embodiment with an oxidizer that produces a flame zone adjacent to liquid heat transfer fluid in the bottom of the heat pipe.
[0176] FIG. 105 depicts a perspective cut-out representation of a portion of a heat pipe embodiment with a tapered bottom that accommodates multiple oxidizers.
[0177] FIG. 106 depicts a cross-sectional representation of a heat pipe embodiment that is angled within the formation.
[0178] FIG. 107 depicts an embodiment of a three-phase temperature limited heater with a portion shown in cross section.

[0179] FIG. 108 depicts an embodiment of temperature limited heaters coupled together in a three-phase configuration.

[0180] FIG. 109 depicts an embodiment of three heaters coupled in a three-phase configuration.

[0181] FIG. 110 depicts a cross-sectional representation of an embodiment of a centralizer on a heater.

[0182] FIG. 111 depicts a cross-sectional representation of an embodiment of a centralizer on a heater.

[0183] FIG. 112 depicts a side view representation of an embodiment of a substantially u-shaped three-phase heater in a formation.

[0184] FIG. 113 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in a formation.

[0185] FIG. 114 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in a formation with production wells.

[0186] FIG. 115 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in a hexagonal pattern.

[0187] FIG. 116 depicts a top view representation of an embodiment of a hexagon from FIG. 115.

[0188] FIG. 117 depicts an embodiment of triads of heaters coupled to a horizontal bus bar.

[0189] FIG. 118 depicts an embodiment of two temperature limited heaters coupled together in a single contacting section.

[0190] FIG. 119 depicts an embodiment of two temperature limited heaters with legs coupled in a contacting section.

[0191] FIG. 120 depicts an embodiment of three diads coupled to a three-phase transformer.

[0192] FIG. 121 depicts an embodiment of groups of diads in a hexagonal pattern.

[0193] FIG. 122 depicts an embodiment of diads in a triangular pattern.

[0194] FIG. 123 depicts a cross-sectional representation of an embodiment of substantially u-shaped heaters in a formation.

[0195] FIG. 124 depicts a representational top view of an embodiment of a surface pattern of heaters depicted in FIG. 123.

[0196] FIG. 125 depicts a cross-sectional representation of substantially u-shaped heaters in a hydrocarbon layer.

[0197] FIG. 126 depicts a side view representation of an embodiment of substantially vertical heaters coupled to a substantially horizontal wellbore.
FIG. 127 depicts an embodiment of pluralities of substantially horizontal heaters coupled to bus bars in a hydrocarbon layer.

FIG. 128 depicts an embodiment of pluralities of substantially horizontal heaters coupled to bus bars in a hydrocarbon layer.

FIG. 129 depicts an embodiment of a bus bar coupled to heaters with connectors.

FIG. 130 depicts an embodiment of a bus bar coupled to heaters with connectors and centralizers.

FIG. 131 depicts a representation of a connector coupling to a bus bar.

FIG. 132 depicts a perspective representation of a connector coupling to a bus bar.

FIG. 133 depicts an embodiment of three u-shaped heaters with common overburden sections coupled to a single three-phase transformer.

FIG. 134 depicts a top view representation of an embodiment of a heater and a drilling guide in a wellbore.

FIG. 135 depicts a top view representation of an embodiment of two heaters and a drilling guide in a wellbore.

FIG. 136 depicts a top view representation of an embodiment of three heaters and a centralizer in a wellbore.

FIG. 137 depicts an embodiment for coupling ends of heaters in a wellbore.

FIG. 138 depicts a schematic of an embodiment of multiple heaters extending in different directions from a wellbore.

FIG. 139 depicts a schematic of an embodiment of multiple levels of heaters extending between two wellbores.

FIG. 140 depicts an embodiment of a u-shaped heater that has an inductively energized tubular.

FIG. 141 depicts an embodiment of an electrical conductor centralized inside a tubular.

FIG. 142 depicts an embodiment of an induction heater with a sheath of an insulated conductor in electrical contact with a tubular.

FIG. 143 depicts an embodiment of a resistive heater with a tubular having radial grooved surfaces.

FIG. 144 depicts an embodiment of an induction heater with a tubular having radial grooved surfaces.

FIG. 145 depicts an embodiment of a heater divided into tubular sections to provide varying heat outputs along the length of the heater.
[0217] FIG. 146 depicts an embodiment of three electrical conductors entering the formation through a first common wellbore and exiting the formation through a second common wellbore with three tubulars surrounding the electrical conductors in the hydrocarbon layer.

[0218] FIG. 147 depicts a representation of an embodiment of three electrical conductors and three tubulars in separate wellbores in the formation coupled to a transformer.

[0219] FIG. 148 depicts an embodiment of a multilayer induction tubular.

[0220] FIG. 149 depicts a cross-sectional end view of an embodiment of an insulated conductor that is used as an induction heater.

[0221] FIG. 150 depicts a cross-sectional side view of the embodiment depicted in FIG. 149.

[0222] FIG. 151 depicts a cross-sectional end view of an embodiment of a two-leg insulated conductor that is used as an induction heater.

[0223] FIG. 152 depicts a cross-sectional side view of the embodiment depicted in FIG. 151.

[0224] FIG. 153 depicts a cross-sectional end view of an embodiment of a multilayered insulated conductor that is used as an induction heater.

[0225] FIG. 154 depicts an end view representation of an embodiment of three insulated conductors located in a coiled tubing conduit and used as induction heaters.

[0226] FIG. 155 depicts a representation of cores of insulated conductors coupled together at their ends.

[0227] FIG. 156 depicts an end view representation of an embodiment of three insulated conductors strapped to a support member and used as induction heaters.

[0228] FIG. 157 depicts a representation of an embodiment of an induction heater with a core and an electrical insulator surrounded by a ferromagnetic layer.

[0229] FIG. 158 depicts a representation of an embodiment of an insulated conductor surrounded by a ferromagnetic layer.

[0230] FIG. 159 depicts a representation of an embodiment of an induction heater with two ferromagnetic layers spirally wound onto a core and an electrical insulator.

[0231] FIG. 160 depicts an embodiment for assembling a ferromagnetic layer onto an insulated conductor.

[0232] FIG. 161 depicts an embodiment of a casing having an axial grooved or corrugated surface.

[0233] FIG. 162 depicts an embodiment of a single-ended, substantially horizontal insulated conductor heater that electrically isolates itself from the formation.

[0234] FIGS. 163A and 163B depict cross-sectional representations of an embodiment of an insulated conductor that is electrically isolated on the outside of the jacket.
FIG. 164 depicts a side view representation with a cut out portion of an embodiment of an insulated conductor inside a tubular.

FIG. 165 depicts a cross-sectional representation of an embodiment of an insulated conductor inside a tubular taken substantially along line A-A of FIG. 164.

FIG. 166 depicts a cross-sectional representation of an embodiment of a distal end of an insulated conductor inside a tubular.

FIG. 167 depicts an embodiment of a wellhead.

FIG. 168 depicts an embodiment of a heater that has been installed in two parts.

FIG. 169 depicts a top view representation of an embodiment of a transformer showing the windings and core of the transformer.

FIG. 170 depicts a side view representation of the embodiment of the transformer showing the windings, the core, and the power leads.

FIG. 171 depicts an embodiment of a transformer in a wellbore.

FIG. 172 depicts an embodiment of a transformer in a wellbore with heat pipes.

FIG. 173 depicts a schematic for a conventional design of a tap changing voltage regulator.

FIG. 174 depicts a schematic for a variable voltage, load tap changing transformer.

FIG. 175 depicts a representation of an embodiment of a transformer and a controller.

FIG. 176 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a relatively thin hydrocarbon layer.

FIG. 177 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 176.

FIG. 178 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 177.

FIG. 179 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that has a shale break.

FIG. 180 depicts a top view representation of an embodiment for preheating using heaters for the drive process.

FIG. 181 depicts a perspective representation of an embodiment for preheating using heaters for the drive process.

FIG. 182 depicts a side view representation of an embodiment of a tar sands formation subsequent to a steam injection process.
[0254] FIG. 183 depicts a side view representation of an embodiment using at least three treatment sections in a tar sands formation.

[0255] FIG. 184 depicts a representation of an embodiment for producing hydrocarbons from a tar sands formation.

[0256] FIG. 185 depicts a representation of an embodiment for producing hydrocarbons from multiple layers in a tar sands formation.

[0257] FIG. 186 depicts an embodiment for heating and producing from a formation with a temperature limited heater in a production wellbore.

[0258] FIG. 187 depicts an embodiment for heating and producing from a formation with a temperature limited heater and a production wellbore.

[0259] FIG. 188 depicts a schematic of an embodiment of a first stage of treating a tar sands formation with electrical heaters.

[0260] FIG. 189 depicts a schematic of an embodiment of a second stage of treating the tar sands formation with fluid injection and oxidation.

[0261] FIG. 190 depicts a schematic of an embodiment of a third stage of treating the tar sands formation with fluid injection and oxidation.

[0262] FIG. 191 depicts a side view representation of a first stage of an embodiment of treating portions in a subsurface formation with heaters, oxidation and/or fluid injection.

[0263] FIG. 192 depicts a side view representation of a second stage of an embodiment of treating portions in the subsurface formation with heaters, oxidation and/or fluid injection.

[0264] FIG. 193 depicts a side view representation of an embodiment of treating portions in subsurface formation with heaters, oxidation and/or fluid injection.

[0265] FIG. 194 depicts an embodiment of treating a subsurface formation using a cylindrical pattern.

[0266] FIG. 195 depicts an embodiment of treating multiple portions of a subsurface formation in a rectangular pattern.

[0267] FIG. 196 is a schematic top view of the pattern depicted in FIG. 195.

[0268] FIG. 197 depicts a schematic representation of an embodiment of a downhole oxidizer assembly.

[0269] FIG. 198 depicts a schematic representation of an embodiment of a system for producing fuel for downhole oxidizer assemblies.

[0270] FIG. 199 depicts a schematic representation of an embodiment of a system for producing oxygen for use in downhole oxidizer assemblies.

[0271] FIG. 200 depicts a schematic representation of an embodiment of a system for producing oxygen for use in downhole oxidizer assemblies.
[0272] FIG. 201 depicts a schematic representation of an embodiment of a system for producing hydrogen for use in downhole oxidizer assemblies.

[0273] FIG. 202 depicts a cross-sectional representation of an embodiment of a downhole oxidizer including an insulating sleeve.

[0274] FIG. 203 depicts a cross-sectional representation of an embodiment of a downhole oxidizer with a gas cooled insulating sleeve.

[0275] FIG. 204 depicts a perspective view of an embodiment of a portion of an oxidizer of a downhole oxidizer assembly.

[0276] FIG. 205 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0277] FIG. 206 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0278] FIG. 207 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0279] FIG. 208 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0280] FIG. 209 depicts a cross-sectional representation of an embodiment of an oxidizer shield with multiple flame stabilizers.

[0281] FIG. 210 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0282] FIG. 211 depicts a perspective representation of an embodiment of a portion of an oxidizer of a downhole oxidizer assembly with louvered openings in the shield.

[0283] FIG. 212 depicts a cross-sectional representation of a portion of a shield with a louvered opening.

[0284] FIG. 213 depicts a perspective representation of an embodiment of a sectioned oxidizer.

[0285] FIG. 214 depicts a perspective representation of an embodiment of a sectioned oxidizer.

[0286] FIG. 215 depicts a perspective representation of an embodiment of a sectioned oxidizer.

[0287] FIG. 216 depicts a cross-sectional representation of an embodiment of a first oxidizer of an oxidizer assembly.

[0288] FIG. 217 depicts a cross-sectional representation of an embodiment of a catalytic burner.

[0289] FIG. 218 depicts a cross-sectional representation of an embodiment of a catalytic burner with an igniter.

[0290] FIG. 219 depicts a cross-sectional representation of an oxidizer assembly.

[0291] FIG. 220 depicts a cross-sectional representation of an oxidizer of an oxidizer assembly.

[0292] FIG. 221 depicts a schematic representation of an oxidizer assembly with flameless distributed combustors and oxidizers.

[0293] FIG. 222 depicts a schematic representation of an embodiment of a downhole oxidizer assembly.

[0294] FIG. 223 depicts a schematic representation of an embodiment of a downhole oxidizer assembly.
FIG. 224 depicts a schematic representation of an embodiment of a heater that uses coal as fuel.

FIG. 225 depicts a schematic representation of an embodiment of a heater that uses coal as fuel.

FIG. 226 depicts an embodiment of a heater with a heating section located in a u-shaped wellbore to create a first heated volume.

FIG. 227 depicts an embodiment of a heater with a heating section located in a u-shaped wellbore to create a second heated volume.

FIG. 228 depicts an embodiment of a heater with a heating section located in a u-shaped wellbore to create a third heated volume.

FIG. 229 depicts an embodiment of a heater with a heating section located in an L-shaped or J-shaped wellbore to create a first heated volume.

FIG. 230 depicts an embodiment of a heater with a heating section located in an L-shaped or J-shaped wellbore to create a second heated volume.

FIG. 231 depicts an embodiment of a heater with a heating section located in an L-shaped or J-shaped wellbore to create a third heated volume.

FIG. 232 depicts an embodiment of two heaters with heating sections located in a u-shaped wellbore to create two heated volumes.

FIG. 233 depicts a schematic representation of an embodiment of a downhole fluid heating system.

FIG. 234 depicts an embodiment of a wellbore for heating a formation using a burning fuel moving through the formation.

FIG. 235 depicts a top view representation of a portion of the fuel train used to heat the treatment area.

FIG. 236 depicts a side view representation of a portion of the fuel train used to heat the treatment area.

FIG. 237 depicts an aerial view representation of a system that heats the treatment area using burning fuel that is moved through the treatment area.

FIG. 238 depicts a schematic representation of a heat transfer fluid circulation system for heating a portion of a formation.

FIG. 239 depicts a schematic representation of an embodiment of an L-shaped heater for use with a heat transfer fluid circulation system for heating a portion of a formation.

FIG. 240 depicts a schematic representation of an embodiment of a vertical heater for use with a heat transfer fluid circulation system for a heating a portion of a formation where thermal expansion of the heater is accommodated below the surface.
[0312] FIG. 241 depicts a schematic representation of an embodiment of a vertical heater for use with a heat transfer fluid circulation system for a heating a portion of a formation where thermal expansion of the heater is accommodated above and below the surface.

[0313] FIG. 242 depicts a schematic representation of a portion of formation that is treated using a corridor pattern system.

[0314] FIG. 243 depicts a schematic representation of a portion of formation that is treated using a radial pattern system.

[0315] FIG. 244 depicts a plan view of wellbore entries and exits from a portion of a formation to be heated using a closed loop circulation system.

[0316] FIG. 245 depicts a cross-sectional view of an embodiment of overburden insulation that utilizes insulating cement.

[0317] FIG. 246 depicts a cross-sectional view of an embodiment of overburden insulation that utilizes an insulating sleeve.

[0318] FIG. 247 depicts a cross-sectional view of an embodiment of overburden insulation that utilizes an insulating sleeve and a vacuum.

[0319] FIG. 248 depicts a representation of bellows used to accommodate thermal expansion.

[0320] FIG. 249 depicts a representation of piping with an expansion loop for accommodating thermal expansion.

[0321] FIG. 250 depicts a representation of insulated piping in a large diameter casing in the overburden.

[0322] FIG. 251 depicts a representation of insulated piping in a large diameter casing in the overburden to accommodate thermal expansion.

[0323] FIG. 252 depicts a representation of an embodiment of a wellhead with a sliding seal, stuffing box or other pressure control equipment that allows a portion of a heater to move relative to the wellhead.

[0324] FIG. 253 depicts a representation of an embodiment of wellhead with a slip joint that interacts with a fixed conduit above the wellhead.

[0325] FIG. 254 depicts a representation of an embodiment of wellhead with a slip joint that interacts with a fixed conduit coupled to the wellhead.

[0326] FIG. 255 depicts a representation of a u-shaped wellbore with hot heat transfer fluid circulation system heater positioned in the wellbore.

[0327] FIG. 256 depicts a side view representation of an embodiment of a system for heating the formation that can use a closed loop circulation system and/or electrical heating.

[0328] FIG. 257 depicts a representation of a heat transfer fluid conduit that may initially be resistively heated with the return current path provided by an insulated conductor.
[0329] FIG. 258 depicts a representation of a heat transfer fluid conduit that may initially be resistively heated with the return current path provided by two insulated conductors.

[0330] FIG. 259 depicts a representation of insulated conductors used to resistively heat heaters of a circulated fluid heating system.

[0331] FIG. 260 depicts a representation of a heater of a heat transfer fluid circulation system with an insulated conductor heater positioned in the piping.

[0332] FIG. 261 depicts a cross-sectional view of an embodiment of a conduit-in-conduit heater for a heat transfer circulation heating system adjacent to the treatment area.

[0333] FIG. 262 depicts a schematic of an embodiment of conduit-in-conduit heaters of a fluid circulation heating system positioned in the formation.

[0334] FIG. 263 depicts a cross-sectional view of an embodiment of a conduit-in-conduit heater adjacent to the overburden.

[0335] FIG. 264 depicts an embodiment of a circulation system for a liquid heat transfer fluid.

[0336] FIG. 265 depicts a schematic representation of an embodiment of a system for heating the formation using gas lift to return the heat transfer fluid to the surface.

[0337] FIG. 266 depicts a schematic representation of an embodiment of an in situ heat treatment system that uses a nuclear reactor.

[0338] FIG. 267 depicts an elevational view of an in situ heat treatment system using pebble bed reactors.

[0339] FIG. 268 depicts a schematic representation of an embodiment of a self-regulating nuclear reactor.

[0340] FIG. 269 depicts power (W/ft)(y-axis) versus time (yr)(x-axis) of in situ hydrocarbon remediation power injection requirements.

[0341] FIG. 270 depicts power (W/ft)(y-axis) versus time (days)(x-axis) of in situ hydrocarbon remediation power injection requirements for different spacings between wellbores.

[0342] FIG. 271 depicts reservoir average temperature (°C)(y-axis) versus time (days)(x-axis) of in situ hydrocarbon remediation for different spacings between wellbores.

[0343] FIG. 272 depicts a schematic representation of an embodiment of an in situ heat treatment system with u-shaped wellbores using self-regulating nuclear reactors.

[0344] FIG. 273 depicts a side view representation of an embodiment for an in situ staged heating and production process for treating a tar sands formation.

[0345] FIG. 274 depicts a top view of a rectangular checkerboard pattern embodiment for the in situ staged heating and production process.

[0346] FIG. 275 depicts a top view of a ring pattern embodiment for the in situ staged heating and production process.
FIG. 276 depicts a top view of a checkerboard ring pattern embodiment for the in situ staged heating and production process.

FIG. 277 depicts a top view an embodiment of a plurality of rectangular checkerboard patterns in a treatment area for the in situ staged heating and production process.

FIG. 278 depicts an embodiment of irregular spaced heat sources with the heater density increasing as distance from a production well increases.

FIG. 279 depicts an embodiment of an irregular spaced triangular pattern.

FIG. 280 depicts an embodiment of irregular spaced square pattern.

FIG. 281 depicts an embodiment of a regular pattern of equally spaced rows of heat sources.

FIG. 282 depicts an embodiment of irregular spaced heat sources defining volumes around a production well.

FIG. 283 depicts an embodiment of a repeated pattern of irregular spaced heat sources with the heater density of each pattern increasing as distance from the production well increases.

FIG. 284 depicts a side view representation of embodiments for producing mobilized fluids from a hydrocarbon formation.

FIG. 285 depicts a side view representation of an embodiment for producing mobilized fluids from a hydrocarbon formation heated by residual heat.

FIG. 286 depicts a schematic representation of a system for inhibiting migration of formation fluid from a treatment area.

FIG. 287 depicts an embodiment of a windmill for generating electricity for subsurface heaters.

FIG. 288 depicts an embodiment of a solution mining well.

FIG. 289 depicts a representation of a portion of a solution mining well.

FIG. 290 depicts a representation of a portion of a solution mining well.

FIG. 291 depicts an elevational view of a well pattern for solution mining and/or an in situ heat treatment process.

FIG. 292 depicts a representation of wells of an in situ heating treatment process for solution mining and producing hydrocarbons from a formation.

FIG. 293 depicts an embodiment for solution mining a formation.

FIG. 294 depicts an embodiment of a formation with nahcolite layers in the formation before solution mining nahcolite from the formation.

FIG. 295 depicts the formation of FIG. 294 after the nahcolite has been solution mined.

FIG. 296 depicts an embodiment of two injection wells interconnected by a zone that has been solution mined to remove nahcolite from the zone.
[0368] FIG. 297 depicts a representation of an embodiment for treating a portion of a formation having a hydrocarbon containing formation between an upper nahcolite bed above and a lower nahcolite bed.

[0369] FIG. 298 depicts a representation of a portion of the formation that is orthogonal to the formation depicted in FIG. 297 and passes through one of the solution mining wells in the upper nahcolite bed.

[0370] FIG. 299 depicts an embodiment for heating a formation with dawsonite in the formation.

[0371] FIG. 300 depicts a representation of an embodiment for solution mining with a steam and electricity cogeneration facility.

[0372] FIG. 301 depicts an embodiment of treating a hydrocarbon containing formation with a combustion front.

[0373] FIG. 302 depicts a representation of an embodiment for treating a hydrocarbon containing formation with a combustion front.

[0374] FIG. 303 depicts a schematic representation of a system for producing formation fluid and introducing sour gas into a subsurface formation.

[0375] FIG. 304 depicts a schematic representation of a circulated fluid cooling system.

[0376] FIG. 305 depicts a schematic of an embodiment for treating a subsurface formation using heat sources having electrically conductive material.

[0377] FIG. 306 depicts a schematic of an embodiment for treating a subsurface formation having a shale layer using heat sources having electrically conductive material.

[0378] FIG. 307 depicts a schematic of an embodiment for treating a subsurface formation using a ground and heat sources having electrically conductive material.

[0379] FIG. 308 depicts a schematic of an embodiment for treating a subsurface formation using heat sources having electrically conductive material and an electrical insulator.

[0380] FIG. 309 depicts a schematic of an embodiment for treating a subsurface formation using electrically conductive heat sources extending from a common wellbore.

[0381] FIG. 310 depicts a schematic of an embodiment of an uncoated electrode and an electrode with a coated end.

[0382] FIG. 311 depicts a schematic of an embodiment of an uncoated electrode and a coated electrode.

[0383] FIG. 312 depicts a perspective view of an embodiment of an underground treatment system.

[0384] FIG. 313 depicts a perspective view of tunnels of an embodiment of an underground treatment system.
FIG. 314 depicts another exploded perspective view of a portion of an underground treatment system and tunnels.

FIG. 315 depicts a side view representation of an embodiment for flowing heated fluid through heat sources between tunnels.

FIG. 316 depicts a top view representation of an embodiment for flowing heated fluid through heat sources between tunnels.

FIG. 317 depicts a perspective view of an embodiment of an underground treatment system having heater wellbores spanning between to two tunnels of the underground treatment system.

FIG. 318 depicts a top view of an embodiment of tunnels with wellbore chambers.

FIG. 319 depicts a schematic view of tunnel sections of an embodiment of an underground treatment system.

FIG. 320 depicts a schematic view of an embodiment of an underground treatment system with surface production.

FIG. 321 depicts a side view of an embodiment of an underground treatment system.

FIG. 322 depicts electrical resistance versus temperature at various applied electrical currents for a 446 stainless steel rod.

FIG. 323 shows resistance profiles as a function of temperature at various applied electrical currents for a copper rod contained in a conduit of Sumitomo HCM12A.

FIG. 324 depicts electrical resistance versus temperature at various applied electrical currents for a temperature limited heater.

FIG. 325 depicts raw data for a temperature limited heater.

FIG. 326 depicts electrical resistance versus temperature at various applied electrical currents for a temperature limited heater.

FIG. 327 depicts power versus temperature at various applied electrical currents for a temperature limited heater.

FIG. 328 depicts electrical resistance versus temperature at various applied electrical currents for a temperature limited heater.

FIG. 329 depicts data of electrical resistance versus temperature for a solid 2.54 cm diameter, 1.8 m long 410 stainless steel rod at various applied electrical currents.

FIG. 330 depicts data of electrical resistance versus temperature for a composite 1.9 cm, 1.8 m long alloy 42-6 rod with a copper core (the rod has an outside diameter to copper diameter ratio of 2:1) at various applied electrical currents.
[0402] FIG. 331 depicts data of power output versus temperature for a composite 1.9 cm diameter, 1.8 m long alloy 42-6 rod with a copper core (the rod has an outside diameter to copper diameter ratio of 2:1) at various applied electrical currents.

[0403] FIG. 332 depicts data for values of skin depth versus temperature for a solid 2.54 cm diameter, 1.8 m long 410 stainless steel rod at various applied AC electrical currents.

[0404] FIG. 333 depicts temperature versus time for a temperature limited heater.

[0405] FIG. 334 depicts temperature versus log time data for a 2.5 cm diameter solid 410 stainless steel rod and a 2.5 cm diameter solid 304 stainless steel rod.

[0406] FIG. 335 depicts experimentally measured resistance versus temperature at several currents for a temperature limited heater with a copper core, a carbon steel ferromagnetic conductor, and a 347H stainless steel support member.

[0407] FIG. 336 depicts experimentally measured resistance versus temperature at several currents for a temperature limited heater with a copper core, an iron-cobalt ferromagnetic conductor, and a 347H stainless steel support member.

[0408] FIG. 337 depicts experimentally measured power factor versus temperature at two AC currents for a temperature limited heater with a copper core, a carbon steel ferromagnetic conductor, and a 347H stainless steel support member.

[0409] FIG. 338 depicts experimentally measured turndown ratio versus maximum power delivered for a temperature limited heater with a copper core, a carbon steel ferromagnetic conductor, and a 347H stainless steel support member.

[0410] FIG. 339 depicts examples of relative magnetic permeability versus magnetic field for both the found correlations and raw data for carbon steel.

[0411] FIG. 340 shows the resulting plots of skin depth versus magnetic field for four temperatures and 400 A current.

[0412] FIG. 341 shows a comparison between the experimental and numerical (calculated) AC resistances for currents of 300 A, 400 A, and 500 A.

[0413] FIG. 342 shows the AC resistance per foot of the heater element as a function of skin depth at 1100 °F calculated from the theoretical model.

[0414] FIG. 343 depicts the power generated per unit length in each heater component versus skin depth for a temperature limited heater.

[0415] FIGS. 344A-C compare the results of theoretical calculations with experimental data for resistance versus temperature in a temperature limited heater.

[0416] FIG. 345 depicts a plot of heater power versus core diameter.

[0417] FIG. 346 depicts power, resistance, and current versus temperature for a heater with a core diameter of 0.105".
FIG. 347 depicts actual heater power versus time during the simulation for three different heater designs.

FIG. 348 depicts heater element temperature (core temperature) and average formation temperature versus time for three different heater designs.

FIG. 349 depicts plots of power versus temperature at three currents for an induction heater.

FIG. 350 depicts temperature versus radial distance for a heater with air between an insulated conductor and conduit.

FIG. 351 depicts temperature versus radial distance for a heater with molten solar salt between an insulated conductor and conduit.

FIG. 352 depicts temperature versus radial distance for a heater with molten tin between an insulated conductor and conduit.

FIG. 353 depicts simulated temperature versus radial distance for various heaters of a first size, with various fluids between the insulated conductors and conduits, and at different temperatures of the outer surfaces of the conduits.

FIG. 354 depicts simulated temperature versus radial distance for various heaters wherein the dimensions of the insulated conductor are half the size of the insulated conductor used to generate FIG. 353, with various fluids between the insulated conductors and conduits, and at different temperatures of the outer surfaces of the conduits.

FIG. 355 depicts simulated temperature versus radial distance for various heaters wherein the dimensions of the insulated conductor is the same as the insulated conductor used to generate FIG. 354, and the conduit is larger than the conduit used to generate FIG. 354 with various fluids between the insulated conductors and conduits, and at various temperatures of the outer surfaces of the conduits.

FIG. 356 depicts simulated temperature versus radial distance for various heaters with molten salt between insulated conductors and conduits of the heaters and a boundary condition of 500 °C.

FIG. 357 depicts a temperature profile in the formation after 360 days using the STARS simulation.

FIG. 358 depicts an oil saturation profile in the formation after 360 days using the STARS simulation.

FIG. 359 depicts the oil saturation profile in the formation after 1095 days using the STARS simulation.

FIG. 360 depicts the oil saturation profile in the formation after 1470 days using the STARS simulation.
[0432] FIG. 361 depicts the oil saturation profile in the formation after 1826 days using the
STARS simulation.

[0433] FIG. 362 depicts the temperature profile in the formation after 1826 days using the
STARS simulation.

[0434] FIG. 363 depicts oil production rate and gas production rate versus time.

[0435] FIG. 364 depicts weight percentage of original bitumen in place (OBIP)(left axis) and
volume percentage of OBIP (right axis) versus temperature (°C).

[0436] FIG. 365 depicts bitumen conversion percentage (weight percentage of (OBIP))(left axis)
and oil, gas, and coke weight percentage (as a weight percentage of OBIP)(right axis) versus
temperature (°C).

[0437] FIG. 366 depicts API gravity (°)(left axis) of produced fluids, blow down production, and
oil left in place along with pressure (psig)(right axis) versus temperature (°C).

[0438] FIGS. 367A-D depict gas-to-oil ratios (GOR) in thousand cubic feet per barrel ((Mcf/
bbl)(y-axis)) versus temperature (°C)(x-axis) for different types of gas at a low temperature blow
down (about 277 °C) and a high temperature blow down (at about 290 °C).

[0439] FIG. 368 depicts coke yield (weight percentage)(y-axis) versus temperature (°C)(x-axis).

[0440] FIGS. 369A-D depict assessed hydrocarbon isomer shifts in fluids produced from the
experimental cells as a function of temperature and bitumen conversion.

[0441] FIG. 370 depicts weight percentage (Wt%)(y-axis) of saturates from SARA analysis of
the produced fluids versus temperature (°C)(x-axis).

[0442] FIG. 371 depicts weight percentage (Wt%)(y-axis) of n-C7 of the produced fluids versus
temperature (°C)(x-axis).

[0443] FIG. 372 depicts oil recovery (volume percentage bitumen in place (vol% BIP)) versus
API gravity (°) as determined by the pressure (MPa) in the formation in an experiment.

[0444] FIG. 373 depicts recovery efficiency (%) versus temperature (°C) at different pressures in
an experiment.

[0445] FIG. 374 depicts average formation temperature (°C) versus days for heating a formation
using molten salt circulated through conduit-in-conduit heaters.

[0446] FIG. 375 depicts molten salt temperature (°C) and power injection rate (W/ft) versus time
(days).

[0447] FIG. 376 depicts temperature (°C) and power injection rate (W/ft) versus time (days) for
heating a formation using molten salt circulated through heaters with a heating length of 8000 ft
at a mass flow rate of 18 kg/s.
[0448] FIG. 377 depicts temperature (°C) and power injection rate (W/ft) versus time (days) for heating a formation using molten salt circulated through heaters with a heating length of 8000 ft at a mass flow rate of 12 kg/s.

[0449] While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and may herein be described in detail. The drawings may not be to scale. It should be understood, however, that the drawings and detailed description thereto are not intended to limit the invention to the particular form disclosed, but on the contrary, the intention is to cover all modifications, equivalents and alternatives falling within the spirit and scope of the present invention as defined by the appended claims.

**DETAILED DESCRIPTION**

[0450] The following description generally relates to systems and methods for treating hydrocarbons in the formations. Such formations may be treated to yield hydrocarbon products, hydrogen, and other products.

[0451] “Alternating current (AC)” refers to a time-varying current that reverses direction substantially sinusoidally. AC produces skin effect electricity flow in a ferromagnetic conductor.

[0452] “Annular region” is the region between an outer conduit and an inner conduit positioned in the outer conduit.

[0453] “API gravity” refers to API gravity at 15.5 °C (60 °F). API gravity is as determined by ASTM Method D6822 or ASTM Method D1298.


[0455] In the context of reduced heat output heating systems, apparatus, and methods, the term “automatically” means such systems, apparatus, and methods function in a certain way without the use of external control (for example, external controllers such as a controller with a temperature sensor and a feedback loop, PID controller, or predictive controller).

[0456] “Bare metal” and “exposed metal” refer to metals of elongated members that do not include a layer of electrical insulation, such as mineral insulation, that is designed to provide electrical insulation for the metal throughout an operating temperature range of the elongated member. Bare metal and exposed metal may encompass a metal that includes a corrosion inhibitor such as a naturally occurring oxidation layer, an applied oxidation layer, and/or a film. Bare metal and exposed metal include metals with polymeric or other types of electrical insulation that cannot retain electrical insulating properties at typical operating temperature of the elongated member. Such material may be placed on the metal and may be thermally degraded during use of the heater.
[0457] Boiling range distributions for the formation fluid and liquid streams described herein are as determined by ASTM Method D5307 or ASTM Method D2887. Content of hydrocarbon components in weight percent for paraffins, iso-paraffins, olefins, naphthenes and aromatics in the liquid streams is as determined by ASTM Method D6730. Content of aromatics in volume percent is as determined by ASTM Method D1319. Weight percent of hydrogen in hydrocarbons is as determined by ASTM Method D3343.

[0458] “Bromine number” refers to a weight percentage of olefins in grams per 100 gram of portion of the produced fluid that has a boiling range below 246 °C and testing the portion using ASTM Method D1159.

[0459] “Carbon number” refers to the number of carbon atoms in a molecule. A hydrocarbon fluid may include various hydrocarbons with different carbon numbers. The hydrocarbon fluid may be described by a carbon number distribution. Carbon numbers and/or carbon number distributions may be determined by true boiling point distribution and/or gas-liquid chromatography.

[0460] “Chemically stability” refers to the ability of a formation fluid to be transported without components in the formation fluid reacting to form polymers and/or compositions that plug pipelines, valves, and/or vessels.

[0461] “Clogging” refers to impeding and/or inhibiting flow of one or more compositions through a process vessel or a conduit.

[0462] “Column X element” or “Column X elements” refer to one or more elements of Column X of the Periodic Table, and/or one or more compounds of one or more elements of Column X of the Periodic Table, in which X corresponds to a column number (for example, 13-18) of the Periodic Table. For example, “Column 15 elements” refer to elements from Column 15 of the Periodic Table and/or compounds of one or more elements from Column 15 of the Periodic Table.

[0463] “Column X metal” or “Column X metals” refer to one or more metals of Column X of the Periodic Table and/or one or more compounds of one or more metals of Column X of the Periodic Table, in which X corresponds to a column number (for example, 1-12) of the Periodic Table. For example, “Column 6 metals” refer to metals from Column 6 of the Periodic Table and/or compounds of one or more metals from Column 6 of the Periodic Table.

[0464] “Condensable hydrocarbons” are hydrocarbons that condense at 25 °C and one atmosphere absolute pressure. Condensable hydrocarbons may include a mixture of hydrocarbons having carbon numbers greater than 4. “Non-condensable hydrocarbons” are hydrocarbons that do not condense at 25 °C and one atmosphere absolute pressure. Non-condensable hydrocarbons may include hydrocarbons having carbon numbers less than 5.
[0465] “Coring” is a process that generally includes drilling a hole into a formation and removing a substantially solid mass of the formation from the hole.

[0466] “Cracking” refers to a process involving decomposition and molecular recombination of organic compounds to produce a greater number of molecules than were initially present. In cracking, a series of reactions take place accompanied by a transfer of hydrogen atoms between molecules. For example, naphtha may undergo a thermal cracking reaction to form ethene and H₂.

[0467] “Curie temperature” is the temperature above which a ferromagnetic material loses all of its ferromagnetic properties. In addition to losing all of its ferromagnetic properties above the Curie temperature, the ferromagnetic material begins to lose its ferromagnetic properties when an increasing electrical current is passed through the ferromagnetic material.

[0468] “Cycle oil” refers to a mixture of light cycle oil and heavy cycle oil. “Light cycle oil” refers to hydrocarbons having a boiling range distribution between 430 °F (221 °C) and 650 °F (343 °C) that are produced from a fluidized catalytic cracking system. Light cycle oil content is determined by ASTM Method D5307. “Heavy cycle oil” refers to hydrocarbons having a boiling range distribution between 650 °F (343 °C) and 800 °F (427 °C) that are produced from a fluidized catalytic cracking system. Heavy cycle oil content is determined by ASTM Method D5307.

[0469] “Diad” refers to a group of two items (for example, heaters, wellbores, or other objects) coupled together.

[0470] “Diesel” refers to hydrocarbons with a boiling range distribution between 260 °C and 343 °C (500-650 °F) at 0.101 MPa. Diesel content is determined by ASTM Method D2887.

[0471] “Enriched air” refers to air having a larger mole fraction of oxygen than air in the atmosphere. Air is typically enriched to increase combustion-supporting ability of the air.

[0472] "Fluid injectivity" is the flow rate of fluids injected per unit of pressure differential between a first location and a second location.

[0473] “Fluid pressure” is a pressure generated by a fluid in a formation. “Lithostatic pressure” (sometimes referred to as “lithostatic stress”) is a pressure in a formation equal to a weight per unit area of an overlying rock mass. “Hydrostatic pressure” is a pressure in a formation exerted by a column of water.

[0474] A “formation” includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. “Hydrocarbon layers” refer to layers in the formation that contain hydrocarbons. The hydrocarbon layers may contain non-hydrocarbon material and hydrocarbon material. The “overburden” and/or the “underburden” include one or more different types of impermeable materials. For example, the overburden
and/or underburden may include rock, shale, mudstone, or wet/tight carbonate. In some embodiments of in situ heat treatment processes, the overburden and/or the underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ heat treatment processing that result in significant characteristic changes of the hydrocarbon containing layers of the overburden and/or the underburden. For example, the underburden may contain shale or mudstone, but the underburden is not allowed to heat to pyrolysis temperatures during the in situ heat treatment process. In some cases, the overburden and/or the underburden may be somewhat permeable.

[0475] "Formation fluids" refer to fluids present in a formation and may include pyrolyzation fluid, synthesis gas, mobilized hydrocarbons, and water (steam). Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids. The term "mobilized fluid" refers to fluids in a hydrocarbon containing formation that are able to flow as a result of thermal treatment of the formation. "Produced fluids" refer to fluids removed from the formation.

[0476] "Freezing point" of a hydrocarbon liquid refers to the temperature below which solid hydrocarbon crystals may form in the liquid. Freezing point is as determined by ASTM Method D5901.

[0477] "Gasoline hydrocarbons" refer to hydrocarbons having a boiling point range from 32 °C (90 °F) to about 204 °C (400 °F). Gasoline hydrocarbons include, but are not limited to, straight run gasoline, naphtha, fluidized or thermally catalytically cracked gasoline, VB gasoline, and coker gasoline. Gasoline hydrocarbons content is determined by ASTM Method D2887.

[0478] A "heat source" is any system for providing heat to at least a portion of a formation substantially by conductive and/or radiative heat transfer. For example, a heat source may include electric heaters such as an insulated conductor, an elongated member, and/or a conductor disposed in a conduit. A heat source may also include systems that generate heat by burning a fuel external to or in a formation. The systems may be surface burners, downhole gas burners, flameless distributed combustors, and natural distributed combustors. In some embodiments, heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer medium that directly or indirectly heats the formation. It is to be understood that one or more heat sources that are applying heat to a formation may use different sources of energy. Thus, for example, for a given formation some heat sources may supply heat from electric resistance heaters, some heat sources may provide heat from combustion, and some heat sources may provide heat from one or more other energy sources (for example, chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may include an exothermic reaction (for example, an oxidation reaction). A
heat source may also include a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0479] A “heater” is any system or heat source for generating heat in a well or a near wellbore region. Heaters may be, but are not limited to, electric heaters, burners, combustors that react with material in or produced from a formation, and/or combinations thereof.

[0480] “Heavy hydrocarbons” are viscous hydrocarbon fluids. Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity. Heavy hydrocarbons generally have an API gravity below about 20°. Heavy oil, for example, generally has an API gravity of about 10-20°, whereas tar generally has an API gravity below about 10°. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15 °C. Heavy hydrocarbons may include aromatics or other complex ring hydrocarbons.

[0481] Heavy hydrocarbons may be found in a relatively permeable formation. The relatively permeable formation may include heavy hydrocarbons entrained in, for example, sand or carbonate. “Relatively permeable” is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or 100 millidarcy). “Relatively low permeability” is defined, with respect to formations or portions thereof, as an average permeability of less than about 10 millidarcy. One darcy is equal to about 0.99 square micrometers. An impermeable layer generally has a permeability of less than about 0.1 millidarcy.

[0482] Certain types of formations that include heavy hydrocarbons may also include, but are not limited to, natural mineral waxes, or natural asphaltites. “Natural mineral waxes” typically occur in substantially tubular veins that may be several meters wide, several kilometers long, and hundreds of meters deep. “Natural asphaltites” include solid hydrocarbons of an aromatic composition and typically occur in large veins. In situ recovery of hydrocarbons from formations such as natural mineral waxes and natural asphaltites may include melting to form liquid hydrocarbons and/or solution mining of hydrocarbons from the formations.

[0483] “Hydrocarbons” are generally defined as molecules formed primarily by carbon and hydrogen atoms. Hydrocarbons may also include other elements such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be, but are not limited to, kerogen, bitumen, pyrobitumen, oils, natural mineral waxes, and asphaltites. Hydrocarbons may be located in or adjacent to mineral matrices in the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and
other porous media. "Hydrocarbon fluids" are fluids that include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids such as hydrogen, nitrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia.

0484 An "in situ conversion process" refers to a process of heating a hydrocarbon containing formation from heat sources to raise the temperature of at least a portion of the formation above a pyrolysis temperature so that pyrolyzation fluid is produced in the formation.

0485 An "in situ heat treatment process" refers to a process of heating a hydrocarbon containing formation with heat sources to raise the temperature of at least a portion of the formation above a temperature that results in mobilized fluid, visbreaking, and/or pyrolysis of hydrocarbon containing material so that mobilized fluids, visbroken fluids, and/or pyrolyzation fluids are produced in the formation.

0486 "Insulated conductor" refers to any elongated material that is able to conduct electricity and that is covered, in whole or in part, by an electrically insulating material.

0487 "Karst" is a subsurface shaped by the dissolution of a soluble layer or layers of bedrock, usually carbonate rock such as limestone or dolomite. The dissolution may be caused by meteoric or acidic water. The Grosmont formation in Alberta, Canada is an example of a karst (or "karsted") carbonate formation.

0488 "Kerogen" is a solid, insoluble hydrocarbon that has been converted by natural degradation and that principally contains carbon, hydrogen, nitrogen, oxygen, and sulfur. Coal and oil shale are typical examples of materials that contain kerogen. "Bitumen" is a non-crystalline solid or viscous hydrocarbon material that is substantially soluble in carbon disulfide. "Oil" is a fluid containing a mixture of condensable hydrocarbons.

0489 "Kerosene" refers to hydrocarbons with a boiling range distribution between 204 °C and 260 °C at 0.101 MPa. Kerosene content is determined by ASTM Method D2887.

0490 "Modulated direct current (DC)" refers to any substantially non-sinusoidal time-varying current that produces skin effect electricity flow in a ferromagnetic conductor.

0491 "Naphtha" refers to hydrocarbon components with a boiling range distribution between 38 °C and 200 °C at 0.101 MPa. Naphtha content is determined by ASTM Method D5307.

0492 "Nitride" refers to a compound of nitrogen and one or more other elements of the Periodic Table. Nitrides include, but are not limited to, silicon nitride, boron nitride, or alumina nitride.

0493 "Nitrogen compound content" refers to an amount of nitrogen in an organic compound. Nitrogen content is as determined by ASTM Method D5762.
“Octane Number” refers to a calculated numerical representation of the antiknock properties of a motor fuel compared to a standard reference fuel. A calculated octane number is determined by ASTM Method D6730.

“Olefins” are molecules that include unsaturated hydrocarbons having one or more non-aromatic carbon-carbon double bonds.

“Olefin content” refers to an amount of non-aromatic olefins in a fluid. Olefin content for a produced fluid is determined by obtaining a portion of the produce fluid that has a boiling point of 246 °C and testing the portion using ASTM Method D1159 and reporting the result as a bromine factor in grams per 100 gram of portion. Olefin content is also determined by the Canadian Association of Petroleum Producers (CAPP) olefin method and is reported in percent olefin as 1-decene equivalent.

“Organonitrogen compounds” refers to hydrocarbons that contain at least one nitrogen atom. Non-limiting examples of organonitrogen compounds include, but are not limited to, alkyl amines, aromatic amines, alkyl amides, aromatic amides, pyridines, pyrazoles, and oxazoles.

“Orifices” refer to openings, such as openings in conduits, having a wide variety of sizes and cross-sectional shapes including, but not limited to, circles, ovals, squares, rectangles, triangles, slits, or other regular or irregular shapes.

“P (peptization) value” or “P-value” refers to a numerical value, which represents the flocculation tendency of asphaltenes in a formation fluid. P-value is determined by ASTM method D7060.

"Perforations" include openings, slits, apertures, or holes in a wall of a conduit, tubular, pipe or other flow pathway that allow flow into or out of the conduit, tubular, pipe or other flow pathway.

“Periodic Table” refers to the Periodic Table as specified by the International Union of Pure and Applied Chemistry (IUPAC), November 2003. In the scope of this application, weight of a metal from the Periodic Table, weight of a compound of a metal from the Periodic Table, weight of an element from the Periodic Table, or weight of a compound of an element from the Periodic Table is calculated as the weight of metal or the weight of element. For example, if 0.1 grams of MoO₃ is used per gram of catalyst, the calculated weight of the molybdenum metal in the catalyst is 0.067 grams per gram of catalyst.

“Phase transformation temperature” of a ferromagnetic material refers to a temperature or a temperature range during which the material undergoes a phase change (for example, from ferrite to austenite) that decreases the magnetic permeability of the ferromagnetic material. The reduction in magnetic permeability is similar to reduction in magnetic permeability due to the magnetic transition of the ferromagnetic material at the Curie temperature.
“Physical stability” refers to the ability of a formation fluid to not exhibit phase separation or flocculation during transportation of the fluid. Physical stability is determined by ASTM Method D7060.

“Pyrolysis” is the breaking of chemical bonds due to the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone. Heat may be transferred to a section of the formation to cause pyrolysis.

“Pyrolyzation fluids” or “pyrolysis products” refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or pyrolyzation product. As used herein, “pyrolysis zone” refers to a volume of a formation (for example, a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.

“Residue” refers to hydrocarbons that have a boiling point above 537 °C (1000 °F).

“Rich layers” in a hydrocarbon containing formation are relatively thin layers (typically about 0.2 m to about 0.5 m thick). Rich layers generally have a richness of about 0.150 L/kg or greater. Some rich layers have a richness of about 0.170 L/kg or greater, of about 0.190 L/kg or greater, or of about 0.210 L/kg or greater. Lean layers of the formation have a richness of about 0.100 L/kg or less and are generally thicker than rich layers. The richness and locations of layers are determined, for example, by coring and subsequent Fischer assay of the core, density or neutron logging, or other logging methods. Rich layers may have a lower initial thermal conductivity than other layers of the formation. Typically, rich layers have a thermal conductivity 1.5 times to 3 times lower than the thermal conductivity of lean layers. In addition, rich layers have a higher thermal expansion coefficient than lean layers of the formation.

“Smart well technology” or “smart wellbore” refers to wells that incorporate downhole measurement and/or control. For injection wells, smart well technology may allow for controlled injection of fluid into the formation in desired zones. For production wells, smart well technology may allow for controlled production of formation fluid from selected zones. Some wells may include smart well technology that allows for formation fluid production from selected zones and simultaneous or staggered solution injection into other zones. Smart well technology may include fiber optic systems and control valves in the wellbore. A smart wellbore used for an in situ heat treatment process may be Westbay Multilevel Well System MP55 available from Westbay Instruments Inc. (Burnaby, British Columbia, Canada).

“Subsidence” is a downward movement of a portion of a formation relative to an initial elevation of the surface.
“Sulfur compound content” refers to an amount of sulfur in an organic compound. Sulfur content is as determined by ASTM Method D4294.

“Superposition of heat” refers to providing heat from two or more heat sources to a selected section of a formation such that the temperature of the formation at least at one location between the heat sources is influenced by the heat sources.

“Synthesis gas” is a mixture including hydrogen and carbon monoxide. Additional components of synthesis gas may include water, carbon dioxide, nitrogen, methane, and other gases. Synthesis gas may be generated by a variety of processes and feedstocks. Synthesis gas may be used for synthesizing a wide range of compounds.

“TAN” refers to a total acid number expressed as milligrams (“mg”) of KOH per gram (“g”) of sample. TAN is as determined by ASTM Method D3242.

“Tar” is a viscous hydrocarbon that generally has a viscosity greater than about 10,000 centipoise at 15 °C. The specific gravity of tar generally is greater than 1.000. Tar may have an API gravity less than 10°.

A “tar sands formation” is a formation in which hydrocarbons are predominantly present in the form of heavy hydrocarbons and/or tar entrained in a mineral grain framework or other host lithology (for example, sand or carbonate). Examples of tar sands formations include formations such as the Athabasca formation, the Grosmont formation, and the Peace River formation, all three in Alberta, Canada; and the Faja formation in the Orinoco belt in Venezuela.

“Temperature limited heater” generally refers to a heater that regulates heat output (for example, reduces heat output) above a specified temperature without the use of external controls such as temperature controllers, power regulators, rectifiers, or other devices. Temperature limited heaters may be AC (alternating current) or modulated (for example, “chopped”) DC (direct current) powered electrical resistance heaters.

“Thermally conductive fluid” includes fluid that has a higher thermal conductivity than air at standard temperature and pressure (STP) (0 °C and 101.325 kPa).

“Thermal conductivity” is a property of a material that describes the rate at which heat flows, in steady state, between two surfaces of the material for a given temperature difference between the two surfaces.

“Thermal fracture” refers to fractures created in a formation caused by expansion or contraction of a formation and/or fluids in the formation, which is in turn caused by increasing/decreasing the temperature of the formation and/or fluids in the formation, and/or by increasing/decreasing a pressure of fluids in the formation due to heating.

“Thermal oxidation stability” refers to thermal oxidation stability of a liquid. Thermal oxidation stability is as determined by ASTM Method D3241.
"Thickness" of a layer refers to the thickness of a cross section of the layer, wherein the cross section is normal to a face of the layer.

"Time-varying current" refers to electrical current that produces skin effect electricity flow in a ferromagnetic conductor and has a magnitude that varies with time. Time-varying current includes both alternating current (AC) and modulated direct current (DC).

"Triad" refers to a group of three items (for example, heaters, wellbores, or other objects) coupled together.

"Turndown ratio" for the temperature limited heater in which current is applied directly to the heater is the ratio of the highest AC or modulated DC resistance below the Curie temperature to the lowest resistance above the Curie temperature for a given current. Turndown ratio for an inductive heater is the ratio of the highest heat output below the Curie temperature to the lowest heat output above the Curie temperature for a given current applied to the heater.

"u-shaped wellbore" refers to a wellbore that extends from a first opening in the formation, through at least a portion of the formation, and out through a second opening in the formation. In this context, the wellbore may be only roughly in the shape of a "v" or "u", with the understanding that the "legs" of the "u" do not need to be parallel to each other, or perpendicular to the "bottom" of the "u" for the wellbore to be considered "u-shaped".

"Upgrade" refers to increasing the quality of hydrocarbons. For example, upgrading heavy hydrocarbons may result in an increase in the API gravity of the heavy hydrocarbons.

"Visbreaking" refers to the untangling of molecules in fluid during heat treatment and/or to the breaking of large molecules into smaller molecules during heat treatment, which results in a reduction of the viscosity of the fluid.

"Viscosity" refers to kinematic viscosity at 40 °C unless otherwise specified. Viscosity is as determined by ASTM Method D445.

"VGO" or "vacuum gas oil" refers to hydrocarbons with a boiling range distribution between 343 °C and 538 °C at 0.101 MPa. VGO content is determined by ASTM Method D5307.

A "vug" is a cavity, void or large pore in a rock that is commonly lined with mineral precipitates.

"Wax" refers to a low melting organic mixture, or a compound of high molecular weight that is a solid at lower temperatures and a liquid at higher temperatures, and when in solid form can form a barrier to water. Examples of waxes include animal waxes, vegetable waxes, mineral waxes, petroleum waxes, and synthetic waxes.

The term "wellbore" refers to a hole in a formation made by drilling or insertion of a conduit into the formation. A wellbore may have a substantially circular cross section, or another
cross-sectional shape. As used herein, the terms “well” and “opening,” when referring to an opening in the formation may be used interchangeably with the term “wellbore.”

[0533] A formation may be treated in various ways to produce many different products. Different stages or processes may be used to treat the formation during an in situ heat treatment process. In some embodiments, one or more sections of the formation are solution mined to remove soluble minerals from the sections. Solution mining minerals may be performed before, during, and/or after the in situ heat treatment process. In some embodiments, the average temperature of one or more sections being solution mined may be maintained below about 120 °C.

[0534] In some embodiments, one or more sections of the formation are heated to remove water from the sections and/or to remove methane and other volatile hydrocarbons from the sections. In some embodiments, the average temperature may be raised from ambient temperature to temperatures below about 220 °C during removal of water and volatile hydrocarbons.

[0535] In some embodiments, one or more sections of the formation are heated to temperatures that allow for movement and/or visbreaking of hydrocarbons in the formation. In some embodiments, the average temperature of one or more sections of the formation are raised to mobilization temperatures of hydrocarbons in the sections (for example, to temperatures ranging from 100 °C to 250 °C, from 120 °C to 240 °C, or from 150 °C to 230 °C).

[0536] In some embodiments, one or more sections are heated to temperatures that allow for pyrolysis reactions in the formation. In some embodiments, the average temperature of one or more sections of the formation may be raised to pyrolysis temperatures of hydrocarbons in the sections (for example, temperatures ranging from 230 °C to 900 °C, from 240 °C to 400 °C or from 250 °C to 350 °C).

[0537] Heating the hydrocarbon containing formation with a plurality of heat sources may establish thermal gradients around the heat sources that raise the temperature of hydrocarbons in the formation to desired temperatures at desired heating rates. The rate of temperature increase through mobilization temperature range and/or pyrolysis temperature range for desired products may affect the quality and quantity of the formation fluids produced from the hydrocarbon containing formation. Slowly raising the temperature of the formation through the mobilization temperature range and/or pyrolysis temperature range may allow for the production of high quality, high API gravity hydrocarbons from the formation. Slowly raising the temperature of the formation through the mobilization temperature range and/or pyrolysis temperature range may allow for the removal of a large amount of the hydrocarbons present in the formation as hydrocarbon product.
[0538] In some in situ heat treatment embodiments, a portion of the formation is heated to a desired temperature instead of slowly heating the temperature through a temperature range. In some embodiments, the desired temperature is 300 °C, 325 °C, or 350 °C. Other temperatures may be selected as the desired temperature.

[0539] Superposition of heat from heat sources allows the desired temperature to be relatively quickly and efficiently established in the formation. Energy input into the formation from the heat sources may be adjusted to maintain the temperature in the formation substantially at a desired temperature.

[0540] Mobilization and/or pyrolysis products may be produced from the formation through production wells. In some embodiments, the average temperature of one or more sections is raised to mobilization temperatures and hydrocarbons are produced from the production wells. The average temperature of one or more of the sections may be raised to pyrolysis temperatures after production due to mobilization decreases below a selected value. In some embodiments, the average temperature of one or more sections may be raised to pyrolysis temperatures without significant production before reaching pyrolysis temperatures. Formation fluids including pyrolysis products may be produced through the production wells.

[0541] In some embodiments, the average temperature of one or more sections may be raised to temperatures sufficient to allow synthesis gas production after mobilization and/or pyrolysis. In some embodiments, hydrocarbons may be raised to temperatures sufficient to allow synthesis gas production without significant production before reaching the temperatures sufficient to allow synthesis gas production. For example, synthesis gas may be produced in a temperature range from about 400 °C to about 1200 °C, about 500 °C to about 1100 °C, or about 550 °C to about 1000 °C. A synthesis gas generating fluid (for example, steam and/or water) may be introduced into the sections to generate synthesis gas. Synthesis gas may be produced from production wells.

[0542] Solution mining, removal of volatile hydrocarbons and water, mobilizing hydrocarbons, pyrolyzing hydrocarbons, generating synthesis gas, and/or other processes may be performed during the in situ heat treatment process. In some embodiments, some processes may be performed after the in situ heat treatment process. Such processes may include, but are not limited to, recovering heat from treated sections, storing fluids (for example, water and/or hydrocarbons) in previously treated sections, and/or sequestering carbon dioxide in previously treated sections.

[0543] FIG. 1 depicts a schematic view of an embodiment of a portion of the in situ heat treatment system for treating the hydrocarbon containing formation. The in situ heat treatment system may include barrier wells 200. Barrier wells are used to form a barrier around a treatment
area. The barrier inhibits fluid flow into and/or out of the treatment area. Barrier wells include, but are not limited to, dewatering wells, vacuum wells, capture wells, injection wells, grout wells, freeze wells, or combinations thereof. In some embodiments, barrier wells 200 are dewatering wells. Dewatering wells may remove liquid water and/or inhibit liquid water from entering a portion of the formation to be heated, or to the formation being heated. In the embodiment depicted in FIG. 1, the barrier wells 200 are shown extending only along one side of heat sources 202, but the barrier wells typically encircle all heat sources 202 used, or to be used, to heat a treatment area of the formation.

[0544] Heat sources 202 are placed in at least a portion of the formation. Heat sources 202 may include heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 202 may also include other types of heaters. Heat sources 202 provide heat to at least a portion of the formation to heat hydrocarbons in the formation. Energy may be supplied to heat sources 202 through supply lines 204. Supply lines 204 may be structurally different depending on the type of heat source or heat sources used to heat the formation. Supply lines 204 for heat sources may transmit electricity for electric heaters, may transport fuel for combustors, or may transport heat exchange fluid that is circulated in the formation. In some embodiments, electricity for an in situ heat treatment process may be provided by a nuclear power plant or nuclear power plants. The use of nuclear power may allow for reduction or elimination of carbon dioxide emissions from the in situ heat treatment process.

[0545] When the formation is heated, the heat input into the formation may cause expansion of the formation and geomechanical motion. The heat sources may be turned on before, at the same time, or during a dewatering process. Computer simulations may model formation response to heating. The computer simulations may be used to develop a pattern and time sequence for activating heat sources in the formation so that geomechanical motion of the formation does not adversely affect the functionality of heat sources, production wells, and other equipment in the formation.

[0546] Heating the formation may cause an increase in permeability and/or porosity of the formation. Increases in permeability and/or porosity may result from a reduction of mass in the formation due to vaporization and removal of water, removal of hydrocarbons, and/or creation of fractures. Fluid may flow more easily in the heated portion of the formation because of the increased permeability and/or porosity of the formation. Fluid in the heated portion of the formation may move a considerable distance through the formation because of the increased permeability and/or porosity. The considerable distance may be over 1000 m depending on various factors, such as permeability of the formation, properties of the fluid, temperature of the
formation, and pressure gradient allowing movement of the fluid. The ability of fluid to travel considerable distance in the formation allows production wells 206 to be spaced relatively far apart in the formation.

[0547] Production wells 206 are used to remove formation fluid from the formation. In some embodiments, production well 206 includes a heat source. The heat source in the production well may heat one or more portions of the formation at or near the production well. In some in situ heat treatment process embodiments, the amount of heat supplied to the formation from the production well per meter of the production well is less than the amount of heat applied to the formation from a heat source that heats the formation per meter of the heat source. Heat applied to the formation from the production well may increase formation permeability adjacent to the production well by vaporizing and removing liquid phase fluid adjacent to the production well and/or by increasing the permeability of the formation adjacent to the production well by formation of macro and/or micro fractures.

[0548] More than one heat source may be positioned in the production well. A heat source in a lower portion of the production well may be turned off when superposition of heat from adjacent heat sources heats the formation sufficiently to counteract benefits provided by heating the formation with the production well. In some embodiments, the heat source in an upper portion of the production well may remain on after the heat source in the lower portion of the production well is deactivated. The heat source in the upper portion of the well may inhibit condensation and reflux of formation fluid.

[0549] In some embodiments, the heat source in production well 206 allows for vapor phase removal of formation fluids from the formation. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, (3) increase production rate from the production well as compared to a production well without a heat source, (4) inhibit condensation of high carbon number compounds (C₆ hydrocarbons and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

[0550] Subsurface pressure in the formation may correspond to the fluid pressure generated in the formation. As temperatures in the heated portion of the formation increase, the pressure in the heated portion may increase as a result of thermal expansion of in situ fluids, increased fluid generation and vaporization of water. Controlling rate of fluid removal from the formation may allow for control of pressure in the formation. Pressure in the formation may be determined at a number of different locations, such as near or at production wells, near or at heat sources, or at monitor wells.
In some hydrocarbon containing formations, production of hydrocarbons from the formation is inhibited until at least some hydrocarbons in the formation have been mobilized and/or pyrolyzed. Formation fluid may be produced from the formation when the formation fluid is of a selected quality. In some embodiments, the selected quality includes an API gravity of at least about 20°, 30°, or 40°. Inhibiting production until at least some hydrocarbons are mobilized and/or pyrolyzed may increase conversion of heavy hydrocarbons to light hydrocarbons. Inhibiting initial production may minimize the production of heavy hydrocarbons from the formation. Production of substantial amounts of heavy hydrocarbons may require expensive equipment and/or reduce the life of production equipment.

In some hydrocarbon containing formations, hydrocarbons in the formation may be heated to mobilization and/or pyrolysis temperatures before substantial permeability has been generated in the heated portion of the formation. An initial lack of permeability may inhibit the transport of generated fluids to production wells 206. During initial heating, fluid pressure in the formation may increase proximate heat sources 202. The increased fluid pressure may be released, monitored, altered, and/or controlled through one or more heat sources 202. For example, selected heat sources 202 or separate pressure relief wells may include pressure relief valves that allow for removal of some fluid from the formation.

In some embodiments, pressure generated by expansion of mobilized fluids, pyrolysis fluids or other fluids generated in the formation may be allowed to increase although an open path to production wells 206 or any other pressure sink may not yet exist in the formation. The fluid pressure may be allowed to increase towards a lithostatic pressure. Fractures in the hydrocarbon containing formation may form when the fluid approaches the lithostatic pressure. For example, fractures may form from heat sources 202 to production wells 206 in the heated portion of the formation. The generation of fractures in the heated portion may relieve some of the pressure in the portion. Pressure in the formation may have to be maintained below a selected pressure to inhibit unwanted production, fracturing of the overburden or underburden, and/or coking of hydrocarbons in the formation.

After mobilization and/or pyrolysis temperatures are reached and production from the formation is allowed, pressure in the formation may be varied to alter and/or control a composition of formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid in the formation fluid, and/or to control an API gravity of formation fluid being produced. For example, decreasing pressure may result in production of a larger condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.
In some in situ heat treatment process embodiments, pressure in the formation may be maintained high enough to promote production of formation fluid with an API gravity of greater than 20°. Maintaining increased pressure in the formation may inhibit formation subsidence during in situ heat treatment. Maintaining increased pressure may reduce or eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to treatment facilities.

Maintaining increased pressure in a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality and of relatively low molecular weight. Pressure may be maintained so that formation fluid produced has a minimal amount of compounds above a selected carbon number. The selected carbon number may be at most 25, at most 20, at most 12, or at most 8. Some high carbon number compounds may be entrained in vapor in the formation and may be removed from the formation with the vapor. Maintaining increased pressure in the formation may inhibit entrainment of high carbon number compounds and/or multi-ring hydrocarbon compounds in the vapor. High carbon number compounds and/or multi-ring hydrocarbon compounds may remain in a liquid phase in the formation for significant time periods. The significant time periods may provide sufficient time for the compounds to pyrolyze to form lower carbon number compounds.

Generation of relatively low molecular weight hydrocarbons is believed to be due, in part, to autogenous generation and reaction of hydrogen in a portion of the hydrocarbon containing formation. For example, maintaining an increased pressure may force hydrogen generated during pyrolysis into the liquid phase within the formation. Heating the portion to a temperature in a pyrolysis temperature range may pyrolyze hydrocarbons in the formation to generate liquid phase pyrolyzation fluids. The generated liquid phase pyrolyzation fluids components may include double bonds and/or radicals. Hydrogen (H₂) in the liquid phase may reduce double bonds of the generated pyrolyzation fluids, thereby reducing a potential for polymerization or formation of long chain compounds from the generated pyrolyzation fluids. In addition, H₂ may also neutralize radicals in the generated pyrolyzation fluids. H₂ in the liquid phase may inhibit the generated pyrolyzation fluids from reacting with each other and/or with other compounds in the formation.

Formation fluid produced from production wells 206 may be transported through collection piping 208 to treatment facilities 210. Formation fluids may also be produced from heat sources 202. For example, fluid may be produced from heat sources 202 to control pressure in the formation adjacent to the heat sources. Fluid produced from heat sources 202 may be transported through tubing or piping to collection piping 208 or the produced fluid may be transported through tubing or piping directly to treatment facilities 210. Treatment facilities 210
may include separation units, reaction units, upgrading units, fuel cells, turbines, storage vessels, and/or other systems and units for processing produced formation fluids. The treatment facilities may form transportation fuel from at least a portion of the hydrocarbons produced from the formation. In some embodiments, the transportation fuel may be jet fuel, such as JP-8.

[0559] Formation fluid may be hot when produced from the formation through the production wells. Hot formation fluid may be produced during solution mining processes and/or during in situ heat treatment processes. In some embodiments, electricity may be generated using the heat of the fluid produced from the formation. Also, heat recovered from the formation after the in situ process may be used to generate electricity. The generated electricity may be used to supply power to the in situ heat treatment process. For example, the electricity may be used to power heaters, or to power a refrigeration system for forming or maintaining a low temperature barrier. Electricity may be generated using a Kalina cycle, Rankine cycle or other thermodynamic cycle. In some embodiments, the working fluid for the cycle used to generate electricity is aqua ammonia.

[0560] FIGS. 2 - 8 depict schematic representation of systems for producing crude products and/or commercial products from the in situ heat treatment process liquid stream and/or the in situ heat treatment process gas stream. As shown in FIGS. 2, 7 and 8, formation fluid 212 enters fluid separation unit 214 and is separated into in situ heat treatment process liquid stream 216, in situ heat treatment process gas 218 and aqueous stream 220. In some embodiments, liquid stream 216 may be transported to other processing units and/or facilities.

[0561] Formation fluid 212 enters fluid separation unit 214 and is separated into in situ heat treatment process liquid stream 216, in situ heat treatment process gas 218, and aqueous stream 220. Liquid stream 216 may be transported to other processing units and/or facilities. In some embodiments, fluid separation unit 214 includes a quench zone.

[0562] In situ heat treatment process gas 218 may enter gas separation unit 222 to separate gas hydrocarbon stream 224 from the in situ heat treatment process gas. In some embodiments, the gas separation unit is a rectified adsorption and high pressure fractionation unit. Gas hydrocarbon stream 224 includes hydrocarbons having a carbon number of at least 3.

[0563] In some embodiments, fluid separation unit 214 includes a quench zone. As produced formation fluid enters the quench zone, quenching fluid such as water, nonpotable water, hydrocarbon diluent, and/or other components may be added to the formation fluid to quench and/or cool the formation fluid to a temperature suitable for handling in downstream processing equipment. Quenching the formation fluid may inhibit formation of compounds that contribute to physical and/or chemical instability of the fluid (for example, inhibit formation of compounds that may precipitate from solution, contribute to corrosion, and/or fouling of downstream
equipment and/or piping). The quenching fluid may be introduced into the formation fluid as a spray and/or a liquid stream. In some embodiments, the formation fluid is introduced into the quenching fluid. In some embodiments, the formation fluid is cooled by passing the fluid through a heat exchanger to remove some heat from the formation fluid. The quench fluid may be added to the cooled formation fluid when the temperature of the formation fluid is near or at the dew point of the quench fluid. Quenching the formation fluid near or at the dew point of the quench fluid may enhance solubilization of salts that may cause chemical and/or physical instability of the quenched fluid (for example, ammonium salts). In some embodiments, an amount of water used in the quench is minimal so that salts of inorganic compounds and/or other components do not separate from the mixture. In separation unit 214, at least a portion of the quench fluid may be separated from the quench mixture and recycled to the quench zone with a minimal amount of treatment. Heat produced from the quench may be captured and used in other facilities. In some embodiments, vapor may be produced during the quench. The produced vapor may be sent to gas separation unit 222 and/or sent to other facilities for processing.

[0564] In situ heat treatment process gas 218 may enter gas separation unit 222 to separate gas hydrocarbon stream 224 from the in situ heat treatment process gas. In some embodiments, the gas separation unit is a rectified adsorption and high pressure fractionation unit. Gas hydrocarbon stream 224 includes hydrocarbons having a carbon number of at least 3. In gas separation unit 222, treatment of in situ heat conversion treatment gas 218 removes sulfur compounds, carbon dioxide, and/or hydrogen to produce gas hydrocarbon stream 224. In some embodiments, in situ heat treatment process gas 218 includes about 20 vol% hydrogen, about 30% methane, about 12% carbon dioxide, about 14 vol% C₂ hydrocarbons, about 5 vol% hydrogen sulfide, about 10 vol% C₃ hydrocarbons, about 7 vol% C₄ hydrocarbons, about 2 vol% C₅ hydrocarbons, and mixtures thereof, with the balance being heavier hydrocarbons, water, ammonia, COS, thiols and thiophenes.

[0565] Gas separation unit 222 may include a physical treatment system and/or a chemical treatment system. The physical treatment system may include, but is not limited to, a membrane unit, a pressure swing adsorption unit, a liquid absorption unit, and/or a cryogenic unit. The chemical treatment system may include units that use amines (for example, diethanolamine or diisopropanolamine), zinc oxide, sulfolane, water, or mixtures thereof in the treatment process. In some embodiments, gas separation unit 222 uses a Sulfinol gas treatment process for removal of sulfur compounds. Carbon dioxide may be removed using Catacarb® (Catacarb, Overland Park, Kansas, U.S.A.) and/or Benfield (UOP, Des Plaines, Illinois, U.S.A.) gas treatment processes. In some embodiments, the gas separation unit is a rectified adsorption and high pressure fractionation unit. In some embodiments, in situ heat treatment process gas is treated to remove...
at least 50%, at least 60%, at least 70%, at least 80% or at least 90% by volume of ammonia present in the gas stream.

[0566] In situ heat treatment process gas 218 may include one or more carbon oxides and sulfur compounds that render the in situ heat treatment process gas unacceptable for sale, transportation, and/or use as a fuel. The in situ heat treatment process gas 218 may be processed as described herein to produce a gas stream acceptable for sale, transportation, and/or use as a fuel. It would be advantageous to separate the in situ treatment process gas 218 at the treatment site to produce streams useable as energy sources to lower overall energy costs. For example, streams containing hydrocarbons and/or hydrogen may be used as fuel for burners and/or process equipment. Streams containing sulfur compounds may be used as fuel for burners. Streams containing one or more carbon oxides and/or hydrocarbons may be used to form barriers around a treatment site. Streams containing hydrocarbons having a carbon number of at most 2 may be provided to ammonia processing facilities and/or barrier well systems. In situ heat treatment process gas 218 may include a sufficient amount of hydrogen such that the freezing point of carbon dioxide is depressed. Depression of the freezing point of carbon dioxide may allow cryogenic separation of hydrogen and/or hydrocarbons from the carbon dioxide using distillation methods instead of removing the carbon dioxide by cryogenic precipitation methods. In some embodiments, the freezing point of carbon dioxide may be depressed by adjusting the concentration of molecular hydrogen and/or addition of heavy hydrocarbons to the process gas stream.

[0567] As shown in FIG. 2, in situ heat treatment process gas 218 may enter compressor 232 of gas separation unit 222 to form compressed gas stream 234 and heavy stream 236. Heavy stream 236 may be transported to one or more liquid separation units for further processing. Compressor 232 may be any compressor suitable for compressing gas. In certain embodiments, compressor 232 is a multistage compressor (for example 2 to 3 compressor trains) having an outlet pressure of about 40 bars. In some embodiments, compressed gas stream 234 may include at least 1 vol% carbon dioxide, at least 10 vol% hydrogen, at least 1 vol% hydrogen sulfide, at least 50 vol% of hydrocarbons having a carbon number of at most 4, or mixtures thereof.

Compression of in situ heat treatment process gas 218 removes hydrocarbons having a carbon number of at least 5 and water. Removal of water and hydrocarbons having a carbon number of at least 5 from the in situ process gas allows compressed gas stream 234 to be treated cryogenically. Cryogenic treatment of compressed gas stream 234 having small amounts of high boiling materials may be done more efficiently. In certain embodiments, compressed gas stream 234 is dried by passing the gas through a water adsorption unit. In some embodiments, compressing in situ heat treatment process gas 218 is not necessary.
As shown in FIGS. 2 through 6, gas separation unit 222 includes one or more cryogenic units or zones. Cryogenic units described herein may include one or more theoretical distillation stages. In FIGS. 2 through 6, one or more heat exchangers may be positioned prior to or after cryogenic units and/or separation units described herein to assist in removing and/or adding heat to one or more streams described herein. At least a portion or all of the separated hydrocarbons streams and/or the separated carbon dioxide streams may be transported to the heat exchangers. Heat integration from one or more heat exchangers to various units or zones may be applied to improve the energy efficiency of the process.

In some embodiments, theoretical distillation stages may include from 1 to about 100 stages, from about 5 to about 50 theoretical distillation stages, or from about 10 to about 40 theoretical distillation stages. Zones of the cryogenic units may be cooled to temperatures ranging from about -110 °C to about 0 °C. For example, zone 1 (top theoretical distillation stage) in a cryogenic unit is cooled to about -110 °C, zone 5 (theoretical distillation stage 5) is cooled to about -25 °C, and zone 10 (theoretical distillation stage 10) is cooled to about -1 °C. Total pressures in cryogenic units may range from about 1 bar to about 50 bar, from about 5 bar to about 40 bar, or from about 10 bar to about 30 bar. Operating the cryogenic zones and/or units at these temperatures and pressures may allow separation of hydrogen sulfide and/or carbon dioxide from hydrocarbons in the process stream. Cryogenic units described herein may include condenser recycle conduits 238 and reboiler recycle conduits 240. Condenser recycle conduits 238 allow recycle of the cooled condensed gases so that the feed may be cooled as it enters the cryogenic units. Condenser liquid recycle or reflux may improve fractionation effectiveness. Temperatures in condensation loops may range from about -110 °C to about -1 °C, from about -90 °C to about -5 °C, or from about -80 °C to about -10 °C. Temperatures in reboiler loops may range from about 25 °C to about 200 °C, from about 50 °C to about 150 °C, or from about 75 °C to about 100 °C. Reboiler recycle conduits 240 allow recycle of the stream exiting the cryogenic unit to heat the feed as it enters the cryogenic unit. Recycle of the cooled and/or warmed separated stream may enhance energy efficiency of the cryogenic unit.

As shown in FIG. 2, compressed gas stream 234 enters methane/hydrogen cryogenic unit 242. In cryogenic unit 242, compressed gas stream 234 may be separated into a methane/molecular hydrogen gas stream 244 and a bottoms stream 246. Bottoms stream 246 may include, but is not limited to carbon dioxide, hydrogen sulfide, and hydrocarbons having a carbon number of at least 2. A majority of methane/hydrogen stream 244 is methane and molecular hydrogen. Methane/hydrogen stream 244 may include a minimal amount of C2 hydrocarbons and carbon dioxide. For example, methane/hydrogen stream 244 may include about 1 vol% C2 hydrocarbons and about 1 vol% carbon dioxide. In some embodiments, the
methane/hydrogen stream is recycled to one or more heat exchangers positioned prior to cryogenic unit 242. In some embodiments, the methane/hydrogen stream is used as a fuel for downhole burners and/or an energy source for surface facilities.

[0571] In some embodiments, cryogenic unit 242 may include one distillation column having 1 to about 30 theoretical distillation stages, about 5 to about 25 theoretical distillation stages, or about 10 to about 20 theoretical distillation stages. Zones of cryogenic unit 242 may be cooled to temperatures ranging from about -150 °C to about 10 °C. For example, zone 1 (top theoretical distillation stage) is cooled to about -138 °C, zone 5 (theoretical distillation stage 5) is cooled to about -25 °C, and zone 10 °C (theoretical distillation stage 10) is cooled to at about -1 °C. At temperatures lower than -79 °C cryogenic separation of the carbon dioxide from other gases may be difficult due to the freezing point of carbon dioxide. In some embodiments, cryogenic unit 242 includes about 20 theoretical distillation stages. Cryogenic unit 242 may be operated at a pressure of 40 bar with distillation temperatures ranging from about -45 °C to about -94 °C.

[0572] Compressed gas stream 234 may include sufficient hydrogen and/or hydrocarbons having a carbon number of at least 1 to inhibit solid carbon dioxide formation. For example, in situ heat treatment process gas 218 may include from about 30 vol% to about 40 vol% of hydrogen, from about 50 vol% to 60 vol% of hydrocarbons having a carbon number from 1 to 2, from about 0.1 vol% to about 15 vol% of carbon dioxide with the balance being other gases such as, but not limited to, carbon monoxide, nitrogen, and hydrogen sulfide. Inhibiting solid carbon dioxide formation may allow for better separation of gases and/or less fouling of the cryogenic unit. In some embodiments, hydrocarbons having a carbon number of at least five may be added to cryogenic unit 242 to inhibit formation of solid carbon dioxide. The resulting methane/hydrogen gas stream 244 may be used as an energy source. For example, methane/hydrogen gas stream 244 may be transported to surface facilities and burned to generate electricity.

[0573] As shown in FIG. 2, bottoms stream 246 enters cryogenic separation unit 248. In cryogenic separation unit 248, bottoms stream 246 is separated into C3 hydrocarbons stream 250 and gas stream 252. C3 hydrocarbons stream 250 may include hydrocarbons having a carbon number of at least 3. C3 hydrocarbons stream 250 may be a liquid and/or a gas depending on the separation conditions. In some embodiments, C3 hydrocarbons stream 250 includes at least 50 vol%, at least 70 vol% or at least 90 vol% of C3 hydrocarbons. C3 hydrocarbons stream 250 may include at most 1 ppm of carbon dioxide, and about 0.1 vol% of hydrogen sulfide. In some embodiments, C3 hydrocarbons stream 250 includes hydrocarbons having a carbon number of at least 2 and organosulfur compounds. In some embodiments, C3 hydrocarbons stream 250 includes hydrocarbons having a carbon number from 3 to 5. In some embodiments, C3 hydrocarbons stream 250 includes hydrogen sulfide in quantities sufficient to require treatment
of the stream to remove the hydrogen sulfide. In some embodiments, C₃ hydrocarbons gas stream 250 is suitable for transportation and/or use as an energy source without further treatment. In some embodiments, C₃ hydrocarbons stream 250 is used as an energy source for in situ heat treatment processes.

[0574] Gas stream 252 may include hydrocarbons having a carbon number of at least 2, carbon oxides and sulfur compounds. In some embodiments, gas stream 252 includes hydrocarbons having a carbon number of at most 2. A portion of gas stream 252 may be transported to one or more portions of the formation and sequestered. In some embodiments, all of gas stream 252 is sequestered in one or more portions of the formation. In some embodiments, a portion of gas stream 252 enters cryogenic unit 256. In cryogenic unit 256, gas stream 252 is separated into C₂ hydrocarbons/carbon dioxide stream 258 and hydrogen sulfide stream 260. In some embodiments, C₂ hydrocarbons/carbon dioxide stream 258 includes at most 0.5 vol% of hydrogen sulfide.

[0575] In some embodiments, hydrogen sulfide stream 260 includes about 0.01 vol% to about 5 vol% of C₃ hydrocarbons. In some embodiments, hydrogen sulfide stream 260 includes hydrogen sulfide, carbon dioxide, C₃ hydrocarbons, or mixtures thereof. For example, hydrogen sulfide stream 260 includes, about 32 vol% of hydrogen sulfide, 67 vol% carbon dioxide, and 1 vol% C₃ hydrocarbons. In some embodiments, hydrogen sulfide stream 260 is used as an energy source for an in situ heat treatment process and/or sent to a Claus plant for further treatment.

[0576] A portion or all of C₂ hydrocarbons/carbon dioxide stream 258 may enter separation unit 262. In separation unit 262, C₂ hydrocarbons/carbon dioxide stream 258 is separated into C₂ hydrocarbons stream 264 and carbon dioxide stream 266. Separation of C₂ hydrocarbons from carbon dioxide is performed using separation methods known in the art, for example, pressure swing adsorption units, and/or extractive distillation units. In some embodiments, C₂ hydrocarbons are separated from carbon dioxide using extractive distillation methods. For example, hydrocarbons having a carbon number from 3 to 8 may be added to separation unit 262. Addition of a higher carbon number hydrocarbon solvent allows C₂ hydrocarbons to be extracted from the carbon dioxide. C₂ hydrocarbons are then separated from the higher carbon number hydrocarbons using distillation techniques. In some embodiments, C₂ hydrocarbons stream 264 is transported to other process facilities and/or used as an energy source. For example, C₂ hydrocarbons stream 264 may be provided to one or more ammonia processing facilities. Carbon dioxide stream 266 may be sequestered in one or more portions of the formation. In some embodiments, carbon dioxide stream 266 is provided to one or more barrier well systems. In some embodiments, carbon dioxide stream 266 contains at most 0.005 grams of non-carbon dioxide compounds per gram of carbon dioxide stream. In some embodiments, carbon dioxide
stream 266 is mixed with one or more oxidant sources supplied to one or more downhole burners.

[0577] In some embodiments, a portion or all of C₂ hydrocarbons/carbon dioxide stream 258 is sequestered and/or transported to other facilities and/or provided to one or more barrier well systems. In some embodiments, a portion or all of C₂ hydrocarbons/carbon dioxide stream 258 is mixed with one or more oxidant sources supplied to one or more downhole burners.

[0578] As depicted in FIG. 3, bottoms stream 246 enters cryogenic separation unit 270. In cryogenic separation unit 270, bottoms stream 246 may be separated into C₂ hydrocarbons/carbon dioxide stream 258 and hydrogen sulfide/hydrocarbon gas stream 272. In some embodiments, C₂ hydrocarbons/carbon dioxide stream 258 contains hydrogen sulfide. Hydrogen sulfide/hydrocarbon gas stream 272 may include hydrocarbons having a carbon number of at least 3.

[0579] In some embodiments, a portion or all of C₂ hydrocarbons/carbon dioxide stream 258 are transported via conduit 268 to other processes and/or to one or more portions of the formation to be sequestered. In some embodiments, a portion or all of C₂ hydrocarbons/carbon dioxide stream 258 are treated in separation unit 262. Separation unit 262 is described above with reference to FIG. 2.

[0580] Hydrogen sulfide/hydrocarbon gas stream 272 may enter cryogenic separation unit 274. In cryogenic separation unit 274, hydrogen sulfide may be separated from hydrocarbons having a carbon number of at least 3 to produce hydrogen sulfide stream 260 and C₃ hydrocarbons stream 250. Hydrogen sulfide stream 260 may include, but is not limited to, hydrogen sulfide, C₃ hydrocarbons, carbon dioxide, or mixtures thereof. In some embodiments, hydrogen sulfide stream 260 may contain from about 20 vol% to about 80 vol% of hydrogen sulfide, from about 4 vol% to about 18 vol% of propane and from about 2 vol% to about 70 vol% of carbon dioxide. In some embodiments, hydrogen sulfide stream 260 is burned to produce SOₓ. The SOₓ may be sequestered and/or treated using known techniques in the art.

[0581] In some embodiments, C₃ hydrocarbons stream 250 includes a minimal amount of hydrogen sulfide and carbon dioxide. For example, C₂ hydrocarbons stream 250 may include about 99.6 vol% of hydrocarbons having a carbon number of at least 3, about 0.4 vol% of hydrogen sulfide and at most 1 ppm of carbon dioxide. In some embodiments, C₃ hydrocarbons stream 250 is transported to other processing facilities as an energy source. In some embodiments, C₃ hydrocarbons stream 250 needs no further treatment.

[0582] As depicted in FIG. 4, bottoms stream 246 may enter cryogenic separation unit 276. In cryogenic separation unit 276, bottoms stream 246 may be separated into C₂ hydrocarbons/hydrogen sulfide/carbon dioxide gas stream 278 and hydrogen sulfide/hydrocarbon
gas stream 272. In some embodiments, cryogenic separation unit 276 includes 45 theoretical distillation stages. A top zone (top theoretical distillation stage) of cryogenic separation unit 276 may be operated at a temperature of -31 °C and a pressure of about 20 bar.

[0583] A portion or all of C₂ hydrocarbons/hydrogen sulfide/carbon dioxide gas stream 278 and hydrocarbon stream 280 may enter cryogenic separation unit 282. Hydrocarbon stream 280 may be any hydrocarbon stream suitable for use in a cryogenic extractive distillation system. In some embodiments, hydrocarbon stream 280 is n-hexane. In cryogenic separation unit 282, C₂ hydrocarbons/hydrogen sulfide/carbon dioxide gas stream 278 is separated into carbon dioxide stream 266 and additional hydrocarbon/hydrogen sulfide stream 284. In some embodiments, cryogenic separation unit 282 includes 40 theoretical distillation stages. Cryogenic separation unit 282 may be operated at a temperature of about -19 °C and a pressure of about 20 bar.

[0584] In some embodiments, carbon dioxide stream 266 includes about 2.5 vol% of hydrocarbons having a carbon number of at most 2. In some embodiments, carbon dioxide stream 266 may be mixed with diluent fluid and/or oxidant for downhole burners, may be used as a carrier fluid for oxidizing fluid for downhole burners, may be used as a drive fluid for producing hydrocarbons, may be vented, may be used in barrier wells, and/or may be sequestered. In some embodiments carbon dioxide stream 266 is solidified.

[0585] Additional hydrocarbon/hydrogen sulfide stream 284 may be in the gas or liquid phase depending on the composition of the stream and/or the process conditions. Additional hydrocarbon/hydrogen sulfide stream 284 may enter cryogenic separation unit 286. Additional hydrocarbon/hydrogen sulfide stream 284 may include solvent hydrocarbons, C₂ hydrocarbons and hydrogen sulfide. In cryogenic separation unit 286, additional hydrocarbon/hydrogen sulfide stream 284 may be separated into C₂ hydrocarbons/hydrogen sulfide gas stream 288 and hydrocarbon stream 290. Hydrocarbon stream 290 may contain hydrocarbons having a carbon number of at least 3. Hydrocarbon stream 290 may be a liquid or gas depending on the composition of the stream and/or process conditions. In some embodiments, separation unit 286 includes 20 theoretical distillation stages. Cryogenic separation unit 286 may be operated at temperatures of about -16 °C and a pressure of about 10 bar.

[0586] Hydrogen sulfide/hydrocarbon gas stream 272 may enter cryogenic separation unit 274. In cryogenic separation unit 274, hydrogen sulfide may be separated from hydrocarbons having a carbon number of at least 3 to produce hydrogen sulfide stream 260 and C₃ hydrocarbons stream 250. Hydrogen sulfide stream 260 may include, but is not limited to, hydrogen sulfide, C₂ hydrocarbons, C₃ hydrocarbons, carbon dioxide, or mixtures thereof. In some embodiments, hydrogen sulfide stream 260 contains about 31 vol% hydrogen sulfide with the balance being C₂
and C₃ hydrocarbons. Hydrogen sulfide stream 260 may be burned to produce SOₓ. The SOₓ may be sequestered and/or treated using known techniques in the art.

[0587] In some embodiments, cryogenic separation unit 274 includes about 40 theoretical distillation stages. Temperatures in cryogenic separation unit 274 may range from about 0 °C to about 10 °C. Pressure in cryogenic separation unit 274 may be about 20 bar.

[0588] C₃ hydrocarbons stream 250 may be a gas or liquid stream depending on the composition of the stream and/or process conditions. C₃ hydrocarbons stream 250 may include a minimal amount of hydrogen sulfide and carbon dioxide. In some embodiments, C₃ hydrocarbons stream 250 includes about 50 ppm of hydrogen sulfide. In some embodiments, C₃ hydrocarbons stream 250 is transported to other processing facilities as an energy source. In some embodiments, hydrocarbons stream C₃ hydrocarbon stream 250 needs no further treatment.

[0589] As depicted in FIG. 5, compressed gas stream 234 may be treated using a modified Ryan/Holmes type process to recover the carbon dioxide from the compressed gas stream. Compressed gas stream 234 enters cryogenic separation unit 292. In some embodiments cryogenic separation unit 292 includes 40 theoretical distillation stages. Cryogenic separation unit 292 may be operated at a temperature ranging from about 60 °C to about -56 °C and a pressure of about 30 bar. In cryogenic separation unit 292, compressed gas stream 234 may be separated into methane/carbon dioxide gas stream 294 and hydrocarbon/hydrogen sulfide stream 296.

[0590] Methane/carbon dioxide gas stream 294 may include hydrocarbons having a carbon number of at most 2 and carbon dioxide. Methane/carbon dioxide gas stream 294 may be compressed in compressor 298 and enter cryogenic separation unit 300. In cryogenic separation unit 300, methane/carbon dioxide gas stream 294 is separated into carbon dioxide stream 266 and methane stream 244. In some embodiments, cryogenic separation unit 300 includes 20 theoretical distillation stages. Temperatures in cryogenic separation unit 300 may range from about -56 °C to about -96 °C at a pressure of about 45 bar.

[0591] Carbon dioxide stream 266 may include some hydrogen sulfide. For example, carbon dioxide stream 266 may include about 80 ppm of hydrogen sulfide. At least a portion of carbon dioxide stream 266 may be used as a heat exchange medium in heat exchanger 302. In some embodiments, at least a portion of carbon dioxide stream 266 is sequestered in the formation and/or at least a portion of the carbon dioxide stream is used as a diluent in downhole oxidizer assemblies.

[0592] Hydrocarbon/hydrogen sulfide stream 296 may include hydrocarbons having a carbon number of at least 2 and hydrogen sulfide. Hydrocarbon/hydrogen sulfide stream 296 may be a gas or liquid stream depending on the hydrocarbon content of the stream and/or process
conditions. Hydrocarbon/hydrogen sulfide stream 296 may pass through heat exchanger 302 and enter separation unit 304. In separation unit 304, hydrocarbon/hydrogen sulfide stream 296 may be separated into hydrocarbon stream 306 and hydrogen sulfide stream 260. In some embodiments, separation unit 304 includes 30 theoretical distillation stages. Temperatures in separation unit 304 may range from about 60 °C to about 27 °C at a pressure of about 10 bar.

[0593] Hydrocarbon stream 306 may include hydrocarbons having a carbon number of at least 3. Hydrocarbon stream 306 may include some hydrocarbons having a carbon number greater than 5. Hydrocarbon stream 306 may include hydrocarbons having a carbon number of at most 5. In some embodiments, hydrocarbon stream 306 includes 10 vol% n-butanes and 85 vol% hydrocarbons having a carbon number of 5. At least a portion of hydrocarbon stream 306 may be recycled to cryogenic separation unit 292 to maintain a ratio of about 1.4:1 of hydrocarbons to compressed gas stream 234.

[0594] Hydrogen sulfide stream 260 may include hydrogen sulfide, C₂ hydrocarbons, and some carbon dioxide. In some embodiments, hydrogen sulfide stream 260 includes about 13 vol% hydrogen sulfide, about 0.8 vol% carbon dioxide with the balance being C₂ hydrocarbons. At least a portion of the hydrogen sulfide stream 260 may be burned as an energy source. In some embodiments, hydrogen sulfide stream 260 is used as a fuel source in downhole burners.

[0595] In some embodiments, substantial removal of all the hydrogen sulfide from the C₂ hydrocarbons is desired. C₂ hydrocarbons may be used as an energy source in surface facilities. Recovery of C₂ hydrocarbons may enhance the energy efficiency of the process. Separation of hydrogen sulfide from C₂ hydrocarbons may be difficult because C₂ hydrocarbons boil at approximately the same temperature as a hydrogen sulfide/C₂ hydrocarbons mixture. Addition of higher molecular weight (higher boiling) hydrocarbons does not enable the separation between hydrogen sulfide and C₂ hydrocarbons as the addition of higher molecular weight hydrocarbons decreases the volatility of the C₂ hydrocarbons. It has been advantageously found that the addition of carbon dioxide to the hydrogen sulfide/C₂ hydrocarbons mixture allows separation of hydrogen sulfide from the C₂ hydrocarbons.

[0596] As shown in FIG. 6, bottoms stream 246 and carbon dioxide stream 314 enter cryogenic separation unit 316. In some embodiments, the carbon dioxide stream is added to the bottom stream prior to entering the cryogenic separation unit. In cryogenic separation unit 316, bottoms stream 246 may be separated into C₂ hydrocarbons/carbon dioxide gas stream 258 and hydrogen sulfide/hydrocarbon stream 318 by addition of sufficient carbon dioxide to form a C₂ hydrocarbons/carbon dioxide azeotrope (for example, a C₂ hydrocarbons/carbon dioxide volume ratio of 0.17:1 may be used). The C₂ hydrocarbons/carbon dioxide azeotrope has a boiling point lower than the boiling point of C₂ hydrocarbons. For example, the C₂ hydrocarbons/carbon
dioxide azeotrope, where the C₂ hydrocarbons are ethane, has a boiling point that is 14 °C lower than C₂ boiling point at 10 bar, and a boiling point that is 22 °C lower than the C₂ boiling point at 40 bar. Use of a C₂ hydrocarbons/carbon dioxide azeotrope allows formation of a C₂ hydrocarbons/carbon dioxide stream having a minimal amount of hydrogen sulfide (for example, a C₂ hydrocarbons/carbon dioxide stream having at most 30 ppm, at most 25 ppm, at most 20 ppm, or at most 10 ppm of hydrogen sulfide). In some embodiments, cryogenic separation unit 316 includes 40 theoretical distillation stages and may be operated at a pressure of about 10 bar.

At least a portion of C₂ hydrocarbons/carbon dioxide stream 258 and hydrocarbon recovery stream 320 may enter separation unit 262. Hydrocarbon recovery stream 320 may include hydrocarbons having a carbon number ranging from 4 to 7. In separation unit 262, contact of C₂ hydrocarbons/carbon dioxide stream 258 with hydrocarbon recovery stream 320 allows for separation of hydrocarbons from the C₂ hydrocarbons/carbon dioxide stream to form separated carbon dioxide stream 266 and C₂ rich hydrocarbon stream 322. For example, a hydrocarbon recovery stream to C₂ hydrocarbons/carbon dioxide stream ratio of 1.25 to 1 may effectively extract all the hydrocarbons from the carbon dioxide. The ratio of hydrocarbon recovery stream to C₂ hydrocarbons/carbon dioxide stream may depend on the relative concentrations of C₂ hydrocarbons and carbon dioxide in the C₂ hydrocarbons/carbon dioxide stream. Separated carbon dioxide stream 266 may be sequestered in the formation, used as a drive fluid, recycled to cryogenic separation unit 316, or used as a cooling fluid in other processes.

C₂ rich hydrocarbon stream 322 may enter hydrocarbon recovery unit 324. In hydrocarbon recovery unit 324, C₂ rich hydrocarbon stream 322 may be separated into light hydrocarbons stream 326 and bottom hydrocarbon stream 328. In some embodiments, hydrocarbon recovery unit 324 includes 30 theoretical distillation stages and is operated at a pressure of 10 bar. Light hydrocarbons stream 326 may include hydrocarbons having a carbon number from 2 to 4, a residual amount of hydrogen sulfide, thiols, and/or COS. For example, light hydrocarbons stream 326 may have about 30 ppm hydrogen sulfide, 280 ppm thiols and 260 ppm COS. Light hydrocarbons stream 326 may be treated further (for example, contacted with molecular sieves) to remove the sulfur compounds. In some embodiments, light hydrocarbons stream 326 requires no further purification and is suitable for transportation and/or use as a fuel.

Hydrocarbon stream 328 may include hydrocarbons having a carbon number ranging from 3 to 7. Some of hydrocarbon stream 328 may be directed to separation unit 330 and/or separation unit 262 after passing through one or more heat exchangers 302. Heat exchangers 302 may be integrated with one or more units to maximize energy efficiency. Mixing of hydrocarbon stream 328 with hydrocarbon recovery stream 320 stabilize the composition of hydrocarbon
recovery stream 320 and avoid build-up of heavy hydrocarbons and sulfur compounds (for example, organosulfur compounds). In some embodiments, hydrocarbon stream 328 and hydrocarbon recovery stream 320 are the same stream. In some embodiments, hydrocarbon stream 328 is treated to remove sulfur compounds (for example, the hydrocarbon stream is contacted with caustic).

[0600] Hydrogen sulfide/hydrocarbon gas stream 318 from cryogenic separation unit 316 may include, but is not limited to, hydrocarbons having a carbon number of at least 3, hydrocarbons that include organosulfur compounds, hydrogen sulfide, or mixtures thereof. A portion or all of hydrogen sulfide/hydrocarbon gas stream 318 and hydrocarbon recovery stream 320 enter hydrogen sulfide separation unit 330. Output from cryogenic separation unit 330 may include hydrogen sulfide stream 260 and rich C3 hydrocarbons stream 332. To facilitate separation of the hydrogen sulfide from rich C3 hydrocarbon stream 332, a volume ratio of 0.73 to 1 of rich C3 hydrocarbons stream to hydrogen sulfide may be used. In some embodiments, separation unit 330 includes 30 theoretical distillation stages. Cryogenic separation unit 330 may be operated at a temperature of about -16 °C and a pressure of about 10 bar. C3 hydrocarbon stream 332 may contain hydrocarbons having a carbon number of at least 3. At least a portion of C3 hydrocarbon stream 332 may enter hydrocarbon recovery unit 324.

[0601] Hydrogen sulfide stream 260 may include, but is not limited to, hydrogen sulfide, C3 hydrocarbons, C3 hydrocarbons, carbon dioxide, or mixtures thereof. In some embodiments, hydrogen sulfide stream 260 contains about 99 vol% hydrogen sulfide with the balance being C2 and C3 hydrocarbons. Hydrogen sulfide stream 260 may be burned to produce SOx. In some embodiments, at least a portion of the hydrogen sulfide stream is used as a fuel in downhole burners. The SOx may be used as a drive fluid, sequestered and/or treated using known techniques in the art.

[0602] As shown in FIGS. 7 and 8, in situ heat treatment process liquid stream 216 enters liquid separation unit 226. In some embodiments, liquid separation unit 226 is not necessary. In liquid separation unit 226, separation of in situ heat treatment process liquid stream 216 produces gas hydrocarbon stream 228 and salty process liquid stream 230. Gas hydrocarbon stream 228 may include hydrocarbons having a carbon number of at most 5. A portion of gas hydrocarbon stream 228 may be combined with gas hydrocarbon stream 224.

[0603] Salty process liquid stream 230 may be processed through desalting unit 336 to form liquid stream 338. Desalting unit 336 removes mineral salts and/or water from salty process liquid stream 230 using known desalting and water removal methods. In certain embodiments, desalting unit 336 is upstream of liquid separation unit 226.
[0604] Liquid stream 338 includes, but is not limited to, hydrocarbons having a carbon number of at least 5 and/or hydrocarbon containing heteroatoms (for example, hydrocarbons containing nitrogen, oxygen, sulfur, and phosphorus). Liquid stream 338 may include at least 0.001 g, at least 0.005 g, or at least 0.01 g of hydrocarbons with a boiling range distribution between about 95 °C and about 200 °C at 0.101 MPa; at least 0.01 g, at least 0.005 g, or at least 0.001 g of hydrocarbons with a boiling range distribution between about 200 °C and about 300 °C at 0.101 MPa; at least 0.001 g, at least 0.005 g, or at least 0.01 g of hydrocarbons with a boiling range distribution between about 300 °C and about 400 °C at 0.101 MPa; and at least 0.001 g, at least 0.005 g, or at least 0.01 g of hydrocarbons with a boiling range distribution between about 400 °C and 650 °C at 0.101 MPa. In some embodiments, liquid stream 338 contains at most 10% by weight water, at most 5% by weight water, at most 1% by weight water, or at most 0.1% by weight water.

[0605] In some embodiments, the separated liquid stream may have a boiling range distribution between about 50 °C and about 350 °C, between about 60 °C and 340 °C, between about 70 °C and 330 °C or between about 80 °C and 320 °C. In some embodiments, the separated liquid stream has a boiling range distribution between 180 °C and 330 °C.

[0606] In some embodiments, at least 50%, at least 70%, or at least 90% by weight of the total hydrocarbons in the separated liquid stream have a carbon number from 8 to 13. About 50% to about 100%, about 60% to about 95%, about 70% to about 90%, or about 75% to 85% by weight of liquid stream may have a carbon number distribution from 8 to 13. At least 50% by weight of the total hydrocarbons in the separated liquid stream may have a carbon number from about 9 to 12 or from 10 to 11.

[0607] In some embodiments, the separated liquid stream has at most 15%, at most 10%, at most 5% by weight of naphthenes; at least 70%, at least 80%, or at least 90% by weight total paraffins; at most 5%, at most 3%, or at most 1% by weight olefins; and at most 30%, at most 20%, or at most 10% by weight aromatics.

[0608] In some embodiments, the separated liquid stream has a nitrogen compound content of at least 0.01%, at least 0.1% or at least 0.4% by weight nitrogen compound. The separated liquid stream may have a sulfur compound content of at least 0.01%, at least 0.5% or at least 1% by weight sulfur compound.

[0609] In some embodiments, liquid stream 338 includes organonitrogen compounds. As shown in FIGS. 7 liquid stream 338 enters separation unit 366. In some embodiments, liquid stream 338 is passed through one or more filtration units in separation unit 226 to remove solids from the liquid stream. In separation unit 366, liquid stream 338 may be treated with an aqueous acid solution 368 to form an aqueous stream 370 and product hydrocarbon stream 372. Hydrocarbon
stream 372 may include at most 0.01% by weight nitrogen compounds. Hydrocarbon stream 372 may enter hydrotreating unit 358.

[0610] Aqueous acid solution 368 includes water and acids suitable to complex with nitrogen compounds (for example, sulfuric acid, phosphoric acid, acetic acid, formic acid and/or other suitable acidic compounds). Aqueous stream 370 includes salts of the organonitrogen compounds and acid and water. At least a portion of aqueous stream 370 is sent separation unit 374. In separation unit 374, aqueous stream 370 is separated (for example, distilled) to form aqueous acid stream 368' and concentrated organonitrogen stream 375. Concentrated organonitrogen stream 375 includes organonitrogen compounds, water, and/or acid. Separated aqueous stream 368' may be introduced into separation unit 366. In some embodiments, separated aqueous stream 368' is combined with aqueous acid solution 368 prior to entering the separation unit.

[0611] In some embodiments, at least a portion of aqueous stream 370 and/or concentrated organonitrogen stream 375 are introduced in a hydrocarbon portion or layer of subsurface formation that has been at least partially treated by an in situ heat treatment process. Aqueous stream 370 and/or concentrated organonitrogen stream 375 may be heated prior to injection in the formation. In some embodiments, the hydrocarbon portion or layer includes a shale and/or nahcolite (for example, a nahcolite zone in the Piceance Basin). In some embodiments, the aqueous stream 370 and/or concentrated organonitrogen stream 375 is used a part of the water source for solution mining nahcolite from the formation. In some embodiments, the aqueous stream 370 and/or concentrated organonitrogen stream 375 is introduced in a portion of a formation that contains nahcolite after at least a portion of the nahcolite has been removed. In some embodiments, the aqueous stream 370 and/or concentrated organonitrogen stream 375 374 is introduced in a portion of a formation that contains nahcolite after at least a portion of the nahcolite has been removed and/or the portion has been at least partially treated using an in situ heat treatment process. The hydrocarbon layer may be heated to temperatures above 200 °C prior to introduction of the aqueous stream. In the heated formation, the organonitrogen compounds may form hydrocarbons, amines, and/or ammonia and at least some of such hydrocarbons, amines and/or ammonia may be produced. In some embodiments, at least some of the acid used in the extraction process is produced.

[0612] In some embodiments, the desalting unit may produce a liquid hydrocarbon stream and a salty process liquid stream, as shown in FIG. 8. In situ heat treatment process liquid stream 216 enters liquid separation unit 226. Separation unit 226 may include one or more distillation units. In liquid separation unit 226, separation of in situ heat treatment process liquid stream 216 produces gas hydrocarbon stream 228, salty process liquid stream 230, and liquid hydrocarbon
stream 350. Gas hydrocarbon stream 228 may include hydrocarbons having a carbon number of at most 5. A portion of gas hydrocarbon stream 228 may be combined with gas hydrocarbon stream 224. Salty process liquid stream 230 may be processed as described in the discussion of FIG. 7. Salty process liquid stream 230 may include hydrocarbons having a boiling point above 260 °C. In some embodiments and as depicted in FIG. 8, salty process liquid stream 230 enters desalting unit 336. In desalting unit 336, salty process liquid stream 230 may be treated to form liquid stream 338 using known desalting and water removal methods. Liquid stream 338 may enter separation unit 352. In separation unit 352, liquid stream 338 is separated into bottoms stream 354 and hydrocarbon stream 356. In some embodiments, hydrocarbon stream 356 may have a boiling range distribution between about 200 °C and about 350 °C, between about 220 °C and 340 °C, between about 230 °C and 330 °C or between about 240 °C and 320 °C.

[0613] In some embodiments, at least 50%, at least 70%, or at least 90% by weight of the total hydrocarbons in hydrocarbon stream 356 have a carbon number from 8 to 13. About 50% to about 100%, about 60% to about 95%, about 70% to about 90%, or about 75% to 85% by weight of liquid stream may have a carbon number distribution from 8 to 13. At least 50% by weight of the total hydrocarbons in the separated liquid stream may have a carbon number from about 9 to 12 or from 10 to 11.

[0614] In some embodiments, hydrocarbon stream 356 has at most 15%, at most 10%, at most 5% by weight of naphthenes; at least 70%, at least 80%, or at least 90% by weight total paraffins; at most 5%, at most 3%, or at most 1% by weight olefins; and at most 30%, at most 20%, or at most 10% by weight aromatics.

[0615] In some embodiments, hydrocarbon stream 356 has a nitrogen compound content of at least 0.01%, at least 0.1% or at least 0.4% by weight nitrogen compound. The separated liquid stream may have a sulfur compound content of at least 0.01%, at least 0.5% or at least 1% by weight sulfur compound.

[0616] Hydrocarbon stream 356 enters hydrotreating unit 358. In hydrotreating unit 358, liquid stream 338 may be hydrotreated to form compounds suitable for processing to hydrogen and/or commercial products.

[0617] Liquid hydrocarbon stream 350 from liquid separation unit 226 may include hydrocarbons having a boiling point up to 260 °C. Liquid hydrocarbon stream 350 may include entrained asphaltenes and/or other compounds that may contribute to the instability of hydrocarbon streams. For example, liquid hydrocarbon stream 350 is a naphtha/kerosene fraction that includes entrained, partially dissolved, and/or dissolved asphaltenes and/or high molecular weight compounds that may contribute to phase instability of the liquid hydrocarbon
stream. In some embodiments, liquid hydrocarbon stream 350 may include at least 0.5% by weight asphaltenes, 1% by weight asphaltenes or at least 5% by weight asphaltenes.

[0618] As properties of the liquid hydrocarbon stream 350 are changed during processing (for example, TAN, asphaltenes, P-value, olefin content, mobilized fluids content, visbroken fluids content, pyrolyzed fluids content, or combinations thereof), the asphaltenes and other components may become less soluble in the liquid hydrocarbon stream. In some instances, components in the produced fluids and/or components in the separated hydrocarbons may form two phases and/or become insoluble. Formation of two phases, through flocculation of asphaltenes, change in concentration of components in the produced fluids, change in concentration of components in separated hydrocarbons, and/or precipitation of components may cause processing problems (for example, plugging) and/or result in hydrocarbons that do not meet pipeline, transportation, and/or refining specifications. In some embodiments, further treatment of the produced fluids and/or separated hydrocarbons is necessary to produce products with desired properties.

[0619] During processing, the P-value of the separated hydrocarbons may be monitored and the stability of the produced fluids and/or separated hydrocarbons may be assessed. Typically, a P-value that is at most 1.0 indicates that flocculation of asphaltenes from the separated hydrocarbons may occur. If the P-value is initially at least 1.0 and such P-value increases or is relatively stable during heating, then this indicates that the separated hydrocarbons are relatively stable.

[0620] Liquid hydrocarbon stream 350 may be treated to at least partially remove asphaltenes and/or other compounds that may contribute to instability. Removal of the asphaltenes and/or other compounds that may contribute to instability may inhibit plugging in downstream processing units. Removal of the asphaltenes and/or other compounds that may contribute to instability may enhance processing unit efficiencies and/or prevent plugging of transportation pipelines.

[0621] Liquid hydrocarbon stream 350 may enter filtration system 342. Filtration system 342 separates at least a portion of the asphaltenes and/or other compounds that contribute to instability from liquid hydrocarbon stream 350. In some embodiments, filtration system 342 is skid mounted. Skid mounting filtration system 342 may allow the filtration system to be moved from one processing unit to another. In some embodiments, filtration system 342 includes one or more membrane separators, for example, one or more nanofiltration membranes or one or more reverse osmosis membranes. Use of a filtration system that operates at below ambient, ambient, or slightly higher than ambient temperatures may reduce energy costs as compared to conventional catalytic and/or thermal methods to remove asphaltenes from a hydrocarbon stream.
[0622] The membranes may be ceramic membranes and/or polymeric membranes. The ceramic membranes may be ceramic membranes having a molecular weight cut off of at most 2000 Daltons (Da), at most 1000 Da, or at most 500 Da. Ceramic membranes may not swell during removal of the desired materials from a substrate (for example, asphaltenes from the liquid stream). In addition, ceramic membranes may be used at elevated temperatures. Examples of ceramic membranes include, but are not limited to, mesoporous titania, mesoporous gamma-alumina, mesoporous zirconia, mesoporous silica, and combinations thereof.

[0623] Polymeric membranes may include top layers made of dense membrane and base layers (supports) made of porous membranes. The polymeric membranes may be arranged to allow the liquid stream (permeate) to flow first through the top layers and then through the base layer so that the pressure difference over the membrane pushes the top layer onto the base layer. The polymeric membranes are organophilic or hydrophobic membranes so that water present in the liquid stream is retained or substantially retained in the retentate.

[0624] The dense membrane layer of the polymeric membrane may separate at least a portion or substantially all of the asphaltenes from liquid hydrocarbon stream 350. In some embodiments, the dense polymeric membrane has properties such that liquid hydrocarbon stream 350 passes through the membrane by dissolving in and diffusing through the structure of dense membrane. At least a portion of the asphaltenes may not dissolve and/or diffuse through the dense membrane, thus they are removed. The asphaltenes may not dissolve and/or diffuse through the dense membrane because of the complex structure of the asphaltenes and/or their high molecular weight. The dense membrane layer may include cross-linked structure as described in WO 96/27430 to Schmidt et al. A thickness of the dense membrane layer may range from 1 micrometer to 15 micrometers, from 2 micrometers to 10 micrometers, or from 3 micrometers to 5 micrometers.

[0625] The dense membrane may be made from polysiloxane, poly-di-methyl siloxane, polyoctyl-methyl siloxane, polyimide, polyaramide, poly-tri-methyl silyl propyne, or mixtures thereof. Porous base layers may be made of materials that provide mechanical strength to the membrane. The porous base layers may be any porous membranes used for ultra filtration, nanofiltration, and/or reverse osmosis. Examples of such materials are polycrylonitrile, polyamideimide in combination with titanium oxide, polyetherimide, polyvinylidenedifluoroide, polytetrafluoroethylene, or combinations thereof.

[0626] During separation of asphaltenes from liquid stream 350, the pressure difference across the membrane may range from about 0.5 MPa to about 6 MPa, from about 1 MPa to about 5 MPa, or from about 2 MPa to about 4 MPa. A temperature of the unit during separation may range from the pour point of liquid hydrocarbon stream 350 up to 100 °C, from about -20 °C to
about 100 °C, from about 10 °C to about 90 °C, or from about 20 °C to about 85 °C. During
discontinuous operation, the permeate flux rate may be at most 50% of the initial flux, at most 70% 
of the initial flux, or at most 90% of the initial flux. A weight recovery of the permeate on feed 
may range from about 50% by weight to 97% by weight, from about 60% by weight to 90% by 
weight, or from about 70% by weight to 80% by weight.

[0527] Filtration system 342 may include one or more membrane separators. The membrane 
separators may include one or more membrane modules. When two or more membrane 
separators are used, the separators may be arranged in a parallel configuration to allow feed 
(retentate) from a first membrane separator to flow into a second membrane separator. Examples 
of membrane modules include, but are not limited to, spirally wound modules, plate and frame 
modules, hollow fibers, and tubular modules. Membrane modules are described in Encyclopedia 
Examples of spirally wound modules are described in, for example, WO/2006/040307 to Boestert 
et al., U.S. Patent No. 5,102,551 to Pasternak; 5,093,002 to Pasternak; 5,275,726 to Feimer et al.; 
5,458,774 to Mannapperuma; and 5,150,118 to Finkle et al.

[0528] In some embodiments, a spirally wound module is used when a dense membrane is used 
in filtration system 342. A spirally wound module may include a membrane assembly of two 
membrane sheets between which a permeate spacer sheet is sandwiched. The membrane 
assembly may be sealed at three sides. The fourth side is connected to a permeate outlet conduit 
such that the area between the membranes is in fluid communication with the interior of the 
conduit. A feed spacer sheet may be arranged on top of one of the membranes. The assembly 
with feed spacer sheet is rolled up around the permeate outlet conduit to form a substantially 
cylindrical spirally wound membrane module. The feed spacer may have a thickness of at least 
0.6 mm, at least 1 mm, or at least 3 mm to allow sufficient membrane surface to be packed into 
the spirally wound module. In some embodiments, the feed spacer is a woven feed spacer. 
During operation, the feed mixture may be passed from one end of the cylindrical module etw\!en the membrane assemblies along the feed spacer sheet sandwiched between feed sides of 
the membranes. Part of the feed mixture passes through either one of the membrane sheets to the 
permeate side. The resulting permeate flows along the permeate spacer sheet into the permeate 
outlet conduit.

[0529] In some embodiments, the membrane separation is a continuous process. Liquid stream 
350 passes over the membrane due to the pressure difference to obtain filtered liquid stream 360 
(permeate) and/or recycle liquid stream 362 (retentate). In some embodiments, filtered liquid 
stream 360 may have reduced concentrations of asphaltenes and/or high molecular weight 
compounds that may contribute to phase instability. Continuous recycling of recycle liquid
stream 362 through the filter system can increase the production of filtered liquid stream 360 to as much as 95% of the original volume of filtered liquid stream 360. Recycle liquid stream 362 may be continuously recycled through a spirally wound membrane module for at least 10 hours, for at least one day, or for at least one week without cleaning the feed side of the membrane. Upon completion of the filtration, asphaltene enriched stream 364 (retentate) may include a high concentration of asphaltenes and/or high molecular weight compounds.

[0630] In some embodiments, liquid stream 338 is contacted with hydrogen in the presence of one or more catalysts to change one or more desired properties of the crude feed to meet transportation and/or refinery specifications using known hydrodemetallation, hydrodesulfurization, hydrodenitrofication techniques. Other methods to change one or more desired properties of the crude feed are described in U.S. Published Patent Applications Nos. 2005-0133414; 2006-0231465; and 2007-0000810 to Bhan et al.; 2005-0133405 to Wellington et al.; and 2006-0289340 to Brownscombe et al.

[0631] In some embodiments, the hydrotreated liquid stream has a nitrogen compound content of at most 200 ppm by weight, at most 150 ppm, at most 110 ppm, at most 50 ppm, or at most 10 ppm of nitrogen compounds. The separated liquid stream may have a sulfur compound content of at most 1000 ppm, at most 500 ppm, at most 300 ppm, at most 100 ppm, or at most 10 ppm by weight of sulfur compounds.

[0632] As shown in FIG. 7 and FIG. 8, liquid stream 338 and/or filtered liquid stream 344 may enter hydrotreating unit 358. In some embodiments, hydrogen source 376 enters hydrotreating unit 358 in addition to liquid stream 338 and/or filtered liquid stream 344. In some embodiments, the hydrogen source is not needed. Liquid stream 338 and/or filtered liquid stream 344 may be selectively hydrogenated in hydrotreating unit 358 such that di-olefins are reduced to mono-olefins. For example, liquid stream 338 and/or filtered liquid stream 344 is contacted with hydrogen in the presence of DN-200 (Criterion Catalysts & Technologies, Houston Texas, U.S.A.) at temperatures ranging from 100 °C to 200 °C and total pressures of 0.1 MPa to 40 MPa to produce liquid stream 378. In some embodiments, filtered liquid stream 344 is hydrotreated at a temperature ranging from about 190 °C to about 200 °C at a pressure of at least 6 MPa. Liquid stream 378 includes a reduced content of di-olefins and an increased content of mono-olefins relative to the di-olefin and mono-olefin content of liquid stream 338. In some embodiments, the conversion of di-olefins to mono-olefins under these conditions is at least 50%, at least 60%, at least 80% or at least 90%. Liquid stream 378 exits hydrotreating unit 358 and enters one or more processing units positioned downstream of hydrotreating unit 358. The units positioned downstream of hydrotreating unit 358 may include distillation units, catalytic reforming units, hydrocracking units, hydrotreating units, hydrogenation units, hydrodesulfurization units,
catalytic cracking units, delayed coking units, gasification units, or combinations thereof. In some embodiments, hydrotreating prior to fractionation is not necessary. In some embodiments, liquid stream 378 may be severely hydrotreated to remove undesired compounds from the liquid stream prior to fractionation. In certain embodiments, liquid stream 378 may be fractionated and the produced streams may each be hydrotreated to meet industry standards and/or transportation standards.

[0633] Liquid stream 378 may exit hydrotreating unit 358 and enter fractionation unit 380. In fractionation unit 380, liquid stream 378 may be distilled to form one or more crude products. Crude products include, but are not limited to, C3-C5 hydrocarbon stream 382, naphtha stream 384, kerosene stream 386, diesel stream 388, and bottoms stream 354. Fractionation unit 380 may be operated at atmospheric and/or under vacuum conditions.

[0634] In some embodiments, hydrotreated liquid streams and/or streams produced from fractions (for example, aromatic rich streams, distillates and/or naphtha) are blended with the in situ heat treatment process liquid and/or formation fluid to produce a blended fluid. The blended fluid may have enhanced physical stability and chemical stability as compared to the formation fluid. The blended fluid may have a reduced amount of reactive species (for example, di-olefins, other olefins and/or compounds containing oxygen, sulfur and/or nitrogen) relative to the formation fluid. Thus, chemical stability of the blended fluid is enhanced. The blended fluid may decrease an amount of asphaltenes relative to the formation fluid. Thus, physical stability of the blended fluid is enhanced. The blended fluid may be a more a fungible feed than the formation fluid and/or the liquid stream produced from the in situ heat treatment process. The blended feed may be more suitable for transportation, for use in chemical processing units and/or for use in refining units than formation fluid.

[0635] In some embodiments, a fluid produced by methods described herein from an oil shale formation may be blended with heavy oil/tar sands in situ heat treatment process (IHTP) fluid. Blended fluids may have properties (for example, viscosity and/or P-value) that make the blended fluid more acceptable for transportation and/or distribution to processing units. In some embodiments, produced oil shale fluid may be blended with bitumen to produce a blended bitumen having acceptable viscosity and/or stability properties. Thus, the blended bitumen may be transported and/or distributed to processing units.

[0636] As shown in FIG. 7 and FIG. 8, C3-C5 hydrocarbon stream 382 produced from fractionation unit 380 and/or hydrocarbon gas stream 224 enter alkylation unit 396. In alkylation unit 396, reaction of the olefins in hydrocarbon gas stream 224 (for example, propylene, butylenes, amylene, or combinations thereof) with the iso-paraffins in C3-C5 hydrocarbon stream 382 produces hydrocarbon stream 398. In some embodiments, the olefin content in
hydrocarbon gas stream 224 is acceptable and an additional source of olefins is not needed. Hydrocarbon stream 398 includes hydrocarbons having a carbon number of at least 4. Hydrocarbons having a carbon number of at least 4 include, but are not limited to, butanes, pentanes, hexanes, heptanes, and octanes. In certain embodiments, hydrocarbons produced from alkylation unit 396 have an octane number greater than 70, greater than 80, or greater than 90. In some embodiments, hydrocarbon stream 398 is suitable for use as gasoline without further processing.

[0637] In some embodiments, and as depicted in FIG. 7 and FIG. 8, bottoms stream 354 may be hydrocracked to produce naphtha and/or other products. The resulting naphtha may, however, need reformation to alter the octane level so that the product may be sold commercially as gasoline. Alternatively, bottoms stream 354 may be treated in a catalytic cracker to produce naphtha and/or feed for an alkylation unit. In some embodiments, naphtha stream 384, kerosene stream 386, and diesel stream 388 have an imbalance of paraffinic hydrocarbons, olefinic hydrocarbons, and/or aromatic hydrocarbons. The streams may not have a suitable quantity of olefins and/or aromatics for use in commercial products. This imbalance may be changed by combining at least a portion of the streams to form combined stream 400 which has a boiling range distribution from about 38 °C to about 343 °C. Catalytically cracking combined stream 400 may produce olefins and/or other streams suitable for use in an alkylation unit and/or other processing units. In some embodiments, naphtha stream 384 is hydrocracked to produce olefins.

[0638] Combined stream 400 and bottoms stream 354 from fractionation unit 380 enter catalytic cracking unit 402. Under controlled cracking conditions (for example, controlled temperatures and pressures), catalytic cracking unit 402 produces additional C3-C5 hydrocarbon stream 382', gasoline hydrocarbons stream 404, and additional kerosene stream 386'.

[0639] Additional C3-C5 hydrocarbon stream 382' may be sent to alkylation unit 396, combined with C3-C5 hydrocarbon stream 382, and/or combined with hydrocarbon gas stream 224 to produce gasoline suitable for commercial sale. In some embodiments, the olefin content in hydrocarbon gas stream 224 is acceptable and an additional source of olefins is not needed.

[0640] Many wells are needed for treating the hydrocarbon formation using the in situ heat treatment process. In some embodiments, vertical or substantially vertical wells are formed in the formation. In some embodiments, horizontal or U-shaped wells are formed in the formation. In some embodiments, combinations of horizontal and vertical wells are formed in the formation.

[0641] A manufacturing approach for forming wellbores in the formation may be used due to the large number of wells that need to be formed for the in situ heat treatment process. The manufacturing approach may be particularly applicable for forming wells for in situ heat treatment processes that utilize u-shaped wells or other types of wells that have long non-
vertically oriented sections. Surface openings for the wells may be positioned in lines running along one or two sides of the treatment area. FIG. 9 depicts a schematic representation of an embodiment of a system for forming wellbores of the in situ heat treatment process.

[0642] The manufacturing approach for forming wellbores may include: 1) delivering flat rolled steel to near site tube manufacturing plant that forms coiled tubulars and/or pipe for surface pipelines; 2) manufacturing large diameter coiled tubing that is tailored to the required well length using electrical resistance welding (ERW), wherein the coiled tubing has customized ends for the bottom hole assembly (BHA) and hang off at the wellhead; 3) deliver the coiled tubing to a drilling rig on a large diameter reel; 4) drill to total depth with coil and a retrievable bottom hole assembly; 5) at total depth, disengage the coil and hang the coil on the wellhead; 6) retrieve the BHA; 7) launch an expansion cone to expand the coil against the formation; 8) return empty spool to the tube manufacturing plant to accept a new length of coiled tubing; 9) move the gantry type drilling platform to the next well location; and 10) repeat.

[0643] In situ heat treatment process locations may be distant from established cities and transportation networks. Transporting formed pipe or coiled tubing for wellbores to the in situ process location may be untenable due to the lengths and quantity of tubulars needed for the in situ heat treatment process. One or more tube manufacturing facilities 406 may be formed at or near to the in situ heat treatment process location. The tubular manufacturing facility may form plate steel into coiled tubing. The plate steel may be delivered to tube manufacturing facilities 406 by truck, train, ship or other transportation system. In some embodiments, different sections of the coiled tubing may be formed of different alloys. The tubular manufacturing facility may use ERW to longitudinally weld the coiled tubing.

[0644] Tube manufacturing facilities 406 may be able to produce tubing having various diameters. Tube manufacturing facilities may initially be used to produce coiled tubing for forming wellbores. The tube manufacturing facilities may also be used to produce heater components, piping for transporting formation fluid to surface facilities, and other piping and tubing needs for the in situ heat treatment process.

[0645] Tube manufacturing facilities 406 may produce coiled tubing used to form wellbores in the formation. The coiled tubing may have a large diameter. The diameter of the coiled tubing may be from about 4 inches to about 8 inches in diameter. In some embodiments, the diameter of the coiled tubing is about 6 inches in diameter. The coiled tubing may be placed on large diameter reels. Large diameter reels may be needed due to the large diameter of the tubing. The diameter of the reel may be from about 10 m to about 50 m. One reel may hold all of the tubing needed for completing a single well to total depth.
In some embodiments, tube manufacturing facilities 406 has the ability to apply expandable zonal inflow profiler (EZiP) material to one or more sections of the tubing that the facility produces. The EZiP material may be placed on portions of the tubing that are to be positioned near and next to aquifers or high permeability layers in the formation. When activated, the EZiP material forms a seal against the formation that may serve to inhibit migration of formation fluid between different layers. The use of EZiP layers may inhibit saline formation fluid from mixing with non-saline formation fluid.

The size of the reels used to hold the coiled tubing may prohibit transport of the reel using standard moving equipment and roads. Because tube manufacturing facility 406 is at or near the in situ heat treatment location, the equipment used to move the coiled tubing to the well sites does not have to meet existing road transportation regulations and can be designed to move large reels of tubing. In some embodiments the equipment used to move the reels of tubing is similar to cargo gantries used to move shipping containers at ports and other facilities. In some embodiments, the gantries are wheeled units. In some embodiments, the coiled tubing may be moved using a rail system or other transportation system.

The coiled tubing may be moved from the tubing manufacturing facility to the well site using gantries 408. Drilling gantry 410 may be used at the well site. Several drilling gantries 410 may be used to form wellbores at different locations. Supply systems for drilling fluid or other needs may be coupled to drilling gantries 410 from central facilities 412.

Drilling gantry 410 or other equipment may be used to set the conductor for the well. Drilling gantry 410 takes coiled tubing, passes the coiled tubing through a straightener, and a BHA attached to the tubing is used to drill the wellbore to depth. In some embodiments, a composite coil is positioned in the coiled tubing at tube manufacturing facility 406. The composite coil allows the wellbore to be formed without having drilling fluid flowing between the formation and the tubing. The composite coil also allows the BHA to be retrieved from the wellbore. The composite coil may be pulled from the tubing after wellbore formation. The composite coil may be returned to the tubing manufacturing facility to be placed in another length of coiled tubing. In some embodiments, the BHAs are not retrieved from the wellbores.

In some embodiments, drilling gantry 410 takes the reel of coiled tubing from gantry 408. In some embodiments, gantry 408 is coupled to drilling gantry 410 during the formation of the wellbore. For example, the coiled tubing may be fed from gantry 408 to drilling gantry 410, or the drilling gantry lifts the gantry to a feed position and the tubing is fed from the gantry to the drilling gantry.

The wellbore may be formed using the bottom hole assembly, coiled tubing and the drilling gantry. The BHA may be self-seeking to the destination. The BHA may form the
opening at a fast rate. In some embodiments, the BHA forms the opening at a rate of about 100 meters per hour.

[0652] After the wellbore is drilled to total depth, the tubing may be suspended from the wellhead. An expansion cone may be used to expand the tubular against the formation. In some embodiments, the drilling gantry is used to install a heater and/or other equipment in the wellbore.

[0653] When drilling gantry 410 is finished at well site 414, the drilling gantry may release gantry 408 with the empty reel or return the empty reel to the gantry. Gantry 408 may take the empty reel back to tube manufacturing facility 406 to be loaded with another coiled tube. Gantries 408 may move on looped path 416 from tube manufacturing facility 406 to well sites 414 and back to the tube manufacturing facility.

[0654] Drilling gantry 410 may be moved to the next well site. Global positioning satellite information, lasers and/or other information may be used to position the drilling gantry at desired locations. Additional wellbores may be formed until all of the wellbores for the in situ heat treatment process are formed.

[0655] In some embodiments, positioning and/or tracking system may be utilized to track gantries 408, drilling gantries 410, coiled tubing reels and other equipment and materials used to develop the in situ heat treatment location. Tracking systems may include bar code tracking systems to ensure equipment and materials arrive where and when needed.

[0656] Directionally drilled wellbores may be formed using steerable motors. Deviations in wellbore trajectory may be made using slide drilling systems or using rotary steerable systems. During use of slide drilling systems, the mud motor rotates the bit downhole with little or no rotation of the drilling string from the surface during trajectory changes. The bottom hole assembly is fitted with a bent sub and/or a bent housing mud motor for directional drilling. The bent sub and the drill bit are oriented in the desired direction. With little or no rotation of the drilling string, the drill bit is rotated with the mud motor to set the trajectory. When the desired trajectory is obtained, the entire drilling string is rotated and drills straight rather than at an angle. Drill bit direction changes may be made by utilizing torque/rotary adjusting to control the drill bit in the desired direction.

[0657] By controlling the amount of wellbore drilled in the sliding and rotating modes, the wellbore trajectory may be controlled. Torque and drag during sliding and rotating modes may limit the capabilities of slide mode drilling. Steerable motors may produce tortuosity in the slide mode. Tortuosity may make further sliding more difficult. Many methods have been developed, or are being developed, to improve slide drilling systems. Examples of improvements to slide
drilling systems include agitators, low weight bits, slippery muds, and torque/toolface control systems.

[0658] Limitations in slide drilling led to the development of rotary steerable systems. Rotary steerable systems allow directional drilling with continuous rotation from the surface, thus making the need to slide the drill string unnecessary. Continuous rotation transfers weight to the drill bit more efficiently, thus increasing the rate of penetration. Current rotary steerable systems may be mechanically and/or electrically complicated with a high cost of delivery due to service companies requiring a high rate of return and due to relatively high failure rates for the systems.

[0659] In some embodiments, a dual motor rotary steerable system is used. The dual motor rotary steerable system allows a bent sub and/or bent housing mud motor to change the trajectory of the drilling while the drilling string remains in rotary mode. The dual motor rotary steerable system uses a second motor in the bottom hole assembly to rotate a portion of the bottom hole assembly in a direction opposite to the direction of rotation of the drilling string. The addition of the second motor may allow continuous forward rotation of a drilling string while simultaneously controlling the drill bit and, thus, the directional response of the bottom hole assembly. In some embodiments, the rotation speed of the drilling string is used in achieving drill bit control.

[0660] FIG. 10 depicts a schematic representation of an embodiment of drilling string 418 with dual motors in bottom hole assembly 420. Drilling string 418 is coupled to bottom hole assembly 420. Bottom hole assembly 420 includes motor 422A and motor 422B. Motor 422A may be a bent sub and/or bent housing steerable mud motor. Motor 422A may drive drill bit 424. Motor 422B may operate in a rotation direction that is opposite to the rotation of drilling string 418 and/or motor 422A. Motor 422B may operate at a relatively low rotary speed and have high torque capacity as compared to motor 422A. Bottom hole assembly 420 may include sensing array 426 between motors 422A, motor 422B.

[0661] As noted above, motor 422B may rotate in a direction opposite to the rotation of drilling string 418. In this manner, portions of bottom hole assembly 420 beyond motor 422B may have less rotation in the direction of rotation of drilling string 418. The revolutions per minute (rpm) versus differential pressure relationship for bottom hole assembly 420 may be assessed prior to running drilling string 418 and the bottom hole assembly 420 in the formation to determine the differential pressure at neutral drilling speed (when the drilling string speed is equal and opposite to the speed of motor 422B). Measured differential pressure may be used by a control system during drilling to control the speed of the drilling string relative to the neutral drilling speed.

[0662] In some embodiments, motor 422B is operated at a substantially fixed speed. For example, motor 422B may be operated at a speed of 30 rpm. Other speeds may be used as desired.
[0663] In some embodiments, a mud motor is installed in a bottom hole assembly in an inverted orientation (for example, upside-down from the normal orientation). The inverted mud motor may be operated in a reverse direction of rotation relative to other mud motors, a drill bit, and/or a drilling string. For example, motor 422B, shown in FIG. 10, may be installed in an inverted orientation to produce a relative counter-clockwise rotation in portions of bottom hole assembly 420 distal to motor 422B (see counterclockwise arrow). Installing a mud motor in an inverted orientation may allow for the use of off-the-shelf motors to produce counter-rotation and/or non-rotation of selected elements of the bottom hole assembly. In one embodiment, a threading kit is used to adapt a threaded mounting for mud motor to ensure that a secure connection between an inverted mud motor and its mounting is maintained during drilling (e.g., by reversing the threads).

[0664] In some embodiments, the rotation speed of drilling string 418 is used to control the trajectory of the wellbore being formed. For example, drilling string 418 may initially be rotating at 40 rpm, and motor 422B rotates at 30 rpm. The counter-rotation of motor 422B and drilling string 418 results in a forward rotation speed (for example, an absolute forward rotation speed) of 10 rpm in the lower portion of bottom hole assembly 420 (the portion of the bottom hole assembly below motor 422B). When a directional course correction is to be made, the speed of drilling string 418 is changed to the neutral drilling speed. Because drilling string 418 is rotating, there is no need to lift drill bit 424 off the bottom of the borehole. Operating at neutral drilling speed may effectively cancel the torque of the drilling string so that drill bit 424 is subjected to torque induced by motor 422A and the formation.

[0665] The continuous rotation of drilling string 418 keeps windup of the drilling string consistent and stabilizes drill bit 424. Directional changes of drill bit 424 may be made by changing the speed of drilling string 418. Using a dual motor rotary steerable system allows the changing of the direction of the drilling string to occur while the drilling string rotates at or near the normal operating rotation speed of drilling string 418. FIG. 11 depicts time at drilling string rotation during direction change versus rotation speed (rpm) of the drilling string for a conventional steerable motor bottom hole assembly during a drill bit direction change. FIG. 12 depicts time at rotation speed during directional change versus change in drilling string rotating speed for the dual motor drilling string during the drill bit direction change. Drill bit control may be substantially the same as for conventional slide mode drilling where torque/rotary adjustment is used to control the drill bit in the desired direction, but to the effect that 0 rpm on the x-axis of FIG. 11 becomes N (the neutral drilling string speed) in FIG. 12.

[0666] The connection of bottom hole assembly 420 to drilling string 418 of the dual motor rotary steerable system depicted in FIG. 10 may be subjected to the net effect of all the torque
components required to rotate the entire bottom hole assembly (including torque generated at
drill bit 424 during wellbore formation). Threaded connections along drilling string 418 may
include profile-matched sleeves such as those known in the art for utilities drilling systems.

[0667] In some embodiments, a control system used to control wellbore formation includes a
system that sets a desired rotation speed of drilling string 418 when direction changes in
trajectory of the wellbore are to be implemented. The system may include fine tuning of the
desired drilling string rotation speed.

[0668] In certain embodiments, drilling string 418 is integrated with position measurement and
down hole tools (for example, sensing array 426) to autonomously control the hole path along a
designed geometry. An autonomous control system for controlling the path of drilling string 418
may utilize two or more domains of functionality. In one embodiment, a control system utilizes
at least three domains of functionality including, but not limited to, measurement, trajectory, and
control. Measurement may be made using sensor systems and/or other equipment hardware that
assess angles, distances, magnetic fields, and/or other data. Trajectory may include flight path
calculation and algorithms that utilize physical measurements to calculate angular and spatial
offsets of the drilling string. The control system may implement actions to keep the drilling
string in the proper path. The control system may include tools that utilize software/control
interfaces built into an operating system of the drilling equipment, drilling string and/or bottom
hole assembly.

[0669] In certain embodiments, the control system utilizes position and angle measurements to
define spatial and angular offsets from the desired drilling geometry. The defined offsets may be
used to determine a steering solution to move the trajectory of the drilling string (thus, the
trajectory of the borehole) back into convergence with the desired drilling geometry. The
steering solution may be based on an optimum alignment solution in which a desired rate of
curvature of the borehole path is set, and required angle change segments and angle change
directions for the path are assessed (for example, by computation).

[0670] In some embodiments, the control system uses a fixed angle change rate associated with
the drilling string, assesses the lengths of the sections of the drilling string, and assesses the
desired directions of the drilling to autonomously execute and control movement of the drilling
string. Thus, the control system assesses position measurements and controls of the drilling
string to control the direction of the drilling string.

[0671] In some embodiments, differential pressure or torque across motor 422A and/or motor
422B is used to control the rate of penetration. A relationship between rate of penetration,
weight-on-bit, and torque may be assessed for drilling string 418. Measurements of torque and
the rate of penetration/weight-on-bit/torque relationship may be used to control the feed rate of drilling string 418 into the formation.

[0672] Accuracy and efficiency in forming wellbores in subsurface formations may be affected by the density and quality of directional data during drilling. The quality of directional data may be diminished by vibrations and angular accelerations during rotary drilling, especially during rotary drilling segments of wellbore formation using slide mode drilling.

[0673] In certain embodiments, the quality of the data assessed during rotary drilling is increased by installing directional sensors in a non-rotating housing. FIG. 13 depicts an embodiment of drilling string 418 with non-rotating sensor 432. Non-rotating sensor 432 is located behind motor 422. Motor 422 may be a steerable motor. Motor 422 is located behind drill bit 424. In certain embodiments, sensor 432 is located between non-magnetic components in drilling string 418.

[0674] In some embodiments, non-rotating sensor 432 is located in a sleeve over motor 422. In some embodiments, non-rotating sensor 432 is run on a bottom hole assembly for improved data assessment. In an embodiment, a non-rotating sensor is coupled to and/or driven by a motor that produces relative counter-rotation of the sensor relative to other components of the bottom hole assembly. For example, a sensor may be coupled to motor having a rotation speed equal and opposite to that of bottom hole assembly housing to which it is attached so that the absolute rotation speed of the sensor is or is substantially zero. In certain embodiments, the motor for a sensor is a mud motor installed in an inverted orientation such as described above relative to FIG. 10.

[0675] In certain embodiments, non-rotating sensor 432 includes one or more transceivers for communicating data either into drilling string 418 within the bottom hole assembly or to similar transceivers in nearby boreholes. The transceivers may be used for telemetry of data and/or as a means of position assessment or verification. In certain embodiments, use of non-rotating sensor 432 is used for continuous position measurement. Continuous position measurement may be useful in control systems used for drilling position systems and/or umbilical position control.

[0676] FIG. 14 depicts an embodiment for assessing a position of a first wellbore relative to a second wellbore using multiple magnets. First wellbore 428A is formed in a subsurface formation. Wellbore 428A may be formed by directionally drilling in the formation along a desired path. For example, wellbore 428A may be horizontally or vertically drilled, or drilled at an inclined angle, in the subsurface formation.

[0677] Second wellbore 428B may be formed in the subsurface formation with drill bit 424 on drilling string 418. In certain embodiments, drilling string 418 includes one or more magnets 430. Wellbore 428B may be formed in a selected relationship to wellbore 428A. In certain
embodiments, wellbore 428B is formed substantially parallel to wellbore 428A. In other embodiments, wellbore 428B is formed at other angles relative to wellbore 428A. In some embodiments, wellbore 428B is formed perpendicular to wellbore 428A.

[0678] In certain embodiments, wellbore 428A includes sensing array 426. Sensing array 426 may include two or more sensors 432. Sensors 432 may sense magnetic fields produced by magnets 430 in wellbore 428B. The sensed magnetic fields may be used to assess a position of wellbore 428A relative to wellbore 428B. In some embodiments, sensors 432 measure two or more magnetic fields provided by magnets 430.

[0679] Two or more sensors 432 in wellbore 428A may allow for continuous assessment of the relative position of wellbore 428A versus wellbore 428B. Using two or more sensors 432 in wellbore 428A may also allow the sensors to be used as gradiometers. In some embodiments, sensors 432 are positioned in advance (ahead of) magnets 430. Positioning sensors 432 in advance of magnets 430 allows the magnets to traverse past the sensors so that the magnet’s position (the position of wellbore 428B) is measurable continuously or “live” during drilling of wellbore 428B. Sensing array 426 may be moved intermittently (at selected intervals) to move sensors 432 ahead of magnets 430. Positioning sensors 432 in advance of magnets 430 also allows the sensors to measure, store, and zero the Earth’s field before sensing the magnetic fields of the magnets. The Earth’s field may be zeroed by, for example, using a null function before arrival of the magnets, calculating background components from a known sensor attitude, or using paired sensors that function as gradiometers.

[0680] The relative position of wellbore 428B versus wellbore 428A may be used to adjust the drilling of wellbore 428B using drilling string 418. For example, the direction of drilling for wellbore 428B may be adjusted so that wellbore 428B remains a set distance away from wellbore 428A and the wellbores remain substantially parallel. In certain embodiments, the drilling of wellbore 428B is continuously adjusted based on continuous position assessments made by sensors 432. Data from drilling string 418 (for example, orientation, attitude, and/or gravitational data) may be combined or synchronized with data from sensors 432 to continuously assess the relative positions of the wellbores and adjust the drilling of wellbore 428B accordingly. Continuously assessing the relative positions of the wellbores may allow for coiled tubing drilling of wellbore 428B.

[0681] In some embodiments, drilling string 418 may include two or more sensing arrays. The sensing arrays may include two or more sensors. Using two or more sensing arrays in drilling string 418 may allow for direct measurement of magnetic interference of magnets 430 on the measurement of the Earth’s magnetic field. Directly measuring any magnetic interference of magnets 430 on the measurement of the Earth’s magnetic field may reduce errors in readings (for
example, error to pointing azimuth). The direct measurement of the field gradient from the magnets from within drill string 418 also provides confirmation of reference field strength of the field to be measured from within wellbore 428A.

[0682] FIG. 15 depicts an embodiment for assessing a position of a first wellbore relative to a second wellbore using a continuous pulsed signal. Signal wire 434 may be placed in wellbore 428A. Sensor 432 may be located in drilling string 418 in wellbore 428B. In certain embodiments, wire 434 provides a current path and/or reference voltage signal (for example, a pulsed DC reference signal) into wellbore 428A. In one embodiment, the reference voltage signal is a 10 Hz pulsed DC signal. In one embodiment, the reference voltage signal is a 5 Hz pulsed DC signal. In some embodiments, the reference voltage signal is between 0.5 Hz pulsed DC signal and 0.75 Hz pulsed DC signal. Providing the current path and reference voltage signal may generate a known and, in some embodiments, fixed current in wellbore 428A. In some embodiments, the voltage signal is automatically varied on the surface to generate a uniform fixed current in the wellbore. Automatically varying the voltage signal on the surface may minimize bandwidth needs by reducing or eliminating the need to send current downhole and/or sensor raw data uphole.

[0683] In some embodiments, wire 434 carries current into and out of wellbore 428A (the forward and return conductors are both on the wire). In some embodiments, wire 434 carries current into wellbore 428A and the current is returned on a casing in the wellbore (for example, the casing of a heater or production conduit in the wellbore). In some embodiments, wire 434 carries current into wellbore 428A and the current is returned on another conductor located in the formation. For example, current flows from wire 434 in wellbore 428A through the formation to an electrode (current return) in the formation. In certain embodiments, current flows out an end of wellbore 428A. The electrode may be, for example, an electrode in another wellbore in the formation or a bare electrode extending from another wellbore in the formation. The electrode may be the casing in another wellbore in the formation. In some embodiments, wellbore 428A is substantially horizontal in the formation and current flows from wire 434 in the wellbore to a bare electrode extending from a substantially vertical wellbore in the formation.

[0684] The electromagnetic field provided by the voltage signal may be sensed by sensor 432. The sensed signal may be used to assess a position of wellbore 428B relative to wellbore 428A.

[0685] In some embodiments, wire 434 is a ranging wire located in wellbore 428A. In some embodiments, the voltage signal is provided by an electrical conductor that will be used as part of a heater in wellbore 428A. In some embodiments, the voltage signal is provided by an electrical conductor that is part of a heater or production equipment located in wellbore 428A. Wire 434, or other electrical conductors used to provide the voltage signal, may be grounded so that there is
no current return along the wire or in the wellbore. Return current may cancel the electromagnetic field produced by the wire.

[0686] Where return current exists, the current may be measured and modeled to generate a “net current” from which a resultant electromagnetic field may be resolved. For example, in some areas, a 600A signal current may only yield a 3 - 6A net current. In some embodiments where it is not feasible to eliminate sufficient return current along the wellbore containing the conductor, two conductors may be installed in separate wellbores. In this method, signal wires from each of the existing wellbores are connected to opposite voltage terminals of the signal generator. The return current path is in this way guided through the earth from the contactor region of one conductor to the other. In certain embodiments, calculations are used to assess (determine) the amount of voltage needed to conduct current through the formation.

[0687] In certain embodiments, the reference voltage signal is turned on and off (pulsed) so that multiple measurements are taken by sensor 432 over a selected time period. The multiple measurements may be averaged to reduce or eliminate resolution error in sensing the reference voltage signal. In some embodiments, providing the reference voltage signal, sensing the signal, and adjusting the drilling based on the sensed signals are performed continuously without providing any data to the surface or any surface operator input to the downhole equipment. For example, an automated system located downhole may be used to perform all the downhole sensing and adjustment operations. In some embodiments, an iterative process is used to perform calculations used in the automated downhole sensing and adjustment operations. In certain embodiments, distance and direction are calculated continuously downhole, filtered and averaged. A best estimate final distance and direction may be output to the surface and combined with known along hole depth and source location to determine three-axis position data.

[0688] The signal field generated by the net current passing through the conductors may be resolved from the general background field existing when the signal field is “off”. A method for resolving the signal field from the general background field on a continuous basis may include: 1.) calculating background components based on the known attitude of the sensors and the known value background field strength and dip; 2.) a synchronized “null” function to be applied immediately before the reference field is switched “on”; 3.) synchronized sampling of forward and reversed DC polarities (the subtraction of these sampled values may effectively remove the background field yielding the reference total current field); and/or 4.) sampling values of background magnetic field at one or more fixed sampling frequencies and storing them for subtraction from the reference signal “on” data.

[0689] In some embodiments, slight changes in the sensor roll position and/or movement of the sensor between sampling steps (for example, between samples of signal off and signal on data) is
compensated or counteracted by rotating the sensor data coordinate system to a reference attitude (for example, a "zero") after each sample is taken or after a set of data is taken. For example, the sensor data coordinate system may be rotated to a tensor coordinate system. Parameters such as position, inclination, roll, and/or azimuth of the sensor may be calculated using sensor data rotated to the tensor coordinate system. In some embodiments, adjustments in calculations and/or data gathering are made to adjust for sensing and ranging at low wellbore inclination angles (for example, angles near vertical).

FIG. 16 depicts an embodiment for assessing a position of a first wellbore relative to a second wellbore using a radio ranging signal. Sensor 432 may be placed in wellbore 428A. Source 436 may be located in drilling string 418 in wellbore 428B. In some embodiments, source 436 is located in wellbore 428A and sensor 432 is located in wellbore 428B. In certain embodiments, source 436 is an electromagnetic wave producing source. For example, source 436 may be an electromagnetic sonde. Sensor 432 may be an antenna (for example, an electromagnetic or radio antenna). In some embodiments sensor 432 is located in part of a heater in wellbore 428A.

The signal provided by source 436 may be sensed by sensor 432. The sensed signal may be used to assess a position of wellbore 428B relative to wellbore 428A. In certain embodiments, the signal is continuously sensed using sensor 432. “Continuous” or “continuously” in the context of sensing signals (such as magnetic, electromagnetic, voltage, or other electrical or magnetic signals) includes sensing continuous signals and sensing pulsed signals repeatedly over a selected period time. The continuously sensed signal may be used to continuously and/or automatically adjust the drilling of wellbore 428B by drillbit 424. The continuous sensing of the electromagnetic signal may be dual directional so as to create a data link between transceivers. The antenna / sensor 432 may be directly connected to a surface interface allowing a data link between surface and subsurface to be established.

In some embodiments, source 436 and/or sensor 432 are sources and sensors used in a walkover radio locater system. Walkover radio locater systems are, for example, used in telecommunications to locate underground lines and to communicate the location to drilling tools used for utilities installation. Radio locater systems may be available, for example, from Digital Control Incorporated (Kent, Washington, U.S.A.). In some embodiments, the walkover radio located system components may be modified to be located in wellbore 428A and wellbore 428B so that the relative positions of the wellbores are assessable using the walkover radio located system components.

In certain embodiments, multiple sources and multiple sensors may be used to assess and adjust the drilling of one or more wellbores. FIG. 17 depicts an embodiment for assessing a
position of a plurality of first wellbores relative to a plurality of second wellbores using radio ranging signals. Sources 436 may be located in a plurality of wellbores 428A. Sensors 432 may be located in one or more wellbores 428B. In some embodiments, sources 436 are located in wellbores 428B and sensors 432 are located in wellbores 428A.

[0694] In one embodiment, wellbores 428A are drilled substantially vertically in the formation and wellbores 428B are drilled substantially horizontally in the formation. Thus, wellbores 428B are substantially perpendicular to wellbores 428A. Sensors 432 in wellbores 428B may detect signals from one or more of sources 436. Detecting signals from more than one source may allow for more accurate measurement of the relative positions of the wellbores in the formation. In some embodiments, electromagnetic attenuation and phase shift detected from multiple sources is used to define the position of a sensor (and the wellbore). The paths of the electromagnetic radio waves may be predicted to allow detection and use of the electromagnetic attenuation and the phase shift to define the sensor position.

[0695] In certain embodiments, continuous pulsed signals and/or radio ranging signals are used to form a plurality of wellbores in a formation. FIG. 18 depicts a top view representation of an embodiment for forming a plurality of wellbores in a formation. Treatment area 816 may include clusters of heaters 438 on opposite sides of the treatment area. Control wellbore 428A may be located at or near the center line of treatment area 816. In certain embodiments, control wellbore 428A is located in a barrier area between heater corridors 1700A, 1700B. Control wellbore 428A may be a horizontal, substantially horizontal, or slightly inclined wellbore. Control wellbore 428A may have a length between about 250 m and about 3000 m, between about 500 m and about 2500 m, or between about 1000 m and about 2000 m.

[0696] In certain embodiments, the position (lateral and/or vertical position) of control wellbore 428A in treatment area 816 is assessed relative to vertical wellbores 428B, 428C, of which the position is known. The relative position to vertical wellbores 428B, 428C of control wellbore 428A may be assessed using, for example, continuous pulsed signals and/or radio ranging signals as described herein. In certain embodiments, vertical wellbores 428B, 428C are located within about 10 m, within about 5 m, or within about 3 m of control wellbore 428A.

[0697] Heater wellbores 428D may be the first heater wellbores deployed in either corridor 1700A or corridor 1700B. Ranging sources (for example, wire 434, depicted in FIG. 15, or source 436, depicted in FIGS. 16 and 17) and/or sensors (for example, sensors 432, depicted in FIGS. 15-17) located in either heater wellbores 428D and/or control wellbore 428A may be used to assess the positions (lateral and/or vertical) of the heater wellbores relative to the control wellbore. In some embodiments, the ranging systems are deployed inside a conduit provided into control wellbore 428A. In some embodiments, control wellbore 428A acts as a current return for
electrical current flowing from heater wellbores 428D. Control wellbore 428A may include a steel casing or other metal element that allows current to flow into the wellbore. The current may be returned to the surface through control wellbore 428A to complete the electrical circuit used for ranging (as shown by the dotted lines in FIG. 18).

[0698] In certain embodiments, the position of heater wellbores 428D are further assessed using ranging from vertical wellbores 428E. Assessing the position of heater wellbores 428D relative to vertical wellbores 428E may be used to verify position data from ranging from control wellbore 428A. Vertical wellbores 428B, 428C, 428E may have depths that are at least the depth of heater wellbores 428D and/or control wellbore 428A. In certain embodiments, vertical wellbores 428E are located within about 10 m, within about 5 m, or within about 3 m of heater wellbores 428D.

[0699] After heater wellbores 428D are formed in treatment area 816, additional heater wellbores may be formed in corridor 1700A and/or corridor 1700B. The additional heater wellbores may be formed using heater wellbores 428D and/or control wellbore 428A as guides. For example, ranging systems may be located in heater wellbores 428D and/or control wellbore 428A to assess and/or adjust the relative position of the additional heater wellbores while the additional heater wellbores are being formed.

[0700] In some embodiments, central monitoring system 1702 is coupled to control wellbore 428A. In certain embodiments, central monitoring system 1702 includes a geomagnetic monitoring system. Central monitoring system 1702 may be located at a known location relative to control wellbore 428A and heater wellbores 428D. The known location may include known alignment azimuths from control wellbore 428A. For example, the known location may include north-south alignment azimuths, east-west alignment azimuths, and any heater wellbore alignment azimuth that is intended for corridor 1700A and/or corridor 1700B (for example, azimuths off the 90° angle depicted in FIG. 18). The geomagnetic monitoring system, along with the known location, may be used to calibrate individual tools used during formation of wellbores and ranging operations and/or to assess the properties of components in bottom hole assemblies or other downhole assemblies.

[0701] FIGS. 19 and 20 depict an embodiment for assessing a position of a first wellbore relative to a second wellbore using a heater assembly as a current conductor. In some embodiments, a heater may be used as a long conductor for a reference current (pulsed DC or AC) to be injected for assessing a position of a first wellbore relative to a second wellbore. If a current is injected onto an insulated internal heater element, the current may pass to the end of heater element 438 where it makes contact with heater casing 440. This is the same current path when the heater is in heating mode. Once the current passes across to bottom hole assembly 420B, at least some of
the current is generally absorbed by the earth on the current’s return trip back to the surface, resulting in a net current (difference in Amps in \( A_1 \) versus Amps out \( A_0 \)).

[0702] Resulting electromagnetic field 442 is measured by sensor 432 (for example, a transceiving antenna) in bottom hole assembly 420A of first wellbore 428A being drilled in proximity to the location of heater 438. A predetermined “known” net current in the formation may be relied upon to provide a reference magnetic field.

[0703] The injection of the reference current may be rapidly pulsed and synchronized with the receiving antenna and/or sensor data. Access to a high data rate signal from the magnetometers can be used to filter the effects of sensor movement during drilling. The measurement of the reference magnetic field may provide a distance and direction to the heater. Averaging many of these results will provide the position of the actively drilled hole. The known position of the heater and known depth of the active sensors may be used to assess position coordinates of easting, northing, and elevation.

[0704] The quality of data generated with such a method may depend on the accuracy of the net current prediction along the length of the heater. Using formation resistivity data, a model may be used to predict the losses to earth along the length of the heater canister and/or wellbore casing or wellbore liner.

[0705] The current may be measured on both the element and the bottom hole assembly at the surface. The difference in values is the overall current loss to the formation. It is anticipated that the net field strength will vary along the length of the heater. The field is expected to be greater at the surface when the positive voltage applies to the bottom hole assembly.

[0706] If there are minimal losses to earth in the formation, the net field may not be strong enough to provide a useful detection range. In some embodiments, a net current in the range of about 2A to about 50A, about 5A to about 40A, or about 10A to about 30A, may be employed.

[0707] In some embodiments, two or more heaters are used as a long conductor for a reference current (pulsed DC or AC) to be injected for assessing a position of a first wellbore relative to a second wellbore. Utilizing two or more separate heater elements may result in relatively better control of return current path and therefore better control of reference current strength.

[0708] A two or more heater method may not rely on the accuracy of a “model of current loss to formation”, as current is contained in the heater element along the full length of the heaters. Current may be rapidly pulsed and synchronized with the transceiving antenna and/or sensor data to resolve distance and direction to the heater. FIGS. 21 and 22 depict an embodiment for assessing a position of first wellbore 428A relative to second wellbore 428B using two heater assemblies 438A and 438B as current conductors. Resulting electromagnetic field 442 is measured by sensor 432 (for example, a transceiving antenna) in bottom hole assembly 420A of
first wellbore 428A being drilled in proximity to the location of heaters 438A in second wellbores 428B.

[0709] In some embodiments, parallel well tracking (PWT) may be used for assessing a position of a first wellbore relative to a second wellbore. Parallel well tracking may utilize magnets of a known strength and a known length positioned in the pre-drilled second wellbore. Magnetic sensors positioned in the active first wellbore may be used to measure the field from the magnets in the second wellbore. Measuring the generated magnetic field in the second wellbore with sensors in the first wellbore may assess distance and direction of the active first wellbore. In some embodiments, magnets positioned in the second wellbore may be carefully positioned and multiple static measurements taken to resolve any general “background” magnetic field. Background magnetic fields may be resolved through use of a null function before positioning the magnets in the second wellbore, calculating background components from known sensor attitudes, and/or a gradiometer setup.

[0710] In some embodiments, reference magnets may be positioned in the drilling bottom hole assembly of the first wellbore. Sensors may be positioned in the passive second wellbore. The prepositioned sensors may be nulled prior to the arrival of the magnets in the detectable range to eliminate Earth’s background field. Nulling the sensors may significantly reduce the time required to assess the position and direction of the first wellbore during drilling as the bottom hole assembly continues drilling with no stoppages. The commercial availability of low cost sensors such as Terrella6™ (available from Clymer Technologies, Mystic, Connecticut, U.S.A.) (utilizing magnetoresistives rather than fluxgates) may be incorporated into the wall of a deployment coil at useful separations.

[0711] In some embodiments, multiple types of sources may be used in combination with two or more sensors to assess and adjust the drilling of one or more wellbores. A method of assessing a position of a first wellbore relative to a second wellbore may include a combination of angle sensors, telemetry, and/or ranging systems. Such a method may be referred to as umbilical position control.

[0712] Angle sensors may assess an attitude (i.e., the azimuth, inclination, and roll) of a bottom hole assembly. Assessing the attitude of a bottom hole assembly may include measuring, for example, azimuth, inclination, and/or roll. Telemetry may transmit data (for example, measurements) between the surface and, for example, sensors positioned in a wellbore. Ranging may assess the position of a bottom hole assembly in a first wellbore relative to a second wellbore. In some embodiments, the second wellbore may include an existing, previously drilled wellbore.
FIG. 23 depicts an embodiment of an umbilical positioning control system employing a magnetic gradiometer system and wellbore to wellbore wireless telemetry system. The magnetic gradiometer system may be used to resolve bottom hole assembly interference. Second transceiver 444B may be deployed from the surface down second wellbore 428B, which effectively functions as a telemetry system for first wellbore 428A. A transceiver may communicate with the surface via wire or fiber optics (for example, wire 446) coupled to the transceiver.

In first wellbore 428A, sensor 432A may be coupled to first transceiving antenna 444A. First transceiving antenna 444A may communicate with second transceiving antenna 444B in second wellbore 428B. The first transceiving antenna may be positioned on bottom hole assembly 420. Sensors coupled to the first transceiving antenna may include, for example, magnetometers and/or accelerometers. In certain embodiments, sensors coupled to the first transceiving antenna may include dual magnetometer/accelerometer sets.

To accomplish data transfer, first transceiving antenna 444A transmits ("short hops") measured data through the ground to second transceiving antenna 444B located in the second wellbore. The data may then be transmitted to the surface via embedded wires 446 in the deployment tubular. In some embodiments, data transmission to/from the surface is provided through one or more data lines (wires) that previously exist in the deployment tubular wellbore.

Two redundant ranging systems may be utilized for umbilical control systems. A first ranging system may include a version of parallel well tracking (PWT). FIG. 24 depicts an embodiment of an umbilical positioning control system employing a magnetic gradiometer system in an existing wellbore. A PWT may include a pair of sensors 432B (for example, magnetometer/accelerometer sets) embedded in the wall of second wellbore deployment coil (the umbilical) or within a nonmagnetic section of jointed tubular string. These sensors act as a magnetic gradiometer to detect the magnetic field from reference magnet 430 installed in bottom hole assembly 420 of first wellbore 428A. In a horizontal section of the second wellbore, a relative position of the umbilical to the first wellbore reference magnet(s) may be determined by the gradient. Data may be sent to the surface through fiber optic cables or wires 446 positioned in second wellbore 428B.

FIGS. 25 and 26 depict an embodiment of umbilical positioning control system employing a combination of systems being used in a first stage of deployment and a second stage of deployment, respectively. A third set of sensors 432C (for example, magnetometers) may be located on the leading end of wire 446 in second wellbore 428B. Sensors 432B, 432C may detect magnetic fields produced by reference magnets 430 in bottom hole assembly 420 of first wellbore 428A. The role of sensors 432C may include mapping the Earth's magnetic field ahead.
of the arrival of the gradient sensors and confirming that the angle of the deployment tubular matches that of the originally defined hole geometry. Since the attitude of the magnetic field sensors are known based on the original survey of the hole and the checks of sensors 432B, 432C, the values for the Earth's field can be calculated based on current sensor orientation (inclinometers measure the roll and inclination and the model defines azimuth, Mag total, and Mag dip). Using this method, an estimation of the field vector due to reference magnets 430 can be calculated allowing distance and direction to be resolved.

[0718] A second ranging system may be based on using the signal strength and phase of the “through the earth” wireless link (for example, radio) established between first transceiving antenna 444A in first wellbore 428A and second transceiving antenna 444B in second wellbore 428B. Sensor 432A may be coupled to first transceiving antenna 444A. Given the close spacing of wellbores 428A, 428B and the variability in electrical properties of the formation, the attenuation rates for the electromagnetic signal may be predictable. Predictable attenuation rates for the electromagnetic signal allow the signal strength to be used as a measure of separation between first and second transceiver pairs 444A, 444B. The vector direction of the magnetic field induced by the electromagnetic transmissions from the first wellbore may provide the direction. A transceiver may communicate with the surface via wire or fiber optics (for example, wire 446) coupled to the transceiver.

[0719] With a known resistivity of the formation and operating frequency, the distance between the source and point of measurement may be calculated. FIG. 27 depicts two examples of the relationship between power received and distance based upon two different formations with different resistivities 448 and 450. If 10 W is transmitted at a 12 Hz frequency in 20 ohm-m formation 448, the power received amounts to approximately 9.10 W at 30 m distance. The resistivity was chosen at random and may vary depending on where you are in the ground. If a higher resistivity was chosen at the given frequency, such as 100 ohm-m formation 450, a lower attenuation is observed, and a low characterization occurs whereupon it receives 9.58 W at 30 m distance. Thus, high resistivity, although transmitting power desirably, shows a negative affect in electromagnetic ranging possibilities. Since the main influence in attenuation is the distance itself, calculations may be made solving for the distance between a source and a point of measurement.

[0720] The frequency of the electromagnetic source operates on is another factor that affects attenuation. Typically, the higher the frequency, the higher the attenuation and vice versa. A strategy for choosing between various frequencies may depend on the formation chosen. For example, while the attenuation at a resistivity of 100 ohm-m may be good for data communications, it may not be sufficient for distance calculations. Thus, a higher frequency may
be chosen to increase attenuation. Alternatively, a lower frequency may be chosen for the opposite purpose. In some embodiments, a combination of different frequencies is used in sequence to optimize for both low and high frequency functions.

[0721] Wireless data communications in ground may allow an opportunity for electromagnetic ranging and the variable frequency it operates on must be observed to balance out benefits for both functionalities. Benefits of wireless data communication may include, but are not be limited to: 1) automatic depth sync through the use of ranging and telemetry; 2) fast communications with a dedicated coil for a transceiving antenna running in the second wellbore that is hardwired (for example, with optic fiber); 3) functioning as an alternative method for fast communication when hardware in the first wellbore is not available; 4) functioning in under balanced and over balanced drilling; 5) providing a similar method for transmitting control commands to a bottom hole assembly; 6) reusing sensors to reduce costs and waste; 7) decreasing noise measurement functions split between the first wellbore and the second wellbore; and/or 8) using simultaneous multiple position measurement techniques to provide real time best estimates of position and attitude.

[0722] In some embodiments, it may be advisable to employ sensors able to compensate for magnetic fields produced internally by carbon steel casing built in the vertical section of a reference hole (for example, high range magnetometers). In some embodiments, modification may be made to account for problems with wireless antenna communications between wellbores penetrating through wellbore casings.

[0723] Pieces of formation or rock may protrude or fall into the wellbore due to various failures including rock breakage or plastic deformation during and/or after wellbore formation. Protrusions may interfere with drilling string movement and/or the flow of drilling fluids. Protrusions may prevent running tubulars into the wellbore after the drilling string has been removed from the wellbore. Significant amounts of material entering or protruding into the wellbore may cause wellbore integrity failure and/or lead to the drilling string becoming stuck in the wellbore. Some causes of wellbore integrity failure may be in situ stresses and high pore pressures. Mud weight may be increased to hold back the formation and inhibit wellbore integrity failure during wellbore formation. When increasing the mud weight is not practical, the wellbore may be reamed.

[0724] Reaming the wellbore may be accomplished by moving the drilling string up and down one joint while rotating and circulating. Picking the drilling string up can be difficult because of material protruding into the borehole above the bit or BHA (bottom hole assembly). Picking up the drilling string may be facilitated by placing upward facing cutting structures on the drill bit. Without upward facing cutting structures on the drill bit, the rock protruding into the borehole
above the drill bit must be broken by grinding or crushing rather than by cutting. Grinding or
 crushing may induce additional wellbore failure.

[0725] Moving the drilling string up and down may induce surging or pressure pulses that
contribute to wellbore failure. Pressure surging or fluctuations may be aggravated or made worse
by blockage of normal drilling fluid flow by protrusions into the wellbore. Thus, attempts to
clear the borehole of debris may cause even more debris to enter the wellbore.

[0726] When the wellbore fails further up the drilling string than one joint from the drill bit, the
drilling string must be raised more than one joint. Lifting more than one joint in length may
require that joints be removed from the drilling string during lifting and placed back on the
drilling string when lowered. Removing and adding joints requires additional time and labor, and
increases the risk of surging as circulation is stopped and started for each joint connection.

[0727] In some embodiments, cutting structures may be positioned at various points along the
drilling string. Cutting structures may be positioned on the drilling string at selected locations,
for example, where the diameter of the drilling string or BHA changes. FIG. 28A and FIG. 28B
depict cutting structures 452 located at or near diameter changes in drilling string 418 near to
drill bit 424 and/or BHA 420. As depicted in FIG. 28C, cutting structures 452 may be positioned
at selected locations along the length of BHA 420 and/or drilling string 418 that has a
substantially uniform diameter. Cutting structures 452 may remove formation that extends into
the wellbore as the drilling string is rotated. Cuttings formed by the cutting structures 452 may
be removed from the wellbore by the normal circulation used during the formation of the
wellbore.

[0728] FIG. 29 depicts an embodiment of drill bit 424 including cutting structures 452. Drill bit
424 includes downward facing cutting structures 452b for forming the wellbore. Cutting
structures 452a are upwardly facing cutting structures for reaming out the wellbore to remove
protrusions from the wellbore.

[0729] In some embodiments, some cutting structures may be upwardly facing, some cutting
structures may be downwardly facing, and/or some cutting structures may be oriented
substantially perpendicular to the drilling string. FIG, 30 depicts an embodiment of a portion of
drilling string 418 including upward facing cutting structures 452a, downward facing cutting
structures 452b, and cutting structures 452c that are substantially perpendicular to the drilling
string. Cutting structures 452a may remove protrusions extending into wellbore 428 that would
inhibit upward movement of drilling string 418. Cutting structures 452a may facilitate reaming
of wellbore 428 and/or removal of drilling string 418 from the wellbore for drill bit change, BHA
maintenance and/or when total depth has been reached. Cutting structures 452b may remove
protrusions extending into wellbore 428 that would inhibit downward movement of drilling string
418. Cutting structures 452c may ensure that enlarged diameter portions of drilling string 418 do not become stuck in wellbore 428.

[0730] Positioning downward facing cutting structures 452b at various locations along a length of the drilling string may allow for reaming of the wellbore while the drill bit forms additional borehole at the bottom of the wellbore. The ability to ream while drilling may avoid pressure surges in the wellbore caused by lifting the drilling string. Reaming while drilling allows the wellbore to be reamed without interrupting normal drilling operation. Reaming while drilling allows the wellbore to be formed in less time because a separate reaming operation is avoided. Upward facing cutting structures 452a allow for easy removal of the drilling string from the wellbore.

[0731] In some embodiments, the drilling string includes a plurality of cutting structures positioned along the length of the drilling string, but not necessarily along the entire length of the drilling string. The cutting structures may be positioned at regular or irregular intervals along the length of the drilling string. Positioning cutting structures along the length of the drilling string allows the entire wellbore to be reamed without the need to remove the entire drilling string from the wellbore.

[0732] Cutting structures may be coupled or attached to the drilling string using techniques known in the art (for example, by welding). In some embodiments, cutting structures are formed as part of a hinged ring or multi-piece ring that may be bolted, welded, or otherwise attached to the drilling string. In some embodiments, the distance that the cutting structures extend beyond the drilling string may be adjustable. For example, the cutting element of the cutting structure may include threading and a locking ring that allows for positioning and setting of the cutting element.

[0733] In some wellbores, a wash over or over-coring operation may be needed to free or recover an object in the wellbore that is stuck in the wellbore due to caving, closing, or squeezing of the formation around the object. The object may be a canister, tool, drilling string, or other item. A wash-over pipe with downward facing cutting structures at the bottom of the pipe may be used. The wash over pipe may also include upward facing cutting structures and downward facing cutting structures at locations near the end of the wash-over pipe. The additional upward facing cutting structures and downward facing cutting structures may facilitate freeing and/or recovery of the object stuck in the wellbore. The formation holding the object may be cut away rather than broken by relying on hydraulics and force to break the portion of the formation holding the stuck object.

[0734] A problem in some formations is that the formed borehole begins to close soon after the drilling string is removed from the borehole. Boreholes which close up soon after being formed
make it difficult to insert objects such as tubulars, canisters, tools, or other equipment into the wellbore. In some embodiments, reaming while drilling applied to the core drilling string allows for emplacement of the objects in the center of the core drill pipe. The core drill pipe includes one or more upward facing cutting structures in addition to cutting structures located at the end of the core drill pipe. The core drill pipe may be used to form the wellbore for the object to be inserted in the formation. The object may be positioned in the core of the core drill pipe. Then, the core drill pipe may be removed from the formation. Any parts of the formation that may inhibit removal of the core drill pipe are cut by the upward facing cutting structures as the core drill pipe is removed from the formation.

[0735] Replacement canisters may be positioned in the formation using over core drill pipe. First, the existing canister to be replaced is over cored. The existing canister is then pulled from within the core drill pipe without removing the core drill pipe from the borehole. The replacement canister is then run inside of the core drill pipe. Then, the core drill pipe is removed from the borehole. Upward facing cutting structures positioned along the length of the core drill pipe cut portions of the formation that may inhibit removal of the core drill pipe.

[0736] During some in situ heat treatment processes, wellbores may need to be formed in heated formations. Wellbores may also need to be formed in hot portions of geothermally heated or other high temperature formations. Certain formations may be heated by heat sources (for example, heaters) to temperatures above ambient temperatures of the formations. In some embodiments, formations are heated to temperatures significantly above ambient temperatures of the formations. For example, a formation may be heated to a temperature at least about 50 °C above ambient temperature, at least about 100 °C above ambient temperature, at least about 200 °C above ambient temperature, or at least about 500 °C above ambient temperature. Wellbores drilled into hot formation may be additional or replacement heater wells, additional or replacement production wells, and/or monitor wells.

[0737] Cooling while drilling may enhance wellbore stability, safety, and longevity of drilling tools. When the drilling fluid is liquid, significant wellbore cooling can occur due to the circulation of the drilling fluid. Downhole cooling does not have to be applied all the way to the bottom of the wellbore to have beneficial effects. Applying cooling to only part of the drilling string and/or downhole equipment may be a trade off between benefit and the effort involved to apply the cooling to the drilling string and downhole equipment. The target of the cooling may be the formation, the drill bit, and/or the bottom hole assembly. In some embodiments, cooling of the formation is inhibited to promote wellbore stability. Cooling of the formation may be inhibited by using insulation to inhibit heat transfer from the formation to the drilling string, bottom hole assembly, and/or the drill bit. In some embodiments, insulation is used to inhibit
heat transfer and/or phase changes of drilling fluid and/or cooling fluid in portions of the drilling string, bottom hole assembly, and/or the drill bit.

[0738] In some in situ heat treatment process embodiments, a barrier formed around all or a portion of the in situ heat treatment process is formed by freeze wells that form a low temperature zone around the freeze wells. A portion of the cooling capacity of the freeze well equipment may be utilized to cool the equipment needed to drill into the hot formation. A closed loop circulation system may be used to cool drilling bits and/or other downhole equipment. Drilling bits may be advanced slowly in hot sections to ensure that the formed wellbore cools sufficiently to preclude drilling problems and/or to enhance borehole stability.

[0739] When using conventional circulation, drilling fluid flows down the inside of the drilling string and back up the outside of the drilling string. Other circulation systems, such as reverse circulation, may also be used. In some embodiments, the drill pipe may be positioned in a pipe-in-pipe configuration, or a pipe-in-pipe-in-pipe configuration (for example, when a closed loop circulation system is used to cool downhole equipment).

[0740] The drilling string used to form the wellbore may function as a counter-flow heat exchanger. The deeper the well, the more the drilling fluid heats up on the way down to the drill bit as the drilling string passes through heated portions of the formation. When normal circulation does not deliver low enough temperatures drilling fluid to the drill bit to provide adequate cooling, two options may be employed to enhance cooling: mud coolers on the surface can be used to reduce the inlet temperature of the drilling fluid being pumped downhole; and, if cooling is still inadequate, an at least partially insulated drilling string can be used to reduce the counter-flow heat exchanger effect.

[0741] For various reasons including, but not limited to, lost circulation, wells are frequently drilled with gas (for example, air, nitrogen, carbon dioxide, methane, ethane, and other light hydrocarbon gases) or gas/liquid mixtures. Gas/liquid mixtures are used as the drilling fluid primarily to maintain a low equivalent circulating density (low downhole pressure gradient). Gas has low potential for cooling the wellbore because mass flow rates of gas drilling are much lower than when liquid drilling fluid is used. Also, gas has a low heat capacity compared to liquid. As a result of heat flow from the outside to the inside of the drilling string, the gas arrives at the drill bit at close to formation temperature. Controlling the inlet temperature of the gas (analogous to using mud coolers when drilling with liquid) or using insulated drilling string may marginally reduce the counter-flow heat exchanger effect when gas drilling. Some gases are more effective than others at transferring heat, but the use of gasses with better heat transfer properties may not significantly improve wellbore cooling while gas drilling.
[0742] Gas drilling may deliver the drilling fluid to the drill bit at close to the formation temperature. The gas may have little capacity to absorb heat. A feature of gas drilling is the low density column in the annulus. The benefits of gas drilling can be accomplished if the drilling fluid or a cooling fluid is liquid while flowing down the drilling string and gas while flowing back up the annulus. The heat of vaporization may be used to cool the drill bit and the formation rather than using the sensible heat of the drilling fluid to cool.

[0743] An advantage of this approach may be that even though the liquid arrives at the bit at close to formation temperature, the liquid can absorb heat by vaporizing. The heat of vaporization is typically larger than the heat that can be absorbed by a temperature rise. As a comparison, a 7-7/8” wellbore is drilled with a 3-1/2” drilling string circulating low density mud at about 203 gpm with about a 100 ft/min typical annular velocity. Drilling through a 450 °F zone at 1000 feet will result in a mud exit temperature about 8 °F hotter than the inlet temperature. This results in the removal of about 14,000 Btu/min. The removal of this heat lowers the bit temperature from about 450 °F to about 285 °F. If liquid water is injected down the drilling string and allowed to boil at the bit and steam is produced up the annulus, the mass flow required to remove 1/2” cuttings is about 34 lbw/min assuming the back pressure is about 100 psia. At 34 lbw/min, the heat removed from the wellbore would be about 34 lbw/min x (1187 - 180) Btu/lbw, or about 34,000 Btu/min. This heat removal amount is about 2.4 times the liquid cooling case. Thus, at reasonable annular steam flow rates, a significant amount of heat may be removed by vaporization.

[0744] The high velocities required for gas drilling may be achieved by the expansion that occurs during vaporization rather than by employing compressors on the surface. Eliminating or minimizing the need for compressors may simplify the drilling process, eliminate or lower compression costs, and eliminate or reduce a source of heat applied to the drilling fluid on the way to the drill bit.

[0745] In some embodiments, it is helpful to inhibit vaporization within the drilling string. If the drilling fluid flowing downwards vaporizes before reaching the drill bit, the heat of vaporization tends to extract heat from the drilling fluid flowing up the annulus. The heat transferred from the annulus (outside the drilling string) to inside the drilling string is heat that is not rejected from the well when drilling fluid reaches the surface. Vaporization that occurs inside of the drilling string before the drilling fluid reaches the bottom of the hole is less beneficial to drill bit and/or wellbore cooling. FIG. 31 depicts drilling fluid flow in drilling string 418 in wellbore 428 with no control of vaporization of the fluid. Liquid drilling fluid flows down drilling string 418 as indicated by arrow 1704. Liquid changes to vapor at interface 1706. Vapor flows down drilling string 418 below interface 1706 as indicated by arrow 1708. In certain embodiments, interface
1706 is a region instead of an abrupt change from liquid to vapor. Vapor and cuttings may flow up the annular region between drilling string 418 and formation 524 in the directions indicated by arrows 1710. Heat transfers from formation 524 to the vapor moving up drilling string 418 and to the drilling string. Heat from drilling string 418 transfers to liquid and vapor flowing down the drilling string.

[0746] If the pressure in the drilling string is maintained above the boiling pressure for a given temperature by use of a back pressure device, then the transfer of heat from outside the drilling string to fluid on the inside of the drilling string can be limited so that the fluid on the inside of the drilling string does not change phases. Fluid downstream of the back pressure device may be allowed to change phase. The fluid downstream the back pressure device may be partially or totally vaporized. Vaporization may result in the drilling fluid absorbing the heat of vaporization from the drill bit and formation. For example, if the back pressure device is set to allow flow only when the back pressure is above a selected pressure (for example, 250 psi for water or another pressure depending on the fluid), the fluid within the drilling string may not vaporize unless the temperature is above a selected temperature (for example, 400 °F for water or another temperature depending on the fluid). If the temperature of the formation is above the selected temperature (for example, the temperature is about 500 °F), steps may be taken to inhibit vaporization of the fluid on the way down to the drill bit. In an embodiment, the back pressure device is set to maintain a back pressure that inhibits vaporization of the drilling fluid at the temperature of the formation (for example, 580 psi to inhibit vaporization up to a temperature of 500 °F for water). In another embodiment, the drilling pipe is insulated and/or the drilling fluid is cooled so that the back pressure device is able to maintain any drilling fluid that reaches the drill bit as a liquid.

[0747] Examples of two back pressure devices that may be used to maintain elevated pressure within the drilling string are a choke and a pressure activated valve. Other types of back pressure devices may also be used. Chokes have a restriction in the flow area that creates back pressure by resisting flow. Resisting the flow results in increased upstream pressure to force the fluid through the restriction. Pressure activated valves may not open until a minimum upstream pressure is obtained. The pressure difference across a pressure activated valve may determine if the pressure activated valve is open to allow flow or the valve is closed.

[0748] In some embodiments, both a choke and a pressure activated valve may be used. A choke can be the bit nozzles allowing the liquid to be jetted toward the drill bit and the bottom of the hole. The bit nozzles may enhance drill bit cleaning and help inhibit fouling of the drill bit and pressure activated valve. Fouling may occur if boiling in the drill bit or pressure activated valve
causes solids to precipitate. The pressure activated valve may inhibit premature vaporization at
low flow rates such as flow rates below which the chokes are effective.

[0749] In some embodiments, additives are added to the cooling fluid or the drilling fluid. The
additives may modify the properties of the fluids in the liquid phase and/or the gas phase.
Additives may include, but are not limited to, surfactants to foam the fluid, additives to
chemically alter the interaction of the fluid with the formations (for example, to stabilize the
formation), additives to control corrosion, and additives for other benefits.

[0750] In some embodiments, a non-condensable gas is added to the cooling fluid or the drilling
fluid pumped down the drilling string. The non-condensable gas may be, but is not limited to,
nitrogen, carbon dioxide, air, and mixtures thereof. Adding the non-condensable gas results in
pumping a two phase mixture down the drilling string. One reason for adding the non-
condensable gas may be to enhance the flow of the fluid out of the formation. The presence of
the non-condensable gas may inhibit condensation of the vaporized cooling or drilling fluid
and/or help to carry cuttings out of the formation. In some embodiments, one or more heaters are
present at one or more locations in the wellbore to provide heat that inhibits condensation and
reflux of cooling or drilling fluid leaving the formation.

[0751] In certain embodiments, managed pressure drilling and/or managed volumetric drilling is
used during the formation of wellbores. The back pressure on the wellbore may be held to a
prescribed value to control the downhole pressure. Similarly, the volume of fluid entering and
exiting the wellbore may be balanced such that there is no or minimally controlled net influx or
out-flux of drilling fluid into the formation.

[0752] FIG. 32 depicts a representation of a system for forming wellbore 428 in heated formation
524. Liquid drilling fluid flows down the drilling string to bottom hole assembly 420 in the
direction indicated by arrow 1704. Bottom hole assembly 420 may include back pressure device
1712. Back pressure device 1712 may include pressure activated valves and/or chokes. In some
embodiments, back pressure device 1712 is adjustable. Back pressure device 1712 may be
electrically coupled to bottom hole assembly 420. The control system for bottom hole assembly
420 may control the inlet flow of cooling or drilling fluid and may adjust the amount of flow
through back pressure device 1712 to maintain the pressure of cooling or drilling fluid located
above the back pressure device above a desired pressure. Thus, back pressure device 1712 may
be operated to control vaporization of the cooling fluid. In certain embodiments, back pressure
device 1712 includes a control volume. In some embodiments, the control volume is a conduit
that carries the cooling fluid to bottom hole assembly 420.

[0753] The desired pressure may be a pressure sufficient to maintain cooling or drilling fluid as a
liquid phase to cool drill bit 424 when the liquid phase of the cooling or drilling fluid is
vaporized. At least a portion of the liquid phase of the cooling or drilling fluid may vaporize and absorb heat from drill bit 424. In certain embodiments, vaporization of the cooling fluid is controlled to control a temperature at or near bottom hole assembly 420. In some embodiments, bottom hole assembly 420 includes insulation to inhibit heat transfer from the formation to the bottom hole assembly. In some embodiments, drill bit 424 includes a conduit for flow of the cooling fluid. Vapor phase cooling or drilling fluid and cuttings may flow upwards to the surface in the direction indicated by arrow 1710.

[0754] In some embodiments, cooling fluid in a closed loop is circulated into and out of the wellbore to provide cooling to the formation, drilling string, and/or downhole equipment. In some embodiments, phase change of the cooling fluid is not utilized during cooling. In some embodiments, the cooling fluid is subjected to a phase change to cool the formation, drilling string, and/or downhole equipment.

[0755] In an embodiment, cooling fluid in a closed loop system is passed through a back pressure device and allowed to vaporize to provide cooling to a selected region. FIG. 33 depicts a representation of a system that uses phase change of a cooling fluid to provide downhole cooling. Drilling fluid may flow down the center drilling string to drill bit 424 in the direction indicated by arrow 1704. Return drilling fluid and cuttings may flow to the surface in the direction indicated by arrows 1710. Cooling fluid may flow down the annular region between center drilling string and the middle drilling string in the direction indicated by arrows 1718. The cooling fluid may pass through back pressure device 1712 to a vaporization chamber. The vaporization chamber may be located above the bottom hole assembly. Back pressure device 1712 may maintain a significant portion of cooling fluid in a liquid phase above the back pressure device. Cooling fluid is allowed to vaporize below back pressure device 1712 in the vaporization chamber. In certain embodiments, at least a majority of the cooling fluid is vaporized. Return vaporized cooling fluid may flow back to a cooling system that reliquefies the cooling fluid for subsequent usage in the drilling string and/or another drilling string. The vaporized cooling fluid may flow to the surface in the annular region between the middle drilling string and the outer drilling string in the direction indicated by arrows 1720. Liquid cooling fluid may maintain the drilling fluid flowing through the center drilling string at a temperature below the boiling temperature of the cooling fluid.

[0756] FIG. 34 depicts a representation of a system for forming wellbore 428 in heated formation 524 using reverse circulation. Drilling fluid flows down the annular region between formation 524 and outer drilling string 418 in the direction indicated by arrows 1714. Drilling fluid and cuttings pass through drill bit 424 and up center drilling string 418’ in the direction indicated by arrow 1716. Cooling fluid may flow down the annular region between outer drilling string 418...
and center drilling string 418' in the direction indicated by arrows 1718. The cooling fluid may be water or another type of cooling fluid that is able to change from a liquid phase to a vapor phase and absorb heat. The cooling fluid may flow to back pressure device 1712. Back pressure device 1712 may maintain the pressure of the cooling fluid located above the back pressure device above a pressure sufficient to maintain the cooling fluid as a liquid phase to cool drill bit 424 when the liquid phase of the drilling fluid is vaporized. Cooling fluid may pass through back pressure device 1712 into vaporization chamber 1722. Vaporization of cooling fluid may absorb heat from drill bit 424 and/or from formation 524. Vaporized cooling fluid may pass through one or more lift valves into center drilling string 418' to help transport drilling fluid and cuttings to the surface.

[0757] In some embodiments, an auto-positioning control system in combination with a rack and pinion drilling system may be used for forming wellbores in a formation. Use of an auto-positioning control and/or measurement system in combination with a rack and pinion drilling system may allow wellbores to be drilled more accurately than drilling using manual positioning and calibration. For example, the auto-positioning system may be continuously and/or semi-continuously calibrated during drilling. FIG. 35 depicts a schematic of a portion of a system including a rack and pinion drive system. Rack and pinion drive system 1724 includes, but is not limited to, rack 1728, carriage 1764, chuck drive system 1730, and circulating sleeve 1748. Chuck drive system 1730 may hold tubular 1734. Push/pull capacity of a rack and pinion type system may allow enough force (for example, about 5 tons) to push tubulars into wellbores so that rotation of the tubulars is not necessary. A rack and pinion system may apply downward force on the drill bit. The force applied to the drill bit may be independent of the weight of the drilling string and/or collars. In certain embodiments, collar size and weight is reduced because the weight of the collars is not needed to enable drilling operations. Drilling wellbores with long horizontal portions may be performed using rack and pinion drilling systems because of the ability of the drilling systems to apply force to the drilling bit.

[0758] Rack and pinion drive system 1724 may be coupled to auto-positioning control system 1766. Auto-positioning control system 1766 may include, but is not limited to, rotary steerable systems, dual motor rotary steerable systems, and/or hole measurement systems. In some embodiments, heaters are included in tubular 1734. In some embodiments, auto-positioning measurement tools are positioned in the heaters. In some embodiments, a measurement system includes magnetic ranging and/or a non-rotating sensor.

[0759] In some embodiments, a hole measuring system includes canted accelerometers. Use of canted accelerometers may allow for surveying of a shallow portion of the formation. For example, shallow portions of the formation may have steel casing strings from drilling operations
and/or other wells. The steel casings may affect the use of magnetic survey tools in determining the direction of deflection incurred during drilling. Canted accelerometers may be positioned in a bottom hole assembly with the surface as reference of string rotational position. Positioning the canted accelerometers in a bottom hole assembly may allow accurate measurement of inclination and direction of a hole regardless of the influence of nearby magnetic interference sources (for example, casing strings). In some embodiments, the relative rotational position of the tubular is monitored by measuring and tracking incremental rotation of the shaft. By monitoring the relative rotation of tubulars added to existing tubulars, more accurate positioning of tubulars may be achieved. Such monitoring may allow tubulars to be added in a continuous manner. In some embodiments, a method of drilling using a rack and pinion system includes continuous downhole measurement. A measurement system may be operated using a predetermined and constant current signal. Distance and direction are calculated continuously downhole. The results of the calculations are filtered and averaged. A best estimate final distance and direction is reported to the surface. When received on surface, the known along hole depth and source location may be combined with the calculated distance and direction to calculate X, Y & Z position data.

[0760] During drilling with jointed pipes, the time taken to shut down circulation, add the next pipe, re-establish circulation, and hole making may require a substantial amount of time, particularly when using two-phase circulation. Handling tubulars (for example, pipes) has historically been a key safety risk area where manual handling techniques have been used. Coiled tubing drilling has had some success in eliminating the need for making connections and manual tubular handling, however, the inability to rotate and the limitations on practical coil diameters may limit the extent to which it can be used.

[0761] In some embodiments, a drilling sequence is used in which tubulars are added to a string without interrupting the drilling process. Such a sequence may allow continuous rotary drilling with large diameter tubulars. A continuous rotary drilling system may include a drilling platform, which includes, but is not limited to, one or more platforms, a top drive system, and a bottom drive system. The platform may include a rack to allow multiple independent traversing of components. The top drive system may include an extended drive sub (for example, an extended drive system manufactured by American Augers, West Salem, Ohio, U.S.A.). The bottom drive system may include a chuck drive system and a hydraulic system. The bottom drive system may operate in a similar manner to a rack and pinion drilling system. The chuck drive system may be mounted on a separate carriage. The hydraulic system may include, but is not limited to, one or more motors and a circulating sleeve. The circulating sleeve may allow circulation between tubulars and the annulus. The circulating sleeve may be used to open or shut off production from various intervals in the well. In some embodiments, a system includes a
tubular handling system. A tubular handling system may be automated, manually operated, or a combination thereof.

[0762] FIGS. 36A-36D depict a schematic of an illustrative continuous drilling sequence. The system used to carry out the continuous drilling sequence includes bottom drive system 1738, tubular handling system 1740, and top drive system 1742. Top drive system 1742 includes circulating sleeve 1744 and drive sub 1758. Top drive system 1740 may be, for example, a rotary drive system or a rack and pinion drive system. Bottom drive system 1738 includes circulating sleeve 1748 and chuck 1762. For example, bottom drive system 1738 may be a rack and pinion type system such as depicted in FIG. 35. In some embodiments, the chuck may be on a separate carriage system. During the sequence, new tubulars (for example, new tubular 1736) may be coupled successively, one after another, to an existing tubular (for example, existing tubular 1734). Bottom drive system 1738 and top drive system 1742 may alternate control of the drilling operation.

[0763] As the sequence commences, existing tubular 1734 is coupled to chuck 1762, and bottom drive system 1738 controls drilling. Fluid may flow through port 1750 into circulating sleeve 1748 of bottom drive system 1738. Top drive system 1742 is at reference line Y and bottom drive system 1738 is at reference line Z. It will be understood that reference lines Y and Z are shown for illustrative purposes only, and the heights of the drive systems at various stages in the sequence may be different than those depicted in FIGS. 36A-36D. As shown in FIG. 36A, new tubular 1736 may be aligned with bottom drive system 1738 using tubular handling system 1740. Once in position, top drive system 1742 may be connected to a top end (for example, a box end) of new tubular 1736.

[0764] As shown in FIG. 36B, as chuck 1762 of bottom drive system 1738 continues to control drilling, top drive system 1742 lowers and positions or drops a bottom end of new tubular 1736 in circulating sleeve 1748 (see arrows). Once new tubular 1736 is in the chamber of circulating sleeve 1748, circulation changes to top drive system 1742 and a connection is made between new tubular 1736 and existing tubular 1734. After the connection between existing tubular 1734 and new tubular 1736 is made, bottom drive system 1738 may relinquish control of the drilling process to top drive system 1742. Fluid flows through port 1746 into circulating sleeve 1744 of top drive system 1742.

[0765] As shown in FIG. 36C, with top drive system 1742 controlling the drilling process, bottom drive system 1738 may be actuated to travel upward (see arrow) toward top drive system 1742 along the length of new tubular 1736. When bottom drive system 1738 reaches the top of new tubular 1736, the new tubular may be engaged with chuck 1762 of bottom drive system 1738. Top drive system 1742 may relinquish control of the drilling process to bottom drive system 1738.
system 1738. Bottom drive system 1738 may resume control of the drilling operation while top drive system 1742 disconnects from the new tubular 1736. Chuck 1762 may transfer force to new tubular 1736 to continue drilling. Top drive system 1742 may be raised relative to bottom drive system 1738 (see arrow) (for example, until top drive system 1742 reaches reference line Y). As shown in FIG. 36D, bottom drive system 1738 may be lowered to push new tubular 1736 and existing tubular 1734 downward into the formation (see arrows). Bottom drive system 1738 may continue to be lowered (for example, until bottom drive system 1738 has returned to reference line Z). The sequence described above may be repeated any number of times so as to maintain continuous drilling operations.

[0766] FIG. 37 depicts a schematic of an embodiment of circulating sleeve 1748. Fluid may enter circulating sleeve 1748 through port 1750 and flow around existing tubular 1734. Fluid may remove heat away from chuck 1762 and/or tubulars. Circulating sleeve 1748 includes opening 1752. Opening 1752 allows new tubular 1736 to enter circulating sleeve 1748 so that the new tubular may be coupled to existing tubular 1734. In some embodiments, a valve is provided at opening 1752. For example, the valve may be a UBD circulation valve. Opening 1752 may include one or more tooljoints 1754. Tooljoints 1754 may guide entry of new tubular 1736 in an inner section of circulating sleeve. As new tubular 1736 enters opening 1752 of circulating sleeve 1748, fluid flow through the circulating sleeve may be under pressure. For example, fluid through the circulating sleeve may be at pressures of up to about 13.8 MPa (up to about 2000 psi).

[0767] In some embodiments, circulating sleeve 1748 may include, and/or operate in conjunction with, one or more valves. FIG. 38 depicts a schematic of system including circulating sleeve 1748, side valve 1756, and top valve 1760. Side valve 1756 may be a check valve incorporated into a side entry flow and check valve port. Top entry valve 1760 may be a check valve. Use of check valves may facilitate change of circulation entry points and creation of a seal.

[0768] As circulating system sleeve 1748 comes into proximity with drive sub 1758 (as described in FIG. 36D), fluid from top drive system 1742 may be flowing from circulating sleeve 1744 of top drive system 1742 through top valve 1760. Circulating sleeve 1748 may be pressurized and side valve 1756 may open to provide flow. Top valve 1760 may shut and/or partially close as side valve 1756 opens to provide flow to circulating sleeve 1744. Circulation may be slowed or discontinued through top drive system 1742. As circulation is stopped through top drive system 1742, top valve 1760 may close completely and all fluid may be furnished through side valve 1756 from port 1750.

[0769] In some embodiments, one piece of equipment may be used to drill multiple wellbores in a single day. The wellbores may be formed at penetration rates that are many times faster than
the penetration rates using conventional drilling with drilling bits. The high penetration rate allows separate equipment to accomplish drilling and casing operations in a more efficient manner than using a one-rig approach. The high penetration rate requires accurate, near real time directional drilling control in three dimensions.

[0770] In some embodiments, high penetration rates may be attained using composite coiled tubing in combination with particle jet drilling. Particle jet drilling forms an opening in a formation by impacting the formation with high velocity fluid containing particles to remove material from the formation. The particles may function as abrasives. In addition to composite coiled tubing and particle jet drilling, a downhole electric orienter, bubble entrained mud, downhole inertial navigation, and a computer control system may be needed. Other types of drilling fluid and drilling fluid systems may be used instead of using bubble entrained mud. Such drilling fluid systems may include, but are not limited to, straight liquid circulation systems, multiphase circulation systems using liquid and gas, and/or foam circulation systems.

[0771] Composite coiled tubing has a fatigue life that is significantly greater than the fatigue life of steel coiled tubing. Composite coiled tubing is available from Airborne Composites BV (The Hague, The Netherlands). Composite coiled tubing can be used to form many boreholes in a formation. The composite coiled tubing may include integral power lines for providing electricity to downhole tools. The composite coiled tubing may include integral data lines for providing real time information regarding downhole conditions to the computer control system and for sending real time control information from the computer control system to the downhole equipment. The primary computer control system may be downhole or may be at surface.

[0772] The coiled tubing may include an abrasion resistant outer sheath. The outer sheath may inhibit damage to the coiled tubing due to sliding experienced by the coiled tubing during deployment and retrieval. In some embodiments, the coiled tubing may be rotated during use in lieu of or in addition to having an abrasion resistant outer sheath to minimize uneven wear of the composite coiled tubing.

[0773] Particle jet drilling may advantageously allow for stepped changes in the drilling rate. Drill bits are no longer needed and downhole motors are eliminated. Particle jet drilling may decouple cutting formation to form the borehole from the bottom hole assembly (BHA). Decoupling cutting formation to form the borehole from the BHA reduces the impact that variable formation properties (for example, formation dip, vugs, fractures and transition zones) have on wellbore trajectory. The decoupling lowers the required torque and thrust that would normally be required if conventional drilling bits were used to form a borehole in the formation. By decoupling cutting formation to form the borehole from the BHA, directional drilling may be reduced to orienting one or more particle jet nozzles in appropriate directions. The orientation of
the BHA becomes easier with the reduced torque on the assembly from the hole making process. Additionally, particle jet drilling may be used to under ream one or more portions of a wellbore to form a larger diameter opening.

[0774] Particles may be introduced into a pressurized injection stream during particle jet drilling. The ability to achieve and circulate high particle laden fluid under pressure may facilitate the successful use of particle jet drilling. Traditional oilfield drilling and/or servicing pumps are not designed to handle the abrasive nature of the particles used for particle jet drilling for extended periods of time. Wear on the pump components may be high resulting in impractical maintenance and repairs. One type of pump that may be used for particle jet drilling is a heavy duty piston membrane pump. Heavy duty piston membrane pumps may be available from ABEL GmbH & Co. KG (Buchen, Germany). Piston membrane pumps have been used for long term, continuous pumping of slurries containing high total solids in the mining and power industries. Piston membrane pumps are similar to triplex pumps used for drilling operations in the oil and gas industry except heavy duty preformed membranes separate the slurry from the hydraulic side of the pump. In this fashion, the solids laden fluid is brought up to pressure in the injection line in one step and circulated downhole without damaging the internal mechanisms of the pump.

[0775] Another type of pump that may be used for particle jet drilling is an annular pressure exchange pump. Annular pressure exchange pumps may be available from Macmahon Mining Services Pty Ltd (Lonsdale, Australia). Annular pressure exchange pumps have been used for long term, continuous pumping of slurries containing high total solids in the mining industry. Annular pressure exchange pumps use hydraulic oil to compress a hose inside a high-strength pressure chamber in a peristaltic like way to displace the contents of the hose. Annular pressure exchange pumps may obtain continuous flow by having twin chambers. One chamber fills while the other chamber is purged.

[0776] The BHA may include a downhole electric orienter. The downhole electric orienter may allow for directional drilling by directing one or more jets or particle jet drilling nozzles in an appropriate fashion to facilitate forward hole making progress in the desired direction. The downhole electric orienter may be coupled to a computer control system through one or more integral data lines of the composite coiled tubing. Power for the downhole electric orienter may be supplied through an integral power line of the composite coiled tubing or through a battery system in the BHA.

[0777] Bubble entrained mud may be used as the drilling fluid. Bubble entrained mud may allow for particle jet drilling without raising the equivalent circulating density to unacceptable levels. A form of managed pressure drilling may be affected by varying the density of bubble entrainment. In some embodiments, particles in the drilling fluid may be separated from the
drilling fluid using magnetic recovery when the particles include iron or alloys that may be influenced by magnetic fields. Bubble entrained mud may be used because using air or other gas as the drilling fluid may result in excessive wear of components from high velocity particles in the return stream. The density of the bubble entrained mud going downhole as a function of real time gains and losses of fluid may be automated using the computer control system.

[0778] In some embodiments, multiphase systems are used. For example, if gas injection rates are low enough that wear rates are acceptable, a gas-liquid circulating system may be used. Bottom hole circulating pressures may be adjusted by the computer control system. The computer control system may adjust the gas and/or liquid injection rates.

[0779] In some embodiments, pipe-in-pipe drilling is used. Pipe-in-pipe drilling may include circulating fluid through the space between the outer pipe and the inner pipe instead of between the wellbore and the drill string. Pipe-in-pipe drilling may be used if contact of the drilling fluid with one or more fresh water aquifers is not acceptable. Pipe-in-pipe drilling may be used if the density of the drilling fluid cannot be adjusted low enough to effectively reduce potential lost circulation issues.

[0780] Downhole inertial navigation may be part of the BHA. The use of downhole inertial navigation allows for determination of the position (including depth, azimuth and inclination) without magnetic sensors. Magnetic interference from casings and/or emissions from the high density of wells in the formation may interfere with a system that determines the position of the BHA based on magnet sensors.

[0781] The computer control system may receive information from the BHA. The computer control system may process the information to determine the position of the BHA. The computer control system may control drilling fluid rate, drilling fluid density, drilling fluid pressure, particle density, other variables, and/or the downhole electric orienter to control the rate of penetration and/or the direction of borehole formation.

[0782] FIG. 39 depicts a representation of an embodiment of bottom hole assembly 420 used to form an opening in the formation. Composite coiled tubing 1768 may be secured to connector 1770 of BHA 420. Connector 1770 may be coupled to combination circulation and disconnect sub 1772. Sub 1772 may include ports 1774. Sub 1772 may be coupled to tractor system 1776. Tractor system 1776 may include a plurality of grippers 1778 and ram 1780. Tractor system 1776 may be coupled to sensor sub 1782 that includes inertial navigation sensors, pressure sensors, temperature sensors and/or other sensors. Sensor sub 1782 may be coupled to orienter 1784. Orienter 1784 may be coupled to jet head 1786. Jet head 1786 may include centralizers 1788. Other BHA embodiments may include other components and/or the same components in a different order.
In some embodiments, the jet head is rotated during use. The BHA may include a motor for rotating the jet head. FIG. 40 depicts an embodiment of jet head 1786 with multiple nozzles 1790. The motor in the BHA may rotate jet head 1786 in the direction indicated by the arrow. Nozzles 1790 may direct particle jet streams 1792 against the formation. FIG. 41 depicts an embodiment of jet head 1786 with single nozzles 1790. Nozzle 1790 may direct particle jet stream 1792 against the formation.

In some embodiments, the jet head is not rotated during use. FIG. 42 depicts an embodiment of non-rotational jet head 1786. Jet head 1786 may include one or more nozzles 1790 that direct particle jet streams against the formation.

Direction change of the wellbore formed by the BHA may be controlled in a number of ways. FIG. 43 depicts a representation wherein the BHA includes an electrical orien ter 1784. Electrical orien ter 1784 adjusts angle θ between a back portion of the BHA and jet head 1786 that allows the BHA to form the opening in the direction indicated by arrow 1794. FIG. 44 depicts a representation wherein jet head 1786 includes directional jets 1796 around the circumference of the jet head. Directing fluid through one or more of the directional jets 1796 applies a force in the direction indicated by arrow 1798 to jet head 1786 that moves the jet head so that one or more jets of the jet head form the wellbore in the direction indicated by arrow 1794.

In some embodiments, the tractor system of the BHA may be used to change the direction of wellbore formation. FIG. 45 depicts tractor system 1776 in use to change the direction of wellbore formation to the direction indicated by arrow 1794. One or more grippers of the rear gripper assembly may be extended to contact the formation and establish a desired angle of jet head. Ram 1780 may be extended to move jet head forward. When ram 1780 is fully extended, grippers of the front gripper assembly may be extended to contact the formation, and grippers of the rear gripper assembly may be retracted to allow the ram to be compressed. Force may be applied to the coiled tubing to compress ram 1780. When the ram is compressed, grippers of the front gripper assembly may be retracted, and grippers of the rear gripper assembly may be extended to contact the formation and set the jet head in the desired direction. Additional wellbore may be formed by directing particle jets through the jet head while extending ram 1780.

In some embodiments, robots are used to perform a task in a wellbore formed or being formed using composite coiled tubing. The task may be, but is not limited to, providing traction to move the coiled tubing, surveying, removing cuttings, logging, and/or freeing pipe. For example, a robot may be used when drilling a horizontal opening if enough weight cannot be applied to the BHA to advance the coiled tubing and BHA in the formed borehole. The robot may be sent down the borehole. The robot may clamp to the composite coiled tubing or BHA.
Portions of the robot may extend to engage the formation. Traction between the robot and the formation may be used to advance the robot forward so that the composite coiled tubing and the BHA advance forward. The displacement data from the forward advancement of the BHA using the robot may be supplied directly to the inertial navigation system to improve accuracy of the opening being formed.

[0788] The robots may be battery powered. To use the robot, drilling could be stopped, and the robot could be connected to the outside of the composite coiled tubing. The robot would run along the outside of the composite coiled tubing to the bottom of the hole. If needed, the robot could electrically couple to the BHA. The robot could couple to a contact plate on the BHA. The BHA may include a step-down transformer that brings the high voltage, low current electricity supplied to the BHA to a lower voltage and higher current (for example, one third the voltage and three times the amperage supplied to the BHA). The lower voltage, higher current electricity supplied from the step-down transformer may be used to recharge the batteries of the robot. In some embodiments, the robot may function while coupled to the BHA. The batteries may supply sufficient energy for the robot to travel to the drill bit and back to the surface.

[0789] A robot may be run integral to the BHA on the end of the composite coiled tubing. Portions of the robot may extend to engage the formation. Traction between the robot and the formation may be used to advance the robot forward so that the composite coiled tubing and the BHA advance forward. The integral robot could be battery powered, could be powered by the composite coiled tubing power lines or could be hydraulically powered by flow through the BHA.

[0790] FIG. 46 depicts a perspective representation of opened robot 1800. Robot 1800 may be used for propelling the BHA forward in the wellbore. Robot 1800 may include electronics, a battery, and a drive mechanism such as wheels, chains, treads, or other mechanism for advancing the robot forward. The battery and the electronics may be power the drive mechanism. Robot 1800 may be placed around composite coiled tubing and closed. Robot 1800 may travel down the composite coiled tubing but cannot pass over the BHA. FIG. 47 depicts a representation of robot attached to composite coiled tubing 1768 and abutting BHA 420. When robot 1800 reaches BHA 420, the robot may electrically couple to the BHA. BHA 420 may supply power to the robot to power the drive mechanism and/or recharge the battery of the robot. BHA 420 may send control signals to the electronics of robot 1800 that control the operation of the robot when the robot is coupled to the BHA. The control signals provided by BHA 420 may instruct robot 1800 to move forward to move the BHA forward.

[0791] Some wellbores formed in the formation may be used to facilitate formation of a perimeter barrier around a treatment area. Heat sources in the treatment area may heat
hydrocarbons in the formation within the treatment area. The perimeter barrier may be, but is not limited to, a low temperature or frozen barrier formed by freeze wells, a wax barrier formed in the formation, dewatering wells, a grout wall formed in the formation, a sulfur cement barrier, a barrier formed by a gel produced in the formation, a barrier formed by precipitation of salts in the formation, a barrier formed by a polymerization reaction in the formation, and/or sheets driven into the formation. Heat sources, production wells, injection wells, dewatering wells, and/or monitoring wells may be installed in the treatment area defined by the barrier prior to, simultaneously with, or after installation of the barrier.

[0792] A low temperature zone around at least a portion of a treatment area may be formed by freeze wells. In an embodiment, refrigerant is circulated through freeze wells to form low temperature zones around each freeze well. The freeze wells are placed in the formation so that the low temperature zones overlap and form a low temperature zone around the treatment area. The low temperature zone established by freeze wells is maintained below the freezing temperature of aqueous fluid in the formation. Aqueous fluid entering the low temperature zone freezes and forms the frozen barrier. In other embodiments, the freeze barrier is formed by batch operated freeze wells. A cold fluid, such as liquid nitrogen, is introduced into the freeze wells to form low temperature zones around the freeze wells. The fluid is replenished as needed.

[0793] In some embodiments, two or more rows of freeze wells are located about all or a portion of the perimeter of the treatment area to form a thick interconnected low temperature zone. Thick low temperature zones may be formed adjacent to areas in the formation where there is a high flow rate of aqueous fluid in the formation. The thick barrier may ensure that breakthrough of the frozen barrier established by the freeze wells does not occur.

[0794] In some embodiments, a double barrier system is used to isolate a treatment area. The double barrier system may be formed with a first barrier and a second barrier. The first barrier may be formed around at least a portion of the treatment area to inhibit fluid from entering or exiting the treatment area. The second barrier may be formed around at least a portion of the first barrier to isolate an inter-barrier zone between the first barrier and the second barrier. The inter-barrier zone may have a thickness from about 1 m to about 300 m. In some embodiments, the thickness of the inter-barrier zone is from about 10 m to about 100 m, or from about 20 m to about 50 m.

[0795] The double barrier system may allow greater project depths than a single barrier system. Greater depths are possible with the double barrier system because the stepped differential pressures across the first barrier and the second barrier is less than the differential pressure across a single barrier. The smaller differential pressures across the first barrier and the second barrier make a breach of the double barrier system less likely to occur at depth for the double barrier
system as compared to the single barrier system. In some embodiments, additional barriers may be positioned to connect the inner barrier to the outer barrier. The additional barriers may further strengthen the double barrier system and define compartments that limit the amount of fluid that can pass from the inter-barrier zone to the treatment area should a breach occur in the first barrier.

[0796] The first barrier and the second barrier may be the same type of barrier or different types of barriers. In some embodiments, the first barrier and the second barrier are formed by freeze wells. In some embodiments, the first barrier is formed by freeze wells, and the second barrier is a grout wall. The grout wall may be formed of cement, sulfur, sulfur cement, or combinations thereof. In some embodiments, a portion of the first barrier and/or a portion of the second barrier is a natural barrier, such as an impermeable rock formation.

[0797] In some embodiments, one or both barriers may be formed from wellbores positioned in the formation. The position of the wellbores used to form the second barrier may be adjusted relative to the wellbores used to form the first barrier to limit a separation distance between a breach or portion of the barrier that is difficult to form and the nearest wellbore. For example, if freeze wells are used to form both barriers of a double barrier system, the position of the freeze wells may be adjusted to facilitate formation of the barriers and limit the distance between a potential breach and the closest wells to the breach. Adjusting the position of the wells of the second barrier relative to the wells of the first barrier may also be used when one or more of the barriers are barriers other than freeze barriers (for example, dewatering wells, cement barriers, grout barriers, and/or wax barriers).

[0798] In some embodiments, wellbores for forming the first barrier are formed in a row in the formation. During formation of the wellbores, logging techniques and/or analysis of cores may be used to determine the principal fracture direction and/or the direction of water flow in one or more layers of the formation. In some embodiments, two or more layers of the formation may have different principal fracture directions and/or the directions of water flow that need to be addressed. In such formations, three or more barriers may need to be formed in the formation to allow for formation of the barriers that inhibit inflow of formation fluid into the treatment area or outflow of formation fluid from the treatment area. Barriers may be formed to isolate particular layers in the formation.

[0799] The principal fracture direction and/or the direction of water flow may be used to determine the placement of wells used to form the second barrier relative to the wells used to form the first barrier. The placement of the wells may facilitate formation of the first barrier and the second barrier.
[0800] FIG. 48 depicts a schematic representation of barrier wells 200 used to form a first barrier and barrier wells 200' used to form a second barrier when the principal fracture direction and/or the direction of water flow is at angle A relative to the first barrier. The principal fracture direction and/or direction of water flow is indicated by arrow 1802. The case where angle A is 0 is the case where the principal fracture direction and/or the direction of water flow is substantially normal to the barriers. Spacing between two adjacent barrier wells 200 of the first barrier or between barrier wells 200' of the second barrier are indicated by distance s. The spacing s may be 2 m, 3 m, 10 m or greater. Distance d indicates the separation distance between the first barrier and the second barrier. Distance d may be less than s, equal to s, or greater than s. Barrier wells 200' of the second barrier may have offset distance od relative to barrier wells 200 of the first barrier. Offset distance od may be calculated by the equation:

\[ od = s/2 - d^*\tan(A) \]  

(EQN. 1)

[0801] Using the od according to EQN. 1 maintains a maximum separation distance of s/4 between a barrier well and a regular fracture extending between the barriers. Having a maximum separation distance of s/4 by adjusting the offset distance based on the principal fracture direction and/or the direction of water flow may enhance formation of the first barrier and/or second barrier. Having a maximum separation distance of s/4 by adjusting the offset distance of wells of the second barrier relative to the wells of the first barrier based on the principal fracture direction and/or the direction of water flow may reduce the time needed to reform the first barrier and/or the second barrier should a breach of the first barrier and/or the second barrier occur.

[0802] In some embodiments, od may be set at a value between the value generated by EQN. 1 and the worst case value. The worst case value of od may be if barrier wells 200 of the first freeze barrier and barrier wells 200' of the second barrier are located along the principal fracture direction and/or direction of water flow (i.e., along arrow 1802). In such a case, the maximum separation distance would be s/2. Having a maximum separation distance of s/2 may slow the time needed to form the first barrier and/or the second barrier, or may inhibit formation of the barriers.

[0803] In some embodiments, the barrier wells for the treatment area are freeze wells. Vertically positioned freeze wells and/or horizontally positioned freeze wells may be positioned around sides of the treatment area. If the upper layer (the overburden) or the lower layer (the underburden) of the formation is likely to allow fluid flow into the treatment area or out of the treatment area, horizontally positioned freeze wells may be used to form an upper and/or a lower barrier for the treatment area. In some embodiments, an upper barrier and/or a lower barrier may not be necessary if the upper layer and/or the lower layer are at least substantially impermeable. If the upper freeze barrier is formed, portions of heat sources, production wells, injection wells,
and/or dewatering wells that pass through the low temperature zone created by the freeze wells forming the upper freeze barrier wells may be insulated and/or heat traced so that the low temperature zone does not adversely affect the functioning of the heat sources, production wells, injection wells and/or dewatering wells passing through the low temperature zone.

**[0804]** FIG. 49 depicts an embodiment of freeze well 466. Freeze well 466 may include canister 468, inlet conduit 470, spacers 472, and wellcap 474. Spacers 472 may position inlet conduit 470 in canister 468 so that an annular space is formed between the canister and the conduit. Spacers 472 may promote turbulent flow of refrigerant in the annular space between inlet conduit 470 and canister 468, but the spacers may also cause a significant fluid pressure drop. Turbulent fluid flow in the annular space may be promoted by roughening the inner surface of canister 468, by roughening the outer surface of inlet conduit 470, and/or by having a small cross-sectional area annular space that allows for high refrigerant velocity in the annular space. In some embodiments, spacers are not used. Wellhead 476 may suspend canister 468 in wellbore 428.

**[0805]** Formation refrigerant may flow through cold side conduit 478 from a refrigeration unit to inlet conduit 470 of freeze well 466. The formation refrigerant may flow through an annular space between inlet conduit 470 and canister 468 to warm side conduit 480. Heat may transfer from the formation to canister 468 and from the canister to the formation refrigerant in the annular space. Inlet conduit 470 may be insulated to inhibit heat transfer to the formation refrigerant during passage of the formation refrigerant into freeze well 466. In an embodiment, inlet conduit 470 is a high density polyethylene tube. At cold temperatures, some polymers may exhibit a large amount of thermal contraction. For example, a 260 m initial length of polyethylene conduit subjected to a temperature of about -25 °C may contract by 6 m or more. If a high density polyethylene conduit, or other polymer conduit, is used, the large thermal contraction of the material must be taken into account in determining the final depth of the freeze well. For example, the freeze well may be drilled deeper than needed, and the conduit may be allowed to shrink back during use. In some embodiments, inlet conduit 470 is an insulated metal tube. In some embodiments, the insulation may be a polymer coating, such as, but not limited to, polyvinylchloride, high density polyethylene, and/or polystyrene.

**[0806]** Freeze well 466 may be introduced into the formation using a coiled tubing rig. In an embodiment, canister 468 and inlet conduit 470 are wound on a single reel. The coiled tubing rig introduces the canister and inlet conduit 470 into the formation. In an embodiment, canister 468 is wound on a first reel and inlet conduit 470 is wound on a second reel. The coiled tubing rig introduces canister 468 into the formation. Then, the coiled tubing rig is used to introduce inlet conduit 470 into the canister. In other embodiments, freeze well is assembled in sections at the wellbore site and introduced into the formation.
An insulated section of freeze well 466 may be placed adjacent to overburden 482. An uninsulated section of freeze well 466 may be placed adjacent to layer or layers 484 where a low temperature zone is to be formed. In some embodiments, uninsulated sections of the freeze wells may be positioned adjacent only to aquifers or other permeable portions of the formation that would allow fluid to flow into or out of the treatment area. Portions of the formation where uninsulated sections of the freeze wells are to be placed may be determined using analysis of cores and/or logging techniques.

Fig. 50 depicts an embodiment of the lower portion of freeze well 466. Freeze well may include canister 468, and inlet conduit 470. Latch pin 486 may be welded to canister 468. Latch pin 486 may include tapered upper end 488 and groove 490. Tapered upper end 488 may facilitate placement of a latch of inlet conduit 470 on latch pin 486. A spring ring of the latch may be positioned in groove 490 to couple inlet conduit 470 to canister 468.

Inlet conduit 470 may include plastic portion 492, transition piece 494, outer sleeve 496, and inner sleeve 498. Plastic portion 492 may be a plastic conduit that carries refrigerant into freeze well 466. In some embodiments, plastic portion 492 is high density polyethylene pipe.

Transition piece 494 may be a transition between plastic portion 492 and outer sleeve 496. A plastic end of transition piece 494 may be fusion welded to the end of plastic portion 492. A metal portion of transition piece may be butt welded to outer sleeve 496. In some embodiments, the metal portion and outer sleeve 496 are formed of 304 stainless steel. Other material may be used in other embodiments. Transition pieces 494 may be available from Central Plastics Company (Shawnee, Oklahoma, U.S.A.).

In some embodiments, outer sleeve 496 may include stop 500. Stop 500 may engage a stop of inner sleeve 498 to limit a bottom position of the outer sleeve relative to the inner sleeve. In some embodiments, outer sleeve 496 may include opening 502. Opening 502 may align with a corresponding opening in inner sleeve 498. A shear pin may be positioned in the openings during insertion of inlet conduit 470 in canister 468 to inhibit movement of outer sleeve 496 relative to inner sleeve 498. Shear pin is strong enough to support the weight of inner sleeve 498, but weak enough to shear due to force applied to the shear pin when outer sleeve 496 moves upwards in the wellbore due to thermal contraction or during installation of the inlet conduit after inlet conduit is coupled to canister 468.

Inner sleeve 498 may be positioned in outer sleeve 496. Inner sleeve has a length sufficient to inhibit separation of the inner sleeve from outer sleeve 496 when inlet conduit has fully contracted due to exposure of the inlet conduit to low temperature refrigerant. Inner sleeve 498 may include a plurality of slip rings 504 held in place by positioners 506, a plurality of openings 508, stop 510, and latch 512. Slip rings 504 may position inner sleeve 498 relative to
outer sleeve 496 and allow the outer sleeve to move relative to the inner sleeve. In some embodiments, slip rings 504 are TFE® rings, such as polytetrafluoroethylene rings. Slip rings 504 may be made of different material in other embodiments. Positioners 506 may be steel rings welded to inner sleeve. Positioners 506 may be thinner than slip rings 504. Positioners 506 may inhibit movement of slip rings 504 relative to inner sleeve 498.

[0813] Openings 508 may be formed in a portion of inner sleeve 498 near the bottom of the inner sleeve. Openings 508 may allow refrigerant to pass from inlet conduit 470 to canister 468. A majority of refrigerant flowing through inlet conduit 470 may pass through openings 508 to canister 468. Some refrigerant flowing through inlet conduit 470 may pass to canister 468 through the space between inner sleeve 498 and outer sleeve 496.

[0814] Stop 510 may be located above openings 508. Stop 510 interacts with stop 500 of outer sleeve 496 to limit the downward movement of the outer sleeve relative to inner sleeve 498.

[0815] Latch 512 may be welded to the bottom of inner sleeve 498. Latch 512 may include flared opening 514 that engages tapered end 488 of latch pin 486. Latch 512 may include spring ring 516 that snaps into groove 490 of latch pin 486 to couple inlet conduit 470 to canister 468.

[0816] To install freeze well 466, a wellbore is formed in the formation and canister 468 is placed in the wellbore. The bottom of canister 468 has latch pin 486. Transition piece is fusion welded to an end of coiled plastic portion 492 of inlet conduit 470. Latch 512 is placed in canister 468 and inlet conduit is spooled into the canister. Spacers may be coupled to plastic portion 492 at selected positions. Latch may be lowered until flared opening 514 engages tapered end 488 of latch pin 486 and spring ring 516 snaps into the groove of the latch pin. After spring ring 516 engages latch pin 486, inlet conduit 470 may be moved upwards to shear the pin joining outer sleeve 496 to inner sleeve 498. Inlet conduit 470 may be coupled to the refrigerant supply piping and canister may be coupled to the refrigerant return piping.

[0817] If needed, inlet conduit 470 may be removed from canister 468. Inlet conduit may be pulled upwards to separate outer sleeve 496 from inner sleeve 498. Plastic portion 492, transition piece 494, and outer sleeve 496 may be pulled out of canister 468. A removal instrument may be lowered into canister 468. The removal instrument may secure to inner sleeve 498. The removal instrument may be pulled upwards to pull spring ring 516 of latch 512 out of groove 490 of latch pin 486. The removal tool may be withdrawn out of canister 468 to remove inner sleeve 498 from the canister.

[0818] Grout, wax, polymer or other material may be used in combination with freeze wells to provide a barrier for the in situ heat treatment process. The material may fill cavities (vugs) in the formation and reduces the permeability of the formation. The material may have higher thermal conductivity than gas and/or formation fluid that fills cavities in the formation. Placing
material in the cavities may allow for faster low temperature zone formation. The material may form a perpetual barrier in the formation that may strengthen the formation. The use of material to form the barrier in unconsolidated or substantially unconsolidated formation material may allow for larger well spacing than is possible without the use of the material. The combination of the material and the low temperature zone formed by freeze wells may constitute a double barrier for environmental regulation purposes. In some embodiments, the material is introduced into the formation as a liquid, and the liquid sets in the formation to form a solid. The material may be, but is not limited to, fine cement, micro fine cement, sulfur, sulfur cement, viscous thermoplastics, and/or waxes. The material may include surfactants, stabilizers or other chemicals that modify the properties of the material. For example, the presence of surfactant in the material may promote entry of the material into small openings in the formation.

[0819] Material may be introduced into the formation through freeze well wellbores. The material may be allowed to set. The integrity of the wall formed by the material may be checked. The integrity of the material wall may be checked by logging techniques and/or by hydrostatic testing. If the permeability of a section formed by the material is too high, additional material may be introduced into the formation through freeze well wellbores. After the permeability of the section is sufficiently reduced, freeze wells may be installed in the freeze well wellbores.

[0820] Material may be injected into the formation at a pressure that is high, but below the fracture pressure of the formation. In some embodiments, injection of material is performed in 16 m increments in the freeze wellbore. Larger or smaller increments may be used if desired. In some embodiments, material is only applied to certain portions of the formation. For example, material may be applied to the formation through the freeze wellbore only adjacent to aquifer zones and/or to relatively high permeability zones (for example, zones with a permeability greater than about 0.1 darcy). Applying material to aquifers may inhibit migration of water from one aquifer to a different aquifer. For material placed in the formation through freeze well wellbores, the material may inhibit water migration between aquifers during formation of the low temperature zone. The material may also inhibit water migration between aquifers when an established low temperature zone is allowed to thaw.

[0821] In some embodiments, the material used to form a barrier may be fine cement and micro fine cement. Cement may provide structural support in the formation. Fine cement may be ASTM type 3 Portland cement. Fine cement may be less expensive than micro fine cement. In an embodiment, a freeze wellbore is formed in the formation. Selected portions of the freeze wellbore are grouted using fine cement. Then, micro fine cement is injected into the formation through the freeze wellbore. The fine cement may reduce the permeability down to about 10 milidarcy. The micro fine cement may further reduce the permeability to about 0.1 milidarcy.
After the grout is introduced into the formation, a freeze wellbore canister may be inserted into the formation. The process may be repeated for each freeze well that will be used to form the barrier.

[0822] In some embodiments, fine cement is introduced into every other freeze wellbore. Microfine cement is introduced into the remaining wellbores. For example, grout may be used in a formation with freeze wellbores set at about 5 m spacing. A first wellbore is drilled and fine cement is introduced into the formation through the wellbore. A freeze well canister is positioned in the first wellbore. A second wellbore is drilled 10 m away from the first wellbore. Fine cement is introduced into the formation through the second wellbore. A freeze well canister is positioned in the second wellbore. A third wellbore is drilled between the first wellbore and the second wellbore. In some embodiments, grout from the first and/or second wellbores may be detected in the cuttings of the third wellbore. Micro fine cement is introduced into the formation through the third wellbore. A freeze wellbore canister is positioned in the third wellbore. The same procedure is used to form the remaining freeze wells that will form the barrier around the treatment area.

[0823] In some embodiments, material including wax is used to form a barrier in a formation. Wax barriers may be formed in wet, dry, or oil wetted formations. Wax barriers may be formed above, at the bottom of, and/or below the water table. Material including liquid wax introduced into the formation may permeate into adjacent rock and fractures in the formation. The material may permeate into rock to fill microscopic as well as macroscopic pores and vugs in the rock. The wax solidifies to form a barrier that inhibits fluid flow into or out of a treatment area. A wax barrier may provide a minimal amount of structural support in the formation. Molten wax may reduce the strength of poorly consolidated soil by reducing inter-grain friction so that the poorly consolidated soil sloughs or liquefies. Poorly consolidated layers may be consolidated by use of cement or other binding agents before introduction of molten wax.

[0824] In some embodiments, the formation where a wax barrier is to be established is dewatered before and/or during formation of the wax barrier. In some embodiments, the portion of the formation where the wax barrier is to form is dewatered or diluted to remove or reduce saline water that could adversely affect the properties of the material introduced into the formation to form the wax barrier.

[0825] In some embodiments, water is introduced into the formation during formation of the wax barrier. Water may be introduced into the formation when the barrier is to be formed below the water table or in a dry portion of the formation. The water may be used to heat the formation to a desired temperature before introducing the material that forms the wax barrier. The water may
be introduced at an elevated temperature and/or the water may be heated in the formation from one or more heaters.

[0826] The wax of the barrier may be a branched paraffin to inhibit biological degradation of the wax. The wax may include stabilizers, surfactants or other chemicals that modify the physical and/or chemical properties of the wax. The physical properties may be tailored to meet specific needs. The wax may melt at a relative low temperature (for example, the wax may have a typical melting point of about 52 °C). The temperature at which the wax congeals may be at least 5 °C, 10 °C, 20 °C, or 30 °C above the ambient temperature of the formation prior to any heating of the formation. When molten, the wax may have a relatively low viscosity (for example, 4 to 10 cp at about 99 °C). The flash point of the wax may be relatively high (for example, the flash point may be over 204 °C). The wax may have a density less than the density of water and may have a heat capacity that is less than half the heat capacity of water. The solid wax may have a low thermal conductivity (for example, about 0.18 W/m °C) so that the solid wax is a thermal insulator. Waxes suitable for forming a barrier are available as WAXFIX™ from Carter Technologies Company (Sugar Land, Texas, U.S.A.). WAXFIX™ is very resistant to microbial attack. WAXFIX™ may have a half life of greater than 5000 years.

[0827] In some embodiments, a wax barrier or wax barriers may be used as the barriers for the in situ heat treatment process. In some embodiments, a wax barrier may be used in conjunction with freeze wells that form a low temperature barrier around the treatment area. In some embodiments, the wax barrier is formed and freeze wells are installed in the wellbores used for introducing wax into the formation. In some embodiments, the wax barrier is formed in wellbores offset from the freeze well wellbores. The wax barrier may be on the outside or the inside of the freeze wells. In some embodiments, a wax barrier may be formed on both the inside and outside of the freeze wells. The wax barrier may inhibit water flow in the formation that would inhibit the formation of the low temperature zone by the freeze wells. In some embodiments, a wax barrier is formed in the inter-barrier zone between two freeze barriers of a double barrier system.

[0828] Material used to form the wax barrier may be introduced into the formation through wellbores. The wellbores may include vertical wellbores, slanted wellbores, and/or horizontal wellbores (for example, wellbores with sections that are horizontally or near horizontally oriented). The use of vertical wellbores, slanted wellbores, and/or horizontal wellbores for forming the wax barrier allows the formation of a barrier that seals both horizontal and vertical fractures.

[0829] Wellbores may be formed in the formation around the treatment area at a close spacing. In some embodiments, the spacing is from about 1.5 m to about 4 m. Larger or smaller spacings
may be used. Low temperature heaters may be inserted in the wellbores. The heaters may 
operate at temperatures from about 260 °C to about 320 °C so that the temperature at the 
formation face is below the pyrolysis temperature of hydrocarbons in the formation. The heaters 
may be activated to heat the formation until the overlap between two adjacent heaters raises the 
temperature of the zone between the two heaters above the melting temperature of the wax. 
Heating the formation to obtain superposition of heat with a temperature above the melting 
temperature of the wax may take one month, two months, or longer. After heating, the heaters 
may be turned off. In some embodiments, the heaters are downhole antennas that operate at 
about 10 MHz to heat the formation.

[0830] After heating, the material used to form the wax barrier may be introduced into the 
wellbores to form the barrier. The material may flow into the formation and fill any fractures and 
porosity that has been heated. The wax in the material congeals when the wax flows to cold 
regions beyond the heated circumference. This wax barrier formation method may form a more 
complete barrier than some other methods of wax barrier formation, but the time for heating may 
be longer than for some of the other methods. Also, if a low temperature barrier is to be formed 
with the freeze wells placed in the wellbores used for injection of the material used to form the 
barrier, the freeze wells will have to remove the heat supplied to the formation to allow for 
introduction of the material used to form the barrier. The low temperature barrier may take 
longer to form.

[0831] In some embodiments, the wax barrier may be formed using a conduit placed in the 
wellbore. FIG. 51 depicts an embodiment of a system for forming a wax barrier in a formation. 
Wellbore 428 may extend into one or more layers 484 below overburden 482. Wellbore 428 may 
be an open wellbore below overburden 482. One or more of the layers 484 may include fracture 
systems 518. One or more of the layers may be vuggy so that the layer or a portion of the layer 
has a high porosity. Conduit 520 may be positioned in wellbore 428. In some embodiments, low 
temperature heater 522 may be strapped or attached to conduit 520. In some embodiments, 
conduit 520 may be a heater element. Heater 522 may be operated so that the heater does not 
cause pyrolysis of hydrocarbons adjacent to the heater. At least a portion of wellbore 428 may be 
filled with fluid. The fluid may be formation fluid or water. Heater 522 may be activated to heat 
the fluid. A portion of the heated fluid may move outwards from heater 522 into the formation. 
The heated fluid may be injected into the fractures and permeable vuggy zones. The heated fluid 
may be injected into the fractures and permeable vuggy zones by introducing heated barrier 
material into wellbore 428 in the annular space between conduit 520 and the wellbore. The 
introduced material flows to the areas heated by the fluid and congeals when the fluid reaches 
cold regions not heated by the fluid. The material fills fracture systems 518 and permeable
vuggy pathways heated by the fluid, but the material may not permeate through a significant portion of the rock matrix as when the hot material is introduced into a heated formation as described above. The material flows into fracture systems 518 a sufficient distance to join with material injected from an adjacent well so that a barrier to fluid flow through the fracture systems forms when the wax congeals. A portion of material may congeal along the wall of a fracture or a vug without completely blocking the fracture or filling the vug. The congealed material may act as an insulator and allow additional liquid wax to flow beyond the congealed portion to penetrate deeply into the formation and form blockages to fluid flow when the material cools below the melting temperature of the wax in the material.

[0832] Material in the annular space of wellbore 428 between conduit 520 and the formation may be removed through conduit by displacing the material with water or other fluid. Conduit 520 may be removed and a freeze well may be installed in the wellbore. This method may use less material than the method described above. The heating of the fluid may be accomplished in less than a week or within a day. The small amount of heat input may allow for quicker formation of a low temperature barrier if freeze wells are to be positioned in the wellbores used to introduce material into the formation.

[0833] In some embodiments, a heater may be suspended in the well without a conduit that allows for removal of excess material from the wellbore. The material may be introduced into the well. After material introduction, the heater may be removed from the well. In some embodiments, a conduit may be positioned in the wellbore, but a heater may not be coupled to the conduit. Hot material may be circulated through the conduit so that the wax enters fractures systems and/or vugs adjacent to the wellbore.

[0834] In some embodiments, material may be used during the formation of a wellbore to improve inter-zonal isolation and protect a low-pressure zone from inflow from a high-pressure zone. During wellbore formation where a high pressure zone and a low pressure zone are penetrated by a common wellbore, it is possible for fluid from the high pressure zone to flow into the low pressure zone and cause an underground blowout. To avoid this, the wellbore may be formed through the first zone. Then, an intermediate casing may be set and cemented through the first zone. Setting casing may be time consuming and expensive. Instead of setting a casing, material may be introduced to form a wax barrier that seals the first zone. The material may also inhibit or prevent mixing of high salinity brines from lower, high pressure zones with fresher brines in upper, lower pressure zones.

[0835] FIG. 52A depicts wellbore 428 drilled to a first depth in formation 524. After the surface casing for wellbore 428 is set and cemented in place, the wellbore is drilled to the first depth which passes through a permeable zone, such as an aquifer. The permeable zone may be fracture
system 518’. In some embodiments, a heater is placed in wellbore 428 to heat the vertical interval of fracture system 518’. In some embodiments, hot fluid is circulated in wellbore 428 to heat the vertical interval of fracture system 518’. After heating, molten material is pumped down wellbore 428. The molten material flows a selected distance into fracture system 518’ before the material cools sufficiently to solidify and form a seal. The molten material is introduced into formation 524 at a pressure below the fracture pressure of the formation. In some embodiments, pressure is maintained on the wellhead until the material has solidified. In some embodiments, the material is allowed to cool until the material in wellbore 428 is almost to the congealing temperature of the material. The material in wellbore 428 may then be displaced out of the wellbore. Wax in the material makes the portion of formation 524 near wellbore 428 into a substantially impermeable zone. Wellbore 428 may be drilled to depth through one or more permeable zones that are at higher pressures than the pressure in the first permeable zone, such as fracture system 518”. Congealed wax in fracture system 518’ may inhibit blowout into the lower pressure zone. FIG. 52B depicts wellbore 428 drilled to depth with congealed wax 526 in formation 524.

[0836] In some embodiments, a material including wax may be used to contain and inhibit migration in a subsurface formation that has liquid hydrocarbon contaminants (for example, compounds such as benzene, toluene, ethylbenzene and xylene) condensed in fractures in the formation. The location of the contaminants may be surrounded with heated injection wells. The material may be introduced into the wells to form an outer wax barrier. The material injected into the fractures from the injection wells may mix with the contaminants. The contaminants may be solubilized into the material. When the material congeals, the contaminants may be permanently contained in the solid wax phase of the material.

[0837] In some embodiments, a portion or all of the wax barrier may be removed after completion of the in situ heat treatment process. Removing all or a portion of the wax barrier may allow fluid to flow into and out of the treatment area of the in situ heat treatment process. Removing all or a portion of the wax barrier may return flow conditions in the formation to substantially the same conditions as existed before the in situ heat treatment process. To remove a portion or all of the wax barrier, heaters may be used to heat the formation adjacent to the wax barrier. In some embodiments, the heaters raise the temperature above the decomposition temperature of the material forming the wax barrier. In some embodiments, the heaters raise the temperature above the melting temperature of the material forming the wax barrier. Fluid (for example water) may be introduced into the formation to drive the molten material to one or more production wells positioned in the formation. The production wells may remove the material from the formation.
[0838] In some embodiments, a composition that includes a cross-linkable polymer may be used with or in addition to a material that includes wax to form the barrier. Such composition may be provided to the formation as is described above for the material that includes wax. The composition may be configured to react and solidify after a selected time in the formation, thereby allowing the composition to be provided as a liquid to the formation. The cross-linkable polymer may include, for example, acrylates, methacrylates, urethanes, and/or epoxies. A cross-linking initiator may be included in the composition. The composition may also include a cross-linking inhibitor. The cross-linking inhibitor may be configured to degrade while in the formation, thereby allowing the composition to solidify.

[0839] In situ heat treatment processes and solution mining processes may heat the treatment area, remove mass from the treatment area, and greatly increase the permeability of the treatment area. In certain embodiments, the treatment area after being treated may have a permeability of at least 0.1 darcy. In some embodiments, the treatment area after being treated has a permeability of at least 1 darcy, of at least 10 darcy, or of at least 100 darcy. The increased permeability allows the fluid to spread in the formation into fractures, microfractures, and/or pore spaces in the formation. Outside of the treatment area, the permeability may remain at the initial permeability of the formation. The increased permeability allows fluid introduced to flow easily within the formation.

[0840] In certain embodiments, a barrier may be formed in the formation after a solution mining process and/or an in situ heat treatment process by introducing a fluid into the formation. The barrier may inhibit formation fluid from entering the treatment area after the solution mining and/or in situ heat treatment processes have ended. The barrier formed by introducing fluid into the formation may allow for isolation of the treatment area.

[0841] The fluid introduced into the formation to form a barrier may include wax, bitumen, heavy oil, sulfur, polymer, gel, saturated saline solution, and/or one or more reactants that react to form a precipitate, solid or high viscosity fluid in the formation. In some embodiments, bitumen, heavy oil, reactants and/or sulfur used to form the barrier are obtained from treatment facilities associated with the in situ heat treatment process. For example, sulfur may be obtained from a Claus process used to treat produced gases to remove hydrogen sulfide and other sulfur compounds.

[0842] The fluid may be introduced into the formation as a liquid, vapor, or mixed phase fluid. The fluid may be introduced into a portion of the formation that is at an elevated temperature. In some embodiments, the fluid is introduced into the formation through wells located near a perimeter of the treatment area. The fluid may be directed away from the treatment area. The elevated temperature of the formation maintains or allows the fluid to have a low viscosity so that
the fluid moves away from the wells. A portion of the fluid may spread outwards in the formation towards a cooler portion of the formation. The relatively high permeability of the formation allows fluid introduced from one wellbore to spread and mix with fluid introduced from other wellbores. In the cooler portion of the formation, the viscosity of the fluid increases, a portion of the fluid precipitates, and/or the fluid solidifies or thickens so that the fluid forms the barrier to flow of formation fluid into or out of the treatment area.

[0843] In some embodiments, a low temperature barrier formed by freeze wells surrounds all or a portion of the treatment area. As the fluid introduced into the formation approaches the low temperature barrier, the temperature of the formation becomes colder. The colder temperature increases the viscosity of the fluid, enhances precipitation, and/or solidifies the fluid to form the barrier to the flow of formation fluid into or out of the formation. The fluid may remain in the formation as a highly viscous fluid or a solid after the low temperature barrier has dissipated.

[0844] In certain embodiments, saturated saline solution is introduced into the formation. Components in the saturated saline solution may precipitate out of solution when the solution reaches a colder temperature. The solidified particles may form the barrier to the flow of formation fluid into or out of the formation. The solidified components may be substantially insoluble in formation fluid.

[0845] In certain embodiments, brine is introduced into the formation as a reactant. A second reactant, such as carbon dioxide, may be introduced into the formation to react with the brine. The reaction may generate a mineral complex that grows in the formation. The mineral complex may be substantially insoluble to formation fluid. In an embodiment, the brine solution includes a sodium and aluminum solution. The second reactant introduced in the formation is carbon dioxide. The carbon dioxide reacts with the brine solution to produce dawsonite. The minerals may solidify and form the barrier to the flow of formation fluid into or out of the formation.

[0846] In some embodiments, the barrier may be formed around a treatment area using sulfur. Advantageously, elemental sulfur is insoluble in water. Liquid and/or solid sulfur in the formation may form a barrier to formation fluid flow into or out of the treatment area.

[0847] A sulfur barrier may be established in the formation during or before initiation of heating to heat the treatment area of the in situ heat treatment process. In some embodiments, sulfur may be introduced into wellbores in the formation that are located between the treatment area and a first barrier (for example, a low temperature barrier established by freeze wells). The formation adjacent to the wellbores that the sulfur is introduced into may be dewatered. In some embodiments, the formation adjacent to the wellbores that the sulfur is introduced into is heated to facilitate removal of water and to prepare the wellbores and adjacent formation for the introduction of sulfur. The formation adjacent to the wellbores may be heated to a temperature
below the pyrolysis temperature of hydrocarbons in the formation. The formation may be heated so that the temperature of a portion of the formation between two adjacent heaters is influenced by both heaters. In some embodiments, the heat may increase the permeability of the formation so that a first wellbore is in fluid communication with an adjacent wellbore.

[0848] After the formation adjacent to the wellbores is heated, molten sulfur at a temperature below the pyrolysis temperature of hydrocarbons in the formation is introduced into the formation. Over a certain temperature range, the viscosity of molten sulfur increases with increasing temperature. The molten sulfur introduced into the formation may be near the melting temperature of sulfur (about 115 °C) so that the sulfur has a relatively low viscosity (about 4-10 cp). Heaters in the wellbores may be temperature limited heaters with Curie temperatures near the melting temperature of sulfur so that the temperature of the molten sulfur stays relatively constant and below temperatures resulting in the formation of viscous molten sulfur. In some embodiments, the region adjacent to the wellbores may be heated to a temperature above the melting point of sulfur, but below the pyrolysis temperature of hydrocarbons in the formation. The heaters may be turned off and the temperature in the wellbores may be monitored (for example, using a fiber optic temperature monitoring system). When the temperature in the wellbore cools to a temperature near the melting temperature of sulfur, molten sulfur may be introduced into the formation.

[0849] The sulfur introduced into the formation is allowed to flow and diffuse into the formation from the wellbores. As the sulfur enters portions of the formation below the melting temperature, the sulfur solidifies and forms a barrier to fluid flow in the formation. Sulfur may be introduced until the formation is not able to accept additional sulfur. Heating may be stopped, and the formation may be allowed to naturally cool so that the sulfur in the formation solidifies. After introduction of the sulfur, the integrity of the formed barrier may be tested using pulse tests and/or tracer tests.

[0850] A barrier may be formed around the treatment area after the in situ heat treatment process. The sulfur may form a substantially permanent barrier in the formation. In some embodiments, a low temperature barrier formed by freeze wells surrounds the treatment area. Sulfur may be introduced on one or both sides of the low temperature barrier to form a barrier in the formation. The sulfur may be introduced into the formation as vapor or a liquid. As the sulfur approaches the low temperature barrier, the sulfur may condense and/or solidify in the formation to form the barrier.

[0851] In some embodiments, the sulfur may be introduced in the heated portion of the portion. The sulfur may be introduced into the formation through wells located near the perimeter of the treatment area. The temperature of the formation may be hotter than the vaporization
temperature of sulfur (about 445 °C). The sulfur may be introduced as a liquid, vapor or mixed phase fluid. If a part of the introduced sulfur is in the liquid phase, the heat of the formation may vaporize the sulfur. The sulfur may flow outwards from the introduction wells towards cooler portions of the formation. The sulfur may condense and/or solidify in the formation to form the barrier.

[0852] In some embodiments, the Claus reaction may be used to form sulfur in the formation after the in situ heat treatment process. The Claus reaction is a gas phase equilibrium reaction. The Claus reaction is:

\[
4\text{H}_2\text{S} + 2\text{SO}_2 \leftrightarrow 3\text{S}_2 + 4\text{H}_2\text{O}
\]  

[0853] Hydrogen sulfide may be obtained by separating the hydrogen sulfide from the produced fluid of an ongoing in situ heat treatment process. A portion of the hydrogen sulfide may be burned to form the needed sulfur dioxide. Hydrogen sulfide may be introduced into the formation through a number of wells in the formation. Sulfur dioxide may be introduced into the formation through other wells. The wells used for injecting sulfur dioxide or hydrogen sulfide may have been production wells, heater wells, monitor wells or other type of well during the in situ heat treatment process. The wells used for injecting sulfur dioxide or hydrogen sulfide may be near the perimeter of the treatment area. The number of wells may be enough so that the formation in the vicinity of the injection wells does not cool to a point where the sulfur dioxide and the hydrogen sulfide can form sulfur and condense, rather than remain in the vapor phase. The wells used to introduce the sulfur dioxide into the formation may also be near the perimeter of the treatment area. In some embodiments, the hydrogen sulfide and sulfur dioxide may be introduced into the formation through the same wells (for example, through two conduits positioned in the same wellbore). The hydrogen sulfide and the sulfur dioxide may react in the formation to form sulfur and water. The sulfur may flow outwards in the formation and condense and/or solidify to form the barrier in the formation.

[0854] The sulfur barrier may form in the formation beyond the area where hydrocarbons in formation fluid generated by the heat treatment process condense in the formation. Regions near the perimeter of the treated area may be at lower temperatures than the treated area. Sulfur may condense and/or solidify from the vapor phase in these lower temperature regions. Additional hydrogen sulfide, and/or sulfur dioxide may diffuse to these lower temperature regions. Additional sulfur may form by the Claus reaction to maintain an equilibrium concentration of sulfur in the vapor phase. Eventually, a sulfur barrier may form around the treated zone. The vapor phase in the treated region may remain as an equilibrium mixture of sulfur, hydrogen sulfide, sulfur dioxide, water vapor and other vapor products present or evolving from the formation.
[0855] The conversion to sulfur is favored at lower temperatures, so the conversion of hydrogen sulfide and sulfur dioxide to sulfur may take place a distance away from the wells that introduce the reactants into the formation. The Claus reaction may result in the formation of sulfur where the temperature of the formation is cooler (for example where the temperature of the formation is at temperatures from about 180 °C to about 240 °C).

[0856] A temperature monitoring system may be installed in wellbores of freeze wells and/or in monitor wells adjacent to the freeze wells to monitor the temperature profile of the freeze wells and/or the low temperature zone established by the freeze wells. The monitoring system may be used to monitor progress of low temperature zone formation. The monitoring system may be used to determine the location of high temperature areas, potential breakthrough locations, or breakthrough locations after the low temperature zone has formed. Periodic monitoring of the temperature profile of the freeze wells and/or low temperature zone established by the freeze wells may allow additional cooling to be provided to potential trouble areas before breakthrough occurs. Additional cooling may be provided at or adjacent to breakthroughs and high temperature areas to ensure the integrity of the low temperature zone around the treatment area. Additional cooling may be provided by increasing refrigerant flow through selected freeze wells, installing an additional freeze well or freeze wells, and/or by providing a cryogenic fluid, such as liquid nitrogen, to the high temperature areas. Providing additional cooling to potential problem areas before breakthrough occurs may be more time efficient and cost efficient than sealing a breach, reheating a portion of the treatment area that has been cooled by influx of fluid, and/or remediating an area outside of the breached frozen barrier.

[0857] In some embodiments, a traveling thermocouple may be used to monitor the temperature profile of selected freeze wells or monitor wells. In some embodiments, the temperature monitoring system includes thermocouples placed at discrete locations in the wellbores of the freeze wells, in the freeze wells, and/or in the monitoring wells. In some embodiments, the temperature monitoring system comprises a fiber optic temperature monitoring system.

[0858] Fiber optic temperature monitoring systems are available from Sensorset (London, United Kingdom), Sensa (Houston, Texas, U.S.A.), Luna Energy (Blacksburg, Virginia, U.S.A.), Lios Technology GMBH (Cologne, Germany), Oxford Electronics Ltd. (Hampshire, United Kingdom), and Sabeus Sensor Systems (Calabasas, California, U.S.A.). The fiber optic temperature monitoring system includes a data system and one or more fiber optic cables. The data system includes one or more lasers for sending light to the fiber optic cable; and one or more computers, software and peripherals for receiving, analyzing, and outputting data. The data system may be coupled to one or more fiber optic cables.
A single fiber optic cable may be several kilometers long. The fiber optic cable may be installed in many freeze wells and/or monitor wells. In some embodiments, two fiber optic cables may be installed in each freeze well and/or monitor well. The two fiber optic cables may be coupled. Using two fiber optic cables per well allows for compensation due to optical losses that occur in the wells and allows for better accuracy of measured temperature profiles.

The fiber optic temperature monitoring system may be used to detect the location of a breach or a potential breach in a frozen barrier. The search for potential breaches may be performed at scheduled intervals, for example, every two or three months. To determine the location of the breach or potential breach, flow of formation refrigerant to the freeze wells of interest is stopped. In some embodiments, the flow of formation refrigerant to all of the freeze wells is stopped. The rise in the temperature profiles, as well as the rate of change of the temperature profiles, provided by the fiber optic temperature monitoring system for each freeze well can be used to determine the location of any breaches or hot spots in the low temperature zone maintained by the freeze wells. The temperature profile monitored by the fiber optic temperature monitoring system for the two freeze wells closest to the hot spot or fluid flow will show the quickest and greatest rise in temperature. A temperature change of a few degrees Centigrade in the temperature profiles of the freeze wells closest to a troubled area may be sufficient to isolate the location of the trouble area. The shut down time of flow of circulation fluid in the freeze wells of interest needed to detect breaches, potential breaches, and hot spots may be on the order of a few hours or days, depending on the well spacing and the amount of fluid flow affecting the low temperature zone.

Fiber optic temperature monitoring systems may also be used to monitor temperatures in heated portions of the formation during in situ heat treatment processes. Temperature monitoring systems positioned in production wells, heater wells, injection wells, and/or monitor wells may be used to measure temperature profiles in treatment areas subjected to in situ heat treatment processes. The fiber of a fiber optic cable used in the heated portion of the formation may be clad with a reflective material to facilitate retention of a signal or signals transmitted down the fiber. In some embodiments, the fiber is clad with gold, copper, nickel, aluminum and/or alloys thereof. The cladding may be formed of a material that is able to withstand chemical and temperature conditions in the heated portion of the formation. For example, gold cladding may allow an optical sensor to be used up to temperatures of 700 °C. In some embodiments, the fiber is clad with aluminum. The fiber may be dipped in or run through a bath of liquid aluminum. The clad fiber may then be allowed to cool to secure the aluminum to the fiber. The gold or aluminum cladding may reduce hydrogen darkening of the optical fiber.
[0862] A potential source of heat loss from the heated formation is due to reflux in wells. Refluxing occurs when vapors condense in a well and flow into a portion of the well adjacent to the heated portion of the formation. Vapors may condense in the well adjacent to the overburden of the formation to form condensed fluid. Condensed fluid flowing into the well adjacent to the heated formation absorbs heat from the formation. Heat absorbed by condensed fluids cools the formation and necessitates additional energy input into the formation to maintain the formation at a desired temperature. Some fluids that condense in the overburden and flow into the portion of the well adjacent to the heated formation may react to produce undesired compounds and/or coke. Inhibiting fluids from refluxing may significantly improve the thermal efficiency of the in situ heat treatment system and/or the quality of the product produced from the in situ heat treatment system.

[0863] For some well embodiments, the portion of the well adjacent to the overburden section of the formation is cemented to the formation. In some well embodiments, the well includes packing material placed near the transition from the heated section of the formation to the overburden. The packing material inhibits formation fluid from passing from the heated section of the formation into the section of the wellbore adjacent to the overburden. Cables, conduits, devices, and/or instruments may pass through the packing material, but the packing material inhibits formation fluid from passing up the wellbore adjacent to the overburden section of the formation.

[0864] In some embodiments, one or more baffle systems may be placed in the wellbores to inhibit reflux. The baffle systems may be obstructions to fluid flow into the heated portion of the formation. In some embodiments, refluxing fluid may revaporize on the baffle system before coming into contact with the heated portion of the formation.

[0865] In some embodiments, a gas may be introduced into the formation through wellbores to inhibit reflux in the wellbores. In some embodiments, gas may be introduced into wellbores that include baffle systems to inhibit reflux of fluid in the wellbores. The gas may be carbon dioxide, methane, nitrogen or other desired gas. In some embodiments, the introduction of gas may be used in conjunction with one or more baffle systems in the wellbores. The introduced gas may enhance heat exchange at the baffle systems to help maintain top portions of the baffle systems colder than the lower portions of the baffle systems.

[0866] The flow of production fluid up the well to the surface is desired for some types of wells, especially for production wells. Flow of production fluid up the well is also desirable for some heater wells that are used to control pressure in the formation. The overburden, or a conduit in the well used to transport formation fluid from the heated portion of the formation to the surface, may be heated to inhibit condensation on or in the conduit. Providing heat in the overburden,
however, may be costly and/or may lead to increased cracking or coking of formation fluid as the formation fluid is being produced from the formation.

[0867] To avoid the need to heat the overburden or to heat the conduit passing through the overburden, one or more diverters may be placed in the wellbore to inhibit fluid from refluxing into the wellbore adjacent to the heated portion of the formation. In some embodiments, the diverter retains fluid above the heated portion of the formation. Fluids retained in the diverter may be removed from the diverter using a pump, gas lifting, and/or other fluid removal technique. In certain embodiments, two or more diverters that retain fluid above the heated portion of the formation may be located in the production well. Two or more diverters provide a simple way of separating initial fractions of condensed fluid produced from the in situ heat treatment system. A pump may be placed in each of the diverters to remove condensed fluid from the diverters.

[0868] In some embodiments, the diverter directs fluid to a sump below the heated portion of the formation. An inlet for a lift system may be located in the sump. In some embodiments, the intake of the lift system is located in casing in the sump. In some embodiments, the intake of the lift system is located in an open wellbore. The sump is below the heated portion of the formation. The intake of the pump may be located 1 m, 5 m, 10 m, 20 m or more below the deepest heater used to heat the heated portion of the formation. The sump may be at a cooler temperature than the heated portion of the formation. The sump may be more than 10 °C, more than 50 °C, more than 75 °C, or more than 100 °C below the temperature of the heated portion of the formation. A portion of the fluid entering the sump may be liquid. A portion of the fluid entering the sump may condense within the sump. The lift system moves the fluid in the sump to the surface.

[0869] Production well lift systems may be used to efficiently transport formation fluid from the bottom of the production wells to the surface. Production well lift systems may provide and maintain the maximum required well drawdown (minimum reservoir producing pressure) and producing rates. The production well lift systems may operate efficiently over a wide range of high temperature/multiphase fluids (gas/vapor/steam/water/hydrocarbon liquids) and production rates expected during the life of a typical project. Production well lift systems may include dual concentric rod pump lift systems, chamber lift systems and other types of lift systems.

[0870] Temperature limited heaters may be in configurations and/or may include materials that provide automatic temperature limiting properties for the heater at certain temperatures. In certain embodiments, ferromagnetic materials are used in temperature limited heaters. Ferromagnetic material may self-limit temperature at or near the Curie temperature of the material and/or the phase transformation temperature range to provide a reduced amount of heat
when a time-varying current is applied to the material. In certain embodiments, the ferromagnetic material self-limits temperature of the temperature limited heater at a selected temperature that is approximately the Curie temperature and/or in the phase transformation temperature range. In certain embodiments, the selected temperature is within about 35 °C, within about 25 °C, within about 20 °C, or within about 10 °C of the Curie temperature and/or the phase transformation temperature range. In certain embodiments, ferromagnetic materials are coupled with other materials (for example, highly conductive materials, high strength materials, corrosion resistant materials, or combinations thereof) to provide various electrical and/or mechanical properties. Some parts of the temperature limited heater may have a lower resistance (caused by different geometries and/or by using different ferromagnetic and/or non-ferromagnetic materials) than other parts of the temperature limited heater. Having parts of the temperature limited heater with various materials and/or dimensions allows for tailoring the desired heat output from each part of the heater.

[0871] Temperature limited heaters may be more reliable than other heaters. Temperature limited heaters may be less apt to break down or fail due to hot spots in the formation. In some embodiments, temperature limited heaters allow for substantially uniform heating of the formation. In some embodiments, temperature limited heaters are able to heat the formation more efficiently by operating at a higher average heat output along the entire length of the heater. The temperature limited heater operates at the higher average heat output along the entire length of the heater because power to the heater does not have to be reduced to the entire heater, as is the case with typical constant wattage heaters, if a temperature along any point of the heater exceeds, or is about to exceed, a maximum operating temperature of the heater. Heat output from portions of a temperature limited heater approaching a Curie temperature and/or the phase transformation temperature range of the heater automatically reduces without controlled adjustment of the time-varying current applied to the heater. The heat output automatically reduces due to changes in electrical properties (for example, electrical resistance) of portions of the temperature limited heater. Thus, more power is supplied by the temperature limited heater during a greater portion of a heating process.

[0872] In certain embodiments, the system including temperature limited heaters initially provides a first heat output and then provides a reduced (second heat output) heat output, near, at, or above the Curie temperature and/or the phase transformation temperature range of an electrically resistive portion of the heater when the temperature limited heater is energized by a time-varying current. The first heat output is the heat output at temperatures below which the temperature limited heater begins to self-limit. In some embodiments, the first heat output is the heat output at a temperature about 50 °C, about 75 °C, about 100 °C, or about 125 °C below the
Curie temperature and/or the phase transformation temperature range of the ferromagnetic material in the temperature limited heater.

[0873] The temperature limited heater may be energized by time-varying current (alternating current or modulated direct current) supplied at the wellhead. The wellhead may include a power source and other components (for example, modulation components, transformers, and/or capacitors) used in supplying power to the temperature limited heater. The temperature limited heater may be one of many heaters used to heat a portion of the formation.

[0874] In certain embodiments, the temperature limited heater includes a conductor that operates as a skin effect or proximity effect heater when time-varying current is applied to the conductor. The skin effect limits the depth of current penetration into the interior of the conductor. For ferromagnetic materials, the skin effect is dominated by the magnetic permeability of the conductor. The relative magnetic permeability of ferromagnetic materials is typically between 10 and 1000 (for example, the relative magnetic permeability of ferromagnetic materials is typically at least 10 and may be at least 50, 100, 500, 1000 or greater). As the temperature of the ferromagnetic material is raised above the Curie temperature, or the phase transformation temperature range, and/or as the applied electrical current is increased, the magnetic permeability of the ferromagnetic material decreases substantially and the skin depth expands rapidly (for example, the skin depth expands as the inverse square root of the magnetic permeability). The reduction in magnetic permeability results in a decrease in the AC or modulated DC resistance of the conductor near, at, or above the Curie temperature, the phase transformation temperature range, and/or as the applied electrical current is increased. When the temperature limited heater is powered by a substantially constant current source, portions of the heater that approach, reach, or are above the Curie temperature and/or the phase transformation temperature range may have reduced heat dissipation. Sections of the temperature limited heater that are not at or near the Curie temperature and/or the phase transformation temperature range may be dominated by skin effect heating that allows the heater to have high heat dissipation due to a higher resistive load.

[0875] Curie temperature heaters have been used in soldering equipment, heaters for medical applications, and heating elements for ovens (for example, pizza ovens). Some of these uses are disclosed in U.S. Patent Nos. 5,579,575 to Lamome et al.; 5,065,501 to Henschen et al.; and 5,512,732 to Yagnik et al. U.S. Patent No. 4,849,611 to Whitney et al. describes a plurality of discrete, spaced-apart heating units including a reactive component, a resistive heating component, and a temperature responsive component.

[0876] An advantage of using the temperature limited heater to heat hydrocarbons in the formation is that the conductor is chosen to have a Curie temperature and/or a phase transformation temperature range in a desired range of temperature operation. Operation within
the desired operating temperature range allows substantial heat injection into the formation while maintaining the temperature of the temperature limited heater, and other equipment, below design limit temperatures. Design limit temperatures are temperatures at which properties such as corrosion, creep, and/or deformation are adversely affected. The temperature limiting properties of the temperature limited heater inhibit overheating or burnout of the heater adjacent to low thermal conductivity “hot spots” in the formation. In some embodiments, the temperature limited heater is able to lower or control heat output and/or withstand heat at temperatures above 25 °C, 37 °C, 100 °C, 250 °C, 500 °C, 700 °C, 800 °C, 900 °C, or higher up to 1131 °C, depending on the materials used in the heater.

[0877] The temperature limited heater allows for more heat injection into the formation than constant wattage heaters because the energy input into the temperature limited heater does not have to be limited to accommodate low thermal conductivity regions adjacent to the heater. For example, in Green River oil shale there is a difference of at least a factor of 3 in the thermal conductivity of the lowest richness oil shale layers and the highest richness oil shale layers. When heating a formation, substantially more heat is transferred to the formation with the temperature limited heater than with the conventional heater that is limited by the temperature at low thermal conductivity layers. The heat output along the entire length of the conventional heater needs to accommodate the low thermal conductivity layers so that the heater does not overheat at the low thermal conductivity layers and burn out. The heat output adjacent to the low thermal conductivity layers that are at high temperature will reduce for the temperature limited heater, but the remaining portions of the temperature limited heater that are not at high temperature will still provide high heat output. Because heaters for heating hydrocarbon formations typically have long lengths (for example, at least 10 m, 100 m, 300 m, 500 m, 1 km or more up to about 10 km), the majority of the length of the temperature limited heater may be operating below the Curie temperature and/or the phase transformation temperature range while only a few portions are at or near the Curie temperature and/or the phase transformation temperature range of the temperature limited heater.

[0878] The use of temperature limited heaters allows for efficient transfer of heat to the formation. Efficient transfer of heat allows for reduction in time needed to heat the formation to a desired temperature. For example, in Green River oil shale, pyrolysis typically requires 9.5 years to 10 years of heating when using a 12 m heater well spacing with conventional constant wattage heaters. For the same heater spacing, temperature limited heaters may allow a larger average heat output while maintaining heater equipment temperatures below equipment design limit temperatures. Pyrolysis in the formation may occur at an earlier time with the larger average heat output provided by temperature limited heaters than the lower average heat output.
provided by constant wattage heaters. For example, in Green River oil shale, pyrolysis may occur in 5 years using temperature limited heaters with a 12 m heater well spacing. Temperature limited heaters counteract hot spots due to inaccurate well spacing or drilling where heater wells come too close together. In certain embodiments, temperature limited heaters allow for increased power output over time for heater wells that have been spaced too far apart, or limit power output for heater wells that are spaced too close together. Temperature limited heaters also supply more power in regions adjacent the overburden and underburden to compensate for temperature losses in these regions.

[0879] Temperature limited heaters may be advantageously used in many types of formations. For example, in tar sands formations or relatively permeable formations containing heavy hydrocarbons, temperature limited heaters may be used to provide a controllable low temperature output for reducing the viscosity of fluids, mobilizing fluids, and/or enhancing the radial flow of fluids at or near the wellbore or in the formation. Temperature limited heaters may be used to inhibit excess coke formation due to overheating of the near wellbore region of the formation.

[0880] In some embodiments, the use of temperature limited heaters eliminates or reduces the need for expensive temperature control circuitry. For example, the use of temperature limited heaters eliminates or reduces the need to perform temperature logging and/or the need to use fixed thermocouples on the heaters to monitor potential overheating at hot spots.

[0881] In certain embodiments, phase transformation (for example, crystalline phase transformation or a change in the crystal structure) of materials used in a temperature limited heater change the selected temperature at which the heater self-limits. Ferromagnetic material used in the temperature limited heater may have a phase transformation (for example, a transformation from ferrite to austenite) that decreases the magnetic permeability of the ferromagnetic material. This reduction in magnetic permeability is similar to reduction in magnetic permeability due to the magnetic transition of the ferromagnetic material at the Curie temperature. The Curie temperature is the magnetic transition temperature of the ferrite phase of the ferromagnetic material. The reduction in magnetic permeability results in a decrease in the AC or modulated DC resistance of the temperature limited heater near, at, or above the temperature of the phase transformation and/or the Curie temperature of the ferromagnetic material.

[0882] The phase transformation of the ferromagnetic material may occur over a temperature range. The temperature range of the phase transformation depends on the ferromagnetic material and may vary, for example, over a range of about 5 °C to a range of about 200 °C. Because the phase transformation takes place over a temperature range, the reduction in the magnetic permeability due to the phase transformation takes place over the temperature range.
reduction in magnetic permeability may also occur hysteretically over the temperature range of the phase transformation. In some embodiments, the phase transformation back to the lower temperature phase of the ferromagnetic material is slower than the phase transformation to the higher temperature phase (for example, the transition from austenite back to ferrite is slower than the transition from ferrite to austenite). The slower phase transformation back to the lower temperature phase may cause hysteretic operation of the heater at or near the phase transformation temperature range that allows the heater to slowly increase to higher resistance after the resistance of the heater reduces due to high temperature.

[0883] In some embodiments, the phase transformation temperature range overlaps with the reduction in the magnetic permeability when the temperature approaches the Curie temperature of the ferromagnetic material. The overlap may produce a faster drop in electrical resistance versus temperature than if the reduction in magnetic permeability is solely due to the temperature approaching the Curie temperature. The overlap may also produce hysteretic behavior of the temperature limited heater near the Curie temperature and/or in the phase transformation temperature range.

[0884] In certain embodiments, the hysteretic operation due to the phase transformation is a smoother transition than the reduction in magnetic permeability due to magnetic transition at the Curie temperature. The smoother transition may be easier to control (for example, electrical control using a process control device that interacts with the power supply) than the sharper transition at the Curie temperature. In some embodiments, the Curie temperature is located inside the phase transformation range for selected metallurgies used in temperature limited heaters. This phenomenon provides temperature limited heaters with the smooth transition properties of the phase transformation in addition to a sharp and definite transition due to the reduction in magnetic properties at the Curie temperature. Such temperature limited heaters may be easy to control (due to the phase transformation) while providing finite temperature limits (due to the sharp Curie temperature transition). Using the phase transformation temperature range instead of and/or in addition to the Curie temperature in temperature limited heaters increases the number and range of metallurgies that may be used for temperature limited heaters.

[0885] In certain embodiments, alloy additions are made to the ferromagnetic material to adjust the temperature range of the phase transformation. For example, adding carbon to the ferromagnetic material may increase the phase transformation temperature range and lower the onset temperature of the phase transformation. Adding titanium to the ferromagnetic material may increase the onset temperature of the phase transformation and decrease the phase transformation temperature range. Alloy compositions may be adjusted to provide desired Curie temperature and phase transformation properties for the ferromagnetic material. The alloy
composition of the ferromagnetic material may be chosen based on desired properties for the ferromagnetic material (such as, but not limited to, magnetic permeability transition temperature or temperature range, resistance versus temperature profile, or power output). Addition of titanium may allow higher Curie temperatures to be obtained when adding cobalt to 410 stainless steel by raising the ferrite to austenite phase transformation temperature range to a temperature range that is above, or well above, the Curie temperature of the ferromagnetic material.

[0886] In some embodiments, temperature limited heaters are more economical to manufacture or make than standard heaters. Typical ferromagnetic materials include iron, carbon steel, or ferritic stainless steel. Such materials are inexpensive as compared to nickel-based heating alloys (such as nichrome, Kanthal™ (Bulten-Kanthal AB, Sweden), and/or LOHM™ (Driver-Harris Company, Harrison, New Jersey, U.S.A.)) typically used in insulated conductor (mineral insulated cable) heaters. In one embodiment of the temperature limited heater, the temperature limited heater is manufactured in continuous lengths as an insulated conductor heater to lower costs and improve reliability.

[0887] In some embodiments, the temperature limited heater is placed in the heater well using a coiled tubing rig. A heater that can be coiled on a spool may be manufactured by using metal such as ferritic stainless steel (for example, 409 stainless steel) that is welded using electrical resistance welding (ERW). U.S. Patent 7,032,809 to Hopkins describes forming seam-welded pipe. To form a heater section, a metal strip from a roll is passed through a former where it is shaped into a tubular and then longitudinally welded using ERW.

[0888] In some embodiments, a composite tubular may be formed from the seam-welded tubular. The seam-welded tubular is passed through a second former where a conductive strip (for example, a copper strip) is applied, drawn down tightly on the tubular through a die, and longitudinally welded using ERW. A sheath may be formed by longitudinally welding a support material (for example, steel such as 347H or 347HH) over the conductive strip material. The support material may be a strip rolled over the conductive strip material. An overburden section of the heater may be formed in a similar manner.

[0889] In certain embodiments, the overburden section uses a non-ferromagnetic material such as 304 stainless steel or 316 stainless steel instead of a ferromagnetic material. The heater section and overburden section may be coupled using standard techniques such as butt welding using an orbital welder. In some embodiments, the overburden section material (the non-ferromagnetic material) may be pre-welded to the ferromagnetic material before rolling. The pre-welding may eliminate the need for a separate coupling step (for example, butt welding). In an embodiment, a flexible cable (for example, a furnace cable such as a MGT 1000 furnace cable) may be pulled through the center after forming the tubular heater. An end bushing on the flexible cable may be
welded to the tubular heater to provide an electrical current return path. The tubular heater, including the flexible cable, may be coiled onto a spool before installation into a heater well. In an embodiment, the temperature limited heater is installed using the coiled tubing rig. The coiled tubing rig may place the temperature limited heater in a deformation resistant container in the formation. The deformation resistant container may be placed in the heater well using conventional methods.

[0890] Temperature limited heaters may be used for heating hydrocarbon formations including, but not limited to, oil shale formations, coal formations, tar sands formations, and formations with heavy viscous oils. Temperature limited heaters may also be used in the field of environmental remediation to vaporize or destroy soil contaminants. Embodiments of temperature limited heaters may be used to heat fluids in a wellbore or sub-sea pipeline to inhibit deposition of paraffin or various hydrates. In some embodiments, a temperature limited heater is used for solution mining a subsurface formation (for example, an oil shale or a coal formation). In certain embodiments, a fluid (for example, molten salt) is placed in a wellbore and heated with a temperature limited heater to inhibit deformation and/or collapse of the wellbore. In some embodiments, the temperature limited heater is attached to a sucker rod in the wellbore or is part of the sucker rod itself. In some embodiments, temperature limited heaters are used to heat a near wellbore region to reduce near wellbore oil viscosity during production of high viscosity crude oils and during transport of high viscosity oils to the surface. In some embodiments, a temperature limited heater enables gas lifting of a viscous oil by lowering the viscosity of the oil without coking the oil. Temperature limited heaters may be used in sulfur transfer lines to maintain temperatures between about 110 °C and about 130 °C.

[0891] The ferromagnetic alloy or ferromagnetic alloys used in the temperature limited heater determine the Curie temperature of the heater. Curie temperature data for various metals is listed in “American Institute of Physics Handbook,” Second Edition, McGraw-Hill, pages 5-170 through 5-176. Ferromagnetic conductors may include one or more of the ferromagnetic elements (iron, cobalt, and nickel) and/or alloys of these elements. In some embodiments, ferromagnetic conductors include iron-chromium (Fe-Cr) alloys that contain tungsten (W) (for example, HCM12A and SAVE12 (Sumitomo Metals Co., Japan) and/or iron alloys that contain chromium (for example, Fe-Cr alloys, Fe-Cr-W alloys, Fe-Cr-V (vanadium) alloys, and Fe-Cr-Nb (Nobium) alloys). Of the three main ferromagnetic elements, iron has a Curie temperature of approximately 770 °C; cobalt (Co) has a Curie temperature of approximately 1131 °C; and nickel has a Curie temperature of approximately 358 °C. An iron-cobalt alloy has a Curie temperature higher than the Curie temperature of iron. For example, iron-cobalt alloy with 2% by weight cobalt has a Curie temperature of approximately 800 °C; iron-cobalt alloy with 12% by weight
cobalt has a Curie temperature of approximately 900 °C; and iron-cobalt alloy with 20% by weight cobalt has a Curie temperature of approximately 950 °C. Iron-nickel alloy has a Curie temperature lower than the Curie temperature of iron. For example, iron-nickel alloy with 20% by weight nickel has a Curie temperature of approximately 720 °C, and iron-nickel alloy with 60% by weight nickel has a Curie temperature of approximately 560 °C.

[0892] Some non-ferromagnetic elements used as alloys raise the Curie temperature of iron. For example, an iron-vanadium alloy with 5.9% by weight vanadium has a Curie temperature of approximately 815 °C. Other non-ferromagnetic elements (for example, carbon, aluminum, copper, silicon, and/or chromium) may be alloyed with iron or other ferromagnetic materials to lower the Curie temperature. Non-ferromagnetic materials that raise the Curie temperature may be combined with non-ferromagnetic materials that lower the Curie temperature and alloyed with iron or other ferromagnetic materials to produce a material with a desired Curie temperature and other desired physical and/or chemical properties. In some embodiments, the Curie temperature material is a ferrite such as NiFe₂O₄. In other embodiments, the Curie temperature material is a binary compound such as FeNi₃ or Fe₃Al.

[0893] In some embodiments, the improved alloy includes carbon, cobalt, iron, manganese, silicon, or mixtures thereof. In certain embodiments, the improved alloy includes, by weight: about 0.1% to about 10% cobalt; about 0.1% carbon, about 0.5% manganese, about 0.5% silicon, with the balance being iron. In certain embodiments, the improved alloy includes, by weight: about 0.1% to about 10% cobalt; about 0.1% carbon, about 0.5% manganese, about 0.5% silicon, with the balance being iron.

[0894] In some embodiments, the improved alloy includes chromium, carbon, cobalt, iron, manganese, silicon, titanium, vanadium, or mixtures thereof. In certain embodiments, the improved alloy includes, by weight: about 5% to about 20% cobalt, about 0.1% carbon, about 0.5% manganese, about 0.5% silicon, about 0.1% to about 2% vanadium with the balance being iron. In some embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese, above 0% to about 15% cobalt, above 0% to about 2% vanadium, above 0% to about 1% titanium, with the balance being iron. In some embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese, above 0% to about 2% vanadium, above 0% to about 1% titanium, with the balance being iron. In some embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese,
above 0% to about 15% cobalt, above 0% to about 1% titanium, with the balance being iron. In certain embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese, above 0% to about 15% cobalt, with the balance being iron. The addition of vanadium may allow for use of higher amounts of cobalt in the improved alloy.

[0895] Certain embodiments of temperature limited heaters may include more than one ferromagnetic material. Such embodiments are within the scope of embodiments described herein if any conditions described herein apply to at least one of the ferromagnetic materials in the temperature limited heater.

[0896] Ferromagnetic properties generally decay as the Curie temperature and/or the phase transformation temperature range is approached. The “Handbook of Electrical Heating for Industry” by C. James Erickson (IEEE Press, 1995) shows a typical curve for 1% carbon steel (steel with 1% carbon by weight). The loss of magnetic permeability starts at temperatures above 650 °C and tends to be complete when temperatures exceed 730 °C. Thus, the self-limiting temperature may be somewhat below the actual Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. The skin depth for current flow in 1% carbon steel is 0.132 cm at room temperature and increases to 0.445 cm at 720 °C. From 720 °C to 730 °C, the skin depth sharply increases to over 2.5 cm. Thus, a temperature limited heater embodiment using 1% carbon steel begins to self-limit between 650 °C and 730 °C.

[0897] Skin depth generally defines an effective penetration depth of time-varying current into the conductive material. In general, current density decreases exponentially with distance from an outer surface to the center along the radius of the conductor. The depth at which the current density is approximately 1/e of the surface current density is called the skin depth. For a solid cylindrical rod with a diameter much greater than the penetration depth, or for hollow cylinders with a wall thickness exceeding the penetration depth, the skin depth, δ, is:

\[
\delta = 1981.5 \times \left( \frac{\rho}{\mu \cdot f} \right)^{1/2};
\]

in which:

- \( \delta \) = skin depth in inches;
- \( \rho \) = resistivity at operating temperature (ohm-cm);
- \( \mu \) = relative magnetic permeability; and
- \( f \) = frequency (Hz).

EQN. 3 is obtained from “Handbook of Electrical Heating for Industry” by C. James Erickson (IEEE Press, 1995). For most metals, resistivity (\( \rho \)) increases with temperature. The relative magnetic permeability generally varies with temperature and with current. Additional equations may be used to assess the variance of magnetic permeability and/or skin depth on both
temperature and/or current. The dependence of \( \mu \) on current arises from the dependence of \( \mu \) on the electromagnetic field.

[0898] Materials used in the temperature limited heater may be selected to provide a desired turndown ratio. Turndown ratios of at least 1.1:1, 2:1, 3:1, 4:1, 5:1, 10:1, 30:1, or 50:1 may be selected for temperature limited heaters. Larger turndown ratios may also be used. A selected turndown ratio may depend on a number of factors including, but not limited to, the type of formation in which the temperature limited heater is located (for example, a higher turndown ratio may be used for an oil shale formation with large variations in thermal conductivity between rich and lean oil shale layers) and/or a temperature limit of materials used in the wellbore (for example, temperature limits of heater materials). In some embodiments, the turndown ratio is increased by coupling additional copper or another good electrical conductor to the ferromagnetic material (for example, adding copper to lower the resistance above the Curie temperature and/or the phase transformation temperature range).

[0899] The temperature limited heater may provide a maximum heat output (power output) below the Curie temperature and/or the phase transformation temperature range of the heater. In certain embodiments, the maximum heat output is at least 400 W/m (Watts per meter), 600 W/m, 700 W/m, 800 W/m, or higher up to 2000 W/m. The temperature limited heater reduces the amount of heat output by a section of the heater when the temperature of the section of the heater approaches or is above the Curie temperature and/or the phase transformation temperature range. The reduced amount of heat may be substantially less than the heat output below the Curie temperature and/or the phase transformation temperature range. In some embodiments, the reduced amount of heat is at most 400 W/m, 200 W/m, 100 W/m or may approach 0 W/m.

[0900] In certain embodiments, the temperature limited heater operates substantially independently of the thermal load on the heater in a certain operating temperature range. "Thermal load" is the rate that heat is transferred from a heating system to its surroundings. It is to be understood that the thermal load may vary with temperature of the surroundings and/or the thermal conductivity of the surroundings. In an embodiment, the temperature limited heater operates at or above the Curie temperature and/or the phase transformation temperature range of the temperature limited heater such that the operating temperature of the heater increases at most by 3 °C, 2 °C, 1.5 °C, 1 °C, or 0.5 °C for a decrease in thermal load of 1 W/m proximate to a portion of the heater. In certain embodiments, the temperature limited heater operates in such a manner at a relatively constant current.

[0901] The AC or modulated DC resistance and/or the heat output of the temperature limited heater may decrease as the temperature approaches the Curie temperature and/or the phase transformation temperature range and decrease sharply near or above the Curie temperature due
to the Curie effect and/or phase transformation effect. In certain embodiments, the value of the electrical resistance or heat output above or near the Curie temperature and/or the phase transformation temperature range is at most one-half of the value of electrical resistance or heat output at a certain point below the Curie temperature and/or the phase transformation temperature range. In some embodiments, the heat output above or near the Curie temperature and/or the phase transformation temperature range is at most 90%, 70%, 50%, 30%, 20%, 10%, or less (down to 1%) of the heat output at a certain point below the Curie temperature and/or the phase transformation temperature range (for example, 30 °C below the Curie temperature, 40 °C below the Curie temperature, 50 °C below the Curie temperature, or 100 °C below the Curie temperature). In certain embodiments, the electrical resistance above or near the Curie temperature and/or the phase transformation temperature range decreases to 80%, 70%, 60%, 50%, or less (down to 1%) of the electrical resistance at a certain point below the Curie temperature and/or the phase transformation temperature range (for example, 30 °C below the Curie temperature, 40 °C below the Curie temperature, 50 °C below the Curie temperature, or 100 °C below the Curie temperature).

[0902] In some embodiments, AC frequency is adjusted to change the skin depth of the ferromagnetic material. For example, the skin depth of 1% carbon steel at room temperature is 0.132 cm at 60 Hz, 0.0762 cm at 180 Hz, and 0.046 cm at 440 Hz. Since heater diameter is typically larger than twice the skin depth, using a higher frequency (and thus a heater with a smaller diameter) reduces heater costs. For a fixed geometry, the higher frequency results in a higher turndown ratio. The turndown ratio at a higher frequency is calculated by multiplying the turndown ratio at a lower frequency by the square root of the higher frequency divided by the lower frequency. In some embodiments, a frequency between 100 Hz and 1000 Hz, between 140 Hz and 200 Hz, or between 400 Hz and 600 Hz is used (for example, 180 Hz, 540 Hz, or 720 Hz). In some embodiments, high frequencies may be used. The frequencies may be greater than 1000 Hz.

[0903] To maintain a substantially constant skin depth until the Curie temperature and/or the phase transformation temperature range of the temperature limited heater is reached, the heater may be operated at a lower frequency when the heater is cold and operated at a higher frequency when the heater is hot. Line frequency heating is generally favorable, however, because there is less need for expensive components such as power supplies, transformers, or current modulators that alter frequency. Line frequency is the frequency of a general supply of current. Line frequency is typically 60 Hz, but may be 50 Hz or another frequency depending on the source for the supply of the current. Higher frequencies may be produced using commercially available equipment such as solid state variable frequency power supplies. Transformers that convert
three-phase power to single-phase power with three times the frequency are commercially available. For example, high voltage three-phase power at 60 Hz may be transformed to single-phase power at 180 Hz and at a lower voltage. Such transformers are less expensive and more energy efficient than solid state variable frequency power supplies. In certain embodiments, transformers that convert three-phase power to single-phase power are used to increase the frequency of power supplied to the temperature limited heater.

[0904] In certain embodiments, modulated DC (for example, chopped DC, waveform modulated DC, or cycled DC) may be used for providing electrical power to the temperature limited heater. A DC modulator or DC chopper may be coupled to a DC power supply to provide an output of modulated direct current. In some embodiments, the DC power supply may include means for modulating DC. One example of a DC modulator is a DC-to-DC converter system. DC-to-DC converter systems are generally known in the art. DC is typically modulated or chopped into a desired waveform. Waveforms for DC modulation include, but are not limited to, square-wave, sinusoidal, deformed sinusoidal, deformed square-wave, triangular, and other regular or irregular waveforms.

[0905] The modulated DC waveform generally defines the frequency of the modulated DC. Thus, the modulated DC waveform may be selected to provide a desired modulated DC frequency. The shape and/or the rate of modulation (such as the rate of chopping) of the modulated DC waveform may be varied to vary the modulated DC frequency. DC may be modulated at frequencies that are higher than generally available AC frequencies. For example, modulated DC may be provided at frequencies of at least 1000 Hz. Increasing the frequency of supplied current to higher values advantageously increases the turndown ratio of the temperature limited heater.

[0906] In certain embodiments, the modulated DC waveform is adjusted or altered to vary the modulated DC frequency. The DC modulator may be able to adjust or alter the modulated DC waveform at any time during use of the temperature limited heater and at high currents or voltages. Thus, modulated DC provided to the temperature limited heater is not limited to a single frequency or even a small set of frequency values. Waveform selection using the DC modulator typically allows for a wide range of modulated DC frequencies and for discrete control of the modulated DC frequency. Thus, the modulated DC frequency is more easily set at a distinct value whereas AC frequency is generally limited to multiples of the line frequency. Discrete control of the modulated DC frequency allows for more selective control over the turndown ratio of the temperature limited heater. Being able to selectively control the turndown ratio of the temperature limited heater allows for a broader range of materials to be used in designing and constructing the temperature limited heater.
In some embodiments, the modulated DC frequency or the AC frequency is adjusted to compensate for changes in properties (for example, subsurface conditions such as temperature or pressure) of the temperature limited heater during use. The modulated DC frequency or the AC frequency provided to the temperature limited heater is varied based on assessed downhole conditions. For example, as the temperature of the temperature limited heater in the wellbore increases, it may be advantageous to increase the frequency of the current provided to the heater, thus increasing the turndown ratio of the heater. In an embodiment, the downhole temperature of the temperature limited heater in the wellbore is assessed.

In certain embodiments, the modulated DC frequency, or the AC frequency, is varied to adjust the turndown ratio of the temperature limited heater. The turndown ratio may be adjusted to compensate for hot spots occurring along a length of the temperature limited heater. For example, the turndown ratio is increased because the temperature limited heater is getting too hot in certain locations. In some embodiments, the modulated DC frequency, or the AC frequency, are varied to adjust a turndown ratio without assessing a subsurface condition.

At or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic material, a relatively small change in voltage may cause a relatively large change in current to the load. The relatively small change in voltage may produce problems in the power supplied to the temperature limited heater, especially at or near the Curie temperature and/or the phase transformation temperature range. The problems include, but are not limited to, reducing the power factor, tripping a circuit breaker, and/or blowing a fuse. In some cases, voltage changes may be caused by a change in the load of the temperature limited heater. In certain embodiments, an electrical current supply (for example, a supply of modulated DC or AC) provides a relatively constant amount of current that does not substantially vary with changes in load of the temperature limited heater. In an embodiment, the electrical current supply provides an amount of electrical current that remains within 15%, within 10%, within 5%, or within 2% of a selected constant current value when a load of the temperature limited heater changes.

Temperature limited heaters may generate an inductive load. The inductive load is due to some applied electrical current being used by the ferromagnetic material to generate a magnetic field in addition to generating a resistive heat output. As downhole temperature changes in the temperature limited heater, the inductive load of the heater changes due to changes in the ferromagnetic properties of ferromagnetic materials in the heater with temperature. The inductive load of the temperature limited heater may cause a phase shift between the current and the voltage applied to the heater.

A reduction in actual power applied to the temperature limited heater may be caused by a time lag in the current waveform (for example, the current has a phase shift relative to the voltage...
due to an inductive load) and/or by distortions in the current waveform (for example, distortions in the current waveform caused by introduced harmonics due to a non-linear load). Thus, it may take more current to apply a selected amount of power due to phase shifting or waveform distortion. The ratio of actual power applied and the apparent power that would have been transmitted if the same current were in phase and undistorted is the power factor. The power factor is always less than or equal to 1. The power factor is 1 when there is no phase shift or distortion in the waveform.

[0912] Actual power applied to a heater due to a phase shift may be described by EQN. 4:

\[
P = I \times V \times \cos(\theta);
\]

(EQN. 4)

in which P is the actual power applied to a heater; I is the applied current; V is the applied voltage; and \( \theta \) is the phase angle difference between voltage and current. Other phenomena such as waveform distortion may contribute to further lowering of the power factor. If there is no distortion in the waveform, then \( \cos(\theta) \) is equal to the power factor.

[0913] In certain embodiments, the temperature limited heater includes an inner conductor inside an outer conductor. The inner conductor and the outer conductor are radially disposed about a central axis. The inner and outer conductors may be separated by an insulation layer. In certain embodiments, the inner and outer conductors are coupled at the bottom of the temperature limited heater. Electrical current may flow into the temperature limited heater through the inner conductor and return through the outer conductor. One or both conductors may include ferromagnetic material.

[0914] The insulation layer may comprise an electrically insulating ceramic with high thermal conductivity, such as magnesium oxide, aluminum oxide, silicon dioxide, beryllium oxide, boron nitride, silicon nitride, or combinations thereof. The insulating layer may be a compacted powder (for example, compacted ceramic powder). Compaction may improve thermal conductivity and provide better insulation resistance. For lower temperature applications, polymer insulation made from, for example, fluoropolymers, polyimides, polyamides, and/or polyethylenes, may be used. In some embodiments, the polymer insulation is made of perfluoroalkoxy (PFA) or polyetheretherketone (PEEK™ (Vicrrex Ltd, England)). The insulating layer may be chosen to be substantially infrared transparent to aid heat transfer from the inner conductor to the outer conductor. In an embodiment, the insulating layer is transparent quartz sand. The insulation layer may be air or a non-reactive gas such as helium, nitrogen, or sulfur hexafluoride. If the insulation layer is air or a non-reactive gas, there may be insulating spacers designed to inhibit electrical contact between the inner conductor and the outer conductor. The insulating spacers may be made of, for example, high purity aluminum oxide or another thermally conducting, electrically insulating material such as silicon nitride. The
insulating spacers may be a fibrous ceramic material such as Nextel™ 312 (3M Corporation, St. Paul, Minnesota, U.S.A.), mica tape, or glass fiber. Ceramic material may be made of alumina, alumina-silicate, alumina-borosilicate, silicon nitride, boron nitride, or other materials.

[0915] The insulation layer may be flexible and/or substantially deformation tolerant. For example, if the insulation layer is a solid or compacted material that substantially fills the space between the inner and outer conductors, the temperature limited heater may be flexible and/or substantially deformation tolerant. Forces on the outer conductor can be transmitted through the insulation layer to the solid inner conductor, which may resist crushing. Such a temperature limited heater may be bent, dog-legged, and spiraled without causing the outer conductor and the inner conductor to electrically short to each other. Deformation tolerance may be important if the wellbore is likely to undergo substantial deformation during heating of the formation.

[0916] In certain embodiments, an outermost layer of the temperature limited heater (for example, the outer conductor) is chosen for corrosion resistance, yield strength, and/or creep resistance. In one embodiment, austenitic (non-ferromagnetic) stainless steels such as 201, 304H, 347H, 347HH, 316H, 310H, 347HP, NF709 (Nippon Steel Corp., Japan) stainless steels, or combinations thereof may be used in the outer conductor. The outermost layer may also include a clad conductor. For example, a corrosion resistant alloy such as 800H or 347H stainless steel may be clad for corrosion protection over a ferromagnetic carbon steel tubular. If high temperature strength is not required, the outermost layer may be constructed from ferromagnetic metal with good corrosion resistance such as one of the ferritic stainless steels. In one embodiment, a ferritic alloy of 82.3% by weight iron with 17.7% by weight chromium (Curie temperature of 678 °C) provides desired corrosion resistance.

[0917] The Metals Handbook, vol. 8, page 291 (American Society of Materials (ASM)) includes a graph of Curie temperature of iron-chromium alloys versus the amount of chromium in the alloys. In some temperature limited heater embodiments, a separate support rod or tubular (made from 347H stainless steel) is coupled to the temperature limited heater made from an iron-chromium alloy to provide yield strength and/or creep resistance. In certain embodiments, the support material and/or the ferromagnetic material is selected to provide a 100,000 hour creep-rupture strength of at least 20.7 MPa at 650 °C. In some embodiments, the 100,000 hour creep-rupture strength is at least 13.8 MPa at 650 °C or at least 6.9 MPa at 650 °C. For example, 347H steel has a favorable creep-rupture strength at or above 650 °C. In some embodiments, the 100,000 hour creep-rupture strength ranges from 6.9 MPa to 41.3 MPa or more for longer heaters and/or higher earth or fluid stresses.

[0918] In temperature limited heater embodiments with both an inner ferromagnetic conductor and an outer ferromagnetic conductor, the skin effect current path occurs on the outside of the
inner conductor and on the inside of the outer conductor. Thus, the outside of the outer conductor may be clad with the corrosion resistant alloy, such as stainless steel, without affecting the skin effect current path on the inside of the outer conductor.

[0919] A ferromagnetic conductor with a thickness of at least the skin depth at the Curie temperature and/or the phase transformation temperature range allows a substantial decrease in resistance of the ferromagnetic material as the skin depth increases sharply near the Curie temperature and/or the phase transformation temperature range. In certain embodiments when the ferromagnetic conductor is not clad with a highly conducting material such as copper, the thickness of the conductor may be 1.5 times the skin depth near the Curie temperature and/or the phase transformation temperature range, 3 times the skin depth near the Curie temperature and/or the phase transformation temperature range, or even 10 or more times the skin depth near the Curie temperature and/or the phase transformation temperature range. If the ferromagnetic conductor is clad with copper, thickness of the ferromagnetic conductor may be substantially the same as the skin depth near the Curie temperature and/or the phase transformation temperature range. In some embodiments, the ferromagnetic conductor clad with copper has a thickness of at least three-fourths of the skin depth near the Curie temperature and/or the phase transformation temperature range.

[0920] In certain embodiments, the temperature limited heater includes a composite conductor with a ferromagnetic tubular and a non-ferromagnetic, high electrical conductivity core. The non-ferromagnetic, high electrical conductivity core reduces a required diameter of the conductor. For example, the conductor may be composite 1.19 cm diameter conductor with a core of 0.575 cm diameter copper clad with a 0.298 cm thickness of ferritic stainless steel or carbon steel surrounding the core. The core or non-ferromagnetic conductor may be copper or copper alloy. The core or non-ferromagnetic conductor may also be made of other metals that exhibit low electrical resistivity and relative magnetic permeabilities near 1 (for example, substantially non-ferromagnetic materials such as aluminum and aluminum alloys, phosphor bronze, beryllium copper, and/or brass). A composite conductor allows the electrical resistance of the temperature limited heater to decrease more steeply near the Curie temperature and/or the phase transformation temperature range. As the skin depth increases near the Curie temperature and/or the phase transformation temperature range to include the copper core, the electrical resistance decreases very sharply.

[0921] The composite conductor may increase the conductivity of the temperature limited heater and/or allow the heater to operate at lower voltages. In an embodiment, the composite conductor exhibits a relatively flat resistance versus temperature profile at temperatures below a region near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic
conductor of the composite conductor. In some embodiments, the temperature limited heater exhibits a relatively flat resistance versus temperature profile between 100 °C and 750 °C or between 300 °C and 600 °C. The relatively flat resistance versus temperature profile may also be exhibited in other temperature ranges by adjusting, for example, materials and/or the configuration of materials in the temperature limited heater. In certain embodiments, the relative thickness of each material in the composite conductor is selected to produce a desired resistivity versus temperature profile for the temperature limited heater.

[0922] In certain embodiments, the relative thickness of each material in a composite conductor is selected to produce a desired resistivity versus temperature profile for a temperature limited heater. In an embodiment, the composite conductor is an inner conductor surrounded by 0.127 cm thick magnesium oxide powder as an insulator. The outer conductor may be 304H stainless steel with a wall thickness of 0.127 cm. The outside diameter of the heater may be about 1.65 cm.

[0923] A composite conductor (for example, a composite inner conductor or a composite outer conductor) may be manufactured by methods including, but not limited to, coextrusion, roll forming, tight fit tubing (for example, cooling the inner member and heating the outer member, then inserting the inner member in the outer member, followed by a drawing operation and/or allowing the system to cool), explosive or electromagnetic cladding, arc overlay welding, longitudinal strip welding, plasma powder welding, billet coextrusion, electroplating, drawing, sputtering, plasma deposition, coextrusion casting, magnetic forming, molten cylinder casting (of inner core material inside the outer or vice versa), insertion followed by welding or high temperature braising, shielded active gas welding (SAG), and/or insertion of an inner pipe in an outer pipe followed by mechanical expansion of the inner pipe by hydroforming or use of a pig to expand and swage the inner pipe against the outer pipe. In some embodiments, a ferromagnetic conductor is braided over a non-ferromagnetic conductor. In certain embodiments, composite conductors are formed using methods similar to those used for cladding (for example, cladding copper to steel). A metallurgical bond between copper cladding and base ferromagnetic material may be advantageous. Composite conductors produced by a coextrusion process that forms a good metallurgical bond (for example, a good bond between copper and 446 stainless steel) may be provided by Anomet Products, Inc. (Shrewsbury, Massachusetts, U.S.A.).

[0924] In certain embodiments, it may be desirable to form a composite conductor by various methods including longitudinal strip welding. In some embodiments, however, it may be difficult to use longitudinal strip welding techniques if the desired thickness of a layer of a first material has such a large thickness, in relation to the inner core/layer onto which such layer is to be bended, that it does not effectively and/or efficiently bend around an inner core or layer that is
made of a second material. In such circumstances, it may be beneficial to use multiple thinner layers of the first material in the longitudinal strip welding process such that the multiple thinner layers can more readily be employed in a longitudinal strip welding process and coupled together to form a composite of the first material with the desired thickness. So, for example, a first layer of the first material may be bent around an inner core or layer of second material, and then a second layer of the first material may be bent around the first layer of the first material, with the thicknesses of the first and second layers being such that the first and second layers will readily bend around the inner core or layer in a longitudinal strip welding process. Thus, the two layers of the first material may together form the total desired thickness of the first material.

[0925] FIGS. 53-74 depict various embodiments of temperature limited heaters. One or more features of an embodiment of the temperature limited heater depicted in any of these figures may be combined with one or more features of other embodiments of temperature limited heaters depicted in these figures. In certain embodiments described herein, temperature limited heaters are dimensioned to operate at a frequency of 60 Hz AC. It is to be understood that dimensions of the temperature limited heater may be adjusted from those described herein to operate in a similar manner at other AC frequencies or with modulated DC current.

[0926] The temperature limited heaters may be used in conductor-in-conduit heaters. In some embodiments of conductor-in-conduit heaters, the majority of the resistive heat is generated in the conductor, and the heat radiatively, conductively and/or convectively transfers to the conduit. In some embodiments of conductor-in-conduit heaters, the majority of the resistive heat is generated in the conduit.

[0927] FIG. 53 depicts a cross-sectional representation of an embodiment of the temperature limited heater with an outer conductor having a ferromagnetic section and a non-ferromagnetic section. FIGS. 54 and 55 depict transverse cross-sectional views of the embodiment shown in FIG. 53. In one embodiment, ferromagnetic section 528 is used to provide heat to hydrocarbon layers in the formation. Non-ferromagnetic section 530 is used in the overburden of the formation. Non-ferromagnetic section 530 provides little or no heat to the overburden, thus inhibiting heat losses in the overburden and improving heater efficiency. Ferromagnetic section 528 includes a ferromagnetic material such as 409 stainless steel or 410 stainless steel. Ferromagnetic section 528 has a thickness of 0.3 cm. Non-ferromagnetic section 530 is copper with a thickness of 0.3 cm. Inner conductor 532 is copper. Inner conductor 532 has a diameter of 0.9 cm. Electrical insulator 534 is silicon nitride, boron nitride, magnesium oxide powder, or another suitable insulator material. Electrical insulator 534 has a thickness of 0.1 cm to 0.3 cm.

[0928] FIG. 56 depicts a cross-sectional representation of an embodiment of a temperature limited heater with an outer conductor having a ferromagnetic section and a non-ferromagnetic
section placed inside a sheath. FIGS. 57, 58, and 59 depict transverse cross-sectional views of the embodiment shown in FIG. 56. Ferromagnetic section 528 is 410 stainless steel with a thickness of 0.6 cm. Non-ferromagnetic section 530 is copper with a thickness of 0.6 cm. Inner conductor 532 is copper with a diameter of 0.9 cm. Outer conductor 536 includes ferromagnetic material. Outer conductor 536 provides some heat in the overburden section of the heater. Providing some heat in the overburden inhibits condensation or refluxing of fluids in the overburden. Outer conductor 536 is 409, 410, or 446 stainless steel with an outer diameter of 3.0 cm and a thickness of 0.6 cm. Electrical insulator 534 includes compacted magnesium oxide powder with a thickness of 0.3 cm. In some embodiments, electrical insulator 534 includes silicon nitride, boron nitride, or hexagonal type boron nitride. Conductive section 538 may couple inner conductor 532 with ferromagnetic section 528 and/or outer conductor 536.

FIG. 60A and FIG. 60B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic inner conductor. Inner conductor 532 is a 1" Schedule XXS 446 stainless steel pipe. In some embodiments, inner conductor 532 includes 409 stainless steel, 410 stainless steel, Invar 36, alloy 42-6, alloy 52, or other ferromagnetic materials. Inner conductor 532 has a diameter of 2.5 cm. Electrical insulator 534 includes compacted silicon nitride, boron nitride, or magnesium oxide powders; or polymers, Nextel ceramic fiber, mica, or glass fibers. Outer conductor 536 is copper or any other non-ferromagnetic material, such as but not limited to copper alloys, aluminum and/or aluminum alloys. Outer conductor 536 is coupled to jacket 540. Jacket 540 is 304H, 316H, or 347H stainless steel. In this embodiment, a majority of the heat is produced in inner conductor 532.

FIG. 61A and FIG. 61B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic inner conductor and a non-ferromagnetic core. Inner conductor 532 may be made of 446 stainless steel, 409 stainless steel, 410 stainless steel, carbon steel, Armco ingot iron, iron-cobalt alloys, or other ferromagnetic materials. Core 542 may be tightly bonded inside inner conductor 532. Core 542 is copper or other non-ferromagnetic material. In certain embodiments, core 542 is inserted as a tight fit inside inner conductor 532 before a drawing operation. In some embodiments, core 542 and inner conductor 532 are coextrusion bonded. Outer conductor 536 is 347H stainless steel. A drawing or rolling operation to compact electrical insulator 534 (for example, compacted silicon nitride, boron nitride, or magnesium oxide powder) may ensure good electrical contact between inner conductor 532 and core 542. In this embodiment, heat is produced primarily in inner conductor 532 until the Curie temperature and/or the phase transformation temperature range is approached. Resistance then decreases sharply as current penetrates core 542.
FIG. 62A and FIG. 62B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic outer conductor. Inner conductor 532 is nickel-clad copper. Electrical insulator 534 is silicon nitride, boron nitride, or magnesium oxide. Outer conductor 536 is a 1” Schedule XXS carbon steel pipe. In this embodiment, heat is produced primarily in outer conductor 536, resulting in a small temperature differential across electrical insulator 534.

FIG. 63A and FIG. 63B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic outer conductor that is clad with a corrosion resistant alloy. Inner conductor 532 is copper. Outer conductor 536 is a 1” Schedule XXS carbon steel pipe. Outer conductor 536 is coupled to jacket 540. Jacket 540 is made of corrosion resistant material (for example, 347H stainless steel). Jacket 540 provides protection from corrosive fluids in the wellbore (for example, sulfidizing and carburizing gases). Heat is produced primarily in outer conductor 536, resulting in a small temperature differential across electrical insulator 534.

FIG. 64A and FIG. 64B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic outer conductor. The outer conductor is clad with a conductive layer and a corrosion resistant alloy. Inner conductor 532 is copper. Electrical insulator 534 is silicon nitride, boron nitride, or magnesium oxide. Outer conductor 536 is a 1” Schedule 80 446 stainless steel pipe. Outer conductor 536 is coupled to jacket 540. Jacket 540 is made from corrosion resistant material such as 347H stainless steel. In an embodiment, conductive layer 544 is placed between outer conductor 536 and jacket 540. Conductive layer 544 is a copper layer. Heat is produced primarily in outer conductor 536, resulting in a small temperature differential across electrical insulator 534. Conductive layer 544 allows a sharp decrease in the resistance of outer conductor 536 as the outer conductor approaches the Curie temperature and/or the phase transformation temperature range. Jacket 540 provides protection from corrosive fluids in the wellbore.

In certain embodiments, inner conductor 532 includes a core of copper or another non-ferromagnetic conductor surrounded by ferromagnetic material (for example, a low Curie temperature material such as Invar 36). In certain embodiments, the copper core has an outer diameter between about 0.125” and about 0.375” (for example, about 0.5”) and the ferromagnetic material has an outer diameter between about 0.625” and about 1” (for example, about 0.75”). The copper core may increase the turndown ratio of the heater and/or reduce the thickness needed in the ferromagnetic material, which may allow a lower cost heater to be made. Electrical insulator 534 may be magnesium oxide with an outer diameter between about 1” and about 1.2” (for example, about 1.11”). Outer conductor 536 may include non-ferromagnetic electrically
conductive material with high mechanical strength such as 825 stainless steel. Outer conductor 536 may have an outer diameter between about 1.2" and about 1.5" (for example, about 1.33"). In certain embodiments, inner conductor 532 is a forward current path and outer conductor 536 is a return current path. Conductive layer 544 may include copper or another non-ferromagnetic material with an outer diameter between about 1.3" and about 1.4" (for example, about 1.384"). Conductive layer 544 may decrease the resistance of the return current path (to reduce the heat output of the return path such that little or no heat is generated in the return path) and/or increase the turndown ratio of the heater. Conductive layer 544 may reduce the thickness needed in outer conductor 536 and/or jacket 540, which may allow a lower cost heater to be made. Jacket 540 may include ferromagnetic material such as carbon steel or 410 stainless steel with an outer diameter between about 1.6" and about 1.8" (for example, about 1.684"). Jacket 540 may have a thickness of at least 2 times the skin depth of the ferromagnetic material in the jacket. Jacket 540 may provide protection from corrosive fluids in the wellbore. In some embodiments, inner conductor 532, electrical insulator 534, and outer conductor 536 are formed as composite heater (for example, an insulated conductor heater) and conductive layer 544 and jacket 540 are formed around (for example, wrapped) the composite heater and welded together to form the larger heater embodiment described herein.

[0935] In certain embodiments, jacket 540 includes ferromagnetic material that has a higher Curie temperature than ferromagnetic material in inner conductor 532. Such a temperature limited heater may “contain” current such that the current does not easily flow from the heater to the surrounding formation and/or to any surrounding fluids (for example, production fluids, formation fluids, brine, groundwater, or formation water). In this embodiment, a majority of the current flows through inner conductor 532 until the Curie temperature of the ferromagnetic material in the inner conductor is reached. After the Curie temperature of ferromagnetic material in inner conductor 532 is reached, a majority of the current flows through the core of copper in the inner conductor. The ferromagnetic properties of jacket 540 inhibit the current from flowing outside the jacket and “contain” the current. Such a heater may be used in lower temperature applications where fluids are present such as providing heat in a production wellbore to increase oil production.

[0936] In some embodiments, the conductor (for example, an inner conductor, an outer conductor, or a ferromagnetic conductor) is the composite conductor that includes two or more different materials. In certain embodiments, the composite conductor includes two or more ferromagnetic materials. In some embodiments, the composite ferromagnetic conductor includes two or more radially disposed materials. In certain embodiments, the composite conductor includes a ferromagnetic conductor and a non-ferromagnetic conductor. In some embodiments,
the composite conductor includes the ferromagnetic conductor placed over a non-ferromagnetic core. Two or more materials may be used to obtain a relatively flat electrical resistivity versus temperature profile in a temperature region below the Curie temperature, and/or the phase transformation temperature range, and/or a sharp decrease (a high turndown ratio) in the electrical resistivity at or near the Curie temperature and/or the phase transformation temperature range. In some cases, two or more materials are used to provide more than one Curie temperature and/or phase transformation temperature range for the temperature limited heater.

[0937] The composite electrical conductor may be used as the conductor in any electrical heater embodiment described herein. For example, the composite conductor may be used as the conductor in a conductor-in-conduit heater or an insulated conductor heater. In certain embodiments, the composite conductor may be coupled to a support member such as a support conductor. The support member may be used to provide support to the composite conductor so that the composite conductor is not relied upon for strength at or near the Curie temperature and/or the phase transformation temperature range. The support member may be useful for heaters of lengths of at least 100 m. The support member may be a non-ferromagnetic member that has good high temperature creep strength. Examples of materials that are used for a support member include, but are not limited to, Haynes® 625 alloy and Haynes® HR120® alloy (Haynes International, Kokomo, Indiana, U.S.A.), NF709, Incoloy® 800H alloy and 347HP alloy (Allegheny Ludlum Corp., Pittsburgh, Pennsylvania, U.S.A.). In some embodiments, materials in a composite conductor are directly coupled (for example, brazed, metallurgically bonded, or swaged) to each other and/or the support member. Using a support member may reduce the need for the ferromagnetic member to provide support for the temperature limited heater, especially at or near the Curie temperature and/or the phase transformation temperature range. Thus, the temperature limited heater may be designed with more flexibility in the selection of ferromagnetic materials.

[0938] FIG. 65 depicts a cross-sectional representation of an embodiment of the composite conductor with the support member. Core 542 is surrounded by ferromagnetic conductor 546 and support member 548. In some embodiments, core 542, ferromagnetic conductor 546, and support member 548 are directly coupled (for example, brazed together or metallurgically bonded together). In one embodiment, core 542 is copper, ferromagnetic conductor 546 is 446 stainless steel, and support member 548 is 347H alloy. In certain embodiments, support member 548 is a Schedule 80 pipe. Support member 548 surrounds the composite conductor having ferromagnetic conductor 546 and core 542. Ferromagnetic conductor 546 and core 542 may be joined to form the composite conductor by, for example, a coextrusion process. For example, the
composite conductor is a 1.9 cm outside diameter 446 stainless steel ferromagnetic conductor surrounding a 0.95 cm diameter copper core.

[0939] In certain embodiments, the diameter of core 542 is adjusted relative to a constant outside diameter of ferromagnetic conductor 546 to adjust the turndown ratio of the temperature limited heater. For example, the diameter of core 542 may be increased to 1.14 cm while maintaining the outside diameter of ferromagnetic conductor 546 at 1.9 cm to increase the turndown ratio of the heater.

[0940] FIG. 66 depicts a cross-sectional representation of an embodiment of the composite conductor with support member 548 separating the conductors. In one embodiment, core 542 is copper with a diameter of 0.95 cm, support member 548 is 347H alloy with an outside diameter of 1.9 cm, and ferromagnetic conductor 546 is 446 stainless steel with an outside diameter of 2.7 cm. The support member depicted in FIG. 66 has a lower creep strength relative to the support members depicted in FIG. 65.

[0941] In certain embodiments, support member 548 is located inside the composite conductor. FIG. 67 depicts a cross-sectional representation of an embodiment of the composite conductor surrounding support member 548. Support member 548 is made of 347H alloy. Inner conductor 532 is copper. Ferromagnetic conductor 546 is 446 stainless steel. In one embodiment, support member 548 is 1.25 cm diameter 347H alloy, inner conductor 532 is 1.9 cm outside diameter copper, and ferromagnetic conductor 546 is 2.7 cm outside diameter 446 stainless steel. The turndown ratio is higher than the turndown ratio for the embodiments depicted in FIGS. 65, 66, and 68 for the same outside diameter, but the creep strength is lower.

[0942] In some embodiments, the thickness of inner conductor 532, which is copper, is reduced and the thickness of support member 548 is increased to increase the creep strength at the expense of reduced turndown ratio. For example, the diameter of support member 548 is increased to 1.6 cm while maintaining the outside diameter of inner conductor 532 at 1.9 cm to reduce the thickness of the conduit. This reduction in thickness of inner conductor 532 results in a decreased turndown ratio relative to the thicker inner conductor embodiment but an increased creep strength.

[0943] FIG. 68 depicts a cross-sectional representation of an embodiment of the composite conductor surrounding support member 548. In one embodiment, support member 548 is 347H alloy with a 0.63 cm diameter center hole. In some embodiments, support member 548 is a preformed conduit. In certain embodiments, support member 548 is formed by having a dissolvable material (for example, copper dissolvable by nitric acid) located inside the support member during formation of the composite conductor. The dissolvable material is dissolved to form the hole after the conductor is assembled. In an embodiment, support member 548 is 347H
alloy with an inside diameter of 0.63 cm and an outside diameter of 1.6 cm, inner conductor 532 is copper with an outside diameter of 1.8 cm, and ferromagnetic conductor 546 is 446 stainless steel with an outside diameter of 2.7 cm.

[0944] In certain embodiments, the composite electrical conductor is used as the conductor in the conductor-in-conduit heater. For example, the composite electrical conductor may be used as conductor 550 in FIG. 69.

[0945] FIG. 69 depicts a cross-sectional representation of an embodiment of the conductor-in-conduit heater. Conductor 550 is disposed in conduit 552. Conductor 550 is a rod or conduit of electrically conductive material. Low resistance sections 554 are present at both ends of conductor 550 to generate less heating in these sections. Low resistance section 554 is formed by having a greater cross-sectional area of conductor 550 in that section, or the sections are made of material having less resistance. In certain embodiments, low resistance section 554 includes a low resistance conductor coupled to conductor 550.

[0946] Conduit 552 is made of an electrically conductive material. Conduit 552 is disposed in opening 556 in hydrocarbon layer 484. Opening 556 has a diameter that accommodates conduit 552.

[0947] Conductor 550 may be centered in conduit 552 by centralizers 558. Centralizers 558 electrically isolate conductor 550 from conduit 552. Centralizers 558 inhibit movement and properly locate conductor 550 in conduit 552. Centralizers 558 are made of ceramic material or a combination of ceramic and metallic materials. Centralizers 558 inhibit deformation of conductor 550 in conduit 552. Centralizers 558 are touching or spaced at intervals between approximately 0.1 m (meters) and approximately 3 m or more along conductor 550.

[0948] A second low resistance section 554 of conductor 550 may couple conductor 550 to wellhead 476. Electrical current may be applied to conductor 550 from power cable 560 through low resistance section 554 of conductor 550. Electrical current passes from conductor 550 through sliding connector 562 to conduit 552. Conduit 552 may be electrically insulated from overburden casing 564 and from wellhead 476 to return electrical current to power cable 560. Heat may be generated in conductor 550 and conduit 552. The generated heat may radiate in conduit 552 and opening 556 to heat at least a portion of hydrocarbon layer 484.

[0949] Overburden casing 564 may be disposed in overburden 482. In some embodiments, overburden casing 564 is surrounded by materials (for example, reinforcing material and/or cement) that inhibit heating of overburden 482. Low resistance section 554 of conductor 550 may be placed in overburden casing 564. Low resistance section 554 of conductor 550 is made of, for example, carbon steel. Low resistance section 554 of conductor 550 may be centralized in overburden casing 564 using centralizers 558. Centralizers 558 are spaced at intervals of
approximately 6 m to approximately 12 m or, for example, approximately 9 m along low resistance section 554 of conductor 550. In a heater embodiment, low resistance sections 554 are coupled to conductor 550 by one or more welds. In other heater embodiments, low resistance sections are threaded, threaded and welded, or otherwise coupled to the conductor. Low resistance section 554 generates little or no heat in overburden casing 564. Packing 566 may be placed between overburden casing 564 and opening 556. Packing 566 may be used as a cap at the junction of overburden 482 and hydrocarbon layer 484 to allow filling of materials in the annulus between overburden casing 564 and opening 556. In some embodiments, packing 566 inhibits fluid from flowing from opening 556 to surface 568.

[0950] FIG. 70 depicts a cross-sectional representation of an embodiment of a removable conductor-in-conduit heat source. Conduit 552 may be placed in opening 556 through overburden 482 such that a gap remains between the conduit and overburden casing 564. Fluids may be removed from opening 556 through the gap between conduit 552 and overburden casing 564. Fluids may be removed from the gap through conduit 570. Conduit 552 and components of the heat source included in the conduit that are coupled to wellhead 476 may be removed from opening 556 as a single unit. The heat source may be removed as a single unit to be repaired, replaced, and/or used in another portion of the formation.

[0951] For a temperature limited heater in which the ferromagnetic conductor provides a majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range, a majority of the current flows through material with highly non-linear functions of magnetic field (H) versus magnetic induction (B). These non-linear functions may cause strong inductive effects and distortion that lead to decreased power factor in the temperature limited heater at temperatures below the Curie temperature and/or the phase transformation temperature range. These effects may render the electrical power supply to the temperature limited heater difficult to control and may result in additional current flow through surface and/or overburden power supply conductors. Expensive and/or difficult to implement control systems such as variable capacitors or modulated power supplies may be used to compensate for these effects and to control temperature limited heaters where the majority of the resistive heat output is provided by current flow through the ferromagnetic material.

[0952] In certain temperature limited heater embodiments, the ferromagnetic conductor confines a majority of the flow of electrical current to an electrical conductor coupled to the ferromagnetic conductor when the temperature limited heater is below or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. The electrical conductor may be a sheath, jacket, support member, corrosion resistant member, or other electrically resistive member. In some embodiments, the ferromagnetic conductor confines a majority of the
flow of electrical current to the electrical conductor positioned between an outermost layer and the ferromagnetic conductor. The ferromagnetic conductor is located in the cross section of the temperature limited heater such that the magnetic properties of the ferromagnetic conductor at or below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor confine the majority of the flow of electrical current to the electrical conductor. The majority of the flow of electrical current is confined to the electrical conductor due to the skin effect of the ferromagnetic conductor. Thus, the majority of the current is flowing through material with substantially linear resistive properties throughout most of the operating range of the heater.

[0953] In certain embodiments, the ferromagnetic conductor and the electrical conductor are located in the cross section of the temperature limited heater so that the skin effect of the ferromagnetic material limits the penetration depth of electrical current in the electrical conductor and the ferromagnetic conductor at temperatures below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. Thus, the electrical conductor provides a majority of the electrically resistive heat output of the temperature limited heater at temperatures up to a temperature at or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. In certain embodiments, the dimensions of the electrical conductor may be chosen to provide desired heat output characteristics.

[0954] Because the majority of the current flows through the electrical conductor below the Curie temperature and/or the phase transformation temperature range, the temperature limited heater has a resistance versus temperature profile that at least partially reflects the resistance versus temperature profile of the material in the electrical conductor. Thus, the resistance versus temperature profile of the temperature limited heater is substantially linear below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor if the material in the electrical conductor has a substantially linear resistance versus temperature profile. For example, the temperature limited heater in which the majority of the current flows in the electrical conductor below the Curie temperature and/or the phase transformation temperature range may have a resistance versus temperature profile similar to the profile shown in FIG. 336. The resistance of the temperature limited heater has little or no dependence on the current flowing through the heater until the temperature nears the Curie temperature and/or the phase transformation temperature range. The majority of the current flows in the electrical conductor rather than the ferromagnetic conductor below the Curie temperature and/or the phase transformation temperature range.

[0955] Resistance versus temperature profiles for temperature limited heaters in which the majority of the current flows in the electrical conductor also tend to exhibit sharper reductions in
resistance near or at the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. For example, the reduction in resistance shown in FIG. 336 is sharper than the reduction in resistance shown in FIG. 322. The sharper reductions in resistance near or at the Curie temperature and/or the phase transformation temperature range are easier to control than more gradual resistance reductions near the Curie temperature and/or the phase transformation temperature range because little current is flowing through the ferromagnetic material.

[0956] In certain embodiments, the material and/or the dimensions of the material in the electrical conductor are selected so that the temperature limited heater has a desired resistance versus temperature profile below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor.

[0957] Temperature limited heaters in which the majority of the current flows in the electrical conductor rather than the ferromagnetic conductor below the Curie temperature and/or the phase transformation temperature range are easier to predict and/or control. Behavior of temperature limited heaters in which the majority of the current flows in the electrical conductor rather than the ferromagnetic conductor below the Curie temperature and/or the phase transformation temperature range may be predicted by, for example, the resistance versus temperature profile and/or the power factor versus temperature profile. Resistance versus temperature profiles and/or power factor versus temperature profiles may be assessed or predicted by, for example, experimental measurements that assess the behavior of the temperature limited heater, analytical equations that assess or predict the behavior of the temperature limited heater, and/or simulations that assess or predict the behavior of the temperature limited heater.

[0958] In certain embodiments, assessed or predicted behavior of the temperature limited heater is used to control the temperature limited heater. The temperature limited heater may be controlled based on measurements (assessments) of the resistance and/or the power factor during operation of the heater. In some embodiments, the power, or current, supplied to the temperature limited heater is controlled based on assessment of the resistance and/or the power factor of the heater during operation of the heater and the comparison of this assessment versus the predicted behavior of the heater. In certain embodiments, the temperature limited heater is controlled without measurement of the temperature of the heater or a temperature near the heater.

Controlling the temperature limited heater without temperature measurement eliminates operating costs associated with downhole temperature measurement. Controlling the temperature limited heater based on assessment of the resistance and/or the power factor of the heater also reduces the time for making adjustments in the power or current supplied to the heater compared to controlling the heater based on measured temperature.
[0959] As the temperature of the temperature limited heater approaches or exceeds the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor, reduction in the ferromagnetic properties of the ferromagnetic conductor allows electrical current to flow through a greater portion of the electrically conducting cross section of the temperature limited heater. Thus, the electrical resistance of the temperature limited heater is reduced and the temperature limited heater automatically provides reduced heat output at or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. In certain embodiments, a highly electrically conductive member is coupled to the ferromagnetic conductor and the electrical conductor to reduce the electrical resistance of the temperature limited heater at or above the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. The highly electrically conductive member may be an inner conductor, a core, or another conductive member of copper, aluminum, nickel, or alloys thereof.

[0960] The ferromagnetic conductor that confines the majority of the flow of electrical current to the electrical conductor at temperatures below the Curie temperature and/or the phase transformation temperature range may have a relatively small cross section compared to the ferromagnetic conductor in temperature limited heaters that use the ferromagnetic conductor to provide the majority of resistive heat output up to or near the Curie temperature and/or the phase transformation temperature range. A temperature limited heater that uses the electrical conductor to provide a majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range has low magnetic inductance at temperatures below the Curie temperature and/or the phase transformation temperature range because less current is flowing through the ferromagnetic conductor as compared to the temperature limited heater where the majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range is provided by the ferromagnetic material. Magnetic field (H) at radius (r) of the ferromagnetic conductor is proportional to the current (I) flowing through the ferromagnetic conductor and the core divided by the radius, or:

\[
H \propto \frac{I}{r}.
\]

Since only a portion of the current flows through the ferromagnetic conductor for a temperature limited heater that uses the outer conductor to provide a majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range, the magnetic field of the temperature limited heater may be significantly smaller than the magnetic field of the temperature limited heater where the majority of the current flows through the ferromagnetic material. The relative magnetic permeability (μ) may be large for small magnetic fields.
[0961] The skin depth ($\delta$) of the ferromagnetic conductor is inversely proportional to the square root of the relative magnetic permeability ($\mu$):

\[
\delta \propto (1/\mu)^{1/2}.
\]

Increasing the relative magnetic permeability decreases the skin depth of the ferromagnetic conductor. However, because only a portion of the current flows through the ferromagnetic conductor for temperatures below the Curie temperature and/or the phase transformation temperature range, the radius (or thickness) of the ferromagnetic conductor may be decreased for ferromagnetic materials with large relative magnetic permeabilities to compensate for the decreased skin depth while still allowing the skin effect to limit the penetration depth of the electrical current to the electrical conductor at temperatures below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. The radius (thickness) of the ferromagnetic conductor may be between 0.3 mm and 8 mm, between 0.3 mm and 2 mm, or between 2 mm and 4 mm depending on the relative magnetic permeability of the ferromagnetic conductor. Decreasing the thickness of the ferromagnetic conductor decreases costs of manufacturing the temperature limited heater, as the cost of ferromagnetic material tends to be a significant portion of the cost of the temperature limited heater. Increasing the relative magnetic permeability of the ferromagnetic conductor provides a higher turndown ratio and a sharper decrease in electrical resistance for the temperature limited heater at or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor.

[0962] Ferromagnetic materials (such as purified iron or iron-cobalt alloys) with high relative magnetic permeabilities (for example, at least 200, at least 1000, at least $1 \times 10^5$, or at least $1 \times 10^6$) and/or high Curie temperatures (for example, at least 600 °C, at least 700 °C, or at least 800 °C) tend to have less corrosion resistance and/or less mechanical strength at high temperatures. The electrical conductor may provide corrosion resistance and/or high mechanical strength at high temperatures for the temperature limited heater. Thus, the ferromagnetic conductor may be chosen primarily for its ferromagnetic properties.

[0963] Confining the majority of the flow of electrical current to the electrical conductor below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor reduces variations in the power factor. Because only a portion of the electrical current flows through the ferromagnetic conductor below the Curie temperature and/or the phase transformation temperature range, the non-linear ferromagnetic properties of the ferromagnetic conductor have little or no effect on the power factor of the temperature limited heater, except at or near the Curie temperature and/or the phase transformation temperature range. Even at or near the Curie temperature and/or the phase transformation temperature range, the effect on the power factor is reduced compared to temperature limited heaters in which the ferromagnetic conductor
provides a majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range. Thus, there is less or no need for external compensation (for example, variable capacitors or waveform modification) to adjust for changes in the inductive load of the temperature limited heater to maintain a relatively high power factor.

[0964] In certain embodiments, the temperature limited heater, which confines the majority of the flow of electrical current to the electrical conductor below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor, maintains the power factor above 0.85, above 0.9, or above 0.95 during use of the heater. Any reduction in the power factor occurs only in sections of the temperature limited heater at temperatures near the Curie temperature and/or the phase transformation temperature range. Most sections of the temperature limited heater are typically not at or near the Curie temperature and/or the phase transformation temperature range during use. These sections have a high power factor that approaches 1.0. The power factor for the entire temperature limited heater is maintained above 0.85, above 0.9, or above 0.95 during use of the heater even if some sections of the heater have power factors below 0.85.

[0965] Maintaining high power factors allows for less expensive power supplies and/or control devices such as solid state power supplies or SCRs (silicon controlled rectifiers). These devices may fail to operate properly if the power factor varies by too large an amount because of inductive loads. With the power factors maintained at high values; however, these devices may be used to provide power to the temperature limited heater. Solid state power supplies have the advantage of allowing fine tuning and controlled adjustment of the power supplied to the temperature limited heater.

[0966] In some embodiments, transformers are used to provide power to the temperature limited heater. Multiple voltage taps may be made into the transformer to provide power to the temperature limited heater. Multiple voltage taps allow the current supplied to switch back and forth between the multiple voltages. This maintains the current within a range bound by the multiple voltage taps.

[0967] The highly electrically conductive member, or inner conductor, increases the turndown ratio of the temperature limited heater. In certain embodiments, thickness of the highly electrically conductive member is increased to increase the turndown ratio of the temperature limited heater. In some embodiments, the thickness of the electrical conductor is reduced to increase the turndown ratio of the temperature limited heater. In certain embodiments, the turndown ratio of the temperature limited heater is between 1.1 and 10, between 2 and 8, or between 3 and 6 (for example, the turndown ratio is at least 1.1, at least 2, or at least 3).
FIG. 71 depicts an embodiment of a temperature limited heater in which the support member provides a majority of the heat output below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. Core 542 is an inner conductor of the temperature limited heater. In certain embodiments, core 542 is a highly electrically conductive material such as copper or aluminum. In some embodiments, core 542 is a copper alloy that provides mechanical strength and good electrically conductivity such as a dispersion strengthened copper. In one embodiment, core 542 is Glidcop® (SCM Metal Products, Inc., Research Triangle Park, North Carolina, U.S.A.). Ferromagnetic conductor 546 is a thin layer of ferromagnetic material between electrical conductor 572 and core 542. In certain embodiments, electrical conductor 572 is also support member 548. In certain embodiments, ferromagnetic conductor 546 is iron or an iron alloy. In some embodiments, ferromagnetic conductor 546 includes ferromagnetic material with a high relative magnetic permeability. For example, ferromagnetic conductor 546 may be purified iron such as Armco ingot iron (AK Steel Ltd., United Kingdom). Iron with some impurities typically has a relative magnetic permeability on the order of 400. Purifying the iron by annealing the iron in hydrogen gas (H₂) at 1450 °C increases the relative magnetic permeability of the iron. Increasing the relative magnetic permeability of ferromagnetic conductor 546 allows the thickness of the ferromagnetic conductor to be reduced. For example, the thickness of unpurified iron may be approximately 4.5 mm while the thickness of the purified iron is approximately 0.76 mm.

In certain embodiments, electrical conductor 572 provides support for ferromagnetic conductor 546 and the temperature limited heater. Electrical conductor 572 may be made of a material that provides good mechanical strength at temperatures near or above the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 546. In certain embodiments, electrical conductor 572 is a corrosion resistant member. Electrical conductor 572 (support member 548) may provide support for ferromagnetic conductor 546 and corrosion resistance. Electrical conductor 572 is made from a material that provides desired electrically resistive heat output at temperatures up to and/or above the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 546.

In an embodiment, electrical conductor 572 is 347H stainless steel. In some embodiments, electrical conductor 572 is another electrically conductive, good mechanical strength, corrosion resistant material. For example, electrical conductor 572 may be 304H, 316H, 347HH, NF709, Incoloy® 800H alloy (Inco Alloys International, Huntington, West Virginia, U.S.A.), Haynes® HR120® alloy, or Inconel® 617 alloy.

In some embodiments, electrical conductor 572 (support member 548) includes different alloys in different portions of the temperature limited heater. For example, a lower portion of
electrical conductor 572 (support member 548) is 347H stainless steel and an upper portion of the electrical conductor (support member) is NF709. In certain embodiments, different alloys are used in different portions of the electrical conductor (support member) to increase the mechanical strength of the electrical conductor (support member) while maintaining desired heating properties for the temperature limited heater.

[0972] In some embodiments, ferromagnetic conductor 546 includes different ferromagnetic conductors in different portions of the temperature limited heater. Different ferromagnetic conductors may be used in different portions of the temperature limited heater to vary the Curie temperature and/or the phase transformation temperature range and, thus, the maximum operating temperature in the different portions. In some embodiments, the Curie temperature and/or the phase transformation temperature range in an upper portion of the temperature limited heater is lower than the Curie temperature and/or the phase transformation temperature range in a lower portion of the heater. The lower Curie temperature and/or the phase transformation temperature range in the upper portion increases the creep-rupture strength lifetime in the upper portion of the heater.

[0973] In the embodiment depicted in FIG. 71, ferromagnetic conductor 546, electrical conductor 572, and core 542 are dimensioned so that the skin depth of the ferromagnetic conductor limits the penetration depth of the majority of the flow of electrical current to the support member when the temperature is below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. Thus, electrical conductor 572 provides a majority of the electrically resistive heat output of the temperature limited heater at temperatures up to a temperature at or near the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 546. In certain embodiments, the temperature limited heater depicted in FIG. 71 is smaller (for example, an outside diameter of 3 cm, 2.9 cm, 2.5 cm, or less) than other temperature limited heaters that do not use electrical conductor 572 to provide the majority of electrically resistive heat output. The temperature limited heater depicted in FIG. 71 may be smaller because ferromagnetic conductor 546 is thin as compared to the size of the ferromagnetic conductor needed for a temperature limited heater in which the majority of the resistive heat output is provided by the ferromagnetic conductor.

[0974] In some embodiments, the support member and the corrosion resistant member are different members in the temperature limited heater. FIGS. 72 and 73 depict embodiments of temperature limited heaters in which the jacket provides a majority of the heat output below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. In these embodiments, electrical conductor 572 is jacket 540. Electrical conductor 572, ferromagnetic conductor 546, support member 548, and core 542 (in FIG. 72) or inner
conductor 532 (in FIG. 73) are dimensioned so that the skin depth of the ferromagnetic conductor limits the penetration depth of the majority of the flow of electrical current to the thickness of the jacket. In certain embodiments, electrical conductor 572 is a material that is corrosion resistant and provides electrically resistive heat output below the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 546. For example, electrical conductor 572 is 825 stainless steel or 347H stainless steel. In some embodiments, electrical conductor 572 has a small thickness (for example, on the order of 0.5 mm).

In FIG. 72, core 542 is highly electrically conductive material such as copper or aluminum. Support member 548 is 347H stainless steel or another material with good mechanical strength at or near the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 546.

In FIG. 73, support member 548 is the core of the temperature limited heater and is 347H stainless steel or another material with good mechanical strength at or near the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 546. Inner conductor 532 is highly electrically conductive material such as copper or aluminum.

In some embodiments, a relatively thin conductive layer is used to provide the majority of the electrically resistive heat output of the temperature limited heater at temperatures up to a temperature at or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. Such a temperature limited heater may be used as the heating member in an insulated conductor heater. The heating member of the insulated conductor heater may be located inside a sheath with an insulation layer between the sheath and the heating member.

FIGS. 74A and 74B depict cross-sectional representations of an embodiment of the insulated conductor heater with the temperature limited heater as the heating member. Insulated conductor 574 includes core 542, ferromagnetic conductor 546, inner conductor 532, electrical insulator 534, and jacket 540. Core 542 is a copper core. Ferromagnetic conductor 546 is, for example, iron or an iron alloy.

Inner conductor 532 is a relatively thin conductive layer of non-ferromagnetic material with a higher electrical conductivity than ferromagnetic conductor 546. In certain embodiments, inner conductor 532 is copper. Inner conductor 532 may be a copper alloy. Copper alloys typically have a flatter resistance versus temperature profile than pure copper. A flatter resistance versus temperature profile may provide less variation in the heat output as a function of temperature up to the Curie temperature and/or the phase transformation temperature range. In some embodiments, inner conductor 532 is copper with 6% by weight nickel (for example, CuNi6 or LOHM™). In some embodiments, inner conductor 532 is CuNi10Fe1Mn alloy.
Below the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 546, the magnetic properties of the ferromagnetic conductor confine the majority of the flow of electrical current to inner conductor 532. Thus, inner conductor 532 provides the majority of the resistive heat output of insulated conductor 574 below the Curie temperature and/or the phase transformation temperature range.

[0980] In certain embodiments, inner conductor 532 is dimensioned, along with core 542 and ferromagnetic conductor 546, so that the inner conductor provides a desired amount of heat output and a desired turndown ratio. For example, inner conductor 532 may have a cross-sectional area that is around 2 or 3 times less than the cross-sectional area of core 542. Typically, inner conductor 532 has to have a relatively small cross-sectional area to provide a desired heat output if the inner conductor is copper or copper alloy. In an embodiment with copper inner conductor 532, core 542 has a diameter of 0.66 cm, ferromagnetic conductor 546 has an outside diameter of 0.91 cm, inner conductor 532 has an outside diameter of 1.03 cm, electrical insulator 534 has an outside diameter of 1.53 cm, and jacket 540 has an outside diameter of 1.79 cm. In an embodiment with a CuNi6 inner conductor 532, core 542 has a diameter of 0.66 cm, ferromagnetic conductor 546 has an outside diameter of 0.91 cm, inner conductor 532 has an outside diameter of 1.12 cm, electrical insulator 534 has an outside diameter of 1.63 cm, and jacket 540 has an outside diameter of 1.88 cm. Such insulated conductors are typically smaller and cheaper to manufacture than insulated conductors that do not use the thin inner conductor to provide the majority of heat output below the Curie temperature and/or the phase transformation temperature range.

[0981] Electrical insulator 534 may be magnesium oxide, aluminum oxide, silicon dioxide, beryllium oxide, boron nitride, silicon nitride, or combinations thereof. In certain embodiments, electrical insulator 534 is a compacted powder of magnesium oxide. In some embodiments, electrical insulator 534 includes beads of silicon nitride.

[0982] In certain embodiments, a small layer of material is placed between electrical insulator 534 and inner conductor 532 to inhibit copper from migrating into the electrical insulator at higher temperatures. For example, a small layer of nickel (for example, about 0.5 mm of nickel) may be placed between electrical insulator 534 and inner conductor 532.

[0983] Jacket 540 is made of a corrosion resistant material such as, but not limited to, 347 stainless steel, 347H stainless steel, 446 stainless steel, or 825 stainless steel. In some embodiments, jacket 540 provides some mechanical strength for insulated conductor 574 at or above the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 546. In certain embodiments, jacket 540 is not used to conduct electrical current.
[0984] For long vertical temperature limited heaters (for example, heaters at least 300 m, at least 500 m, or at least 1 km in length), the hanging stress becomes important in the selection of materials for the temperature limited heater. Without the proper selection of material, the support member may not have sufficient mechanical strength (for example, creep-rupture strength) to support the weight of the temperature limited heater at the operating temperatures of the heater.

[0985] In certain embodiments, materials for the support member are varied to increase the maximum allowable hanging stress at operating temperatures of the temperature limited heater and, thus, increase the maximum operating temperature of the temperature limited heater. Altering the materials of the support member affects the heat output of the temperature limited heater below the Curie temperature and/or the phase transformation temperature range because changing the materials changes the resistance versus temperature profile of the support member. In certain embodiments, the support member is made of more than one material along the length of the heater so that the temperature limited heater maintains desired operating properties (for example, resistance versus temperature profile below the Curie temperature and/or the phase transformation temperature range) as much as possible while providing sufficient mechanical properties to support the heater. In some embodiments, transition sections are used between sections of the heater to provide strength that compensates for the difference in temperature between sections of the heater. In certain embodiments, one or more portions of the temperature limited heater have varying outside diameters and/or materials to provide desired properties for the heater.

[0986] In certain embodiments of temperature limited heaters, three temperature limited heaters are coupled together in a three-phase wye configuration. Coupling three temperature limited heaters together in the three-phase wye configuration lowers the current in each of the individual temperature limited heaters because the current is split between the three individual heaters. Lowering the current in each individual temperature limited heater allows each heater to have a small diameter. The lower currents allow for higher relative magnetic permeabilities in each of the individual temperature limited heaters and, thus, higher turndown ratios. In addition, there may be no return current path needed for each of the individual temperature limited heaters. Thus, the turndown ratio remains higher for each of the individual temperature limited heaters than if each temperature limited heater had its own return current path.

[0987] In the three-phase wye configuration, individual temperature limited heaters may be coupled together by shorting the sheaths, jackets, or canisters of each of the individual temperature limited heaters to the electrically conductive sections (the conductors providing heat) at their terminating ends (for example, the ends of the heaters at the bottom of a heater wellbore).
In some embodiments, the sheaths, jackets, canisters, and/or electrically conductive sections are coupled to a support member that supports the temperature limited heaters in the wellbore.

[0988] In certain embodiments, coupling multiple heaters (for example, mineral insulated conductor heaters) to a single power source, such as a transformer, is advantageous. Coupling multiple heaters to a single transformer may result in using fewer transformers to power heaters used for a treatment area as compared to using individual transformers for each heater. Using fewer transformers reduces surface congestion and allows easier access to the heaters and surface components. Using fewer transformers reduces capital costs associated with providing power to the treatment area. In some embodiments, at least 4, at least 5, at least 10, at least 25 heaters, at least 35 heaters, or at least 45 heaters are powered by a single transformer. Additionally, powering multiple heaters (in different heater wells) from the single transformer may reduce overburden losses because of reduced voltage and/or phase differences between each of the heater wells powered by the single transformer. Powering multiple heaters from the single transformer may inhibit current imbalances between the heaters because the heaters are coupled to the single transformer.

[0989] To provide power to multiple heaters using the single transformer, the transformer may have to provide power at higher voltages to carry the current to each of the heaters effectively. In certain embodiments, the heaters are floating (ungrounded) heaters in the formation. Floating the heaters allows the heaters to operate at higher voltages. In some embodiments, the transformer provides power output of at least about 3 kV, at least about 4 kV, at least about 5 kV, or at least about 6 kV.

[0990] FIG. 75 depicts a top view representation of heater 438 with three insulated conductors 574 in conduit 570. Heater 438 may be located in a heater well in the subsurface formation. Conduit 570 may be a sheath, jacket, or other enclosure around insulated conductors 574. Each insulated conductor 574 includes core 542, electrical insulator 534, and jacket 540. Insulated conductors 574 may be mineral insulated conductors with core 542 being a copper alloy (for example, a copper-nickel alloy such as Alloy 180), electrical insulator 534 being magnesium oxide, and jacket 540 being Incoloy® 825, copper, or stainless steel (for example 347H stainless steel). In some embodiments, jacket 540 includes non-work hardenable metals so that the jacket is annealable.

[0991] In some embodiments, core 542 and/or jacket 540 include ferromagnetic materials. In some embodiments, one or more insulated conductors 574 are temperature limited heaters. In certain embodiments, the overburden portion of insulated conductors 574 include high electrical conductivity materials in core 542 (for example, pure copper or copper alloys such as copper with 3% silicon at a weld joint) so that the overburden portions of the insulated conductors
provide little or no heat output. In certain embodiments, conduit 570 includes non-corrosive materials and/or high strength materials such as stainless steel. In one embodiment, conduit 570 is 347H stainless steel.

[0992] Insulated conductors 574 may be coupled to the single transformer in a three-phase configuration (for example, a three-phase wye configuration). Each insulated conductor 574 may be coupled to one phase of the single transformer. In certain embodiments, the single transformer is also coupled to a plurality of identical heaters 438 in other heater wells in the formation (for example, the single transformer may couple to 40 or more heaters in the formation). In some embodiments, the single transformer couples to at least 4, at least 5, at least 10, at least 15, or at least 25 additional heaters in the formation.

[0993] Electrical insulator 534’ may be located inside conduit 570 to electrically insulate insulated conductors 574 from the conduit. In certain embodiments, electrical insulator 534’ is magnesium oxide (for example, compacted magnesium oxide). In some embodiments, electrical insulator 534’ is silicon nitride (for example, silicon nitride blocks). Electrical insulator 534’ electrically insulates insulated conductors 574 from conduit 570 so that at high operating voltages (for example, 3 kV or higher), there is no arcing between the conductors and the conduit. In some embodiments, electrical insulator 534’ inside conduit 570 has at least the thickness of electrical insulators 534 in insulated conductors 574. The increased thickness of insulation in heater 438 (from electrical insulators 534 and/or electrical insulator 534’) inhibits and may prevent current leakage into the formation from the heater. In some embodiments, electrical insulator 534’ spatially locates insulated conductors 574 inside conduit 570.

[0994] FIG. 76 depicts an embodiment of three-phase wye transformer 580 coupled to a plurality of heaters 438. For simplicity in the drawing, only four heaters 438 are shown in FIG. 76. It is to be understood that several more heaters may be coupled to the transformer 580. As shown in FIG. 76, each leg (each insulated conductor) of each heater is coupled to one phase of transformer 580 and current is returned to the neutral or ground of the transformer (for example, returned through conductor 582 depicted in FIGS. 75 and 77).

[0995] Return conductor 582 may be electrically coupled to the ends of insulated conductors 574 (as shown in FIG. 77) current returns from the ends of the insulated conductors to the transformer on the surface of the formation. Return conductor 582 may include high electrical conductivity materials such as pure copper, nickel, copper alloys, or combinations thereof so that the return conductor provides little or no heat output. In some embodiments, return conductor 582 is a tubular (for example, a stainless steel tubular) that allows an optical fiber to be placed inside the tubular to be used for temperature and/or other measurement. In some embodiments, return conductor 582 is a small insulated conductor (for example, small mineral insulated conductor).
Return conductor 582 may be coupled to the neutral or ground leg of the transformer in a three-phase wye configuration. Thus, insulated conductors 574 are electrically isolated from conduit 570 and the formation. Using return conductor 582 to return current to the surface may make coupling the heater to a wellhead easier. In some embodiments, current is returned using one or more of jackets 540, depicted in FIG. 75. One or more jackets 540 may be coupled to cores 542 at the end of the heaters and return current to the neutral of the three-phase wye transformer.

[0996] FIG. 77 depicts a side view representation of the end section of three insulated conductors 574 in conduit 570. The end section is the section of the heaters the furthest away from (distal from) the surface of the formation. The end section includes contactor section 576 coupled to conduit 570. In some embodiments, contactor section 576 is welded or brazed to conduit 570. Termination 578 is located in contactor section 576. Termination 578 is electrically coupled to insulated conductors 574 and return conductor 582. Termination 578 electrically couples the cores of insulated conductors 574 to the return conductor 582 at the ends of the heaters.

[0997] In certain embodiments, heater 438, depicted in FIGS. 75 and 77, includes an overburden section using copper as the core of the insulated conductors. The copper in the overburden section may be the same diameter as the cores used in the heating section of the heater. The copper in the overburden section may have a larger diameter than the cores in the heating section of the heater. Increasing the size of the copper in the overburden section may decrease losses in the overburden section of the heater.

[0998] Heaters that include three insulated conductors 574 in conduit 570, as depicted in FIGS. 75 and 77, may be made in a multiple step process. In some embodiments, the multiple step process is performed at the site of the formation or treatment area. In some embodiments, the multiple step process is performed at a remote manufacturing site away from the formation. The finished heater is then transported to the treatment area.

[0999] Insulated conductors 574 may be pre-assembled prior to the bundling either on site or at a remote location. Insulated conductors 574 and return conductor 582 may be positioned on spools. A machine may draw insulated conductors 574 and return conductor 582 from the spools at a selected rate. Preformed blocks of insulation material may be positioned around return conductor 582 and insulated conductors 574. In an embodiment, two blocks are positioned around return conductor 582 and three blocks are positioned around insulated conductors 574 to form electrical insulator 534'. The insulated conductors and return conductor may be drawn or pushed into a plate of conduit material that has been rolled into a tubular shape. The edges of the plate may be pressed together and welded (for example, by laser welding). After forming conduit 570 around electrical insulator 534', the bundle of insulated conductors 574, and return conductor 582, the conduit may be compacted against the electrical insulator 582 so that all of
the components of the heater are pressed together into a compact and tightly fitting form. During the compaction, the electrical insulator may flow and fill any gaps inside the heater.

[1000] In some embodiments, heater 438 (which includes conduit 570 around electrical insulator 534' and the bundle of insulated conductors 574 and return conductor 582) is inserted into a coiled tubing tubular that is placed in a wellbore in the formation. The coiled tubing tubular may be left in place in the formation (left in during heating of the formation) or removed from the formation after installation of the heater. The coiled tubing tubular may allow for easier installation of heater 438 into the wellbore.

[1001] In some embodiments, one or more components of heater 438 are varied (for example, removed, moved, or replaced) while the operation of the heater remains substantially identical. FIG. 78 depicts an embodiment of heater 438 with three insulated cores 542 in conduit 570. In this embodiment, electrical insulator 534' surrounds cores 542 and return conductor 582 in conduit 570. Cores 542 are located in conduit 570 without an electrical insulator and jacket surrounding the cores. Cores 542 are coupled to the single transformer in a three-phase wye configuration with each core 542 coupled to one phase of the transformer. Return conductor 582 is electrically coupled to the ends of cores 542 and returns current from the ends of the cores to the transformer on the surface of the formation.

[1002] FIG. 79 depicts an embodiment of heater 438 with three insulated conductors 574 and insulated return conductor in conduit 570. In this embodiment, return conductor 582 is an insulated conductor with core 542, electrical insulator 534, and jacket 540. Return conductor 582 and insulated conductors 574 are located in conduit 570 surrounded by electrical insulator 534'. Return conductor 582 and insulated conductors 574 may be the same size or different sizes. Return conductor 582 and insulated conductors 574 operate substantially the same as in the embodiment depicted in FIGS. 75 and 77.

[1003] FIGS. 80 and 81 depict embodiments of three insulated conductors 574 banded together. Heater 438 includes three insulated conductors 574 coupled together in a spiral configuration. In other embodiments, six, nine, or multiples of three insulated conductors are coupled together. In certain embodiments, insulated conductors 574 are held together in the spiral configuration with bands 584 that are periodically placed around insulated conductors 574.

[1004] Banding insulated conductors 574 together instead of placing the conductors in a casing allows open spaces between the conductors to radiate heat to the formation, thus increasing the radiating surface area of heater 438. Banding insulated conductors 574 together may improve the insertion strength of heater 438.

[1005] In some embodiments, insulated conductors 574 are banded onto and around support member 586, as shown in FIG. 81. Support member 586 may provide structural support and/or
increase the insertion strength of heater 438. In some embodiments, support member 586
includes a conduit used to provide fluids and/or to remove fluids from heater 438. For example,
oxidization inhibiting fluids may be provided to heater 438 through support member 586. In
some embodiments, other structures are used to provide fluids and/or to remove fluids from
heater 438.

[1006] Heater 438 may be provided power from single phase power sources (for example, as
depicted in FIG. 80), or from three-phase power sources (for example, as depicted in FIG. 81)
depending on desired operation of the heater. Support member 586 may provide electrical
isolation for insulated conductors 438 coupled to the three-phase power source. The voltage
differentials on the surfaces (jackets) of insulated conductors 574 in the three-phase embodiment
may be reduced because of the proximity effect.

[1007] In some embodiments, optical sensor 588 is located at or near a center of insulated
conductors 574. Optical sensor 588 may be used to assess properties of heater 438 such as, but
not limited to, stress, temperature, and/or pressure. In some embodiments, support member 586
includes a notch, as shown in FIG. 81, for insertion of optical sensor 588. The notch may allow
continuous insertion of optical sensor optical sensor 588 during installation of heater 438.

[1008] In some embodiments, three insulated conductor heaters (for example, mineral insulated
conductor heaters) are coupled together into a single assembly. The single assembly may be built
in long lengths and may operate at high voltages (for example, voltages of 4000 V nominal). In
certain embodiments, the individual insulated conductor heaters are enclosed in corrosive
resistant jackets to resist damage from the external environment. The jackets may be, for
example, seam welded stainless steel armor similar to that used on type MC/CWCMC cable.

[1009] In some embodiments, three insulated conductor heaters are cabled and the insulating
filler added in conventional methods known in the art. The insulated conductor heaters may
include one or more heater sections that resistively heat and provide heat to formation adjacent to
the heater sections. The insulated conductors may include one or more other sections that
provide electricity to the heater sections with relatively small heat loss. The individual insulated
conductor heaters may be wrapped with high temperature fiber tapes before being placed on a
take-up reel (for example, a coiled tubing rig). The reel assembly may be moved to another
machine for application of an outer metallic sheath or outer protective conduit.

[1010] In some embodiments, the fillers include glass, ceramic or other temperature resistant
fibers that withstand operating temperature of 760 °C or higher. In addition, the insulated
conductor cables may be wrapped in multiple layers of a ceramic fiber woven tape material. By
wrapping the tape around the cabled insulated conductor heaters prior to application of the outer
metallic sheath, electrical isolation is provided between the insulated conductor heaters and the
outer sheath. This electrical isolation inhibits leakage current from the insulated conductor heaters passing into the subsurface formation and forces any leakage currents to return directly to the power source on the individual insulated conductor sheaths and/or on a lead-in conductor or lead-out conductor coupled to the insulated conductors. The lead-in or lead-out conductors may be coupled to the insulated conductors when the insulated conductors are placed into an assembly with the outer metallic sheath.

[1011] In certain embodiments, the insulated conductor heaters are wrapped with a metallic tape or other type of tape instead of the high temperature ceramic fiber woven tape material. The metallic tape holds the insulated conductor heaters together. A widely-spaced wide pitch spiral wrapping of a high temperature fiber rope may be wrapped around the insulated conductor heaters. The fiber rope may provide electrical isolation between the insulated conductors and the outer sheath. The fiber rope may be added at any stage during assembly. For example, the fiber rope may be added as a part of the final assembly when the outer sheath is added. Application of the fiber rope may be simpler than other electrical isolation methods because application of the fiber rope is done with only a single layer of rope instead of multiple layers of ceramic tape. The fiber rope may be less expensive than multiple layers of ceramic tape. The fiber rope may increase heat transfer between the insulated conductors and the outer sheath and/or reduce interference with any welding process used to weld the outer sheath around the insulated conductors (for example, seam welding).

[1012] In certain embodiments, an insulated conductor or another type of heater is installed in a wellbore or opening in the formation using outer tubing coupled to a coiled tubing rig. FIG. 82 depicts outer tubing 1128 partially unspooled from coiled tubing rig 1804. Outer tubing 1128 may be made of metal or polymeric material. Outer tubing 1128 may be a flexible conduit such as, for example, a tubing guide string or other coiled tubing string. Heater 438 may be pushed into outer tubing 1128, as shown in FIG. 83. In certain embodiments, heater 438 is pushed into outer tubing 1128 by pumping the heater into the outer tubing.

[1013] In certain embodiments, one or more flexible cups 1806 are coupled to the outside of heater 438. Flexible cups 1806 may have a variety of shapes and/or sizes but typically are shaped and sized to maintain at least some pressure inside at least a portion of outer tubing 1128 as heater 438 is pushed or pumped into the outer tubing. For example, flexible cups 1806 may have flexible edges that provide limited mechanical resistance as heater 438 is pushed into outer tubing 1128 but remain in contact with the inner walls of outer tubing 1128 as the heater is pushed so that pressure is maintained between the heater and the outer tubing. Maintaining at least some pressure in outer tubing 1128 between flexible cups 1806 allows heater 438 to be continuously pushed into the outer tubing with lower pump pressures. Without flexible cups
1806, higher pressures may be needed to push heater 438 into outer tubing 1128. In some embodiments, cups 1806 allow some pressure to be released while maintaining some pressure in outer tubing 1128. In certain embodiments, flexible cups 1806 are spaced to distribute pumping forces optimally along heater 438 inside outer tubing 1128.

[1014] Heater 438 is pushed into outer tubing 1128 until the heater is fully inserted into the outer tubing, as shown in FIG. 84. Drilling guide 696 may be coupled to the end of heater 438. Heater 438, outer tubing 1128, and drilling guide 696 may be spooled onto coiled tubing rig 1804, as shown in FIG. 85. After heater 438, outer tubing 1128, and drilling guide 696 are spooled onto coiled tubing rig 1804, the assembly may be transported to a location for installation of the heater. For example, the assembly may be transported to the location of a subsurface heater wellbore (opening).

[1015] FIG. 86 depicts coiled tubing rig 1804 being used to install heater 438 and outer tubing 1128 into opening 556 using drilling guide 696. In certain embodiments, opening 556 is an L-shaped opening or wellbore with a substantially horizontal or inclined portion in a hydrocarbon containing layer of the formation. In such embodiments, heater 438 has a heating section that is placed in the substantially horizontally or inclined portion of opening 556 to be used to heat the hydrocarbon containing layer. In some embodiments, opening 556 has a horizontal or inclined section that is at least about 1000 m in length, at least about 1500 m in length, or at least about 2000 m in length. Overburden casing 564 may be located around the outer walls of opening 556 in an overburden section of the formation. In some embodiments, drilling fluid is left in opening 556 after the opening has been completed (the opening has been drilled).

[1016] FIG. 87 depicts heater 438 and outer tubing 1128 installed in opening 556. Gap 1808 may be left at or near the far end of heater 438 and outer tubing 1128. Gap 1808 may allow for some heater expansion in opening 556 after the heater is energized.

[1017] After heater 438 and outer tubing 1128 are installed in opening 556, the outer tubing may be removed from the opening to leave the heater in place in the opening. FIG. 88 depicts outer tubing 1128 being removed from opening 556 while leaving heater 438 installed in the opening. Outer tubing 1128 is spooled back onto coiled tubing rig 1804 as the outer tubing is pulled off heater 438. In some embodiments, outer tubing 1128 is pumped down to allow the outer tubing to be pulled off heater 438.

[1018] FIG. 89 depicts outer tubing 1128 used to provide packing material 566 into opening 556. As outer tubing 1128 reaches the "shoe" or bend in opening 556, the outer tubing may be used to provide packing material into the opening. The shoe of opening 556 may be located at or near the bottom of overburden casing 564. Packing material 566 may be provided (for example, pumped) through outer tubing 1128 and out the end of the outer tubing at the shoe of opening.
Packing material 566 is provided into opening 556 to seal off the opening around heater 438. Packing material 566 provides a barrier between the overburden section and heating section of opening 556. In certain embodiments, packing material 566 is cement or another suitable plugging material. In some embodiments, outer tubing 1128 is continuously spooled while packing material 566 is provided into opening 556. Outer tubing 1128 may be spooled slowly while packing material 566 is provided into opening 556 to allow the packing material to settle into the opening properly.

[1019] After packing material 566 is provided into opening 556, outer tubing 1128 is spooled further onto coiled tubing rig 1804, as shown in FIG. 90. FIG. 91 depicts outer tubing 1128 spooled onto coiled tubing rig 1804 with heater 438 installed in opening 556. In certain embodiments, flexible cups 1806 are spaced in the portion of opening 556 with overburden casing 564 to facilitate adequate stand-off of heater 438 in the overburden portion of the opening. Flexible cups 1806 may electrically insulate heater 438 from overburden casing 564. For example, flexible cups 1806 may space apart heater 438 and overburden casing 564 such that they are not in physical contact with each other.

[1020] After outer tubing 1128 is removed from opening 556, wellhead 476 and/or other completions may be installed at the surface of the opening, as shown in FIG. 92. When heater 438 is energized to begin heating, flexible cups 1806 may begin to burn or melt off. Flexible cups 1806 may begin to burn or melt off at relatively low temperatures during the heating process.

[1021] FIG. 93 depicts an embodiment of a heater in wellbore 742 in formation 524. The heater includes insulated conductor 574 in conduit 552 with material 590 between the insulated conductor and the conduit. In some embodiments, insulated conductor 574 is a mineral insulated conductor. Electricity supplied to insulated conductor 574 resistively heats the insulated conductor. Insulated conductor conductively transfers heat to material 590. Heat may transfer within material 590 by heat conduction and/or by heat convection. Radiant heat from insulated conductor 574 and/or heat from material 590 transfers to conduit 552. Heat may transfer to the formation from the heater by conductive or radiative heat transfer from conduit 552. Material 590 may be molten metal, molten salt, or other liquid. In some embodiments, a gas (for example, nitrogen, carbon dioxide, and/or helium) is in conduit 552 above material 590. The gas may inhibit oxidation or other chemical changes of material 590. The gas may inhibit vaporization of material 590. U.S. Published Patent Application 2008-0078551 to DeVault et al. describes a system for placement in a wellbore, the system including a heater in a conduit with a liquid metal between the heater and the conduit for heating subterranean earth.
Insulated conductor 574 and conduit 552 may be placed in an opening in a subsurface formation. Insulated conductor 574 and conduit 552 may have any orientation in a subsurface formation (for example, the insulated conductor and conduit may be substantially vertical or substantially horizontally oriented in the formation). Insulated conductor 574 includes core 542, electrical insulator 534, and jacket 540. In some embodiments, core 542 is a copper core. In some embodiments, core 542 includes other electrical conductors or alloys (for example, copper alloys). In some embodiments, core 542 includes a ferromagnetic conductor so that insulated conductor 574 operates as a temperature limited heater. In some embodiments, core 542 does not include a ferromagnetic conductor.

In some embodiments, core 542 of insulated conductor 574 is made of two or more portions. The first portion may be placed adjacent to the overburden. The first portion may be sized and/or made of a highly conductive material so that the first portion does not resistively heat to a high temperature. One or more other portions of core 574 may be sized and/or made of material that resistively heats to a high temperature. These portions of core 574 may be positioned adjacent to sections of the formation that are to be heated by the heater. In some embodiments, the insulated conductor does not include a highly conductive first portion. A lead in cable may be coupled to the insulated conductor to supply electricity to the insulated conductor.

In some embodiments, core 542 of insulated conductor 574 is a highly conductive material such as copper. Core 542 may be electrically coupled to jacket 540 at or near the end of the insulated conductor. In some embodiments, insulated conductor 574 is electrically coupled to conduit 552. Electrical current supplied to insulated conductor 574 may resistively heat core 542, jacket 540, material 590, and/or conduit 552. Resistive heating of core 542, jacket 540, material 590, and/or conduit 552 generates heat that may transfer to the formation.

Electrical insulator 534 may be magnesium oxide, aluminum oxide, silicon dioxide, beryllium oxide, boron nitride, silicon nitride, or combinations thereof. In certain embodiments, electrical insulator 534 is a compacted powder of magnesium oxide. In some embodiments, electrical insulator 534 includes beads of silicon nitride. In certain embodiments, a thin layer of material clad over core 542 to inhibit the core from migrating into the electrical insulator at higher temperatures (i.e., to inhibit copper of the core from migrating into magnesium oxide of the insulation). For example, a small layer of nickel (for example, about 0.5 mm of nickel) may be clad on core 542.

In some embodiments, material 590 may be relatively corrosive. Jacket 540 and/or at least the inside surface of conduit 552 may be made of a corrosion resistant material such as, but not limited to, nickel, Alloy N (Carpenter Metals), 347 stainless steel, 347H stainless steel, 446
stainless steel, or 825 stainless steel. For example, conduit 552 may be plated or lined with nickel. In some embodiments, material 590 may be relatively non-corrosive. Jacket 540 and/or at least the inside surface of conduit 552 may be made of a material such as carbon steel.

[1027] In some embodiments, jacket 540 of insulated conductor 574 is not used as the main return of electrical current for the insulated conductor. In embodiments where material 590 is a good electrical conductor such as a molten metal, current returns through the molten metal in the conduit and/or through the conduit 552. In some embodiments, conduit 552 is made of a ferromagnetic material, (for example 410 stainless steel). Conduit 552 may function as a temperature limited heater until the temperature of the conduit approaches, reaches or exceeds the Curie temperature or phase transition temperature of the conduit material.

[1028] In some embodiments, material 590 returns electrical current to the surface from insulated conductor 574 (i.e., the material acts as the return or ground conductor for the insulated conductor). Material 590 may provide a current path with low resistance so that a long insulated conductor 574 is useable in conduit 552. The long heater may operate at low voltages for the length of the heater due to the presence of material 590 that is conductive.

[1029] FIG. 94 depicts an embodiment of a portion of insulated conductor 574 in conduit 552 wherein material 590 is a good conductor (for example, a liquid metal) and current flow is indicated by the arrows. Current flows down core 542 and returns through jacket 540, material 590, and conduit 552. Jacket 540 and conduit 552 may be at approximately constant potential. Current flows radially from jacket 540 to conduit 552 through material 590. Material 590 may resistively heat. Heat from material 590 may transfer through conduit 552 into the formation.

[1030] In embodiments where material 590 is partially electrically conductive (for example, the material is a molten salt), current returns mainly through jacket 540. All or a portion of the current that passes through partially conductive material 590 may pass to ground through conduit 552.

[1031] In the embodiment depicted in FIG. 93, core 542 of insulated conductor 574 has a diameter of about 1 cm, electrical insulator 534 has an outside diameter of about 1.6 cm, and jacket 540 has an outside diameter of about 1.8 cm. In other embodiments, the insulated conductor is smaller. For example, core 542 has a diameter of about 0.5 cm, electrical insulator 534 has an outside diameter of about 0.8 cm, and jacket 540 has an outside diameter of about 0.9 cm. Other insulated conductor geometries may be used. For the same size conduit 552, the smaller geometry of insulated conductor 574 may result in a higher operating temperature of the insulated conductor to achieve the same temperature at the conduit. The smaller geometry insulated conductors may be significantly more economically favorable due to manufacturing cost, weight, and other factors.
[1032] Material 590 may be placed between the outside surface of insulated conductor 574 and the inside surface of conduit 552. In certain embodiments, material 590 is placed in the conduit in a solid form as balls or pellets. Material 590 may melt below the operating temperatures of insulated conductor 574. Material may melt above ambient subsurface formation temperatures. Material 590 may be placed in conduit 552 after insulated conductor 574 is placed in the conduit. In certain embodiments, material 590 is placed in conduit 574 as a liquid. The liquid may be placed in conduit 552 before or after insulated conductor 574 is placed in the conduit (for example, the molten liquid may be poured into the conduit before or after the insulated conductor is placed in the conduit). Additionally, material 590 may be placed in conduit 552 before or after insulated conductor 574 is energized (i.e., supplied with electricity). Material 590 may be added to conduit 552 or removed from the conduit after operation of the heater is initialized. Material 590 may be added to or removed from conduit 552 to maintain a desired head of fluid in the conduit. In some embodiments, the amount of material 590 in conduit 552 may be adjusted (i.e., added to or depleted) to adjust or balance the stresses on the conduit. Material 590 may inhibit deformation of conduit 552. The head of material 590 in conduit 552 may inhibit the formation from crushing or otherwise deforming the conduit should the formation expand against the conduit. The head of fluid in conduit 552 allows the wall of the conduit to be relatively thin. Having thin conduits 552 may increase the economic viability of using multiple heaters of this type to heat portions of the formation.

[1033] Material 590 may support insulated conductor 574 in conduit 552. The support provided by material 590 of insulated conductor 574 may allow for the deployment of long insulated conductors as compared to insulated conductors positioned only in a gas in a conduit without the use of special metallurgy to accommodate the weight of the insulated conductor. In certain embodiments, insulated conductor 574 is buoyant in material 590 in conduit 552. For example, insulated conductor may be buoyant in molten metal. The buoyancy of insulated conductor 574 reduces creep associated problems in long, substantially vertical heaters. A bottom weight or tie down may be coupled to the bottom of insulated conductor 574 to inhibit the insulated conductor from floating in material 590.

[1034] Material 590 may remain a liquid at operating temperatures of insulated conductor 574. In some embodiments, material 590 melts at temperatures above about 100 °C, above about 200 °C, or above about 300 °C. The insulated conductor may operate at temperatures greater than 200 °C, greater than 400 °C, greater than 600 °C, or greater than 800 °C. In certain embodiments, material 590 provides enhanced heat transfer from insulated conductor 574 to conduit 552 at or near the operating temperatures of the insulated conductor.
Material 590 may include metals such as tin, zinc, an alloy such as a 60% by weight tin, 40% by weight zinc alloy; bismuth; indium; cadmium, aluminum; lead; and/or combinations thereof (for example, eutectic alloys of these metals such as binary or ternary alloys). In one embodiment, material 590 is tin. Some liquid metals may be corrosive. The jacket of the insulated conductor and/or at least the inside surface of the canister may need to be made of a material that is resistant to the corrosion of the liquid metal. The jacket of the insulated conductor and/or at least the inside surface of the conduit may be made of materials that inhibit the molten metal from leaching materials from the insulating conductor and/or the conduit to form eutectic compositions or metal alloys. Molten metals may be highly thermal conductive, but may block radiant heat transfer from the insulated conductor and/or have relatively small heat transfer by natural convection.

Material 590 may be or include molten salts such as solar salt, salts presented in Table 1, or other salts. The molten salts may be infrared transparent to aid in heat transfer from the insulated conductor to the canister. In some embodiments, solar salt includes sodium nitrate and potassium nitrate (for example, about 60% by weight sodium nitrate and about 40% by weight potassium nitrate). Solar salt melts at about 220 °C and is chemically stable up to temperatures of about 593 °C. Other salts that may be used include, but are not limited to LiNO₃ (melt temperature (Tₘ) of 264 °C and a decomposition temperature of about 600 °C) and eutectic mixtures such as 53% by weight KNO₃, 40% by weight NaNO₃ and 7% by weight NaNO₂ (Tₘ of about 142 °C and an upper working temperature of over 500 °C); 45.5% by weight KNO₃ and 54.5% by weight NaNO₂ (Tₘ of about 142-145 °C and an upper working temperature of over 500 °C); or 50% by weight NaCl and 50% by weight SrCl₂ (Tₘ of about 19 °C and an upper working temperature of over 1200 °C).

### Table 1

<table>
<thead>
<tr>
<th>Material</th>
<th>Tₘ (°C)</th>
<th>Tₖ (°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zn</td>
<td>420</td>
<td>907</td>
</tr>
<tr>
<td>CdBr₂</td>
<td>568</td>
<td>863</td>
</tr>
<tr>
<td>CdI₂</td>
<td>388</td>
<td>744</td>
</tr>
<tr>
<td>CuBr₂</td>
<td>498</td>
<td>900</td>
</tr>
<tr>
<td>PbBr₂</td>
<td>371</td>
<td>892</td>
</tr>
<tr>
<td>TlBr</td>
<td>460</td>
<td>819</td>
</tr>
<tr>
<td>TlF</td>
<td>326</td>
<td>826</td>
</tr>
<tr>
<td>ThI₄</td>
<td>566</td>
<td>837</td>
</tr>
<tr>
<td>SnF₂</td>
<td>215</td>
<td>850</td>
</tr>
</tbody>
</table>
SnI₂ | 320 | 714
ZnCl₂ | 290 | 732

[1037] Some molten salts, such as solar salt, may be relatively non-corrosive so that the conduit and/or the jacket may be made of relatively inexpensive material (for example, carbon steel). Some molten salts may have good thermal conductivity, may have high heat density, and may result in large heat transfer by natural convection.

[1038] In fluid mechanics, the Rayleigh number is a dimensionless number associated with heat transfer in a fluid. When the Rayleigh number is below the critical value for the fluid, heat transfer is primarily in the form of conduction; and when the Rayleigh number is above the critical value, heat transfer is primarily in the form of convection. The Rayleigh number is the product of the Grashof number (which describes the relationship between buoyancy and viscosity in a fluid) and the Prandtl number (which describes the relationship between momentum diffusivity and thermal diffusivity). For the same size insulated conductors in conduits, and where the temperature of the conduit is 500 °C, the Rayleigh number for solar salt in the conduit is about 10 times the Rayleigh number for tin in the conduit. The higher Rayleigh number implies that the strength of natural convection in the molten solar salt is much stronger than the strength of the natural convection in molten tin. The stronger natural convection of molten salt may distribute heat and inhibit the formation of hot spots at locations along the length of the conduit. Hot spots may be caused by coke build up at isolated locations adjacent to or on the conduit, contact of the conduit by the formation at isolated locations, and/or other high thermal load situations.

[1039] Conduit 552 may be a carbon steel or stainless steel canister. In some embodiments, conduit 552 may include cladding on the outer surface to inhibit corrosion of the conduit by formation fluid. Conduit 552 may include cladding on an inner surface of the conduit that is corrosion resistant to material 590 in the conduit. Cladding applied to conduit 552 may be a coating and/or a liner. If the conduit contains a metal salt, the inner surface of the conduit may include coating of nickel, or the conduit may be or include a liner of a corrosion resistant metal such as Alloy N. If the conduit contains a molten metal, the conduit may include a corrosion resistant metal liner or coating, and/or a ceramic coating (for example, a porcelain coating or fired enamel coating). In an embodiment, conduit 552 is a canister of 410 stainless steel with an outside diameter of about 6 cm. Conduit 552 may not need a thick wall because material 590 may provide internal pressure that inhibits deformation or crushing of the conduit due to external stresses.
FIG. 95 depicts an embodiment of the heater positioned in wellbore 742 of formation 524 with a portion of insulated conductor 574 and conduit 552 oriented substantially horizontally in the formation. Material 590 may provide a head in conduit 552 due to the pressure of the material. The pressure head may keep material 590 in conduit 552. The pressure head may also provide internal pressure that inhibits deformation or collapse of conduit 552 due to external stresses.

In some embodiments, two or more insulated conductors are placed in the conduit. In some embodiments, only one of the insulated conductors is energized. Should the energized conductor fail, one of the other conductors may be energized to maintain the material in a molten phase. The failed insulated conductor may be removed and/or replaced.

The conduit of the heater may be a ribbed conduit. The ribbed conduit may improve the heat transfer characteristics of the conduit as compared to a cylindrical conduit. FIG. 96 depicts a cross-sectional representation of ribbed conduit 592. FIG. 97 depicts a perspective view of a portion of ribbed conduit 592. Ribbed conduit 592 may include rings 594 and ribs 596. Rings 594 and ribs 596 may improve the heat transfer characteristics of ribbed conduit 592. In an embodiment, the cylinder of conduit has an inner diameter of about 5.1 cm and a wall thickness of about 0.57 cm. Rings 594 may be spaced about every 3.8 cm. Rings 594 may have a height of about 1.9 cm and a thickness of about 0.5 cm. Six ribs 596 may be spaced evenly about conduit 552. Ribs 596 may have a thickness of about 0.5 cm and a height of about 1.6 cm. Other dimensions for the cylinder, rings and ribs may be used. Ribbed conduit 592 may be formed from two or more rolled pieces that are welded together to form the ribbed conduit. Other types of conduit with extra surface area to enhance heat transfer from the conduit to the formation may be used.

In some embodiments, the ribbed conduit may be used as the conduit of a conductor-in-conduit heater. For example, the conductor may be a 3.05 cm 410 stainless steel rod and the conduit has dimensions as described above. In other embodiments, the conductor is an insulated conductor and a fluid is positioned between the conductor and the ribbed conduit. The fluid may be a gas or liquid at operating temperatures of the insulated conductor.

In some embodiments, the heat source for the heater is not an insulated conductor. For example, the heat source may be hot fluid circulated through an inner conduit positioned in an outer conduit. The material may be positioned between the inner conduit and the outer conduit. Convection currents in the material may help to more evenly distribute heat to the formation and may inhibit or limit formation of a hot spot where insulation that limits heat transfer to the overburden ends. In some embodiments, the heat sources are downhole oxidizers. The material is placed between an outer conduit and an oxidizer conduit. The oxidizer conduit may be an
exhaust conduit for the oxidizers or the oxidant conduit if the oxidizers are positioned in a u-shaped wellbore with exhaust gases exiting the formation through one of the legs of the u-shaped conduit. The material may help inhibit the formation of hot spots adjacent to the oxidizers of the oxidizer assembly.

[1045] The material to be heated by the insulated conductor may be placed in an open wellbore. FIG. 98 depicts material 590 in open wellbore 742 in formation 524 with insulated conductor 574 in the wellbore. In some embodiments, a gas (for example, nitrogen, carbon dioxide, and/or helium) is placed in wellbore 742 above material 590. The gas may inhibit oxidation or other chemical changes of material 590. The gas may inhibit vaporization of material 590.

[1046] Material 590 may have a melting point that is above the pyrolysis temperature of hydrocarbons in the formation. The melting point of material 590 may be above 375 °C, above 400 °C, or above 425 °C. The insulated conductor may be energized to heat the formation. Heat from the insulated conductor may pyrolyze hydrocarbons in the formation. Adjacent the wellbore, the heat from insulated conductor 574 may result in coking that reduces the permeability and plugs the formation near wellbore 742. The plugged formation inhibits material 590 from leaking from wellbore 742 into formation 524 when the material is a liquid. In some embodiments, material 590 is a salt.

[1047] In some embodiments, material 590 leaking from wellbore 742 into formation 524 may be self-healing and/or self-sealing. Material 590 flowing away from wellbore 742 may travel until the temperature becomes less than the solidification temperature of the material. Temperature may drop rapidly a relatively small distance away from the heater used to maintain material 590 in a liquid state. The rapid drop off in temperature may result in migrating material 590 solidifying close to wellbore 742. Solidified material 590 may inhibit migration of additional material from wellbore 742, and thus self-heal and/or self-seal the wellbore.

[1048] Return electrical current for insulated conductor 574 may return through jacket 540 of the insulated conductor. Any current that passes through material 590 may pass to ground. Above the level of material 590, any remaining return electrical current may be confined to jacket 540 of insulated conductor 574.

[1049] Using liquid material in open wellbores heated by heaters may allow for delivery of high power rates (for example, up to about 2000 W/m) to the formation with relatively low heater surface temperatures. Hot spot generation in the formation may be reduced or eliminated due to convection smoothing out the temperature profile along the length of the heater. Natural convection occurring in the wellbore may greatly enhance heat transfer from the heater to the formation. Also, the large gap between the formation and the heater may prevent thermal expansion of the formation from harming the heater.
[1050] In some embodiments, an 8" (20.3 cm) wellbore may be formed in the formation. In some embodiments, casing may be placed through all or a portion of the overburden. A 0.6 inch (1.5 cm) diameter insulated conductor heater may be placed in the wellbore. The wellbore may be filled with solid material (for example, solid particles of salt). A packer may be placed near an interface between the treatment area and the overburden. In some embodiments, a pass through conduit in the packer may be included to allow for the addition of more material to the treatment area. A non-reactive or substantially non-reactive gas (for example, carbon dioxide and/or nitrogen) may be introduced into the wellbore. The insulated conductor may be energized to begin the heating that melts the solid material and heats the treatment area.

[1051] In some embodiments, other types of heat sources besides for insulated conductors are used to heat the material placed in the open wellbore. The other types of heat sources may include gas burners, pipes through which hot heat transfer fluid flows, or other types of heaters.

[1052] In some embodiments, heat pipes are placed in the formation. The heat pipes may reduce the number of active heat sources needed to heat a treatment area of a given size. The heat pipes may reduce the time needed to heat the treatment area of a given size to a desired average temperature. A heat pipe is a closed system that utilizes phase change of fluid in the heat pipe to transport heat applied to a first region to a second region remote from the first region. The phase change of the fluid allows for large heat transfer rates. Heat may be applied to the first region of the heat pipes from any type of heat source, including but not limited to, electric heaters, oxidizers, heat provided from geothermal sources, and/or heat provided from nuclear reactors.

[1053] Heat pipes are passive heat transport systems that include no moving parts. Heat pipes may be positioned in near horizontal to vertical configurations. The fluid used in heat pipes for heating the formation may have a low cost, a low melting temperature, a boiling temperature that is not too high (for example, generally below about 900 °C), a low viscosity at temperatures below about 540 °C, a high heat of vaporization, and a low corrosion rate for the heat pipe material. In some embodiments, the heat pipe includes a liner of material that is resistant to corrosion by the fluid. TABLE 1 shows melting and boiling temperatures for several materials that may be used as the fluid in heat pipes. Other salts that may be used include, but are not limited to LiNO₃, and eutectic mixtures such as 53% by weight KNO₃; 40% by weight NaNO₃ and 7% by weight NaNO₂; 45.5% by weight KNO₃ and 54.5% by weight NaNO₂; or 50% by weight NaCl and 50% by weight SrCl₂.

[1054] FIG. 99 depicts schematic cross-sectional representation of a portion of the formation with heat pipes 598 positioned adjacent to a substantially horizontal portion of heat source 202. Heat source 202 is placed in a wellbore in the formation. Heat source 202 may be a gas burner assembly, an electrical heater, a leg of a circulation system that circulates hot fluid through the
formation, or other type of heat source. Heat pipes 598 may be placed in the formation so that
distal ends of the heat pipes are near or contact heat source 202. In some embodiments, heat
pipes 598 mechanically attach to heat source 202. Heat pipes 598 may be spaced a desired
distance apart. In an embodiment, heat pipes 598 are spaced apart by about 40 feet. In other
embodiments, large or smaller spacings are used. Heat pipes 598 may be placed in a regular
pattern with each heat pipe spaced a given distance from the next heat pipe. In some
embodiments, heat pipes 598 are placed in an irregular pattern. An irregular pattern may be used
to provide a greater amount of heat to a selected portion or portions of the formation. Heat pipes
598 may be vertically positioned in the formation. In some embodiments, heat pipes 598 are
placed at an angle in the formation.

[1055] Heat pipes 598 may include sealed conduit 600, seal 602, liquid heat transfer fluid 604
and vaporized heat transfer fluid 606. In some embodiments, heat pipes 598 include metal mesh
or wicking material that increases the surface area for condensation and/or promotes flow of the
heat transfer fluid in the heat pipe. Conduit 600 may have first portion 608 and second portion
610. Liquid heat transfer fluid 604 may be in first portion 608. Heat source 202 external to heat
pipe 598 supplies heat that vaporizes liquid heat transfer fluid 604. Vaporized heat transfer fluid
606 diffuses into second portion 610. Vaporized heat transfer fluid 606 condenses in second
portion and transfers heat to conduit 600, which in turn transfers heat to the formation. The
condensed liquid heat transfer fluid 604 flows by gravity to first portion 608.

[1056] Position of seal 602 is a factor in determining the effective length of heat pipe 598. The
effective length of heat pipe 598 may also depend on the physical properties of the heat transfer
fluid and the cross-sectional area of conduit 600. Enough heat transfer fluid may be placed in
conduit 600 so that some liquid heat transfer fluid 604 is present in first portion 608 at all times.

[1057] Seal 602 may provide a top seal for conduit 600. In some embodiments, conduit 600 is
purged with nitrogen, helium or other fluid prior to being loaded with heat transfer fluid and
sealed. In some embodiments, a vacuum may be drawn on conduit 600 to evacuate the conduit
before the conduit is sealed. Drawing a vacuum on conduit 600 before sealing the conduit may
enhance vapor diffusion throughout the conduit. In some embodiments, an oxygen getter may be
introduced in conduit 600 to react with any oxygen present in the conduit.

[1058] FIG. 100 depicts a perspective cut-out representation of a portion of a heat pipe
embodiment with heat pipe 598 located radially around oxidizer assembly 612. Oxidizers 614 of
oxidizer assembly 612 are positioned adjacent to first portion 608 of heat pipe 598. Fuel may be
supplied to oxidizers 614 through fuel conduit 616. Oxidant may be supplied to oxidizers 614
through oxidant conduit 618. Exhaust gas may flow through the space between outer conduit
620 and oxidant conduit 618. Oxidizers 614 combust fuel to provide heat that vaporizes liquid
heat transfer fluid 604. Vaporized heat transfer fluid 606 rises in heat pipe 598 and condenses on walls of the heat pipe to transfer heat to sealed conduit 600. Exhaust gas from oxidizers 614 provides heat along the length of sealed conduit 600. The heat provided by the exhaust gas along the effective length of heat pipe 598 may increase convective heat transfer and/or reduce the lag time before significant heat is provided to the formation from the heat pipe along the effective length of the heat pipe.

[1059] FIG. 101 depicts a cross-sectional representation of an angled heat pipe embodiment with oxidizer assembly 612 located near a lowermost portion of heat pipe 598. Fuel may be supplied to oxidizers 614 through fuel conduit 616. Oxidant may be supplied to oxidizers 614 through oxidant conduit 618. Exhaust gas may flow through the space between outer conduit 620 and oxidant conduit 618.

[1060] FIG. 102 depicts a perspective cut-out representation of a portion of a heat pipe embodiment with oxidizer 614 located at the bottom of heat pipe 598. Fuel may be supplied to oxidizer 614 through fuel conduit 616. Oxidant may be supplied to oxidizer 614 through oxidant conduit 618. Exhaust gas may flow through the space between the outer wall of heat pipe 598 and outer conduit 620. Oxidizer 614 combusts fuel to provide heat that vaporizes liquid heat transfer fluid 604. Vaporized heat transfer fluid 606 rises in heat pipe 598 and condenses on walls of the heat pipe to transfer heat to sealed conduit 600. Exhaust gas from oxidizers 614 provides heat along the length of sealed conduit 600 and to outer conduit 620. The heat provided by the exhaust gas along the effective length of heat pipe 598 may increase convective heat transfer and/or reduce the lag time before significant heat is provided to the formation from the heat pipe and oxidizer combination along the effective length of the heat pipe. FIG. 103 depicts a similar embodiment with heat pipe 598 positioned at an angle in the formation.

[1061] FIG. 104 depicts a perspective cut-out representation of a portion of a heat pipe embodiment with oxidizer 614 that produces flame zone adjacent to liquid heat transfer fluid 604 in the bottom of heat pipe 598. Fuel may be supplied to oxidizer 614 through fuel conduit 616. Oxidant may be supplied to oxidizer 614 through oxidant conduit 618. Oxidant and fuel are mixed and combusted to produce flame zone 622. Flame zone 622 provides heat that vaporizes liquid heat transfer fluid 604. Exhaust gases from oxidizer 614 may flow through the space between oxidant conduit 618 and the inner surface of heat pipe 598, and through the space between the outer surface of the heat pipe and outer conduit 620. The heat provided by the exhaust gas along the effective length of heat pipe 598 may increase convective heat transfer and/or reduce the lag time before significant heat is provided to the formation from the heat pipe and oxidizer combination along the effective length of the heat pipe.
[1062] FIG. 105 depicts a perspective cut-out representation of a portion of a heat pipe embodiment with a tapered bottom that accommodates multiple oxidizers of an oxidizer assembly. In some embodiments, efficient heat pipe operation requires a high heat input. Multiple oxidizers of oxidizer assembly 612 may provide high heat input to liquid heat transfer fluid 604 of heat pipe 598. A portion of oxidizer assembly with the oxidizers may be helically wound around a tapered portion of heat pipe 598. The tapered portion may have a large surface area to accommodate the oxidizers. Fuel may be supplied to the oxidizers of oxidizer assembly 612 through fuel conduit 616. Oxidant may be supplied to oxidizer 614 through oxidant conduit 618. Exhaust gas may flow through the space between the outer wall of heat pipe 598 and outer conduit 620. Exhaust gas from oxidizers 614 provides heat along the length of sealed conduit 600 and to outer conduit 620. The heat provided by the exhaust gas along the effective length of heat pipe 598 may increase convective heat transfer and/or reduce the lag time before significant heat is provided to the formation from the heat pipe and oxidizer combination along the effective length of the heat pipe.

[1063] FIG. 106 depicts a cross-sectional representation of a heat pipe embodiment that is angled within the formation. First wellbore 624 and second wellbore 626 are drilled in the formation using magnetic ranging or techniques so that the first wellbore intersects the second wellbore. Heat pipe 598 may be positioned in first wellbore 624. First wellbore 624 may be sloped so that liquid heat transfer fluid 604 within heat pipe 598 is positioned near the intersection of the first wellbore and second wellbore 626. Oxidizer assembly 612 may be positioned in second wellbore 626. Oxidizer assembly 612 provides heat to heat pipe 598 that vaporizes liquid heat transfer fluid in the heat pipe. Packer or seal 628 may direct exhaust gas from oxidizer assembly 612 through first wellbore 624 to provide additional heat to the formation from the exhaust gas.

[1064] In some embodiments, the temperature limited heater is used to achieve lower temperature heating (for example, for heating fluids in a production well, heating a surface pipeline, or reducing the viscosity of fluids in a wellbore or near wellbore region). Varying the ferromagnetic materials of the temperature limited heater allows for lower temperature heating. In some embodiments, the ferromagnetic conductor is made of material with a lower Curie temperature than that of 446 stainless steel. For example, the ferromagnetic conductor may be an alloy of iron and nickel. The alloy may have between 30% by weight and 42% by weight nickel with the rest being iron. In one embodiment, the alloy is Invar 36. Invar 36 is 36% by weight nickel in iron and has a Curie temperature of 277 °C. In some embodiments, an alloy is a three component alloy with, for example, chromium, nickel, and iron. For example, an alloy may have 6% by weight chromium, 42% by weight nickel, and 52% by weight iron. A 2.5 cm diameter rod of Invar 36 has a turndown ratio of approximately 2 to 1 at the Curie temperature. Placing the
Invar 36 alloy over a copper core may allow for a smaller rod diameter. A copper core may result in a high turndown ratio. The insulator in lower temperature heater embodiments may be made of a high performance polymer insulator (such as PFA or PEEK\textsuperscript{TM}) when used with alloys with a Curie temperature that is below the melting point or softening point of the polymer insulator.

[1065] In certain embodiments, a conductor-in-conduit temperature limited heater is used in lower temperature applications by using lower Curie temperature and/or the phase transformation temperature range ferromagnetic materials. For example, a lower Curie temperature and/or the phase transformation temperature range ferromagnetic material may be used for heating inside sucker pump rods. Heating sucker pump rods may be useful to lower the viscosity of fluids in the sucker pump or rod and/or to maintain a lower viscosity of fluids in the sucker pump rod. Lowering the viscosity of the oil may inhibit sticking of a pump used to pump the fluids. Fluids in the sucker pump rod may be heated up to temperatures less than about 250 °C or less than about 300 °C. Temperatures need to be maintained below these values to inhibit coking of hydrocarbon fluids in the sucker pump system.

[1066] In certain embodiments, a temperature limited heater includes a flexible cable (for example, a furnace cable) as the inner conductor. For example, the inner conductor may be a 27% nickel-clad or stainless steel-clad stranded copper wire with four layers of mica tape surrounded by a layer of ceramic and/or mineral fiber (for example, alumina fiber, aluminosilicate fiber, borosilicate fiber, or aluminoborosilicate fiber). A stainless steel-clad stranded copper wire furnace cable may be available from Anomet Products, Inc. The inner conductor may be rated for applications at temperatures of 1000 °C or higher. The inner conductor may be pulled inside a conduit. The conduit may be a ferromagnetic conduit (for example, a 3/4” Schedule 80 446 stainless steel pipe). The conduit may be covered with a layer of copper, or other electrical conductor, with a thickness of about 0.3 cm or any other suitable thickness. The assembly may be placed inside a support conduit (for example, a 1-1/4” Schedule 80 347H or 347HH stainless steel tubular). The support conduit may provide additional creep-rupture strength and protection for the copper and the inner conductor. For uses at temperatures greater than about 1000 °C, the inner copper conductor may be plated with a more corrosion resistant alloy (for example, Incoloy\textsuperscript{®} 825) to inhibit oxidation. In some embodiments, the top of the temperature limited heater is sealed to inhibit air from contacting the inner conductor.

[1067] The temperature limited heater may be a single-phase heater or a three-phase heater. In a three-phase heater embodiment, the temperature limited heater has a delta or a wye configuration. Each of the three ferromagnetic conductors in the three-phase heater may be inside a separate sheath. A connection between conductors may be made at the bottom of the
heater inside a splice section. The three conductors may remain insulated from the sheath inside the splice section.

**[1068]** FIG. 107 depicts an embodiment of a three-phase temperature limited heater with ferromagnetic inner conductors. Each leg 632 has inner conductor 532, core 542, and jacket 540. Inner conductors 532 are ferritic stainless steel or 1\% carbon steel. Inner conductors 532 have core 542. Core 542 may be copper. Each inner conductor 532 is coupled to its own jacket 540. Jacket 540 is a sheath made of a corrosion resistant material (such as 304H stainless steel). Electrical insulator 534 is placed between inner conductor 532 and jacket 540. Inner conductor 532 is ferritic stainless steel or carbon steel with an outside diameter of 1.14 cm and a thickness of 0.445 cm. Core 542 is a copper core with a 0.25 cm diameter. Each leg 632 of the heater is coupled to terminal block 634. Terminal block 634 is filled with insulation material 636 and has an outer surface of stainless steel. In some embodiments, insulation material 636 is silicon nitride, boron nitride, magnesium oxide or other suitable electrically insulating material. Inner conductors 532 of legs 632 are coupled (welded) in terminal block 634. Jackets 540 of legs 632 are coupled (welded) to the outer surface of terminal block 634. Terminal block 634 may include two halves coupled around the coupled portions of legs 632.

**[1069]** In some embodiments, the three-phase heater includes three legs that are located in separate wellbores. The legs may be coupled in a common contacting section (for example, a central wellbore, a connecting wellbore, or a solution filled contacting section). FIG. 108 depicts an embodiment of temperature limited heaters coupled in a three-phase configuration. Each leg 638, 640, 642 may be located in separate openings 556 in hydrocarbon layer 484. Each leg 638, 640, 642 may include heating element 644. Each leg 638, 640, 642 may be coupled to single contacting element 646 in one opening 556. Contacting element 646 may electrically couple legs 638, 640, 642 together in a three-phase configuration. Contacting element 646 may be located in, for example, a central opening in the formation. Contacting element 646 may be located in a portion of opening 556 below hydrocarbon layer 484 (for example, in the underburden). In certain embodiments, magnetic tracking of a magnetic element located in a central opening (for example, opening 556 of leg 640) is used to guide the formation of the outer openings (for example, openings 556 of legs 638 and 642) so that the outer openings intersect the central opening. The central opening may be formed first using standard wellbore drilling methods. Contacting element 646 may include funnels, guides, or catchers for allowing each leg to be inserted into the contacting element.

**[1070]** FIG. 109 depicts an embodiment of three heaters coupled in a three-phase configuration. Conductor "legs" 638, 640, 642 are coupled to three-phase transformer 648. Transformer 648 may be an isolated three-phase transformer. In certain embodiments, transformer 648 provides
three-phase output in a wye configuration. Input to transformer 648 may be made in any input configuration, such as the shown delta configuration. Legs 638, 640, 642 each include lead-in conductors 650 in the overburden of the formation coupled to heating elements 644 in hydrocarbon layer 484. Lead-in conductors 650 include copper with an insulation layer. For example, lead-in conductors 650 may be a 4-0 copper cables with TEFLO®N® insulation, a copper rod with polyurethane insulation, or other metal conductors such as bare copper or aluminum. In certain embodiments, lead-in conductors 650 are located in an overburden portion of the formation. The overburden portion may include overburden casings 564. Heating elements 644 may be temperature limited heater heating elements. In an embodiment, heating elements 644 are 410 stainless steel rods (for example, 3.1 cm diameter 410 stainless steel rods). In some embodiments, heating elements 644 are composite temperature limited heater heating elements (for example, 347 stainless steel, 410 stainless steel, copper composite heating elements; 347 stainless steel, iron, copper composite heating elements; or 410 stainless steel and copper composite heating elements). In certain embodiments, heating elements 644 have a length of about 10 m to about 2000 m, about 20 m to about 400 m, or about 30 m to about 300 m.

In certain embodiments, heating elements 644 are exposed to hydrocarbon layer 484 and fluids from the hydrocarbon layer. Thus, heating elements 644 are “bare metal” or “exposed metal” heating elements. Heating elements 644 may be made from a material that has an acceptable sulfidation rate at high temperatures used for pyrolyzing hydrocarbons. In certain embodiments, heating elements 644 are made from material that has a sulfidation rate that decreases with increasing temperature over at least a certain temperature range (for example, 500 °C to 650 °C, 530 °C to 650 °C, or 550 °C to 650 °C). For example, 410 stainless steel may have a sulfidation rate that decreases with increasing temperature between 530 °C and 650 °C. Using such materials reduces corrosion problems due to sulfur-containing gases (such as H₂S) from the formation. In certain embodiments, heating elements 644 are made from material that has a sulfidation rate below a selected value in a temperature range. In some embodiments, heating elements 644 are made from material that has a sulfidation rate at most about 25 mils per year at a temperature between about 800 °C and about 880 °C. In some embodiments, the sulfidation rate is at most about 35 mils per year at a temperature between about 800 °C and about 880 °C, at most about 45 mils per year at a temperature between about 800 °C and about 880 °C, or at most about 55 mils per year at a temperature between about 800 °C and about 880 °C. Heating elements 644 may also be substantially inert to galvanic corrosion.

In some embodiments, heating elements 644 have a thin electrically insulating layer such as aluminum oxide or thermal spray coated aluminum oxide. In some embodiments, the thin electrically insulating layer is a ceramic composition such as an enamel coating. Enamel
coatings include, but are not limited to, high temperature porcelain enamels. High temperature porcelain enamels may include silicon dioxide, boron oxide, alumina, and alkaline earth oxides (CaO or MgO), and minor amounts of alkali oxides (Na₂O, K₂O, LiO). The enamel coating may be applied as a finely ground slurry by dipping the heating element into the slurry or spray coating the heating element with the slurry. The coated heating element is then heated in a furnace until the glass transition temperature is reached so that the slurry spreads over the surface of the heating element and makes the porcelain enamel coating. The porcelain enamel coating contracts when cooled below the glass transition temperature so that the coating is in compression. Thus, when the coating is heated during operation of the heater, the coating is able to expand with the heater without cracking.

[1073] The thin electrically insulating layer has low thermal impedance allowing heat transfer from the heating element to the formation while inhibiting current leakage between heating elements in adjacent openings and/or current leakage into the formation. In certain embodiments, the thin electrically insulating layer is stable at temperatures above at least 350 °C, above 500 °C, or above 800 °C. In certain embodiments, the thin electrically insulating layer has an emissivity of at least 0.7, at least 0.8, or at least 0.9. Using the thin electrically insulating layer may allow for long heater lengths in the formation with low current leakage.

[1074] Heating elements 644 may be coupled to contacting elements 646 at or near the underburden of the formation. Contacting elements 646 are copper or aluminum rods or other highly conductive materials. In certain embodiments, transition sections 652 are located between lead-in conductors 650 and heating elements 644, and/or between heating elements 644 and contacting elements 646. Transition sections 652 may be made of a conductive material that is corrosion resistant such as 347 stainless steel over a copper core. In certain embodiments, transition sections 652 are made of materials that electrically couple lead-in conductors 650 and heating elements 644 while providing little or no heat output. Thus, transition sections 652 help to inhibit overheating of conductors and insulation used in lead-in conductors 650 by spacing the lead-in conductors from heating elements 644. Transition section 652 may have a length of between about 3 m and about 9 m (for example, about 6 m).

[1075] Contacting elements 646 are coupled to contactor 654 in contacting section 656 to electrically couple legs 638, 640, 642 to each other. In some embodiments, contact solution 658 (for example, conductive cement) is placed in contacting section 656 to electrically couple contacting elements 646 in the contacting section. In certain embodiments, legs 638, 640, 642 are substantially parallel in hydrocarbon layer 484 and leg 638 continues substantially vertically into contacting section 656. The other two legs 640, 642 are directed (for example, by directionally drilling the wellbores for the legs) to intercept leg 638 in contacting section 656.
[1076] Each leg 638, 640, 642 may be one leg of a three-phase heater embodiment so that the legs are substantially electrically isolated from other heaters in the formation and are substantially electrically isolated from the formation. Legs 638, 640, 642 may be arranged in a triangular pattern so that the three legs form a triangular shaped three-phase heater. In an embodiment, legs 638, 640, 642 are arranged in a triangular pattern with 12 m spacing between the legs (each side of the triangle has a length of 12 m).

[1077] FIG. 110 depicts a side view representation of an embodiment of centralizer 558 on heater 438. FIG. 111 depicts an end view representation of the embodiment of centralizer 558 on heater 438 depicted in FIG. 110. In certain embodiments, centralizers 558 are made of three or more parts coupled to heater 438 so that the parts are spaced around the outside diameter of the heater. Having spaces between the parts of a centralizer allows debris to fall along the heater (when the heater is vertical or substantially vertical) and inhibit debris from collecting at the centralizer. In certain embodiments, the centralizer is installed on a long heater without inserting a ring. In certain embodiments, heater 438, as depicted in FIGS. 110 and 111, is an electrical conductor used as part of a heater (for example, the electrical conductor of a conductor-in-conduit heater). In certain embodiments, centralizer 558 includes three centralizer parts 558A, 558B, and 558C. In other embodiments, centralizer 558 includes four or more centralizer parts. Centralizer parts 558A, 558B, 558C may be evenly distributed around the outside diameter of heater 438. Centralizer parts 558A, 558B, 558C may have shapes that inhibit collection of material and/or gouging of the canister that surrounds heater 438, even when the centralizer parts are rotated in the canister. In some embodiments, upper portions of centralizer parts 558A, 558B, 558C may taper and/or be rounded to inhibit accumulation of material on top of the centralizer parts.

[1078] In certain embodiments, centralizer parts 558A, 558B, 558C include insulators 660 and weld bases 662. Insulators 660 may be made of electrically insulating material such as, but not limited to, ceramic (for example, magnesium oxide) or silicon nitride. Weld bases 662 may be made of weldable metal such as, but not limited to, Alloy 625, the same metal used for heater 438, or another metal that may be brazed or solid state welded to insulators 660 and welded to a metal used for heater 438.

[1079] Weld bases 662 may be brazed or brazed to heater 438. In certain embodiments, insulators 660 are brazed, or otherwise coupled, to weld bases 662 to form centralizer parts 558A, 558B, 558C. Point load transfer between insulators 660 and weld bases 662 may be minimized by the coupling. In some embodiments, weld bases 662 are coupled to heater 438 first and then insulators 660 are coupled to the weld bases to form centralizer parts 558A, 558B, 558C. Insulators 660 may be coupled to weld bases 662 as the heater is being installed into the
formation. In some embodiments, the bottoms of insulators 660 conform to the shape of heater 438. In other embodiments, the bottoms of insulators 660 are flat or have other geometries.

[1080] In certain embodiments, centralizer parts 558A, 558B, 558C are spaced evenly around the outside diameter of heater 438, as shown in FIGS. 110 and 111. In other embodiments, centralizer parts 558A, 558B, 558C have other spacings around the outside diameter of heater 438.

[1081] Having space between centralizer parts 558A, 558B, 558C allows installation of the heaters and centralizers from a spool or coiled tubing installation of the heaters and centralizers. Centralizer parts 558A, 558B, 558C also allow debris (for example, metal dust or pieces of formation) to fall along heater 438 through the area of the centralizer. Thus, debris is inhibited from collecting at or near centralizer 558. In addition, centralizer parts 558A, 558B, 558C may be inexpensive to manufacture and install and easy to replace if broken.

[1082] FIG. 112 depicts a side view representation of an embodiment of a substantially u-shaped three-phase heater. First ends of legs 638, 640, 642 are coupled to transformer 648 at first location 664. In an embodiment, transformer 648 is a three-phase AC transformer. Ends of legs 638, 640, 642 are electrically coupled together with connector 666 at second location 668. Connector 666 electrically couples the ends of legs 638, 640, 642 so that the legs can be operated in a three-phase configuration. In certain embodiments, legs 638, 640, 642 are coupled to operate in a three-phase wye configuration. In certain embodiments, legs 638, 640, 642 are substantially parallel in hydrocarbon layer 484. In certain embodiments, legs 638, 640, 642 are arranged in a triangular pattern in hydrocarbon layer 484. In certain embodiments, heating elements 644 include thin electrically insulating material (such as a porcelain enamel coating) to inhibit current leakage from the heating elements. In certain embodiments, the thin electrically insulating layer allows for relatively long, substantially horizontal heater leg lengths in the hydrocarbon layer with a substantially u-shaped heater. In certain embodiments, legs 638, 640, 642 are electrically coupled so that the legs are substantially electrically isolated from other heaters in the formation and are substantially electrically isolated from the formation.

[1083] In certain embodiments, overburden casings (for example, overburden casings 564, depicted in FIGS. 109 and 112) in overburden 482 include materials that inhibit ferromagnetic effects in the casings. Inhibiting ferromagnetic effects in casings 564 reduces heat losses to the overburden. In some embodiments, casings 564 may include non-metallic materials such as fiberglass, polyvinylchloride (PVC), chlorinated polyvinylchloride (CPVC), or high-density polyethylene (HDPE). HDPEs with working temperatures in a range for use in overburden 482 include HDPEs available from Dow Chemical Co., Inc. (Midland, Michigan, U.S.A.). A non-metallic casing may also eliminate the need for an insulated overburden conductor. In some
embodiments, casings 564 include carbon steel coupled on the inside diameter of a non-ferromagnetic metal (for example, carbon steel clad with copper or aluminum) to inhibit ferromagnetic effects or inductive effects in the carbon steel. Other non-ferromagnetic metals include, but are not limited to, manganese steels with at least 10% by weight manganese, iron aluminum alloys with at least 18% by weight aluminum, and austenitic stainless steels such as 304 stainless steel or 316 stainless steel.

[1084] In certain embodiments, one or more non-ferromagnetic materials used in casings 564 are used in a wellhead coupled to the casings and legs 638, 640, 642. Using non-ferromagnetic materials in the wellhead inhibits undesirable heating of components in the wellhead. In some embodiments, a purge gas (for example, carbon dioxide, nitrogen or argon) is introduced into the wellhead and/or inside of casings 564 to inhibit reflux of heated gases into the wellhead and/or the casings.

[1085] In certain embodiments, one or more of legs 638, 640, 642 are installed in the formation using coiled tubing. In certain embodiments, coiled tubing is installed in the formation, the leg is installed inside the coiled tubing, and the coiled tubing is pulled out of the formation to leave the leg installed in the formation. The leg may be placed concentrically inside the coiled tubing. In some embodiments, coiled tubing with the leg inside the coiled tubing is installed in the formation and the coiled tubing is removed from the formation to leave the leg installed in the formation. The coiled tubing may extend only to a junction of the hydrocarbon layer and the contacting section, or to a point at which the leg begins to bend in the contacting section.

[1086] FIG. 113 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in the formation. Each triad 670 includes legs A, B, C (which may correspond to legs 638, 640, 642 depicted in FIGS. 109 and 112) that are electrically coupled by linkages 674. Each triad 670 is coupled to its own electrically isolated three-phase transformer so that the triads are substantially electrically isolated from each other. Electrically isolating the triads inhibits net current flow between triads.

[1087] The phases of each triad 670 may be arranged so that legs A, B, C correspond between triads as shown in FIG. 113. Legs A, B, C are arranged such that a phase leg (for example, leg A) in a given triad is about two triad heights from a same phase leg (leg A) in an adjacent triad. The triad height is the distance from a vertex of the triad to a midpoint of the line intersecting the other two vertices of the triad. In certain embodiments, the phases of triads 670 are arranged to inhibit net current flow between individual triads. There may be some leakage of current within an individual triad but little net current flows between two triads due to the substantial electrical isolation of the triads and, in certain embodiments, the arrangement of the triad phases.
In the early stages of heating, an exposed heating element (for example, heating element 644 depicted in FIGS. 109 and 112) may leak some current to water or other fluids that are electrically conductive in the formation so that the formation itself is heated. After water or other electrically conductive fluids are removed from the wellbore (for example, vaporized or produced), the heating elements become electrically isolated from the formation. Later, when water is removed from the formation, the formation becomes even more electrically resistant and heating of the formation occurs even more predominantly via thermally conductive and/or radiative heating. Typically, the formation (the hydrocarbon layer) has an initial electrical resistance that averages at least 10 ohm-m. In some embodiments, the formation has an initial electrical resistance of at least 100 ohm-m or of at least 300 ohm-m.

Using the temperature limited heaters as the heating elements limits the effect of water saturation on heater efficiency. With water in the formation and in heater wellbores, there is a tendency for electrical current to flow between heater elements at the top of the hydrocarbon layer where the voltage is highest and cause uneven heating in the hydrocarbon layer. This effect is inhibited with temperature limited heaters because the temperature limited heaters reduce localized overheating in the heating elements and in the hydrocarbon layer.

In certain embodiments, production wells are placed at a location at which there is relatively little or zero voltage potential. This location minimizes stray potentials at the production well. Placing production wells at such locations improves the safety of the system and reduces or inhibits undesired heating of the production wells caused by electrical current flow in the production wells. FIG. 114 depicts a top view representation of the embodiment depicted in FIG. 113 with production wells 206. In certain embodiments, production wells 206 are located at or near center of triad 670. In certain embodiments, production wells 206 are placed at a location between triads at which there is relatively little or zero voltage potential (at a location at which voltage potentials from vertices of three triads average out to relatively little or zero voltage potential). For example, production well 206 may be at a location equidistant from leg A of one triad, leg B of a second triad, and leg C of a third triad, as shown in FIG. 114.

FIG. 115 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in a hexagonal pattern in the formation. FIG. 116 depicts a top view representation of an embodiment of a hexagon from FIG. 115. Hexagon 672 includes two triads of heaters. The first triad includes legs A1, B1, C1 electrically coupled together by linkages 674 in a three-phase configuration. The second triad includes legs A2, B2, C2 electrically coupled together by linkages 674 in a three-phase configuration. The triads are arranged so that corresponding legs of the triads (for example, A1 and A2, B1 and B2, C1 and C2) are at opposite
vertices of hexagon 672. The triads are electrically coupled and arranged so that there is relatively little or zero voltage potential at or near the center of hexagon 672.

[1092] Production well 206 may be placed at or near the center of hexagon 672. Placing production well 206 at or near the center of hexagon 672 places the production well at a location that reduces or inhibits undesired heating due to electromagnetic effects caused by electrical current flow in the legs of the triads and increases the safety of the system. Having two triads in hexagon 672 provides for redundant heating around production well 206. Thus, if one triad fails or has to be turned off, production well 206 still remains at a center of one triad.

[1093] As shown in FIG. 115, hexagons 672 may be arranged in a pattern in the formation such that adjacent hexagons are offset. Using electrically isolated transformers on adjacent hexagons may inhibit electrical potentials in the formation so that little or no net current leaks between hexagons.

[1094] Triads of heaters and/or heater legs may be arranged in any shape or desired pattern. For example, as described above, triads may include three heaters and/or heater legs arranged in an equilateral triangular pattern. In some embodiments, triads include three heaters and/or heater legs arranged in other triangular shapes (for example, an isosceles triangle or a right angle triangle). In some embodiments, heater legs in the triad cross each other (for example, criss-cross) in the formation. In certain embodiments, triads includes three heaters and/or heater legs arranged sequentially along a straight line.

[1095] Distal sections of the heater legs may be electrically coupled together. The distal sections may be electrically coupled to a connector or to each other. In certain embodiments, contacting elements of the heater legs are physically coupled to establish the electrical coupling. For example, heater legs may be electrically coupled by soldering, by welding, by explosive crimping, by interconnecting brush contacts and/or by other techniques that involve physically attaching the legs to each other or to a connector. In some embodiments, the contacting elements of the heater legs are placed in a contacting solution or other electrically conductive material to electrically couple the heater legs together.

[1096] FIG. 117 depicts an embodiment with triads coupled to a horizontal connector well. Triad 670A includes legs 638A, 640A, 642A. Triad 670B includes legs 638B, 640B, 642B. Legs 638A, 640A, 642A and legs 638B, 640B, 642B may be arranged along a straight line on the surface of the formation. In some embodiments, legs 638A, 640A, 642A are arranged along a straight line and offset from legs 638B, 640B, 642B, which may be arranged along a straight line. Legs 638A, 640A, 642A and legs 638B, 640B, 642B include heating elements 644 located in hydrocarbon layer 484. Lead-in conductors 650 couple heating elements 644 to the surface of the formation. Heating elements 644 are coupled to contacting elements 646 at or near the
underburden of the formation. In certain embodiments, transition sections (for example, transition sections 652 depicted in FIG. 109) are located between lead-in conductors 650 and heating elements 644, and/or between heating elements 644 and contacting elements 646.

[1097] Contacting elements 646 are coupled to contactor 654 in contacting section 656 to electrically couple legs 638A, 640A, 642A to each other to form triad 670A and electrically couple legs 638B, 640B, 642B to each other to form triad 670B. In certain embodiments, contactor 654 is a ground conductor so that triad 670A and/or triad 670B may be coupled in three-phase wye configurations. In certain embodiments, triad 670A and triad 670B are electrically isolated from each other. In some embodiments, triad 670A and triad 670B are electrically coupled to each other (for example, electrically coupled in series or parallel).

[1098] In certain embodiments, contactor 654 is a substantially horizontal contactor located in contacting section 656. Contactor 654 may be a casing or a solid rod placed in a wellbore drilled substantially horizontally in contacting section 656. Legs 638A, 640A, 642A and legs 638B, 640B, 642B may be electrically coupled to contactor 654 by any method described herein or any method known in the art. For example, containers with thermite powder are coupled to contactor 654 (for example, by welding or brazing the containers to the contactor); legs 638A, 640A, 642A and legs 638B, 640B, 642B are placed inside the containers; and the thermite powder is activated to electrically couple the legs to the contactor. The containers may be coupled to contactor 654 by, for example, placing the containers in holes or recesses in contactor 654 or coupled to the outside of the contactor and then brazing or welding the containers to the contactor.

[1099] In certain embodiments, two legs in separate wellbores intercept in a single contacting section. FIG. 118 depicts an embodiment of two temperature limited heaters coupled in a single contacting section. Legs 638 and 640 include one or more heating elements 644. Heating elements 644 may include one or more electrical conductors. In certain embodiments, legs 638 and 640 are electrically coupled in a single-phase configuration with one leg positively biased versus the other leg so that current flows downhole through one leg and returns through the other leg.

[1100] Heating elements 644 in legs 638 and 640 may be temperature limited heaters. In certain embodiments, heating elements 644 are solid rod heaters. For example, heating elements 644 may be rods made of a single ferromagnetic conductor element or composite conductors that include ferromagnetic material. During initial heating when water is present in the formation being heated, heating elements 644 may leak current into hydrocarbon layer 484. The current leaked into hydrocarbon layer 484 may resistively heat the hydrocarbon layer.

[1101] In some embodiments (for example, in oil shale formations), heating elements 644 do not need support members. Heating elements 644 may be partially or slightly bent, curved, made
into an S-shape, or made into a helical shape to allow for expansion and/or contraction of the heating elements. In certain embodiments, solid rod heating elements 644 are placed in small diameter wellbores (for example, about 3 ¾” (about 9.5 cm) diameter wellbores). Small diameter wellbores may be less expensive to drill or form than larger diameter wellbores, and there will be less cuttings to dispose of.

[1102] In certain embodiments, portions of legs 638 and 640 in overburden 482 have insulation (for example, polymer insulation) to inhibit heating the overburden. Heating elements 644 may be substantially vertical and substantially parallel to each other in hydrocarbon layer 484. At or near the bottom of hydrocarbon layer 484, leg 638 may be directionally drilled towards leg 640 to intercept leg 640 in contacting section 656. Drilling two wellbores to intercept each other may be easier and less expensive than drilling three or more wellbores to intercept each other. The depth of contacting section 656 depends on the length of bend in leg 638 needed to intercept leg 640. For example, for a 40 ft (about 12 m) spacing between vertical portions of legs 638 and 640, about 200 ft (about 61 m) is needed to allow the bend of leg 638 to intercept leg 640. Coupling two legs may require a thinner contacting section 656 than coupling three or more legs in the contacting section.

[1103] FIG. 119 depicts an embodiment for coupling legs 638 and 640 in contacting section 656. Heating elements 644 are coupled to contacting elements 646 at or near junction of contacting section 656 and hydrocarbon layer 484. Contacting elements 646 may be copper or another suitable electrical conductor. In certain embodiments, contacting element 646 in leg 640 is a liner with opening 676. Contacting element 646 from leg 638 passes through opening 676. Contactor 654 is coupled to the end of contacting element 646 from leg 638. Contactor 654 provides electrical coupling between contacting elements in legs 638 and 640.

[1104] In certain embodiments, contacting elements 646 include one or more fins or projections. The fins or projections may increase an electrical contact area of contacting elements 646. In some embodiments, contacting element 646 of leg 640 has an opening or other orifice that allows the contacting element of 638 to couple to the contacting element of leg 640.

[1105] In certain embodiments, legs 638 and 640 are coupled together to form a diad. Three diads may be coupled to a three-phase transformer to power the legs of the heaters. FIG. 120 depicts an embodiment of three diads coupled to a three-phase transformer. In certain embodiments, transformer 648 is a delta three-phase transformer. Diad 678A includes legs 638A and 640A. Diad 678B includes legs 638B and 640B. Diad 678C includes legs 638C and 640C. Diads 678A, 678B, 678C are coupled to the secondaries of transformer 648. Diad 678A is coupled to the “A” secondary. Diad 678B is coupled to the “B” secondary. Diad 678C is coupled to the “C” secondary.
[1106] Coupling the diads to the secondaries of the delta three-phase transformer isolates the diads from ground. Isolating the diads from ground inhibits leakage to the formation from the diads. Coupling the diads to different phases of the delta three-phase transformer also inhibits leakage between the heating legs of the diads in the formation.

[1107] In some embodiments, diads are used for treating formations using triangular or hexagonal heater patterns. FIG. 121 depicts an embodiment of groups of diads in a hexagonal pattern. Heaters may be placed at the vertices of each of the hexagons in the hexagonal pattern. Each group 680 of diads (enclosed by dashed circles) may be coupled to a separate three-phase transformer. “A”, “B”, and “C” inside groups 680 represent each diad (for example, diads 678A, 678B, 678C depicted in FIG. 120) that is coupled to each of the three secondary phases of the transformer with each phase coupled to one diad (with the heaters at the vertices of the hexagon). The numbers “1”, “2”, and “3” inside the hexagons represent the three repeating types of hexagons in the pattern depicted in FIG. 121.

[1108] FIG. 122 depicts an embodiment of diads in a triangular pattern. Three diads 678A, 678B, 678C may be enclosed in each group 680 of diads (enclosed by dashed rectangles). Each group 680 may be coupled to a separate three-phase transformer.

[1109] In certain embodiments, exposed metal heating elements are used in substantially horizontal sections of u-shaped wellbores. Substantially u-shaped wellbores may be used in tar sands formations, oil shale formation, or other formations with relatively thin hydrocarbon layers. Tar sands or thin oil shale formations may have thin shallow layers that are more easily and uniformly heated using heaters placed in substantially u-shaped wellbores. Substantially u-shaped wellbores may also be used to process formations with thick hydrocarbon layers. In some embodiments, substantially u-shaped wellbores are used to access rich layers in a thick hydrocarbon formation.

[1110] Heaters in substantially u-shaped wellbores may have long lengths compared to heaters in vertical wellbores because horizontal heating sections do not have problems with creep or hanging stress encountered with vertical heating elements. Substantially u-shaped wellbores may make use of natural seals in the formation and/or the limited thickness of the hydrocarbon layer. For example, the wellbores may be placed above or below natural seals in the formation without punching large numbers of holes in the natural seals, as would be needed with vertically oriented wellbores. Using substantially u-shaped wellbores instead of vertical wellbores may also reduce the number of wells needed to treat a surface footprint of the formation. Using less wells reduces capital costs for equipment and reduces the environmental impact of treating the formation by reducing the amount of wellbores on the surface and the amount of equipment on the surface.
Substantially u-shaped wellbores may also utilize a lower ratio of overburden section to heated section than vertical wellbores. [1111] Substantially u-shaped wellbores may allow for flexible placement of the openings of the wellbores on the surface. Openings to the wellbores may be placed according to the surface topology of the formation. In certain embodiments, the openings of wellbores are placed at geographically accessible locations such as topological highs (for examples, hills). For example, the wellbore may have a first opening on a first topologic high and a second opening on a second topologic high and the wellbore crosses beneath a topologic low (for example, a valley with alluvial fill) between the first and second topologic highs. This placement of the openings may avoid placing openings or equipment in topologic lows or other inaccessible locations. In addition, the water level may not be artesian in topologically high areas. Wellbores may be drilled so that the openings are not located near environmentally sensitive areas such as, but not limited to, streams, nesting areas, or animal refuges. [1112] FIG. 123 depicts a cross-sectional representation of an embodiment of a heater with an exposed metal heating element placed in a substantially u-shaped wellbore. Heaters 438A, 438B, 438C have first end portions at first location 664 on surface 568 of the formation and second end portions at second location 668 on the surface. Heaters 438A, 438B, 438C have sections 682 in overburden 482. Sections 682 are configured to provide little or no heat output. In certain embodiments, sections 682 include an insulated electrical conductor such as insulated copper. Sections 682 are coupled to heating elements 644. [1113] In certain embodiments, portions of heating elements 644 are substantially parallel in hydrocarbon layer 484. In certain embodiments, heating elements 644 are exposed metal heating elements. In certain embodiments, heating elements 644 are exposed metal temperature limited heating elements. Heating elements 644 may include ferromagnetic materials such as 9% by weight to 13% by weight chromium stainless steel like 410 stainless steel, chromium stainless steels such as T/P91 or T/P92, 409 stainless steel, VM12 (Vallourec and Mannesmann Tubes, France) or iron-cobalt alloys for use as temperature limited heaters. In some embodiments, heating elements 644 are composite temperature limited heating elements such as 410 stainless steel and copper composite heating elements or 347H, iron, copper composite heating elements. Heating elements 644 may have lengths of at least about 100 m, at least about 500 m, or at least about 1000 m, up to lengths of about 6000 m. [1114] Heating elements 644 may be solid rods or tubulars. In certain embodiments, solid rod heating elements have diameters several times the skin depth at the Curie temperature of the ferromagnetic material. Typically, the solid rod heating elements may have diameters of 1.91 cm or larger (for example, 2.5 cm, 3.2 cm, 3.81 cm, or 5.1 cm). In certain embodiments, tubular
heating elements have wall thicknesses of at least twice the skin depth at the Curie temperature of the ferromagnetic material. Typically, the tubular heating elements have outside diameters of between about 2.5 cm and about 15.2 cm and wall thickness in range between about 0.13 cm and about 1.01 cm.

[1115] In certain embodiments, tubular heating elements 644 allow fluids to be convected through the tubular heating elements. Fluid flowing through the tubular heating elements may be used to preheat the tubular heating elements to initially heat the formation and/or to recover heat from the formation after heating is completed for the in situ heat treatment process. Fluids that may flow through the tubular heating elements include, but are not limited to, air, water, steam, helium, carbon dioxide or other fluids. In some embodiments, a hot fluid, such as carbon dioxide or helium, flows through the tubular heating elements to provide heat to the formation. The hot fluid may be used to provide heat to the formation before electrical heating is used to provide heat to the formation. In some embodiments, the hot fluid is used to provide heat in addition to electrical heating. Using the hot fluid to provide heat to the formation in addition to providing electrical heating may be less expensive than using electrical heating alone to provide heat to the formation. In some embodiments, water and/or steam flows through the tubular heating element to recover heat from the formation. The heated water and/or steam may be used for solution mining and/or other processes.

[1116] Transition sections 684 may couple heating elements 644 to sections 682. In certain embodiments, transition sections 684 include material that has a high electrical conductivity but is corrosion resistant, such as 347 stainless steel over copper. In an embodiment, transition sections include a composite of stainless steel clad over copper. Transition sections 684 inhibit overheating of copper and/or insulation in sections 682.

[1117] FIG. 124 depicts a top view representation of an embodiment of a surface pattern of the heaters depicted in FIG. 123. Heaters 438A-L may be arranged in a repeating triangular pattern on the surface of the formation. A triangle may be formed by heaters 438A, 438B, and 438C and a triangle formed by heaters 438C, 438D, and 438E. In some embodiments, heaters 438A-L are arranged in a straight line on the surface of the formation. Heaters 438A-L have first end portions at first location 664 on the surface and second end portions at second location 668 on the surface. Heaters 438A-L are arranged such that (a) the patterns at first location 664 and second location 668 correspond to each other, (b) the spacing between heaters is maintained at the two locations on the surface, and/or (c) the heaters all have substantially the same length (substantially the same horizontal distance between the end portions of the heaters on the surface as shown in the top view of FIG. 124).
[1118] As depicted in FIGS. 123 and 124, cables 686, 688 may be coupled to transformer 580 and one or more heater units, such as the heater unit including heaters 438A, 438B, 438C. Cables 686, 688 may carry a large amount of power. In certain embodiments, cables 686, 688 are capable of carrying high currents with low losses. For example, cables 686, 688 may be thick copper or aluminum conductors. The cables may also have thick insulation layers. In some embodiments, cable 686 and/or cable 688 may be superconducting cables. The superconducting cables may be cooled by liquid nitrogen. Superconducting cables are available from Superpower, Inc. (Schenectady, New York, U.S.A.). Superconducting cables may minimize power loss and reduce the size of the cables needed to couple transformer 580 to the heaters. In some embodiments, cables 686, 688 may be made of carbon nanotubes. Carbon nanotubes as conductors may have about 1000 times the conductivity of copper for the same diameter. Also, carbon nanotubes may not require refrigeration during use.

[1119] In certain embodiments, bus bar 690A is coupled to first end portions of heaters 438A-L and bus bar 690B is coupled to second end portions of heaters 438A-L. Bus bars 690A,B electrically couple heaters 438A-L to cables 686, 688 and transformer 580. Bus bars 690A,B distribute power to heaters 438A-L. In certain embodiments, bus bars 690A,B are capable of carrying high currents with low losses. In some embodiments, bus bars 690A,B are made of superconducting material such as the superconductor material used in cables 686, 688. In some embodiments, bus bars 690A,B may include carbon nanotube conductors.

[1120] As shown in FIG. 124, heaters 438A-L are coupled to a single transformer 580. In certain embodiments, transformer 580 is a source of time-varying current. In certain embodiments, transformer 580 is an electrically isolated, single-phase transformer. In certain embodiments, transformer 580 provides power to heaters 438A-L from an isolated secondary phase of the transformer. First end portions of heaters 438A-L may be coupled to one side of transformer 580 while second end portions of the heaters are coupled to the opposite side of the transformer. Transformer 580 provides a substantially common voltage to the first end portions of heaters 438A-L and a substantially common voltage to the second end portions of heaters 438A-L. In certain embodiments, transformer 580 applies a voltage potential to the first end portions of heaters 438A-L that is opposite in polarity and substantially equal in magnitude to a voltage potential applied to the second end portions of the heaters. For example, a +660 V potential may be applied to the first end portions of heaters 438A-L and a -660 V potential applied to the second end portions of the heaters at a selected point on the wave of time-varying current (such as AC or modulated DC). Thus, the voltages at the two end portion of the heaters may be equal in magnitude and opposite in polarity with an average voltage that is substantially at ground potential.
[1121] Applying the same voltage potentials to the end portions of all heaters 438A-L produces voltage potentials along the lengths of the heaters that are substantially the same along the lengths of the heaters. FIG. 125 depicts a cross-sectional representation, along a vertical plane, such as the plane A-A shown in FIG. 123, of substantially u-shaped heaters in a hydrocarbon layer. The voltage potential at the cross-sectional point shown in FIG. 125 along the length of heater 438A is substantially the same as the voltage potential at the corresponding cross-sectional points on heaters 438B-L. At lines equidistant between heater wellheads, the voltage potential is approximately zero. Other wells, such as production wells or monitoring wells, may be located along these zero voltage potential lines, if desired. Production wells 206 located close to the overburden may be used to transport formation fluid that is initially in a vapor phase to the surface. Production wells located close to a bottom of the heated portion of the formation may be used to transport formation fluid that is initially in a liquid phase to the surface.

[1122] In certain embodiments, the voltage potential at the midpoint of heaters 438A-L is about zero. Having similar voltage potentials along the lengths of heaters 438A-L inhibits current leakage between the heaters. Thus, there is little or no current flow in the formation and the heaters may have long lengths. Having the opposite polarity and substantially equal voltage potentials at the end portions of the heaters also halves the voltage applied at either end portion of the heater versus having one end portion of the heater grounded and one end portion at full potential. Reducing (halving) the voltage potential applied to an end portion of the heater generally reduces current leakage, reduces insulator requirements, and/or reduces arcing distances because of the lower voltage potential to ground applied at the end portions of the heaters.

[1123] In certain embodiments, substantially vertical heaters are used to provide heat to the formation. Opposite polarity and substantially equal voltage potentials, as described above, may be applied to the end portions of the substantially vertical heaters. FIG. 126 depicts a side view representation of substantially vertical heaters coupled to a substantially horizontal wellbore. Heaters 438A, 438B, 438C, 438D, 438E, 438F are substantially vertical in hydrocarbon layer 484. First end portions of heaters 438A, 438B, 438C, 438D, 438E, 438F are coupled to bus bar 690A on a surface of the formation. Second end portions of heaters 438A, 438B, 438C, 438D, 438E, 438F are coupled to bus bar 690B in contacting section 656.

[1124] Bus bar 690B may be a bus bar located in a substantially horizontal wellbore in contacting section 656. Second end portions of heaters 438A, 438B, 438C, 438D, 438E, 438F may be coupled to bus bar 690B by any method described herein or any method known in the art. For example, containers with thermite powder are coupled to bus bar 690B (for example, by welding or brazing the containers to the bus bar), end portions of heaters 438A, 438B, 438C,
438D, 438E, 438F are placed inside the containers, and the thermite powder is activated to electrically couple the heaters to the bus bar. The containers may be coupled to bus bar 690B by, for example, placing the containers in holes or recesses in bus bar 690B or coupled to the outside of the bus bar and then brazing or welding the containers to the bus bar.

Bus bar 690A and bus bar 690B may be coupled to transformer 580 with cables 686, 688, as described above. Transformer 580 may provide voltages to bar 690A and bus bar 690B as described above for the embodiments depicted in FIGS. 123 and 124. For example, transformer 580 may apply a voltage potential to the first end portions of heaters 438A-F that is opposite in polarity and substantially equal in magnitude to a voltage potential applied to the second end portions of the heaters. Applying the same voltage potentials to the end portions of all heaters 438A-F may produce voltage potentials along the lengths of the heaters that are substantially the same along the lengths of the heaters. Applying the same voltage potentials to the end portions of all heaters 438A-F may inhibit current leakage between the heaters and/or into the formation. In some embodiments, heaters 438A-F are electrically coupled in pairs to the isolated delta winding on the secondary of a three-phase transformer.

In certain embodiments, it may be advantageous to allow some current leakage into the formation during early stages of heating to heat the formation at a faster rate. Current leakage from the heaters into the formation electrically heats the formation directly. The formation is heated by direct electrical heating in addition to conductive heat provided by the heaters. The formation (the hydrocarbon layer) may have an initial electrical resistance that averages at least 10 ohm-m. In some embodiments, the formation has an initial electrical resistance of at least 100 ohm-m or of at least 300 ohm-m. Direct electrical heating is achieved by having opposite potentials applied to adjacent heaters in the hydrocarbon layer. Current may be allowed to leak into the formation until a selected temperature is reached in the heaters or in the formation. The selected temperature may be below or near the temperature that water proximate one or more heaters boils off. After water boils off, the hydrocarbon layer is substantially electrically isolated from the heaters and direct heating of the formation is inefficient. After the selected temperature is reached, the voltage potential is applied in the opposite polarity and substantially equal magnitude manner described above for FIGS. 123 and 124 so that adjacent heaters will have the same voltage potential along their lengths.

Current is allowed to leak into the formation by reversing the polarity of one or more heaters shown in FIG. 124 so that a first group of heaters has a positive voltage potential at first location 664 and a second group of heaters has a negative voltage potential at the first location. The first end portions, at first location 664, of a first group of heaters (for example, heaters 438A, 438B, 438D, 438E, 438G, 438H, 438J, 438K, depicted in FIG. 124) are applied with a positive
voltage potential that is substantially equal in magnitude to a negative voltage potential applied to the second end portions, at second location 668, of the first group of heaters. The first end portions, at first location 664, of the second group of heaters (for example, heaters 438C, 438F, 438I, 438L) are applied with a negative voltage potential that is substantially equal in magnitude to the positive voltage potential applied to the first end portions of the first group of heaters. Similarly, the second end portions, at second location 668, of the second group of heaters are applied with a positive voltage potential substantially equal in magnitude to the negative potential applied to the second end portions of the first group of heaters. After the selected temperature is reached, the first end portions of both groups of heaters are applied with voltage potential that is opposite in polarity and substantially similar in magnitude to the voltage potential applied to the second end portions of both groups of heaters.

[1128] In some embodiments, the heating elements have thin electrically insulating material to inhibit current leakage from the heating elements. In some embodiments, the thin electrically insulating layer is aluminum oxide or thermal spray coated aluminum oxide. In some embodiments, the thin electrically insulating layer is an enamel coating of a ceramic composition. The thin electrically insulating layer may inhibit heating elements of a three-phase heater from leaking current between the elements, from leaking current into the formation, and from leaking current to other heaters in the formation. Thus, the three-phase heater may have a longer heater length.

[1129] In certain embodiments, a plurality of substantially horizontal (or inclined) heaters are coupled to a single substantially horizontal bus bar in the subsurface formation. Having the plurality of substantially horizontal heaters connected to a single bus bar in the subsurface reduces the overall footprint of heaters on the surface of the formation and the number of wells drilled in the formation. In addition, the amount of subsurface space used to couple the heaters may be minimized so that more of the formation is treated with heat to recover hydrocarbons (for example, there is less unheated depth in the formation). The number and spacing of heaters coupled to the single bus bar may be varied depending on factors such as, but not limited to, size of the treatment area, vertical thickness of the formation, heating requirements for the formation, number of layers in the formation, and capacity limitations of the surface power supply.

[1130] FIG. 127 depicts an embodiment of pluralities of substantially horizontal heaters 438A,B coupled to bus bars 690A,B in hydrocarbon layer 484. Heaters 438A,B have sections 682 in the overburden of hydrocarbon layer 484. Sections 682 may include high electrical conductivity, low thermal loss electrical conductors such as copper or copper clad carbon steel. Heaters 438A,B enter hydrocarbon layer 484 with substantially vertical sections and then redirect so that the heaters have substantially horizontal sections in hydrocarbon layer 484. The substantially
horizontal sections of heaters 438A,B in hydrocarbon layer 484 may provide the majority of the heat to the hydrocarbon layer. Heaters 438A,B may be coupled to bus bars 690A,B, which are located distant from each other in the formation while being substantially parallel to each other.

[1131] In certain embodiments, heaters 438A,B include exposed metal heating elements. In certain embodiments, heaters 438A,B include exposed metal temperature limited heating elements. The heating elements may include ferromagnetic materials such as 9% by weight to 13% by weight chromium stainless steel like 410 stainless steel, chromium stainless steels such as T/P91 or T/P92, 409 stainless steel, VM12 (Vallourec and Mannesmann Tubes, France) or iron-cobalt alloys for use as temperature limited heaters. In some embodiments, the heating elements are composite temperature limited heating elements such as 410 stainless steel and copper composite heating elements or 347H, iron, copper composite heating elements. The substantially horizontal sections of heaters 438A,B in hydrocarbon layer 484 may have lengths of at least about 100 m, at least about 500 m, or at least about 1000 m, up to lengths of about 6000 m.

[1132] In some embodiments, two groups of heaters 438A,B enter the subsurface near each other and then branch away from each other in hydrocarbon layer 484. Having the surface portions of more than one group of heaters located near each other creates less of a surface footprint of the heaters and allows a single group of surface facilities to be used for both groups of heaters.

[1133] In certain embodiments, the groups of heaters 438A or 438B are each coupled to a single transformer. In some embodiments, three heaters in the groups are coupled in a triad configuration (each heater is coupled to one of the phases (A, B, or C) of a three phase transformer and the bus bar is coupled to the neutral, or center point, of the transformer). Each phase of the three-phase transformer may be coupled to more than one heater in each group of heaters (for example, phase A may be coupled to 5 heaters in the group of heaters 438A). In some embodiments, the heaters are coupled to a single phase transformer (either in series or in parallel configurations).

[1134] FIG. 128 depicts an embodiment of pluralities of substantially horizontal heaters 438A,B coupled to bus bars 690A,B in hydrocarbon layer 484. In such an embodiment, two groups of heaters 438A,B enter the formation at distal locations on the surface of the formation. Heaters 438A,B branch towards each other in hydrocarbon layer 484 so that the ends of the heaters are directed towards each other. Heaters 438A,B may be coupled to bus bars 690A,B, which are located proximate each other and substantially parallel to each other. Bus bars 690A,B may enter the subsurface in proximity to each other so that the footprint of the bus bars on the surface is small.
[1135] In certain embodiments, heaters 438A,B are coupled to a single phase transformer in series or parallel. The heaters may be coupled so that the polarity (direction of current flow) alternates in the row of heaters so that each heater has a polarity opposite the heater adjacent to it. Additionally, heaters 438A,B and bus bars 690A,B may be electrically coupled such that the bus bars are opposite in polarity from each other (the current flows in opposite directions at any point in time in each bus bar). Coupling the heaters and the bus bars in such a manner inhibits current leakage into and/or through the formation.

[1136] As shown in FIGS. 127 and 128, heaters 438A may be electrically coupled to bus bar 690A and heaters 438B may be electrically coupled to bus bar 690B. Bus bars 690A,B may electrically couple to the ends of heaters 438A,B and be a return or neutral connection for the heaters with bus bar 690A being the neutral connection for heaters 438A and bus bar 690B being the neutral connection for heaters 438B. Bus bars 690A,B may be located in wellbores that are formed substantially perpendicular to the path of wellbores with heaters 438A,B, as shown in FIG. 127. Directional drilling and/or magnetic steering may be used so that the wells for bus bars 690A,B and the wellbores for heaters 438A,B intersect.

[1137] In certain embodiments, heaters 438A,B are coupled to bus bars 690A,B using "mousetrap" type connectors 692. In some embodiments, other couplings, such as those described herein or known in the art, are used to couple heaters 438A,B to bus bars 690A,B. For example, a molten metal or a liquid conducting fluid may fill up the connection space (in the wellbores) to electrically couple the heaters and the bus bars.

[1138] FIG. 129 depicts an enlarged view of an embodiment of bus bar 690 coupled to heaters 438 with connectors 692. In certain embodiments, bus bar 690 includes carbon steel or other electrically conducting metals. In some embodiments, a high electrical conductivity conductor or metal is coupled to or included in bus bar 690. For example, bus bar 690 may include carbon steel with copper cladded to the carbon steel.

[1139] In some embodiments, a centralizer or other centralizing device is used to locate or guide heaters 438 and/or bus bars 690 so that the heaters and bus bars can be coupled. FIG. 130 depicts an enlarged view of an embodiment of bus bar 690 coupled to heater 438 with connectors 692 and centralizers 558. Centralizers 558 may locate heater 438 and/or bus bar 690 so that connectors 692 easily couple the heater and the bus bar. Centralizers 558 may ensure proper spacing of heater 438 and/or bus bar 690 so that the heater and the bus bar can be coupled with connectors 692. Centralizers 558 may inhibit heater 438 and/or bus bar 690 from contacting the sides of the wellbores at or near connectors 692.

[1140] FIG. 131 depicts a cross-sectional representation of connector 692 coupling to bus bar 690. FIG. 132 depicts a perspective representation of connector 692 coupling to bus bar 690.
Connectors 692 are shown in proximity to bus bar 690 (before the connector clamps around the bus bar). Connector 692 is connected or directly attached to the heater so that the connector is rotatable around the end of the heater while maintaining electrical contact with the heater. In some embodiments, the connector and the end of the heater are twisted into position to align with the bus bar. Connector 692 includes collets 694. Collets 694 are shaped (for example, diagonally cut or helically profiled) so that as the connector is pushed onto bus bar 690, the shape of the collets rotates the head of the connector as the collets slide over the bus bar. Collets 694 may be spring loaded so that the collets hold down against bus bar 690 after the collets slide over the bus bar. Thus, connector 692 clamps to bus bar 690 using collets 694. Connector 692, including collets 694, is made of electrically conductive materials so that the connector electrically couples bus bar 690 to the heater attached to the connector.

[1141] In some embodiments, an explosive element is added to connectors 692, such as the connectors shown in FIGS. 131 and 132. Connector 692 is used to position bus bar 690 and the heater in proper positions for explosive bonding of the bus bar to the heater. The explosive element may be located on connector 692. For example, the explosive element may be located on one or both of collets 694. The explosive element may be used to explosively bond connector 692 to bus bar 690 so that the heater is metallically bonded to the bus bar.

[1142] In some embodiment, the explosive bonding is applied along the axial direction of bus bar 690. In some embodiments, the explosive bonding process is a self cleaning process. For example, the explosive bonding process may drive out air and/or debris from between components during the explosion. In some embodiments, the explosive element is a shape charge explosive element. Using the shape charge element may focus the explosive energy in a desired direction.

[1143] FIG. 133 depicts an embodiment of three u-shaped heaters with common overburden sections coupled to a single three-phase transformer. In certain embodiments, heaters 438A, 438B, 438C are exposed metal heaters. In some embodiments, heaters 438A, 438B, 438C are exposed metal heaters with a thin, electrically insulating coating on the heaters. For example, heaters 438A, 438B, 438C may be 410 stainless steel, carbon steel, 347H stainless steel, or other corrosion resistant stainless steel rods or tubulars (such as 2.5 cm or 3.2 cm diameter rods). The rods or tubulars may have porcelain enamel coatings on the exterior of the rods to electrically insulate the rods.

[1144] In some embodiments, heaters 438A, 438B, 438C are insulated conductor heaters. In some embodiments, heaters 438A, 438B, 438C are conductor-in-conduit heaters. Heaters 438A, 438B, 438C may have substantially parallel heating sections in hydrocarbon layer 484. Heaters 438A, 438B, 438C may be substantially horizontal or at an incline in hydrocarbon layer 484. In
some embodiments, heaters 438A, 438B, 438C enter the formation through common wellbore 428A. Heaters 438A, 438B, 438C may exit the formation through common wellbore 428B. In certain embodiments, wellbores 428A, 428B are uncased (for example, open wellbores) in hydrocarbon layer 484.

[1145] Openings 556A, 556B, 556C span between wellbore 428A and wellbore 428B. Openings 556A, 556B, 556C may be uncased openings in hydrocarbon layer 484. In certain embodiments, openings 556A, 556B, 556C are formed by drilling from wellbore 428A and/or wellbore 428B. In some embodiments, openings 556A, 556B, 556C are formed by drilling from each wellbore 428A and 428B and connecting at or near the middle of the openings. Drilling from both sides towards the middle of hydrocarbon layer 484 allows longer openings to be formed in the hydrocarbon layer. Thus, longer heaters may be installed in hydrocarbon layer 484. For example, heaters 438A, 438B, 438C may have lengths of at least about 1500 m, at least about 3000 m, or at least about 4500 m.

[1146] Having multiple long, substantially horizontal or inclined heaters extending from only two wellbores in hydrocarbon layer 484 reduces the footprint of wells on the surface needed for heating the formation. The number of overburden wellbores that need to be drilled in the formation is reduced, which reduces capital costs per heater in the formation. Heating the formation with long, substantially horizontal or inclined heaters also reduces overall heat losses in overburden 482 when heating the formation because of the reduced number of overburden sections used to treat the formation (for example, losses in overburden 482 are a smaller fraction of total power supplied to the formation).

[1147] In some embodiments, heaters 438A, 438B, 438C are installed in wellbores 428A, 428B and openings 556A, 556B, 556C by pulling the heaters through the wellbores and the openings from one end to the other. For example, an installation tool may be pushed through the openings and coupled to a heater in wellbore 428A. The heater may then be pulled through the openings towards wellbore 428B using the installation tool. The heater may be coupled to the installation tool using a connector such as a claw, a catcher, or other devices known in the art.

[1148] In some embodiments, the first half of an opening is drilled from wellbore 428A and then the second half of the opening is drilled from wellbore 428B through the first half of the opening. The drill bit may be pushed through to wellbore 428A and a first heater may be coupled to the drill bit to pull the first heater back through the opening and install the first heater in the opening. The first heater may be coupled to the drill bit using a connector such as a claw, a catcher, or other devices known in the art.

[1149] After the first heater is installed, a tube or other guide may be placed in wellbore 428A and/or wellbore 428B to guide drilling of a second opening. FIG. 134 depicts a top view of an
embodiment of heater 438A and drilling guide 696 in wellbore 428. Drilling guide 696 may be used to guide the drilling of the second opening in the formation and the installation of a second heater in the second opening. Insulator 534A may electrically and mechanically insulate heater 438A from drilling guide 696. Drilling guide 696 and insulator 534A may protect heater 438A from being damaged while the second opening is being drilled and the second heater is being installed.

[1150] After the second heater is installed, drilling guide 696 may be placed in wellbore 428 to guide drilling of a third opening, as shown in FIG. 135. Drilling guide 696 may be used to guide the drilling of the third opening in the formation and the installation of a third heater in the third opening. Insulators 534A and 534B may electrically and mechanically insulate heaters 438A and 438B, respectively, from drilling guide 696. Drilling guide 696 and insulators 534A and 534B may protect heaters 438A and 438B from being damaged while the third opening is being drilled and the third heater is being installed. After the third heater is installed, insulators 534A and 534B may be removed and a centralizer may be placed in wellbore 428 to separate and space heaters 438A, 438B, 438C. FIG. 136 depicts heaters 438A, 438B, 438C in wellbore 428 separated by centralizer 558.

[1151] In some embodiments, all the openings are formed in the formation and then the heaters are installed in the formation. In certain embodiments, one of the openings is formed and one of the heaters is installed in the formation before the other openings are formed and the other heaters are installed. The first installed heater may be used as a guide during the formation of additional openings. The first installed heater may be energized to produce an electromagnetic field that is used to guide the formation of the other openings. For example, the first installed heater may be energized with a bipolar DC current to magnetically guide drilling of the other openings.

[1152] In certain embodiments, heaters 438A, 438B, 438C are coupled to a single three-phase transformer 580 at one end of the heaters, as shown in FIG. 133. Heaters 438A, 438B, 438C may be electrically coupled in a triad configuration. In some embodiments, two heaters are coupled together in a diad configuration. Transformer 580 may be a three-phase wye transformer. The heaters may each be coupled to one phase of transformer 580. Using three-phase power to power the heaters may be more efficient than using single-phase power. Using three-phase connections for the heaters allows the magnetic fields of the heaters in wellbore 428A to cancel each other. The cancelled magnetic fields may allow overburden casing 564A to be ferromagnetic (for example, carbon steel). Using ferromagnetic casings in the wellbores may be less expensive and/or easier to install than non-ferromagnetic casings (such as fiberglass casings).
[1153] In some embodiments, the overburden section of heaters 438A, 438B, 438C are coated with an insulator, such as a polymer or an enamel coating, to inhibit shorting between the overburden sections of the heaters. In some embodiments, only the overburden sections of the heaters in wellbore 428A are coated with the insulator as the heater sections in wellbore 428B may not have significant electrical losses. In some embodiments, ends or end portions (portions at, near, or in the vicinity of the ends) of heaters 438A, 438B, 438C in wellbore 428A are at least one diameter of the heaters away from overburden casing 564A so that no insulator is needed. The ends or end portions of heaters 438A, 438B, 438C may be, for example, centralized in wellbore 428A using a centralizer to keep the heaters the desired distance away from overburden casing 564A.

[1154] In some embodiments, the ends or end portions of heaters 438A, 438B, 438C passing through wellbore 428B are electrically coupled together and grounded outside of the wellbore, as shown in FIG. 133. The magnetic fields of the heaters may cancel each other in wellbore 428B. Thus, overburden casing 564B may be ferromagnetic (for example, carbon steel). In certain embodiments, the overburden section of heaters 438A, 438B, 438C are copper rods or tubulars. The build sections of the heaters (the transition sections between the overburden sections and the heating sections) may also be made of copper or similar electrically conductive material.

[1155] In some embodiments, the ends or end portions of heaters 438A, 438B, 438C passing through wellbore 428B are electrically coupled together inside the wellbore. The ends or end portions of the heaters may be coupled inside the wellbore at or near the bottom of overburden 482. Coupling the heaters together at or near overburden 482 reduces electrical losses in the overburden section of the wellbore.

[1156] FIG. 137 depicts an embodiment for coupling ends or end portions of heaters 438A, 438B, 438C in wellbore 428B. Plate 698 may be located at or near the bottom of the overburden section of wellbore 428B. Plate 698 may have openings sized to allow heaters 438A, 438B, 438C to be inserted through the plate. Plate 698 may be slid down heaters 438A, 438B, 438C into position in wellbore 428B. Plate 698 may be made of copper or another electrically conductive material.

[1157] Balls 700 may be placed into the overburden section of wellbore 428B. Plate 698 may allow balls 700 to settle in the overburden section of wellbore 428B around heaters 438A, 438B, 438C. Balls 700 may be made of electrically conductive material such as copper or nickel-plated copper. Balls 700 and plate 698 may electrically couple heaters 438A, 438B, 438C to each other so that the heaters are grounded. In some embodiments, portions of the heaters above plate 698 (the overburden sections of the heaters) are made of carbon steel while portions of the heaters below the plate (build sections of the heaters) are made of copper.
[1158] In some embodiments, heaters 438A, 438B, 438C, as depicted in FIG. 133, provide varying heat outputs along the lengths of the heaters. For example, heaters 438A, 438B, 438C may have varying dimensions (for example, thicknesses or diameters) along the lengths of the heater. The varying thicknesses may provide different electrical resistances along the length of the heater and, thus, different heat outputs along the length of the heaters.

[1159] In some embodiments, heaters 438A, 438B, 438C are divided into two or more sections of heating. In some embodiments, the heaters are divided into repeating sections of different heat outputs (for example, alternating sections of two different heat outputs that are repeated). In some embodiments, the repeating sections of different heat outputs may be used to heat the formation in stages. In one embodiment, the halves of the heaters closest to wellbore 428A may provide heat in a first section of hydrocarbon layer 484 and the halves of the heaters closest to wellbore 428B may provide heat in a second section of hydrocarbon layer 484. Hydrocarbons in the formation may be mobilized by the heat provided in the first section. Hydrocarbons in the second section may be heated to higher temperatures than the first section to upgrade the hydrocarbons in the second section (for example, the hydrocarbons may be further mobilized and/or pyrolyzed). Hydrocarbons from the first section may move, or be moved, into the second section for the upgrading. For example, a drive fluid may be provided through wellbore 428A to move the first section mobilized hydrocarbons to the second section.

[1160] In some embodiments, more than three heaters extend from wellbore 428A and/or 428B. If multiples of three heaters extend from the wellbores and are coupled to transformer 580, the magnetic fields may cancel in the overburden sections of the wellbores as in the case of three heaters in the wellbores. For example, six heaters may be coupled to transformer 580 with two heaters coupled to each phase of the transformer to cancel the magnetic fields in the wellbores.

[1161] In some embodiments, multiple heaters extend from one wellbore in different directions. FIG. 138 depicts a schematic of an embodiment of multiple heaters extending in different directions from wellbore 428A. Heaters 438A, 438B, 438C may extend to wellbore 428B. Heaters 438D, 438E, 438F may extend to wellbore 428C in the opposite direction of heaters 438A, 438B, 438C. Heaters 438A, 438B, 438C and heaters 438D, 438E, 438F may be coupled to a single, three-phase transformer so that magnetic fields are cancelled in wellbore 428A.

[1162] In some embodiments, heaters 438A, 438B, 438C may have different heat outputs from heaters 438D, 438E, 438F so that hydrocarbon layer 484 is divided into two heating sections with different heating rates and/or temperatures (for example, a mobilization and a pyrolyzation section). In some embodiments, heaters 438A, 438B, 438C and/or heaters 438D, 438E, 438F may have heat outputs that vary along the lengths of the heaters to further divide hydrocarbon layer 484 into more heating sections. In some embodiments, additional heaters may extend from
wellbore 428B and/or wellbore 428C to other wellbores in the formation as shown by the dashed lines in FIG. 138.

[1163] In some embodiments, multiple levels of heaters extend between two wellbores. FIG. 139 depicts a schematic of an embodiment of multiple levels of heaters extending between wellbore 428A and wellbore 428B. Heaters 438A, 438B, 438C may provide heat to a first level of hydrocarbon layer 484. Heaters 438D, 438E, 438F may branch off and provide heat to a second level of hydrocarbon layer 484. Heaters 438G, 438H, 438I may further branch off and provide heat to a third level of hydrocarbon layer 484. In some embodiments, heaters 438A, 438B, 438C, heaters 438D, 438E, 438F, and heaters 438G, 438H, 438I provide heat to levels in the formation with different properties. For example, the different groups of heaters may provide different heat outputs to levels with different properties in the formation so that the levels are heated at or about the same rate.

[1164] In some embodiments, the levels are heated at different rates to create different heating zones in the formation. For example, the first level (heated by heaters 438A, 438B, 438C) may be heated so that hydrocarbons are mobilized, the second level (heated by heaters 438D, 438E, 438F) may be heated so that hydrocarbons are somewhat upgraded from the first level, and the third level (heated by heaters 438G, 438H, 438I) may be heated to pyrolyze hydrocarbons. As another example, the first level may be heated to create gases and/or drive fluid in the first level and either the second level or the third level may be heated to mobilize and/or pyrolyze fluids or just to a level to allow production in the level. In addition, heaters 438A, 438B, 438C, heaters 438D, 438E, 438F, and/or heaters 438G, 438H, 438I may have heat outputs that vary along the lengths of the heaters to further divide hydrocarbon layer 484 into more heating sections.

[1165] FIG. 140 depicts a schematic of an embodiment of a u-shaped heater that has an inductively energized tubular. Heater 438 includes electrical conductor 572 and tubular 702 in an opening that spans between wellbore 428A and wellbore 428B. In certain embodiments, electrical conductor 572 and/or the current carrying portion of the electrical conductor is electrically insulated from tubular 702. Electrical conductor 572 and/or the current carrying portion of the electrical conductor is electrically insulated from tubular 702 such that electrical current does not flow from the electrical conductor to the tubular, or vice versa (for example, the tubular is not directly connected electrically to the electrical conductor).

[1166] In some embodiments, electrical conductor 572 is centralized inside tubular 702 (for example, using centralizers 558 or other support structures, as shown in FIG. 141). Centralizers 558 may electrically insulate electrical conductor 572 from tubular 702. In some embodiments, tubular 702 contacts electrical conductor 572. For example, tubular 702 may hang, drape, or otherwise touch electrical conductor 572. In some embodiments, electrical conductor 572
includes electrical insulation (for example, magnesium oxide or porcelain enamel) that insulates the current carrying portion of the electrical conductor from tubular 702. The electrical insulation inhibits current from flowing between the current carrying portion of electrical conductor 572 and tubular 702 if the electrical conductor and the tubular are in physical contact with each other.

[1167] In some embodiments, electrical conductor 572 is an exposed metal conductor heater or a conductor-in-conduit heater. In certain embodiments, electrical conductor 572 is an insulated conductor such as a mineral insulated conductor. The insulated conductor may have a copper core, copper alloy core, or a similar electrically conductive, low resistance core that has low electrical losses. In some embodiments, the core is a copper core with a diameter between about 0.5” (1.27 cm) and about 1” (2.54 cm). The sheath or jacket of the insulated conductor may be a non-ferromagnetic, corrosion resistant steel such as 347 stainless steel, 625 stainless steel, 825 stainless steel, 304 stainless steel, or copper with a protective layer (for example, a protective cladding). The sheath may have an outer diameter of between about 1” (2.54 cm) and about 1.25” (3.18 cm).

[1168] In some embodiments, the sheath or jacket of the insulated conductor is in physical contact with the tubular 702 (for example, the tubular is in physical contact with the sheath along the length of the tubular) or the sheath is electrically connected to the tubular. In such embodiments, the electrical insulation of the insulated conductor electrically insulates the core of the insulated conductor from the jacket and the tubular. FIG. 142 depicts an embodiment of an induction heater with the sheath of an insulated conductor in electrical contact with tubular 702. Electrical conductor 572 is the insulated conductor. The sheath of the insulated conductor is electrically connected to tubular 702 using electrical contactors 704. In some embodiments, electrical contactors 704 are sliding contactors. In certain embodiments, electrical contactors 704 electrically connect the sheath of the insulated conductor to tubular 702 at or near the ends of the tubular. Electrically connecting at or near the ends of tubular 702 substantially equalizes the voltage along the tubular with the voltage along the sheath of the insulated conductor. Equalizing the voltages along tubular 702 and along the sheath may inhibit arcing between the tubular and the sheath.

[1169] Tubular 702, such as the tubular shown in FIGS. 140, 141, and 142, may be ferromagnetic or include ferromagnetic materials. Tubular 702 may have a thickness such that when electrical conductor 572 induces electrical current flow on the surfaces of tubular 702 when the electrical conductor is energized with time-varying current. The electrical conductor induces electrical current flow due to the ferromagnetic properties of the tubular. Current flow is induced on both the inside surface of the tubular and the outside surface of tubular 702. Tubular 702 may
operate as a skin effect heater when current flow is induced in the skin depth of one or more of the tubular surfaces. In certain embodiments, the induced current circulates axially (longitudinally) on the inside and/or outside surfaces of tubular 702. Longitudinal flow of current through electrical conductor 572 induces primarily longitudinal current flow in tubular 702 (the majority of the induced current flow is in the longitudinal direction in the tubular). Having primarily longitudinal induced current flow in tubular 702 may provide a higher resistance per foot than if the induced current flow is primarily angular current flow.

[1170] In certain embodiments, current flow in tubular 702 is induced with low frequency current in electrical conductor 572 (for example, from 50 Hz or 60 Hz up to about 1000 Hz). In some embodiments, induced currents on the inside and outside surfaces of tubular 702 are substantially equal.

[1171] In certain embodiments, tubular 702 has a thickness that is greater than the skin depth of the ferromagnetic material in the tubular at or near the Curie temperature of the ferromagnetic material or at or near the phase transformation temperature of the ferromagnetic material. For example, tubular 702 may have a thickness of at least 2.1, at least 2.5 times, at least 3 times, or at least 4 times the skin depth of the ferromagnetic material in the tubular near the Curie temperature or the phase transformation temperature of the ferromagnetic material. In certain embodiments, tubular 702 has a thickness of at least 2.1 times, at least 2.5 times, at least 3 times, or at least 4 times the skin depth of the ferromagnetic material in the tubular at about 50 °C below the Curie temperature or the phase transformation temperature of the ferromagnetic material.

[1172] In certain embodiments, tubular 702 is carbon steel. In some embodiments, tubular 702 is coated with a corrosion resistant coating (for example, porcelain or ceramic coating) and/or an electrically insulating coating. In some embodiments, electrical conductor 572 has an electrically insulating coating. Examples of the electrically insulating coating on tubular 702 and/or electrical conductor 572 include, but are not limited to, a porcelain enamel coating, an alumina coating, or an alumina-titania coating.

[1173] In some embodiments, tubular 702 and/or electrical conductor 572 are coated with a coating such as polyethylene or another suitable low friction coefficient coating that may melt or decompose when the heater is energized. The coating may facilitate placement of the tubular and/or the electrical conductor in the formation.

[1174] In some embodiments, tubular 702 includes corrosion resistant ferromagnetic material such as, but not limited to, 410 stainless steel, 446 stainless steel, T/P91 stainless steel, T/P92 stainless steel, alloy 52, alloy 42, and Invar 36. In some embodiments, tubular 702 is a stainless
steel tubular with cobalt added (for example, between about 3% by weight and about 10% by weight cobalt added) and/or molybdenum (for example, about 0.5 % molybdenum by weight).

At or near the Curie temperature or the phase transformation temperature of the ferromagnetic material in tubular 702, the magnetic permeability of the ferromagnetic material decreases rapidly. When the magnetic permeability of tubular 702 decreases at or near the Curie temperature or the phase transformation temperature, there is little or no current flow in the tubular because, at these temperatures, the tubular is essentially non-ferromagnetic and electrical conductor 572 is unable to induce current flow in the tubular. With little or no current flow in tubular 702, the temperature of the tubular will drop to lower temperatures until the magnetic permeability increases and the tubular becomes ferromagnetic. Thus, tubular 702 self-limits at or near the Curie temperature or the phase transformation temperature and operates as a temperature limited heater due to the ferromagnetic properties of the ferromagnetic material in the tubular. Because current is induced in tubular 702, the turndown ratio may be higher and the drop in current sharper for the tubular than for temperature limited heaters that apply current directly to the ferromagnetic material. For example, heaters with current induced in tubular 702 may have turndown ratios of at least about 5, at least about 10, or at least about 20 while temperature limited heaters that apply current directly to the ferromagnetic material may have turndown ratios that are at most about 5.

When current is induced in tubular 702, the tubular provides heat to hydrocarbon layer 484 and defines the heating zone in the hydrocarbon layer. In certain embodiments, tubular 702 heats to temperatures of at least about 300 °C, at least about 500 °C, or at least about 700 °C. Because current is induced on both the inside and outside surfaces of tubular 702, the heat generation of the tubular is increased as compared to temperature limited heaters that have current directly applied to the ferromagnetic material and current flow is limited to one surface. Thus, less current may be provided to electrical conductor 572 to generate the same heat as heaters that apply current directly to the ferromagnetic material. Using less current in electrical conductor 572 decreases power consumption and reduces power losses in the overburden of the formation.

In certain embodiments, tubulars 702 have large diameters. The large diameters may be used to equalize or substantially equalize high pressures on the tubular from either the inside or the outside of the tubular. In some embodiments, tubular 702 has a diameter in a range between about 1.5” (about 3.8 cm) and about 6” (about 15.2 cm). In some embodiments, tubular 702 has a diameter in a range between about 3 cm and about 13 cm, between about 4 cm and about 12 cm, or between about 5 cm and about 11 cm. Increasing the diameter of tubular 702 may provide more heat output to the formation by increasing the heat transfer surface area of the tubular.
[1178] In certain embodiments, tubular 702 has surfaces that are shaped to increase the resistance of the tubular. FIG. 143 depicts an embodiment of a heater with tubular 702 having radial grooved surfaces. Heater 438 may include electrical conductors 572A,B coupled to tubular 702. Electrical conductors 572A,B may be insulated conductors. Electrical contactors may electrically and physically couple electrical conductors 572A,B to tubular 702. In certain embodiments, the electrical contactors are attached to ends of electrical conductors 572A,B. The electrical contactors have a shape such that when the ends of electrical conductors 572A,B are pushed into the ends of tubular 702, the electrical contactors physically and electrically couple the electrical conductors to the tubular. For example, the electrical contactors may be cone shaped. Heater 438 generates heat when current is applied directly to tubular 702. Current is provided to tubular 702 using electrical conductors 572A,B. Grooves 706 may increase the heat transfer surface area of tubular 702.

[1179] In some embodiments, one or more surfaces of the tubular of an induction heater may be textured to increase the resistance of the heater and increase the heat transfer surface area of the tubular. FIG. 144 depicts heater 438 that is an induction heater. Electrical conductor 572 extends through tubular 702.

[1180] Tubular 702 may include grooves 706. In some embodiments, grooves 706 are cut in tubular 702. In some embodiments, fins are coupled to tubular to form ridges and grooves 706. The fins may be welded or otherwise attached to the tubular. In an embodiment, the fins are coupled to a tubular sheath that is placed over the tubular. The sheath is physically and electrically coupled to the tubular to form tubular 702.

[1181] In certain embodiments, grooves 706 are on the outer surface of tubular 702. In some embodiments, the grooves are on the inner surface of the tubular. In some embodiments, the grooves are on both the inner and outer surfaces of the tubular.

[1182] In certain embodiments, grooves 706 are radial grooves (grooves that wrap around the circumference of tubular 702). In certain embodiments, grooves 706 are straight, angled, or spiral grooves or protrusions. In some embodiments, grooves 706 are evenly spaced grooves along the surface of tubular 702. In some embodiments, grooves 706 are part of a threaded surface on tubular 702 (the grooves are formed as a winding thread on the surface). Grooves 706 may have a variety of shapes as desired. For example, grooves 706 may have square edges, rectangular edges, v-shaped edges, u-shaped edges, or have rounded edges.

[1183] Grooves 706 increase the effective resistance of tubular 702 by increasing the path length of induced current on the surface of the tubular. Grooves 706 increase the effective resistance of tubular 702 as compared to a tubular with the same inside and outside diameters with smooth surfaces. Because induced current travels axially, the induced current has to travel up and down
the grooves along the surface of the tubular. Thus, the depth of grooves 706 may be varied to provide a selected resistance in tubular 702. For example, increasing the grooves depth increases the path length and the resistance.

**[1184]** Increasing the resistance of tubular 702 with grooves 706 increases the heat generation of the tubular as compared to a tubular with smooth surfaces. Thus, the same electrical current in electrical conductor 572 will provide more heat output in the radial grooved surface tubular than the smooth surface tubular. Therefore, to provide the same heat output with the radial grooved surface tubular as the smooth surface tubular, less current is needed in electrical conductor 572 with the radial grooved surface tubular.

**[1185]** In some embodiments, grooves 706 are filled with materials that decompose at lower temperatures to protect the grooves during installation of tubular 702. For example, grooves 706 may be filled with polyethylene or asphalt. The polyethylene or asphalt may melt and/or desorb when heater 438 reaches normal operating temperatures of the heater.

**[1186]** It is to be understood that grooves 706 may be used in other embodiments of tubulars 702 described herein to increase the resistance of such tubulars. For example, grooves 706 may be used in embodiments of tubulars 702 depicted in FIGS. 140, 141, and 142.

**[1187]** FIG. 145 depicts an embodiment of heater 438 divided into tubular sections to provide varying heat outputs along the length of the heater. Heater 438 may include tubular sections 702A, 702B, 702C, 702D that have different properties to provide different heat outputs in each tubular section. Heat output from tubular sections 702D may be less than the heat output from grooved sections 702A, 702B, 702C. Examples of properties that may be varied include, but are not limited to, thicknesses, diameters, cross-sectional areas, resistances, materials, number of grooves, depth of grooves. The different properties in tubular sections 702A, 702B, and 702C may provide different maximum operating temperatures (for example, different Curie temperatures or phase transformation temperatures) along the length of heater 438. The different maximum temperatures of the tubular sections provides different heat outputs from the tubular sections. Sections such as grooved section 702A may be separate sections that are placed down the wellbore in separation installation procedures. Some sections, such as grooved section 702B and 702C may be connected together by non-grooved section 702D, and may be placed down the wellbore together.

**[1188]** Providing different heat outputs along heater 438 may provide different heating in one or more hydrocarbon layers. For example, heater 438 may be divided into two or more sections of heating to provide different heat outputs to different sections of a hydrocarbon layer and/or different hydrocarbon layers.
In one embodiment, a first portion of heater 438 may provide heat to a first section of the hydrocarbon layer and a second portion of the heater may provide heat to a second section of the hydrocarbon layer. Hydrocarbons in the first section may be mobilized by the heat provided by the first portion of the heater. Hydrocarbons in the second section may be heated by the second portion of the heater to a higher temperature than the first section. The higher temperature in the second section may upgrade hydrocarbons in the second section relative to the first section. For example, the hydrocarbons may be mobilized, visbroken, and/or pyrolyzed in the second section. Hydrocarbons from the first section may be moved into the second section by, for example, a drive fluid provided to the first section. As another example, heater 438 may have end sections that provide higher heat outputs to counteract heat losses at the ends of the heater to maintain a more constant temperature in the heated portion of the formation.

In certain embodiments, three, or multiples of three, electrical conductors enter and exit the formation through common wellbores with tubulars surrounding the electrical conductors in the portion of the formation to be heated. FIG. 146 depicts an embodiment of three electrical conductors 572A,B,C entering the formation through first common wellbore 428A and exiting the formation through second common wellbore 428C with three tubulars 702A,B,C surrounding the electrical conductors in hydrocarbon layer 484. In some embodiments, electrical conductors 572A,B,C are powered by a single, three-phase wye transformer. Tubulars 702A,B,C and portions of electrical conductors 572A,B,C may be in three separate wellbores in hydrocarbon layer 484. The three separate wellbores may be formed by drilling the wellbores from first common wellbore 428A to second common wellbore 428B, vice versa, or drilling from both common wellbores and connecting the drilled openings in the hydrocarbon layer.

Having multiple induction heaters extending from only two wellbores in hydrocarbon layer 484 reduces the footprint of wells on the surface needed for heating the formation. The number of overburden wellbores drilled in the formation is reduced, which reduces capital costs per heater in the formation. Power losses in the overburden may be a smaller fraction of total power supplied to the formation because of the reduced number of wells through the overburden used to treat the formation. In addition, power losses in the overburden may be smaller because the three phases in the common wellbores substantially cancel each other and inhibit induced currents in the casings or other structures of the wellbores.

In some embodiments, three, or multiples of three, electrical conductors and tubulars are located in separate wellbores in the formation. FIG. 147 depicts an embodiment of three electrical conductors 572A,B,C and three tubulars 702A,B,C in separate wellbores in the formation. Electrical conductors 572A,B,C may be powered by single, three-phase wye transformer 580 with each electrical conductor coupled to one phase of the transformer. In some
embodiments, the single, three-phase wye transformer is used to power 6, 9, 12, or other multiples of three electrical conductors. Connecting multiples of three electrical conductors to the single, three-phase wye transformer may reduce equipment costs for providing power to the induction heaters.

[1193] In some embodiments, two, or multiples of two, electrical conductors enter the formation from a first common wellbore and exit the formation from a second common wellbore with tubulars surrounding each electrical conductor in the hydrocarbon layer. The multiples of two electrical conductors may be powered by a single, two-phase transformer. In such embodiments, the electrical conductors may be homogenous electrical conductors (for example, insulated conductors using the same materials throughout) in the overburden sections and heating sections of the insulated conductor. The reverse flow of current in the overburden sections may reduce power losses in the overburden sections of the wellbores because the currents reduce or cancel inductive effects in the overburden sections.

[1194] In certain embodiments, tubulars 702 depicted in FIGS. 140-146 include multiple layers of ferromagnetic materials separated by electrical insulators. FIG. 148 depicts an embodiment of a multilayered induction tubular. Tubular 702 includes ferromagnetic layers 708A,B,C separated by electrical insulators 534A,B. Three ferromagnetic layers and two layers of electrical insulators are shown in FIG. 148. Tubular 702 may include additional ferromagnetic layers and/or electrical insulators as desired. For example, the number of layers may be chosen to provide a desired heat output from the tubular.

[1195] Ferromagnetic layers 708A,B,C are electrically insulated from electrical conductor 572 by, for example, an air gap. Ferromagnetic layers 708A,B,C are electrically insulated from each other by electrical insulator 534A and electrical insulator 534B. Thus, direct flow of current is inhibited between ferromagnetic layers 708A,B,C and electrical conductor 572. When current is applied to electrical conductor 572, electrical current flow is induced in ferromagnetic layers 708A,B,C because of the ferromagnetic properties of the layers. Having two or more electrically insulated ferromagnetic layers provides multiple current induction loops for the induced current. The multiple current induction loops may effectively appear as electrical loads in series to a power source for electrical conductor 572. The multiple current induction loops may increase the heat generation per unit length of tubular 702 as compared to a tubular with only one current induction loop. For the same heat output, the tubular with multiple layers may have a higher voltage and lower current as compared to the single layer tubular.

[1196] In certain embodiments, ferromagnetic layers 708A,B,C include the same ferromagnetic material. In some embodiments, ferromagnetic layers 708A,B,C include different ferromagnetic materials. Properties of ferromagnetic layers 708A,B,C may be varied to provide different heat
outputs from the different layers. Examples of properties of ferromagnetic layers 708A, B, C that may be varied include, but are not limited to, ferromagnetic material and thicknesses of the layers.

[1197] Electrical insulators 534A and 534B may be magnesium oxide, porcelain enamel, and/or another suitable electrical insulator. The thicknesses and/or materials of electrical insulators 534A and 534B may be varied to provide different operating parameters for tubular 702.

[1198] In some embodiments, fluids are circulated through tubulars 702 depicted in FIGS. 140-146. In some embodiments, fluids are circulated through the tubulars to add heat to the formation. For example, fluids may be circulated through the tubulars to preheat the formation prior to energizing the tubulars (providing current to the heating system). In some embodiments, fluids are circulated through the tubulars to recover heat from the formation. The recovered heat may be used to provide heat to other portions of the formation and/or surface processes used to treat fluids produced from the formation. In some embodiments, the fluids are used to cool down the heater.

[1199] In certain embodiments, insulated conductors are operated as induction heaters. FIG. 149 depicts a cross-sectional end view of an embodiment of insulated conductor 574 that is used as an induction heater. FIG. 150 depicts a cross-sectional side view of the embodiment depicted in FIG. 149. Insulated conductor 574 includes core 542, electrical insulator 534, and jacket 540. Core 542 may be copper or another non-ferromagnetic electrical conductor with low resistance that provides little or no heat output. In some embodiments, core may be clad with a thin layer of material such as nickel to inhibit migration of portions of the core into electrical insulator 534. Electrical insulator 534 may be magnesium oxide or another suitable electrical insulator that inhibits arcing at high voltages.

[1200] Jacket 540 includes at least one ferromagnetic material. In certain embodiments, jacket 540 includes carbon steel or another ferromagnetic steel (for example, 410 stainless steel, 446 stainless steel, T/P91 stainless steel, T/P92 stainless steel, alloy 52, alloy 42, and Invar 36). In some embodiments, jacket 540 includes an outer layer of corrosion resistant material (for example, stainless steel such as 347H stainless steel or 304 stainless steel). The outer layer may be clad to the ferromagnetic material or otherwise coupled to the ferromagnetic material using methods known in the art.

[1201] In certain embodiments, jacket 540 has a thickness of at least about 2 skin depths of the ferromagnetic material in the jacket. In some embodiments, jacket 540 has a thickness of at least about 3 skin depths, at least about 4 skin depths, or at least about 5 skin depths. Increasing the thickness of jacket 540 may increase the heat output from insulated conductor 574.
[1202] In one embodiment, core 542 is copper with a diameter of about 0.5" (1.27 cm), electrical insulator 534 is magnesium oxide with a thickness of about 0.20" (0.5 cm) (the outside diameter is about 0.9" (2.3 cm)), and jacket 540 is carbon steel with an outside diameter of about 1.6" (4.1 cm) (the thickness is about 0.35" (0.88 cm)). A thin layer (about 0.1" (0.25 cm) thickness (outside diameter of about 1.7" (4.3 cm)) of corrosion resistant material 347H stainless steel may be clad on the outside of jacket 540.

[1203] In another embodiment, core 542 is copper with a diameter of about 0.338" (0.86 cm), electrical insulator 534 is magnesium oxide with a thickness of about 0.096" (0.24 cm) (the outside diameter is about 0.53" (1.3 cm)), and jacket 540 is carbon steel with an outside diameter of about 1.13" (2.9 cm) (the thickness is about 0.30" (0.76 cm)). A thin layer (about 0.065" (0.17 cm) thickness (outside diameter of about 1.26" (3.2 cm)) of corrosion resistant material 347H stainless steel may be clad on the outside of jacket 540.

[1204] In another embodiment, core 542 is copper, electrical insulator 534 is magnesium oxide, and jacket 540 is a thin layer of copper surrounded by carbon steel. Core 542, electrical insulator 534, and the thin copper layer of jacket 540 may be obtained as a single piece of insulated conductor. Such insulated conductors may be obtained as long pieces of insulated conductors (for example, lengths of about 500' (about 150 m) or more). The carbon steel layer of jacket 540 may be added by drawing down the carbon steel over the long insulated conductor. Such an insulated conductor may only generate heat on the outside of jacket 540 as the thin copper layer in the jacket shorts to the inside surface of the jacket.

[1205] In some embodiments, jacket 540 is made of multiple layers of ferromagnetic material. The multiple layers may be the same ferromagnetic material or different ferromagnetic materials. For example, in one embodiment, jacket 540 is a 0.35" (0.88 cm) thick carbon steel jacket made from three layers of carbon steel. The first and second layers are 0.10" (0.25 cm) thick and the third layer is 0.15" (0.38 cm) thick. In another embodiment, jacket 540 is a 0.3" (0.76 cm) thick carbon steel jacket made from three 0.10" (0.25 cm) thick layers of carbon steel.

[1206] In certain embodiments, jacket 540 and core 542 are electrically insulated such that there is no direct electrical connection between the jacket and the core. Core 542 may be electrically coupled to a single power source with each end of the core being coupled to one pole of the power source. For example, insulated conductor 574 may be a u-shaped heater located in a u-shaped wellbore with each end of core 542 being coupled to one pole of the power source.

[1207] When core 542 is energized with time-varying current, the core induces electrical current flow on the surfaces of jacket 540 (as shown by the arrows in FIG. 150) due to the ferromagnetic properties of the ferromagnetic material in the jacket. In certain embodiments, current flow is
induced on both the inside and outside surfaces of jacket 540. In these induction heater embodiments, jacket 540 operates as the heating element of insulated conductor 574.

[1208] At or near the Curie temperature or the phase transformation temperature of the ferromagnetic material in jacket 540, the magnetic permeability of the ferromagnetic material decreases rapidly. When the magnetic permeability of jacket 540 decreases at or near the Curie temperature or the phase transformation temperature, there is little or no current flow in the jacket because, at these temperatures, the jacket is essentially non-ferromagnetic and core 542 is unable to induce current flow in the jacket. With little or no current flow in jacket 540, the temperature of the jacket will drop to lower temperatures until the magnetic permeability increases and the jacket becomes ferromagnetic. Thus, jacket 540 self-limits at or near the Curie temperature or the phase transformation temperature and insulated conductor 574 operates as a temperature limited heater due to the ferromagnetic properties of the jacket. Because current is induced in jacket 540, the turndown ratio may be higher and the drop in current sharper for the jacket than if current is directly applied to the jacket.

[1209] In certain embodiments, portions of jacket 540 in the overburden of the formation do not include ferromagnetic material (for example, are non-ferromagnetic). Having the overburden portions of jacket 540 made of non-ferromagnetic material inhibits current induction in the overburden portions of the jackets. Power losses in the overburden are inhibited or reduced by inhibiting current induction in the overburden portions.

[1210] FIG. 151 depicts a cross-sectional view of an embodiment of two-leg insulated conductor 574 that is used as an induction heater. FIG. 152 depicts a longitudinal cross-sectional view of the embodiment depicted in FIG. 151. Insulated conductor 574 is a two-leg insulated conductor that includes two cores 542A,B; two electrical insulators 534A,B; and two jackets 540A,B. The two legs of insulated conductor 574 may be in physical contact with each other such that jacket 540A contacts jacket 540B along their lengths. Cores 542A,B; electrical insulators 534A,B; and jackets 540A,B may include materials such as those used in the embodiment of insulated conductor 574 depicted in FIGS. 149 and 150.

[1211] As shown in FIG. 152, core 542A and core 542B are coupled to transformer 580 and terminal block 634. Thus, core 542A and core 542B are electrically coupled in series such that current in core 542A flows in an opposite direction from current in core 542B, as shown by the arrows in FIG. 152. Current flow in cores 542A,B induces current flow in jackets 540A,B, respectively, as shown by the arrows in FIG. 152.

[1212] In certain embodiments, portions of jacket 540A and/or jacket 540B are coated with an electrically insulating coating (for example, a porcelain enamel coating, alumina coating, and/or alumina-titania coating). The electrically insulating coating may inhibit the currents in one jacket
from affecting current in the other jacket or vice versa (for example, current in one jacket cancelling out current in the other jacket). Electrically insulating the jackets from each other may inhibit the turndown ratio of the heater from being reduced by the interaction of induced currents in the jackets.

[1213] Because core 542A and core 542B are electrically coupled in series to a single transformer (transformer 580), insulated conductor 574 may be located in a wellbore that terminates in the formation (for example, a wellbore with a single surface opening such as an L-shaped or J-shaped wellbore). Insulated conductor 574, as depicted in FIG. 152, may be operated as a subsurface termination induction heater with electrical connections between the heater and the power source (the transformer) being made through one surface opening.

[1214] Portions of jackets 540A,B in the overburden and/or adjacent to portions of the formation that are not to be significantly heated (for example, thick shale breaks between two hydrocarbon layers) may be non-ferromagnetic to inhibit induction currents in such portions. The jacket may include one or more sections that are electrically insulating to restrict induced current flow to heater portions of the insulated conductor. Inhibiting induction currents in the overburden portion of the jackets inhibits inductive heating and/or power losses in the overburden. Induction effects in other structures in the overburden that surround insulated conductor 574 (for example, overburden casings) may be inhibited because the current in core 542A flows in an opposite direction from the current in core 542B.

[1215] FIG. 153 depicts a cross-sectional view of an embodiment of a multilayered insulated conductor that is used as an induction heater. Insulated conductor 574 includes core 542 surrounded by electrical insulator 534A and jacket 540A. Electrical insulator 534A and jacket 540A comprise a first layer of insulated conductor 574. The first layer is surrounded by a second layer that includes electrical insulator 534B and jacket 540B. Two layers of electrical insulators and jackets are shown in FIG. 153. The insulated conductor may include additional layers as desired. For example, the number of layers may be chosen to provide a desired heat output from the insulated conductor.

[1216] Jacket 540A and jacket 540B are electrically insulated from core 542 and each other by electrical insulator 534A and electrical insulator 534B. Thus, direct flow of current is inhibited between jacket 540A and jacket 540B and core 542. When current is applied to core 542, electrical current flow is induced in both jacket 540A and jacket 540B because of the ferromagnetic properties of the jackets. Having two or more layers of electrical insulators and jackets provides multiple current induction loops. The multiple current induction loops may effectively appear as electrical loads in series to a power source for insulated conductor 574. The multiple current induction loops may increase the heat generation per unit length of insulated
conductor 574 as compared to an insulated conductor with only one current induction loop. For the same heat output, the insulated conductor with multiple layers may have a higher voltage and lower current as compared to the single layer insulated conductor.

[1217] In certain embodiments, jacket 540A and jacket 540B include the same ferromagnetic material. In some embodiments, jacket 540A and jacket 540B include different ferromagnetic materials. Properties of jacket 540A and jacket 540B may be varied to provide different heat outputs from the different layers. Examples of properties of jacket 540A and jacket 540B that may be varied include, but are not limited to, ferromagnetic material and thicknesses of the layers.

[1218] Electrical insulators 534A and 534B may be magnesium oxide, porcelain enamel, and/or another suitable electrical insulator. The thicknesses and/or materials of electrical insulators 534A and 534B may be varied to provide different operating parameters for insulated conductor 574.

[1219] FIG. 154 depicts an end view of an embodiment of three insulated conductors 574 located in a coiled tubing conduit and used as induction heaters. Insulated conductors 574 may each be, for example, the insulated conductor depicted in FIGS. 149, 150, and 153. The cores of insulated conductors 574 may be coupled to each other such that the insulated conductors are electrically coupled in a three-phase wye configuration. FIG. 155 depicts a representation of cores 542 of insulated conductors 574 coupled together at their ends.

[1220] As shown in FIG. 154, insulated conductors 574 are located in tubular 702. Tubular 702 may be a coiled tubing conduit or other coiled tubing tubular or casing. Insulated conductors 574 may be in a spiral or helix formation inside tubular 702 to reduce stresses on the insulated conductors when the insulated conductors are coiled, for example, on a coiled tubing reel. Tubular 702 allows the insulated conductors to be installed in the formation using a coiled tubing rig and protects the insulated conductors during installation into the formation.

[1221] FIG. 156 depicts an end view of an embodiment of three insulated conductors 574 located on a support member and used as induction heaters. Insulated conductors 574 may each be, for example, the insulated conductor depicted in FIGS. 149, 150, and 153. The cores of insulated conductors 574 may be coupled to each other such that the insulated conductors are electrically coupled in a three-phase wye configuration. For example, the cores may be coupled together as shown in FIG. 155.

[1222] As shown in FIG. 156, insulated conductors 574 are coupled to support member 548. Support member 548 provides support for insulated conductors 574. Insulated conductors 574 may be wrapped around support member 548 in a spiral or helix formation. In some embodiments, support member 548 includes ferromagnetic material. Current flow may be
induced in the ferromagnetic material of support member 548. Thus, support member 548 may generate some heat in addition to the heat generated in the jackets of insulated conductors 574. [1223] In certain embodiments, insulated conductors 574 are held together on support member 548 with band 584. Band 584 may be stainless steel or another non-corrosive material. In some embodiments, band 584 includes a plurality of bands that hold together insulated conductors 574. The bands may be periodically placed around insulated conductors 574 to hold the conductors together.

[1224] In some embodiments, jacket 540, depicted in FIGS. 149 and 150, or jackets 540A,B, depicted in FIG. 152, include grooves or other structures on the outer surface and/or the inner surface of the jacket to increase the effective resistance of the jacket. Increasing the resistance of jacket 540 and/or jackets 540A,B with grooves increases the heat generation of the jackets as compared to jackets with smooth surfaces. Thus, the same electrical current in core 542 and/or cores 542A,B will provide more heat output in the grooved surface jackets than the smooth surface jackets.

[1225] In some embodiments, jacket 540 (such as the jackets depicted in FIGS. 149 and 150, or jackets 540A,B depicted in FIG. 152) are divided into sections to provide varying heat outputs along the length of the heaters. For example, jacket 540 and/or jackets 540A,B may be divided into sections such as tubular sections 702A, 702B, and 702C, depicted in FIG. 145. The sections of the jackets 540 depicted in FIGS. 149, 150, and 152 may have different properties to provide different heat outputs in each section. Examples of properties that may be varied include, but are not limited to, thicknesses, diameters, resistances, materials, number of grooves, depth of grooves. The different properties in the sections may provide different maximum operating temperatures (for example, different Curie temperatures or phase transformation temperatures) along the length of insulated conductor 574. The different maximum temperatures of the sections provides different heat outputs from the sections.

[1226] In certain embodiments, induction heaters include insulated electrical conductors surrounded by spiral wound ferromagnetic materials. For example, the spiral wound ferromagnetic materials may operate as inductive heating elements similarly to tubulars 702, depicted in FIGS. 140-146. FIG. 157 depicts a representation of an embodiment of an induction heater with core 542 and electrical insulator 534 surrounded by ferromagnetic layer 708. Core 542 may be copper or another non-ferromagnetic electrical conductor with low resistance that provides little or no heat output. Electrical insulator 534 may be a polymeric electrical insulator such as Teflon®, XPLE (cross-linked polyethylene), or EPDM (ethylene-propylene diene monomer). In some embodiments, core 542 and electrical insulator 534 are obtained together as a polymer (insulator) coated cable. In some embodiments, electrical insulator 534 is magnesium
oxide or another suitable electrical insulator that inhibits arcing at high voltages and/or at high temperatures.

[1227] In certain embodiments, ferromagnetic layer 708 is spirally wound onto core 542 and electrical insulator 534. Ferromagnetic layer 708 may include carbon steel or another ferromagnetic steel (for example, 410 stainless steel, 446 stainless steel, T/P91 stainless steel, T/P92 stainless steel, alloy 52, alloy 42, and Invar 36).

[1228] In some embodiments, ferromagnetic layer 708 is spirally wound onto an insulated conductor. In some embodiments, ferromagnetic layer 708 includes an outer layer of corrosion resistant material. In some embodiments, ferromagnetic layer is bar stock. FIG. 158 depicts a representation of an embodiment of insulated conductor 574 surrounded by ferromagnetic layer 708. Insulated conductor 574 includes core 542, electrical insulator 534, and jacket 540. Core 542 is copper or another non-ferromagnetic electrical conductor with low resistance that provides little or no heat output. Electrical insulator 534 is magnesium oxide or another suitable electrical insulator. Ferromagnetic layer 708 is spirally wound onto insulated conductor 574.

[1229] Spirally winding ferromagnetic layer 708 onto the heater may increase control over the thickness of the ferromagnetic layer as compared to other construction methods for induction heaters. For example, more than one ferromagnetic layer 708 may be wound onto the heater to vary the output of the heater. The number of ferromagnetic layers 708 may be chosen to provide desired output from the heater. FIG. 159 depicts a representation of an embodiment of an induction heater with two ferromagnetic layers 708A, B spirally wound onto core 542 and electrical insulator 534. In some embodiments, ferromagnetic layer 708A is counter-wound relative to ferromagnetic layer 708B to provide neutral torque on the heater. Neutral torque may be useful when the heater is suspended or allowed to hang freely in an opening in the formation.

[1230] The number of spiral windings (for example, the number of ferromagnetic layers) may be varied to alter the heat output of the induction heater. In addition, other parameters may be varied to alter the heat output of the induction heater. Examples of other varied parameters include, but are not limited to, applied current, applied frequency, geometry, ferromagnetic materials, and thickness and/or number of spiral windings.

[1231] Use of spiral wound ferromagnetic layers may allow induction heaters to be manufactured in continuous long lengths by spiral winding the ferromagnetic material onto long lengths of conventional or easily manufactured insulated cable. Thus, spiral wound induction heaters may have reduced manufacturing costs as compared to other induction heaters. The spiral wound ferromagnetic layers may increase the mechanical flexibility of the induction heater as compared to solid ferromagnetic tubular induction heaters. The increased flexibility may allow spiral wound induction heaters to be bent over surface protrusions such as hanger joints.
[1232] FIG. 160 depicts an embodiment for assembling ferromagnetic layer 708 onto insulated conductor 574. Insulated conductor 574 may be an insulated conductor cable (for example, mineral insulated conductor cable or polymer insulated conductor cable) or other suitable electrical conductor core covered by insulation.

[1233] In certain embodiments, ferromagnetic layer 708 is made of ferromagnetic material 1812 fed from reel 1810 and wound onto insulated conductor 574. Reel 1810 may be a coiled tubing rig or other rotatable feed rig. Reel 1810 may rotate around insulated conductor 574 as ferromagnetic material 1812 is wound onto the insulated conductor to form ferromagnetic layer 708. Insulated conductor 574 may be fed from a reel or from a mill as reel 1810 rotates around the insulated conductor.

[1234] In some embodiments, ferromagnetic material 1812 is heated prior to winding the material onto insulated conductor 574. For example, ferromagnetic material 1812 may be heated using inductive heater 1814. Pre-heating ferromagnetic material 1812 prior to winding the ferromagnetic material may allow the ferromagnetic material to contract and grip onto insulated conductor 574 when the ferromagnetic material cools.

[1235] In some embodiments, portions of casings in the overburden sections of heater wellbores have surfaces that are shaped to increase the effective diameter of the casing. Casings in the overburden sections of heater wellbores may include, but are not limited to, overburden casings, heater casings, heater tubulars, and/or jackets of insulated conductors. Increasing the effective diameter of the casing may reduce inductive effects in the casing when current used to power a heater or heaters below the overburden is transmitted through the casing (for example, when one phase of power is being transmitted through the overburden section). When current is transmitted in only one direction through the overburden, the current may induce other currents in ferromagnetic or other electrically conductive materials such as those found in overburden casings. These induced currents may provide undesired power losses and/or undesired heating in the overburden of the formation.

[1236] FIG. 161 depicts an embodiment of casing 710 having a grooved or corrugated surface. In certain embodiments, casing 710 includes grooves 712. In some embodiments, grooves 712 are corrugations or include corrugations. Grooves 712 may be formed as a part of the surface of casing 710 (for example, the casing is formed with grooved surfaces) or the grooves may be formed by adding or removing (for example, milling) material on the surface of the casing. For example, grooves 712 may be located on a long piece of tubular that is welded to casing 710.

[1237] In certain embodiments, grooves 712 are on the outer surface of casing 710. In some embodiments, grooves 712 are on the inner surface of casing 710. In some embodiments, grooves 712 are on both the inner and outer surfaces of casing 710.
[1238] In certain embodiments, grooves 712 are axial grooves (grooves that go longitudinally along the length of casing 710). In certain embodiments, grooves 712 are straight, angled, or longitudinally spiral. In some embodiments, grooves 712 are substantially axial grooves or spiral grooves with a significant longitudinal component (i.e., the spiral angle is less than 10°, less than 5°, or less than 1°). In some embodiments, grooves 712 extend substantially axially along the length of casing 710. In some embodiments, grooves 712 are evenly spaced grooves along the surface of casing 710. Grooves 712 may have a variety of shapes as desired. For example, grooves 712 may have square edges, v-shaped edges, u-shaped edges, rectangular edges, or have rounded edges.

[1239] Grooves 712 increase the effective circumference of casing 710. Grooves 712 increase the effective circumference of casing 710 as compared to the circumference of a casing with the same inside and outside diameters and smooth surfaces. The depth of grooves 712 may be varied to provide a selected effective circumference of casing 710. For example, axial grooves that are ¼” (0.63 cm) wide and ¼” (0.63 cm) deep, and spaced ¼” (0.63 cm) apart may increase the effective circumference of a 6” (15.24 cm) diameter pipe from 18.84” (47.85 cm) to 37.68” (95.71 cm) (or the circumference of a 12” (30.48 cm) diameter pipe).

[1240] In certain embodiments, grooves 712 increase the effective circumference of casing 710 by a factor of at least about 2 as compared to a casing with the same inside and outside diameters and smooth surfaces. In some embodiments, grooves 712 increase the effective circumference of casing 710 by a factor of at least about 3, at least about 4, or at least about 6 as compared to a casing with the same inside and outside diameters and smooth surfaces.

[1241] Increasing the effective circumference of casing 710 with grooves 712 increases the surface area of the casing. Increasing the surface area of casing 710 reduces the induced current in the casing for a given current flux. Power losses associated with inductive heating in casing 710 are reduced as compared to a casing with smooth surfaces because of the reduced induced current. Thus, the same electrical current will provide less heat output from inductive heating in the axial grooved surface casing than the smooth surface casing. Reducing the heat output in the overburden section of the heater will increase the efficiency of, and reduce the costs associated with, operating the heater. Increasing the effective circumference of casing 710 and reducing inductive effects in the casing allows the casing to be made with less expensive materials such as carbon steel.

[1242] In some embodiments, an electrically insulating coating (for example, a porcelain enamel coating) is placed on one or more surfaces of casing 710 to inhibit current and/or power losses from the casing. In some embodiments, casing 710 is formed from two or more longitudinal sections of casing (for example, longitudinal sections welded or threaded together end to end).
The longitudinal sections may be aligned so that the grooves on the sections are aligned. Aligning the sections may allow for cement or other material to flow along the grooves.

[1243] In some embodiments, an insulated conductor heater is placed in the formation by itself and the outside of the insulated conductor heater is electrically isolated from the formation because the heater has little or no voltage potential on the outside of the heater. FIG. 162 depicts an embodiment of a single-ended, substantially horizontal insulated conductor heater that electrically isolates itself from the formation. In such an embodiment, heater 438 is insulated conductor 574. Insulated conductor 574 may be a mineral insulated conductor heater (for example, insulated conductor 574 depicted in FIGS. 163A and 163B). Insulated conductor 574 is located in opening 556 in hydrocarbon layer 484. In certain embodiments, opening 556 is an uncased or open wellbore. In some embodiments, opening 556 is a cased or lined wellbore. In some embodiments, insulated conductor heater 574 is a substantially u-shaped heater and is located in a substantially u-shaped opening.

[1244] Insulated conductor 574 has little or no current flowing along the outside surface of the insulated conductor so that the insulated conductor is electrically isolated from the formation and leaks little or no current into the formation. The outside surface (or jacket) of insulated conductor 574 is a metal or thermal radiating body so that heat is radiated from the insulated conductor to the formation.

[1245] FIGS. 163A and 163B depict cross-sectional representations of an embodiment of insulated conductor 574 that is electrically isolated on the outside of jacket 540. In certain embodiments, jacket 540 is made of ferromagnetic materials. In one embodiment, jacket 540 is made of 410 stainless steel. In other embodiments, jacket 540 is made of T/P91 or T/P92 stainless steel. In some embodiments, jacket 540 may include carbon steel. Core 542 is made of a highly conductive material such as copper or a copper alloy. Electrical insulator 534 is an electrically insulating material such as magnesium oxide. Insulated conductor 574 may be an inexpensive and easy to manufacture heater.

[1246] In the embodiment depicted in FIGS. 163A and 163B, core 542 brings current into the formation, as shown by the arrow. Core 542 and jacket 540 are electrically coupled at the distal end (bottom) of the heater. Current returns to the surface of the formation through jacket 540. The ferromagnetic properties of jacket 540 confine the current to the skin depth along the inside diameter of the jacket, as shown by arrows 714 in FIG. 163A. Jacket 540 has a thickness at least 2 or 3 times the skin depth of the ferromagnetic material used in the jacket at 25 °C and at the design current frequency so that most of the current is confined to the inside surface of the jacket and little or no current flows on the outside diameter of the jacket. Thus, there is little or no voltage potential on the outside of jacket 540. Having little or no voltage potential on the outside
surface of insulated conductor 574 does not expose the formation to any high voltages, inhibits current leakage to the formation, and reduces or eliminates the need for isolation transformers, which decrease energy efficiency.

[1247] Because core 542 is made of a highly conductive material such as copper and jacket 540 is made of more resistive ferromagnetic material, a majority of the heat generated by insulated conductor 574 is generated in the jacket. Generating the majority of the heat in jacket 540 increases the efficiency of heat transfer from insulated conductor 574 to the formation over an insulated conductor (or other heater) that uses a core or a center conductor to generate the majority of the heat.

[1248] In certain embodiments, core 542 is made of copper. Using copper in core 542 allows the heating section of the heater and the overburden section to have identical core materials. Thus, the heater may be made from one long core assembly. The long single core assembly reduces or eliminates the need for welding joints in the core, which can be unreliable and susceptible to failure. Additionally, the long, single core assembly heater may be manufactured remote from the installation site and transported in a final assembly (ready to install assembly) to the installation site. The single core assembly also allows for long heater lengths (for example, about 1000 m or longer) depending on the breakdown voltage of the electrical insulator.

[1249] In certain embodiments, jacket 540 is made from two or more layers of the same materials and/or different materials. Jacket 540 may be formed from two or more layers to achieve thicknesses needed for the jacket (for example, to have a thickness at least 3 times the skin depth of the ferromagnetic material used in the jacket at 25 °C and at the design current frequency). Manufacturing and/or material limitations may limit the thickness of a single layer of jacket material. For example, the amount each layer can be strained during manufacturing (forming) the layer on the heater may limit the thickness of each layer. Thus, to reach jacket thicknesses needed for certain embodiments of insulated conductor 574, jacket 540 may be formed from several layers of jacket material. For example, three layers of T/P92 stainless steel may be used to form jacket 540 with a thickness of about 3 times the skin depth of the T/P92 stainless steel at 25 °C and at the design current frequency.

[1250] In some embodiments, jacket 540 includes two or more different materials. In some embodiments, jacket 540 includes different materials in different layers of the jacket. For example, jacket 540 may have one or more inner layers of ferromagnetic material chosen for their electrical and/or electromagnetic properties and one or more outer layers chosen for its non-corrosive properties.

[1251] In some embodiments, the thickness of jacket 540 and/or the material of the jacket are varied along the heater length. The thickness and/or material of jacket 540 may be varied to vary
electrical properties and/or mechanical properties along the length of the heater. For example, the thickness and/or material of jacket 540 may be varied to vary the turndown ratio or the Curie temperature along the length of the heater. In some embodiments, the inner layer of jacket 540 includes copper or other highly conductive metals in the overburden section of the heater. The inner layer of copper limits heat losses in the overburden section of the heater.

[1252] FIGS. 164 and 165 depict an embodiment of insulated conductor 574 inside tubular 702. Insulated conductor 574 may include core 542, electrical insulator 534, and jacket 540. Core 542 and jacket 540 may be electrically coupled (shorted) at a distal end of the insulated conductor. FIG. 166 depicts a cross-sectional representation of an embodiment of the distal end of insulated conductor 574 inside tubular 702. Endcap 630 may electrically couple core 542 and jacket 540 to tubular 702 at the distal end of insulated conductor 574 and the tubular. Endcap 630 may include electrical conducting materials such as copper or steel.

[1253] In certain embodiments, core 542 is copper, electrical insulator 534 is magnesium oxide, and jacket 540 is non-ferromagnetic stainless steel (for example, 316H stainless steel, 347H stainless steel, 204-Cu stainless steel, 201Ln stainless steel, or 204 M stainless steel). Insulated conductor 574 may be placed in tubular 702 to protect the insulated conductor, increase heat transfer to the formation, and/or allow for coiled tubing or continuous installation of the insulated conductor. Tubular 702 may be made of ferromagnetic material such as 410 stainless steel, T/P 9 alloy steel, T/P91 alloy steel, low alloy steel, or carbon steel. In certain embodiments, tubular 702 is made of corrosion resistant materials. In some embodiments, tubular 702 is made of non-ferromagnetic materials.

[1254] In certain embodiments, jacket 540 of insulated conductor 574 is longitudinally welded to tubular 702 along weld joint 716, as shown in FIG. 165. The longitudinal weld may be a laser weld, a tandem GTAW (gas tungsten arc welding) weld, or an electron beam weld that welds the surface of jacket 540 to tubular 702. In some embodiments, tubular 702 is made from a longitudinal strip of metal. Tubular 702 may be made by rolling the longitudinal strip to form a cylindrical tube and then welding the longitudinal ends of the strip together to make the tubular.

[1255] In certain embodiments, insulated conductor 574 is welded to tubular 702 as the longitudinal ends of the strip are welded together (in the same welding process). For example, insulated conductor 574 is placed along one of the longitudinal ends of the strip so that jacket 540 is welded to tubular 702 at the location where the ends are welded together. In some embodiments, insulated conductor 574 is welded to one of the longitudinal ends of the strip before the strip is rolled to form the cylindrical tube. The ends of the strip may then be welded to form tubular 702.
In some embodiments, insulated conductor 574 is welded to tubular 702 at another location (for example, at a circumferential location away from the weld joining the ends of the strip used to form the tubular). For example, jacket 540 of insulated conductor 574 may be welded to tubular 702 diametrically opposite from where the longitudinal ends of the strip used to form the tubular are welded. In some embodiments, tubular 702 is made of multiple strips of material that are rolled together and coupled (for example, welded) to form the tubular with a desired thickness. Using more than one strip of metal may be easier to roll into the cylindrical tube used to form the tubular.

Jacket 540 and tubular 702 may be electrically and mechanically coupled at weld joint 716. Longitudinally welding jacket 540 to tubular 702 inhibits arcing between insulated conductor 574 and the tubular. Tubular 702 may return electrical current from core 542 along the inside of the tubular if the tubular is ferromagnetic. If tubular 702 is non-ferromagnetic, a thin electrically insulating layer such as a porcelain enamel coating or a spray coated ceramic may be put on the outside of the tubular to inhibit current leakage from the tubular into the formation. In some embodiments, a fluid is placed in tubular 702 to increase heat transfer between insulated conductor 574 and the tubular and/or to inhibit arcing between the insulated conductor and the tubular. Examples of fluids include, but are not limited to, thermally conductive gases such as helium, carbon dioxide, or steam. Fluids may also include fluids such as oil, molten metals, or molten salts (for example, solar salt (60% NaNO₃/40%KNO₃)). In some embodiments, heat transfer fluids are transported inside tubular 702 and heated inside the tubular (in the space between the tubular and insulated conductor 574). In some embodiments, an optical fiber, thermocouple, or other temperature sensor is placed inside tubular 702.

In certain embodiments, the heater depicted in FIGS. 164, 165, and 166 is energized with AC current (or time-varying electrical current). A majority of the heat is generated in tubular 702 when the heater is energized with AC current. If tubular 702 is ferromagnetic and the wall thickness of the tubular is at least about twice the skin depth at 25 °C and at the design current frequency, then the heater will operate as a temperature limited heater. Generating the majority of the heat in tubular 702 improves heat transfer to the formation as compared to a heater that generates a majority of the heat in the insulated conductor.

In certain embodiments, portions of the wellbore that extend through the overburden include casings. The casings may include materials that inhibit inductive effects in the casings. Inhibiting inductive effects in the casings may inhibit induced currents in the casing and/or reduce heat losses to the overburden. In some embodiments, the overburden casings may include non-metallic materials such as fiberglass, polyvinylchloride (PVC), chlorinated PVC (CPVC), high-density polyethylene (HDPE), high temperature polymers (such as nitrogen based
polymers), or other high temperature plastics. HDPEs with working temperatures in a usable range include HDPEs available from Dow Chemical Co., Inc. (Midland, Michigan, U.S.A.). The overburden casings may be made of materials that are spoolable so that the overburden casings can be spooled into the wellbore. In some embodiments, overburden casings may include non-magnetic metals such as aluminum or non-magnetic alloys such as manganese steels having at least 10% manganese, iron aluminum alloys with at least 18% aluminum, or austenitic stainless steels such as 304 stainless steel or 316 stainless steel. In some embodiments, overburden casings may include carbon steel or other ferromagnetic material coupled on the inside diameter to a highly conductive non-ferromagnetic metal (for example, copper or aluminum) to inhibit inductive effects or skin effects. In some embodiments, overburden casings are made of inexpensive materials that may be left in the formation (sacrificial casings).

[1260] In certain embodiments, wellheads for the wellbores may be made of one or more non-ferromagnetic materials. FIG. 167 depicts an embodiment of wellhead 718. The components in the wellheads may include fiberglass, PVC, CPVC, HDPE, high temperature polymers (such as nitrogen based polymers), and/or non-magnetic alloys or metals. Some materials (such as polymers) may be extruded into a mold or reaction injection molded (RIM) into the shape of the wellhead. Forming the wellhead from a mold may be a less expensive method of making the wellhead and save in capital costs for providing wellheads to a treatment site. Using non-ferromagnetic materials in the wellhead may inhibit undesired heating of components in the wellhead. Ferromagnetic materials used in the wellhead may be electrically and/or thermally insulated from other components of the wellhead. In some embodiments, an inert gas (for example, nitrogen or argon) is purged inside the wellhead and/or inside of casings to inhibit reflux of heated gases into the wellhead and/or the casings.

[1261] In some embodiments, ferromagnetic materials in the wellhead are electrically coupled to a non-ferromagnetic material (for example, copper) to inhibit skin effect heat generation in the ferromagnetic materials in the wellhead. The non-ferromagnetic material is in electrical contact with the ferromagnetic material so that current flows through the non-ferromagnetic material. In certain embodiments, as shown in FIG. 167, non-ferromagnetic material 720 is coupled (and electrically coupled) to the inside walls of conduit 552 and wellhead walls 722. In some embodiments, copper may be plasma sprayed, coated, clad, or lined on the inside and/or outside walls of the wellhead. In some embodiments, a non-ferromagnetic material such as copper is welded, brazed, clad, or otherwise electrically coupled to the inside and/or outside walls of the wellhead. For example, copper may be swaged out to line the inside walls in the wellhead. Copper may be liquid nitrogen cooled and then allowed to expand to contact and swage against
the inside walls of the wellhead. In some embodiments, the copper is hydraulically expanded or explosively bonded to contact against the inside walls of the wellhead.

[1262] In some embodiments, two or more substantially horizontal wellbores are branched off of a first substantially vertical wellbore drilled downwards from a first location on a surface of the formation. The substantially horizontal wellbores may be substantially parallel through a hydrocarbon layer. The substantially horizontal wellbores may reconnect at a second substantially vertical wellbore drilled downwards at a second location on the surface of the formation. Having multiple wellbores branching off of a single substantially vertical wellbore drilled downwards from the surface reduces the number of openings made at the surface of the formation.

[1263] In certain embodiments, a horizontal heater, or a heater at an incline is installed in more than one part. FIG. 168 depicts an embodiment of heater 438 that has been installed in two parts. Heater 438 includes heating section 438A and lead-in section 438B. Heating section 438A may be located horizontally or at an incline in a hydrocarbon layer in the formation. Lead-in section 438B may be the overburden section or low resistance section of the heater (for example, the section of the heater with little or no electrical heat output).

[1264] During installation of heater 438, heating section 438A may be installed first into the formation. Heating section 438A may be installed by pushing the heating section into the opening in the formation using a drill pipe or other installation tool that pushes the heating section into the opening. After installation of heating section 438A, the installation tool may be removed from the opening in the formation. Installing only heating section 438A with the installation tool at this time may allow the heating section to be installed further into the formation than if the heating section and the lead-in section are installed together because a higher compressive strength may be applied to the heating section alone (for example, the installation tool only has to push in the horizontal or inclined direction).

[1265] In some embodiments, heating section 438A is coupled to mechanical connector 692. Connector 692 may be used to hold heating section 438A in the opening. In some embodiments, connector 692 includes copper or other electrically conductive materials so that the connector is used as an electrical connector (for example, as an electrical ground). In some embodiments, connector 692 is used to couple heating section 438A to a bus bar or electrical return rod located in an opening perpendicular to the opening of the heating section.

[1266] Lead-in section 438B may be installed after installation of heating section 438A. Lead-in section 438B may be installed with a drill pipe or other installation tool. In some embodiments, the installation tool may be the same tool used to install heating section 438A.
[1267] Lead-in section 438B may couple to heating section 438A as the lead-in section is installed into the opening. In certain embodiments, coupling joint 724 is used to couple lead-in section 438B to heating section 438A. Coupling joint 724 may be located on either lead-in section 438B or heating section 438A. In some embodiments, coupling joint 724 includes portions located on both sections. Coupling joint 724 may be a coupler such as, but not limited to, a wet connect or wet stab. In some embodiments, heating section 438A includes a catcher or other tool that guides an end of lead-in section 438B to form coupling joint 724.

[1268] In some embodiments, coupling joint 724 includes a container (for example, a can) located on heating section 438A that accepts the end of lead-in section 438B. Electrically conductive beads (for example, balls, spheres, or pebbles) may be located in the container. The beads may move around as the end of lead-in section 438B is pushed into the container to make electrical contact between the lead-in section and heating section 438A. The beads may be made of, for example, copper or aluminum. The beads may be coated or covered with a corrosion inhibitor such as nickel. In some embodiments, the beads are coated with a solder material that melts at lower temperatures (for example, below the boiling point of water in the formation). A high electrical current may be applied to the container to melt the solder. The melted solder may flow and fill void spaces in the container and be allowed to solidify before energizing the heater. In some embodiments, sacrificial beads are put in the container. The sacrificial beads may corrode first so that copper or aluminum beads in the container are less likely to be corroded during operation of the heater.

[1269] Power supplies are used to provide power to downhole power devices (downhole loads) such as, but not limited to, reservoir heaters, electric submersible pumps (ESPs), compressors, electric drills, electrical tools for construction and maintenance, diagnostic systems, sensors, or acoustic wave generators. Surface based power supplies may have long supply cabling (power cables) that contribute to problems such as voltage drops and electrical losses. Thus, it may be necessary to provide power to the downhole loads at high voltages to reduce electrical losses. However, many downhole loads are limited by an acceptable supply voltage level to the load. Therefore, an efficient high-voltage energy supply may not be viable without further conditioning. In such cases, a system for stepping down the voltage from the high voltage supply cable to the low voltage load may be necessary. The system may be a transformer.

[1270] The electrical power supply for downhole loads is typically provided using alternating current voltage (AC voltage) from supply grids of 50 Hz or 60 Hz frequency. The voltage of the supply grid may correspond to the voltage of the downhole load. High supply voltages may reduce loss and voltage drop in the supply cable and/or allow the use of supply cables with relatively small cross sections. High supply voltages, however, may cause technical difficulties
and require cost intensive isolation efforts at the load. Voltage drops, electrical losses, and supply cable cross section limits may limit the length of the supply cable and, thus, the wellbore depth or depth of the downhole load. Locating the transformer downhole may reduce the amount of cabling needed to provide power to the downhole loads and allow deeper wellbore depths and/or downhole load depths while minimizing voltage drops and electrical losses in the power system.


[1272] FIGS. 169 and 170 depict an embodiment of transformer 580 that may be located in a subsurface wellbore. FIG. 169 depicts a top view representation of the embodiment of transformer 580 showing the windings and core of the transformer. FIG. 170 depicts a side view representation of the embodiment of transformer 580 showing the windings, the core, and the power leads. Transformer 580 includes primary windings 738A and secondary windings 738B. Primary windings 738A and secondary windings 738B may have different cross-sectional areas.

[1273] Core 740 may include two half-shell core sections 740A and 740B around primary windings 738A and secondary windings 738B. In certain embodiments, core sections 740A and 740B are semicircular, symmetric shells. Core sections 740A and 740B may be single pieces that extend the full length of transformer 580 or the core sections may be assembled from multiple shell segments put together (for example, multiple pieces strung together to make the core sections). In certain embodiments, a core section is formed by putting together the section from two halves. The two halves of the core section may be put together after the windings, which may be pre-fabricated, are placed in the transformer.

[1274] In certain embodiments, core sections 740A and 740B have about the same cross section on the circumference of transformer 580 so that the core properly guides the magnetic flux in the transformer. Core sections 740A and 740B may be made of several layers of core material. Certain orientations of these layers may be designed to minimize eddy current losses in transformer 580. In some embodiments, core sections 740A and 740B are made of continuous ribbons and windings 738A and 738B are wound into the core sections.

[1275] Transformer 580 may have certain advantages over current transformer configurations (such as a toroid core design with the winding on the outside of the cores). Core sections 740A and 740B have outer surfaces that offer large surface areas for cooling transformer 580.
Additionally, transformer 580 may be sealed so that a cooling liquid may be continuously run across the outer surfaces of the transformer to cool the transformer. Transformer 580 may be sealed so that cooling liquids do not directly contact the inside of the core and/or the windings. In certain embodiments, transformer is sealed in an epoxy resin or other electrically insulating sealing material. Cooling transformer 580 allows the transformer to operate at higher power densities. In certain embodiments, windings 738A and 738B are substantially isolated from core sections 740A and 740B so that the outside surfaces of transformer 580 may touch the walls of a wellbore without causing electrical problems in the wellbore.

[1276] In some embodiments, the profile of the core of transformer 580 and/or the winding window profile are made with clearances to allow for additional cooling devices, mechanical supports, and/or electrical contacts on the transformer. In some embodiments, transformer 580 is coupled to one or more additional transformers in the subsurface wellbore to increase power in the wellbore and/or phase options in the wellbore. Transformer 580 and/or the phases of the transformer may be coupled to the additional transformers, and/or the varying phases of the additional transformers, in either series or parallel configurations as needed to provide power to the downhole load.

[1277] FIG. 171 depicts an embodiment of transformer 580 in a wellbore 742. Transformer 580 is located in the overburden section of wellbore 742. The overburden section of wellbore 742 has overburden casing 564. Overburden casing 564 electrically and thermally insulates the overburden from the inside of wellbore 742. Packing material 566 is located at the bottom of the overburden section of wellbore 742. Packing material 566 inhibits fluid flow between the overburden section of wellbore 742 and the heating section of the wellbore.

[1278] Power lead 744 may be coupled to transformer 580 and pass through packing material 566 to provide power to the downhole load (for example, a downhole heater). In certain embodiments, cooling fluid 746 is located in wellbore 742. Transformer 580 may be immersed in cooling fluid 746. Cooling fluid 746 may cool transformer 580 by removing heat from the transformer and moving the heat away from the transformer. Cooling fluid 746 may be circulated in wellbore 742 to increase heat transfer between transformer 580 and the cooling fluid. In some embodiments, cooling fluid 746 is circulated to a chiller or other heat exchanger to remove heat from the cooling fluid and maintain a temperature of the cooling fluid at a selected temperature. Maintaining cooling fluid 746 at a selected temperature may provide efficient heat transfer between the cooling fluid and transformer 580 so that the transformer is maintained at a desired operating temperature.

[1279] In certain embodiments, cooling fluid 746 maintains a temperature of transformer 580 below a selected temperature. The selected temperature may be a maximum operating
temperature of the transformer. In some embodiments, the selected temperature is a maximum temperature that allows for a selected operational efficiency of the transformer. In some embodiments, transformer 580 operates at an efficiency of at least 95%, at least 90%, at least 80%, or at least 70% when the transformer operates below the selected temperature.

[1280] In certain embodiments, cooling fluid 746 is water. In some embodiments, cooling fluid 746 is another heat transfer fluid such as, but not limited to, oil, ammonia, helium, or Freon® (E. I. du Pont de Nemours and Company, Wilmington, Delaware, U.S.A.). In some embodiments, the wellbore adjacent to the overburden functions as a heat pipe. Transformer 580 boils cooling fluid 746. Vaporized cooling fluid 746 rises in the wellbore, condenses, and flows back to transformer 580. Vaporization of cooling fluid 746 transfers heat to the cooling fluid and condensation of the cooling fluid allows heat to transfer to the overburden. Transformer 580 may operate near the vaporization temperature of cooling fluid 746.

[1281] In some embodiments, cooling fluid is circulated in a pipe that surrounds the transformer. The pipe may be in direct thermal contact with the transformer so that heat is removed from the transformer into the cooling fluid circulating through the pipe. In some embodiments, the transformer includes fans, heat sinks, fins, or other devices that assist in transferring heat away from the transformer. In some embodiments, the transformer is, or includes, a solid state transformer device such as an AC to DC converter.

[1282] In certain embodiments, the cooling fluid for the downhole transformer is circulated using a heat pipe in the wellbore. FIG. 172 depicts an embodiment of transformer 580 in wellbore 742 with heat pipes 748A,B. Lid 750 is placed at the top of a reservoir of cooling fluid 746 that surrounds transformer 580. Heated cooling fluid expands and flows up heat pipe 748A. The heated cooling fluid 746 cools adjacent to the overburden and flows back to lid 750. The cooled cooling fluid 746 flows back into the reservoir through heat pipe 748B. Heat pipes 748A,B act to create a flow path for the cooling fluid so that the cooling fluid circulates around transformer 580 and maintains a temperature of the transformer below the selected temperature.

[1283] Computational analysis has shown that a circulated water column was sufficient to cool a 60 Hz transformer that was 125 feet in length and generated 80 W/ft of heat. The transformer and the formation were initially at ambient temperatures. The water column was initially at an elevated temperature. The water column and transformer cooled over a period of about 1 to 2 hours. The transformer initially heated up (but was still at operable temperatures) but then was cooled by the water column to lower operable temperatures. The computations also showed that the transformer would be cooled by the water column when the transformer and the formation were initially at higher than normal temperatures.
Modern utility voltage regulators have microprocessor controllers that monitor output voltage and adjust taps up or down to match a desired setting. Typical controllers include current monitoring and may be equipped with remote communications capabilities. The controller firmware may be modified for current based control (for example, control desired for maintaining constant wattage as heater resistances vary with temperature). Load resistance monitoring as well as other electrical analysis based evaluation and control are a possibility because of the availability of both current and voltage sensing by the controller. In addition to current, sensed electrical properties including, but not limited to power, voltage, power factor, resistance or harmonics may be used as control parameters. Typical tap changers have a 200% of nominal, short time current rating. Thus, the regulator controller may be programmed to respond to overload currents by means of tap changer operation.

Electronic heater controls such as silicon-controlled rectifiers (SCRs) may be used to provide power to and control subsurface heaters. SCRs may be expensive to use and may waste electrical energy in the power circuit. SCRs may also produce harmonic distortions during power control of the subsurface heaters. Harmonic distortion may put noise on the power line and stress heaters. In addition, SCRs may overly stress heaters by switching the power between being full on and full off rather than regulating the power at or near the ideal current setting. Thus, there may be significant overshooting and/or undershooting at the target current for temperature limited heaters (for example, heaters using ferromagnetic materials for self-limiting temperature control).

A variable voltage, load tap changing transformer, which is based on a load tap changing regulator design, may be used to provide power to and control subsurface heaters more simply and without the harmonic distortion associated with electronic heater control. The variable voltage transformer may be connected to power distribution systems by simple, inexpensive fused cutouts. The variable voltage transformer may provide a cost effective, stand alone, full function heater controller and isolation transformer.

FIG. 173 depicts a schematic for a conventional design of tap changing voltage regulator 752. Regulator 752 provides plus or minus 10% adjustment of the input or line voltage. Regulator 752 includes primary winding 754 and tap changer section 756, which includes the secondary winding of the regulator. Primary winding 754 is a series winding electrically coupled to the secondary winding of tap changer section 756. Tap changer section 756 includes eight taps 758A-H that separate the voltage on the secondary winding into voltage steps. Moveable tap changer 760 is a moveable preventive autotransformer with a balance winding. Tap changer 760 may be a sliding tap changer that moves between taps 758A-H in tap changer section 756. Tap changer 760 may be capable of carrying high currents up to, for example, 668 A or more.
Tap changer 760 contacts either one tap 758 or bridges between two taps to provide a midpoint between the two tap voltages. Thus, 16 equivalent voltage steps are created for tap changer 760 to couple to in tap changer section 756. The voltage steps divide the 10% range of regulation equally (5/8% per step). Switch 762 changes the voltage adjustment between plus and minus adjustment. Thus, voltage can be regulated plus 10% or minus 10% from the input voltage.

Voltage transformer 764 senses the potential at bushing 766. The potential at bushing 766 may be used for evaluation by a microprocessor controller. The controller adjusts the tap position to match a preset value. Control power transformer 768 provides power to operate the controller and the tap changer motor. Current transformer 770 is used to sense current in the regulator.

FIG. 174 depicts a schematic for variable voltage, load tap changing transformer 772. The schematic for transformer 772 is based on the load tap changing regulator schematic depicted in FIG. 173. Primary winding 754 is isolated from the secondary winding of tap changer section 756 to create distinct primary and secondary windings. Primary winding 754 may be coupled to a voltage source using bushings 774, 776. The voltage source may provide a first voltage across primary winding 754. The first voltage may be a high voltage such as voltages of at least 5 kV, at least 10 kV, at least 25kV, or at least 35kV up to about 50kV. The secondary winding in tap changer section 756 may be coupled to an electrical load (for example, one or more subsurface heaters) using bushings 778, 780. The electrical load may include, but not be limited to, an insulated conductor heater (for example, mineral insulated conductor heater), a conductor-in-conduit heater, a temperature limited heater, a dual leg heater, or one heater leg of a three-phase heater configuration. The electrical load may be other than a heater (for example, a bottom hole assembly for forming a wellbore).

The secondary winding in tap changer section 756 steps down the first voltage across primary winding 754 to a second voltage (for example, voltage lower than the first voltage or a second voltage). In certain embodiments, the secondary winding in tap changer section 756 steps down the voltage from primary winding 754 to the second voltage that is between 5% and 20% of the first voltage across the primary winding. In some embodiments, the secondary winding in tap changer section 756 steps down the voltage from primary winding 754 to the second voltage that is between 1% and 30% or between 3% and 25% of the first voltage across the primary winding. In one embodiment, the secondary winding in tap changer section 756 steps down the voltage from primary winding 754 to the second voltage that is 10% of the first voltage across the primary winding.
stepped down to a second voltage of 720 V across the secondary winding in tap changer section 756.

[1292] In some embodiments, the step down percentage in tap changer section 756 is preset. In some embodiments, the step down percentage in tap changer section 756 may be adjusted as needed for desired operation of a load coupled to transformer 772.

[1293] Taps 758A-H (or any other number of taps) divide the second voltage on the secondary winding in tap changer section 756 into voltage steps. The second voltage is divided into voltage steps from a selected minimum percentage of the second voltage up to the full value of the second voltage. In certain embodiments, the second voltage is divided into equivalent voltage steps between the selected minimum percentage and the full second voltage value. In some embodiments, the selected minimum percentage is 0% of the second voltage. For example, the second voltage may be equally divided by the taps in voltage steps ranging between 0 V and 720 V. In some embodiments, the selected minimum percentage is 25% or 50% of the second voltage.

[1294] Transformer 772 includes tap changer 760 that contacts either one tap 758 or bridges between two taps to provide a midpoint between the two tap voltages. The position of tap changer 760 on the taps determines the voltage provided to an electrical load coupled to bushings 778, 780. As an example, an arrangement with 8 taps in tap changer section 756 provides 16 voltage steps for tap changer 760 to couple to in tap changer section 756. Thus, the electrical load may be provided with 16 different voltages varying between the selected minimum percentage and the second voltage.

[1295] In certain embodiments of transformer 772, the voltage steps divide the range between the selected minimum percentage and the second voltage equally (the voltage steps are equivalent). For example, eight taps may divide a second voltage of 720 V into 16 voltage steps between 0 V and 720 V so that each tap increments the voltage provided to the electrical load by 45V. In some embodiments, the voltage steps divide the range between the selected minimum percentage and the second voltage in non-equal increments (the voltage steps are not equivalent).

[1296] Switch 762 may be used to electrically disconnect bushing 780 from the secondary winding and taps 758. Electrically isolating bushing 780 from the secondary winding turns off the power (voltage) provided to the electrical load coupled to bushings 778, 780. Thus, switch 762 provides an internal disconnect in transformer 772 to electrically isolate and turn off power (voltage) to the electrical load coupled to the transformer.

[1297] In transformer 772, voltage transformer 764, control power transformer 768, and current transformer 770 are electrically isolated from primary winding 754. Electrical isolation protects
voltage transformer 764, control power transformer 768, and current transformer 770 from current and/or voltage overloads caused by primary winding 754.

[1298] In certain embodiments, transformer 772 is used to provide power to a variable electrical load (for example, a subsurface heater such as, but not limited to, a temperature limited heater using ferromagnetic material that self-limits at the Curie temperature or a phase transition temperature range). Transformer 772 allows power to the electrical load to be adjusted in small voltage increments (voltage steps) by moving tap changer 760 between taps 758. Thus, the voltage supplied to the electrical load may be adjusted incrementally to provide constant current to the electrical load in response to changes in the electrical load (for example, changes in resistance of the electrical load). Voltage to the electrical load may be controlled from a minimum voltage (the selected minimum percentage) up to full potential (the second voltage) in increments. The increments may be equal increments or non-equal increments. Thus, power to the electrical load does not have to be turned full on or off to control the electrical load such as is done with a SCR controller. Using small increments may reduce cycling stress on the electrical load and may increase the lifetime of the device that is the electrical load. Transformer 772 changes the voltage using mechanical operation instead of the electrical switching used in SCRs. Electrical switching can add harmonics and/or noise to the voltage signal provided to the electrical load. The mechanical switching of transformer 772 provides clean, noise free, incrementally adjustable control of the voltage provided to the electrical load.

[1299] Transformer 772 may be controlled by controller 782. Controller 782 may be a microprocessor controller. Controller 782 may be powered by control power transformer 768. Controller 782 may assess properties of transformer 772, including tap changer section 756, and/or the electrical load coupled to the transformer. Examples of properties that may be assessed by controller 782 include, but are not limited to, voltage, current, power, power factor, harmonics, tap change operation count, maximum and minimum value recordings, wear of the tap changer contacts, and electrical load resistance.

[1300] In certain embodiments, controller 782 is coupled to the electrical load to assess properties of the electrical load. For example, controller 782 may be coupled to the electrical load using an optical fiber. The optical fiber allows measurement of properties of the electrical load such as, but not limited to, electrical resistance, impedance, capacitance, and/or temperature. In some embodiments, controller 782 is coupled to voltage transformer 764 and/or current transformer 770 to assess the voltage and/or current output of transformer 772. In some embodiments, the voltage and current are used to assess a resistance of the electrical load over one or more selected time periods. In some embodiments, the voltage and current are used to assess or diagnose other properties of the electrical load (for example, temperature).
[1301] In certain embodiments, controller 782 adjusts the voltage output of transformer 772 in response to changes in the electrical load coupled to the transformer or other changes in the power distribution system such as, but not limited to, input voltage to the primary winding or other power supply changes. For example, controller 782 may adjust the voltage output of transformer 772 in response to changes in the electrical resistance of the electrical load. Controller 782 may adjust the output voltage by controlling the movement of control tap changer 760 between taps 758 to adjust the voltage output of transformer 772. In some embodiments, controller 782 adjusts the voltage output of transformer 772 so that the electrical load (for example, a subsurface heater) is operated at a relatively constant current. In some embodiments, controller 782 may adjust the voltage output of transformer 772 by moving tap changer 760 to a new tap, assess the resistance and/or power at the new tap, and move the tap changer to another new tap if needed.

[1302] In some embodiments, controller 782 assesses the electrical resistance of the load (for example, by measuring the voltage and current using the voltage and current transformers or by measuring the resistance of the electrical load using the optical fiber) and compares the assessed electrical resistance to a theoretical resistance. Controller 782 may adjust the voltage output of transformer 772 in response to differences between the assessed resistance and the theoretical resistance. In some embodiments, the theoretical resistance is an ideal resistance for operation of the electrical load. In some embodiments, the theoretical resistance varies over time due to other changes in the electrical load (for example, temperature of the electrical load).

[1303] In some embodiments, controller 782 is programmable to cycle tap changer 760 between two or more taps 758 to achieve intermediate voltage outputs (for example, a voltage output between two tap voltage outputs). Controller 782 may adjust the time tap changer 760 is on each of the taps cycled between to obtain an average voltage at or near the desired intermediate voltage output. For example, controller 782 may keep tap changer 760 at two taps approximately 50% of the time each to maintain an average voltage approximately midway between the voltages at the two taps.

[1304] In some embodiments, controller 782 is programmable to limit the numbers of voltage changes (movement of tap changer 760 between taps 758 or cycles of tap changes) over a period of time. For example, controller 782 may only allow 1 tap change every 30 minutes or 2 tap changes per hour. Limiting the number of tap changes over the period of time reduces the stress on the electrical load (for example, a heater) from changes in voltage to the load. Reducing the stresses applied to the electrical load may increase the lifetime of the electrical load. Limiting the number of tap changes may also increase the lifetime of the tap changer apparatus. In some embodiments, the number of tap changes over the period of time is adjustable using the
controller. For example, a user may be allowed to adjust the cycle limit for tap changes on transformer 772.

[1305] In some embodiments, controller 782 is programmable to power the electrical load in a start up sequence. For example, subsurface heaters may require a certain start up protocol (such as high current during early times of heating and lower current as the temperature of the heater reaches a set point). Ramping up power to the heaters in a desired procedure may reduce mechanical stresses on the heaters from materials expanding at different rates. In some embodiments, controller 782 ramps up power to the electrical load with controlled increases in voltage steps over time. In some embodiments, controller 782 ramps up power to the electrical load with controlled increases in watts per hour. Controller 782 may be programmed to automatically start up the electrical load according to a user input start up procedure or a pre-programmed start up procedure.

[1306] In some embodiments, controller 782 is programmable to turn off power to the electrical load in a shut down sequence. For example, subsurface heaters may require a certain shut down protocol to inhibit the heaters from cooling to quickly. Controller 782 may be programmed to automatically shut down the electrical load according to a user input shut down procedure or a pre-programmed shut down procedure.

[1307] In some embodiments, controller 782 is programmable to power the electrical load in a moisture removal sequence. For example, subsurface heaters or motors may require start up at second voltages to remove moisture from the system before application of higher voltages. In some embodiments, controller 782 inhibits increases in voltage until required electrical load resistance values are met. Limiting increases in voltage may inhibit transformer 772 from applying voltages that cause shorting due to moisture in the system. Controller 782 may be programmed to automatically start up the electrical load according to a user input moisture removal sequence or a pre-programmed moisture removal procedure.

[1308] In some embodiments, controller 782 is programmable to reduce power to the electrical load based on changes in the voltage input to primary winding 754. For example, the power to the electrical load may be reduced during brownouts or other power supply shortages. Reducing the power to the electrical load may compensate for the reduced power supply.

[1309] In some embodiments, controller 782 is programmable to protect the electrical load from being overloaded. Controller 782 may be programmed to automatically and immediately reduce the voltage output if the current to the electrical load increases above a selected value. The voltage output may be stepped down as fast as possible while sensing the current. Sensing of the current occurs on a faster time scale than the step downs in voltage so the voltage may be stepped down as fast as possible until the current drops below a selected level. In some embodiments, tap
DEMANDE OU BREVET VOLUMINEUX

LA PRÉSENTE PARTIE DE CETTE DEMANDE OU CE BREVET COMPREND PLUS D’UN TOME.

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JUMBO APPLICATIONS/PATENTS

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NOM DU FICHIER / FILE NAME :

NOTE POUR LE TOME / VOLUME NOTE:
WHAT IS CLAIMED IS:

1. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming a first wellbore in the formation;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
   providing at least one magnetic field in the second wellbore using one or more magnets in the second wellbore located on a drilling string used to drill the second wellbore;
   sensing at least one magnetic field in the first wellbore using at least two sensors in the first wellbore as the magnetic field passes by the at least two sensors while the second wellbore is being drilled;
   continuously assessing a position of the second wellbore relative to the first wellbore using the sensed magnetic field; and
   adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

2. The method of claim 1, wherein the second wellbore is formed substantially parallel to the first wellbore.

3. The method of claim 1, further comprising moving the at least two sensors after sensing the magnetic field so that the sensors are allowed to sense the magnetic field at a second position while drilling the second wellbore.

4. The method of claim 1, further comprising providing at least two magnetic fields with at least two magnets in the second wellbore.

5. The method of claim 1, wherein the at least two sensors are positioned in advance of the sensed magnetic field so that the sensors sense the magnetic field as the magnetic field passes the sensors.

6. The method of claim 1, wherein the at least two sensors are positioned in advance of the sensed magnetic field so that the sensors may be set to “null” the background magnetic field allowing direct measurement of the reference magnetic field as it passes the sensors.

7. The method of claim 1, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.

8. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming at least a first wellbore in the formation;
   providing a voltage signal to the first wellbore;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;

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continuously sensing the voltage signal in the second wellbore;
continuously assessing a position of the second wellbore relative to the first wellbore using the sensed voltage signal; and
adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

9. The method of claim 8, further comprising:
providing the voltage signal to the first wellbore and a third wellbore, wherein the second wellbore is positioned substantially adjacent the first wellbore; and
creating an electrical current and magnetic field signal.

10. The method of claim 8, wherein the provided voltage signal creates a magnetic field.

11. The method of claim 8, wherein the second wellbore is formed substantially parallel to the first wellbore.

12. The method of claim 8, wherein the voltage signal comprises a pulsed direct current (DC) signal.

13. The method of claim 8, further comprising providing the voltage signal through an electrical conductor that is to be used as a heater in the first wellbore.

14. The method of claim 8, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.

15. A method for forming two or more wellbores in a subsurface formation, comprising:
forming a first wellbore in the formation;
directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
providing an electromagnetic wave in the second wellbore;
continuously sensing the electromagnetic wave in the first wellbore using at least one electromagnetic antenna;
continuously assessing a position of the second wellbore relative to the first wellbore using the sensed electromagnetic wave; and
adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

16. The method of claim 15, wherein the second wellbore is formed substantially parallel to the first wellbore.

17. The method of claim 15, further comprising providing the electromagnetic wave using an electromagnetic sonde.
18. The method of claim 15, wherein the antenna is located in a heater that is to be used to provide heat in the first wellbore.

19. The method of claim 15, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.

20. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming a first wellbore in the formation;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
   transmitting a first electromagnetic wave from a first transceiver in the first wellbore and sensing the first electromagnetic wave using a second transceiver in the second wellbore;
   transmitting a second electromagnetic wave from the second transceiver in the second wellbore and sensing the second electromagnetic wave using the first transceiver in the first wellbore;
   continuously assessing a position of the second wellbore relative to the first wellbore using the sensed first electromagnetic wave and the sensed second electromagnetic wave; and
   adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

21. The method of claim 20, further comprising assessing natural electromagnetic fields using a third transceiver positioned at a distal end of the first wellbore.

22. The method of claim 20, wherein the first transceiver is coupled to a surface of the formation.

23. The method of claim 20, wherein the first transceiver is directly coupled to a surface of the formation via a wire.

24. The method of claim 20, wherein the first transceiver is directly coupled to a surface of the formation via a wire.

25. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming a plurality of first wellbores in the formation;
   providing a plurality of electromagnetic waves in the first wellbores;
   directionally drilling one or more second wellbores in a selected relationship relative to the first wellbores;
   continuously sensing the electromagnetic waves in the first wellbores using at least one electromagnetic antenna in the second wellbores;
   continuously assessing a position of the second wellbores relative to the first wellbores using the sensed electromagnetic waves; and
adjusting the direction of drilling of at least one of the second wellbores so that the second wellbore remains in the selected relationship relative to the first wellbores.
26. The method of claim 25, wherein at least one of the second wellbores is formed substantially perpendicular to at least one of the first wellbores.
27. The method of claim 25, further comprising providing the electromagnetic waves using electromagnetic sondes.
28. The method of claim 25, wherein the antenna is located in a heater that is to be used to provide heat in at least one of the second wellbores.
29. The method of claim 25, further comprising continuously adjusting the direction of drilling of at least one of the second wellbores using the continuously assessed position of the second wellbore relative to the first wellbore.
30. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming a first wellbore in the formation;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
   providing an electromagnetic field in the first wellbore using one or more magnets;
   continuously sensing the electromagnetic field in the first wellbore using at least one electromagnetic field sensor positioned in the second wellbore;
   continuously assessing a position of the second wellbore relative to the first wellbore using the sensed electromagnetic field; and
   adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.
31. The method of claim 30, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.
32. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming a first wellbore in the formation;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
   providing an electromagnetic field in the second wellbore using one or more magnets;
   continuously sensing the electromagnetic field in the second wellbore using at least one electromagnetic field sensor positioned in the first wellbore;
   continuously assessing a position of the second wellbore relative to the first wellbore using the sensed electromagnetic field; and
adjusting the direction of drilling of the second wellbore so that the second wellbore
remains in the selected relationship relative to the first wellbore.
33. The method of claim 32, further comprising continuously adjusting the direction of drilling of
the second wellbore using the continuously assessed position of the second wellbore relative to
the first wellbore.
34. The method of claim 32, further comprising calibrating the sensors to adjust for natural
magnetic fields positioned adjacent the first wellbore.
35. A system for forming wellbores in a formation, comprising:
   composite coiled tubing;
   a particle jet drilling nozzle coupled to the coiled tubing;
   a downhole electric orienter coupled to the particle jet drilling nozzle;
   downhole inertial navigation system coupled to the composite tubing; and
   a computer system coupled to the downhole inertial navigation system and the downhole
electric orienter to control the direction of the opening formed by particles passing through the
particle jet drilling nozzle.
36. The system of claim 35, further comprising bubble entrained mud as the drilling fluid.
37. The system of claim 36, wherein the computer system is used to control the density of the
bubble entrained mud as a function of real time gains and losses of fluid while drilling.
38. The system of claim 35, further comprising a multiphase fluid as the drilling fluid.
39. The system of claim 35, wherein the downhole inertial navigation system provides depth,
azimuth and inclination information to the computer system.
40. The system of claim 35, wherein power for the downhole electric orienter is provided through
a power line formed in the composite coiled tubing.
41. The system of claim 35, further comprising steel abrasives as particles used to form the
wellbore.
42. The system of claim 41, further comprising a magnetic separator for separating steel
abrasives from drilling fluid.
43. The system of claim 35, further comprising one or more piston membrane pumps used to
move drilling fluid.
44. The system of claim 35, further comprising one or more annular pressure exchange pumps.
45. A method for forming wellbores in a formation comprising:
   flowing particles entrained in drilling fluid down composite coil tubing;
   passing particles through one or more nozzles to impinge upon formation and remove
material from the formation to extend an opening in the formation;
using a downhole inertial navigation system to provide at least depth, azimuth and inclination information to a computer system;

sending control information from a computer system to a downhole electric orienter; and

adjusting the position of the one or more nozzles to form the opening in the desired direction using the downhole electric orienter.

46. The method of claim 45, further comprising transferring data to and from the computer system in data lines built into the composite coil tubing.

47. The method of claim 45, further comprising powering downhole components through power lines built into the composite coil tubing.

48. The method of claim 45, further comprising pumping drilling fluid using one or more piston member pumps.

49. The method of claim 45, further comprising pumping drilling fluid using one or more annular pressure exchange pumps.

50. The method of claim 45, wherein the drilling fluid comprises a multiphase fluid, and further comprising using the computer system to control injection rates of gas and/or liquid comprising the multiphase fluid.

51. A method, comprising:

coupling a robot to coiled tubing positioned in a wellbore, wherein the robot comprises one or more batteries;

moving the robot down the coiled tubing to the bottom hole assembly in the borehole;

electrically coupling the robot to the bottom hole assembly to charge the one or more batteries of the robot;

decoupling the robot from the bottom hole assembly; and

using the robot to perform a task in the wellbore.

52. The method of claim 51, wherein the robot is a tractor robot, and using the robot to apply force to formation adjacent to the wellbore and to apply force to the bottom hole assembly to move the bottom hole assembly.

53. The method of claim 51, wherein the task comprises surveying the position of the bottom hole assembly.

54. The method of claim 51, wherein task comprises removing cuttings.

55. The method of claim 51, wherein the task comprises logging.

56. The method of claim 51, wherein the task comprises pipe freeing.

57. A method for forming a wellbore in a heated formation, comprising:

flowing liquid drilling fluid to a bottom hole assembly;

vaporizing at least a portion of the drilling fluid at or near a drill bit; and
removing the drilling fluid and cuttings from the wellbore.

58. The method of claim 57, further comprising maintaining a high pressure on the drilling fluid flowing to the drill bit to maintain the drilling fluid in a liquid phase.

59. The method of claim 57, wherein the drilling fluid is directed down the drilling string to the drill bit using conventional circulation.

60. The method of claim 57, wherein the drilling fluid is directed to the drill bit using reverse circulation.

61. The method of claim 57, wherein the drilling fluid provided to the bottom hole assembly is a two-phase mixture comprising a non-condensable gas in a liquid.

62. The method of claim 57, further comprising lifting the cuttings at least partially using pressure and velocity resulting from phase change of drilling fluid to vapor.

63. The method of claim 57, further comprising removing heat from the drill bit by vaporizing drilling fluid.

64. The method of claim 57, further comprising controlling down hole pressure by maintaining a desired back pressure on the drilling fluid.

65. A method for forming a wellbore in a heated formation, comprising:

   flowing a two-phase drilling fluid to a bottom hole assembly;

   vaporizing at least a portion of a liquid phase of the two-phase drilling fluid at or near a drill bit; and

   removing cuttings and the drilling fluid from the wellbore.

66. The method of claim 65, further comprising maintaining a high pressure on the drilling fluid flowing to the drill bit to maintain the a liquid phase of the drilling fluid as a liquid.

67. The method of claim 65, wherein the drilling fluid is directed down the drilling string to the drill bit using conventional circulation.

68. The method of claim 65, wherein the drilling fluid is directed to the drill bit using reverse circulation.

69. The method of claim 65, further comprising lifting the cuttings partially using pressure and velocity resulting from phase change of drilling fluid to vapor.

70. The method of claim 65, further comprising removing heat from the drill bit by vaporizing drilling fluid.

71. The method of claim 65, further comprising controlling down hole pressure by maintaining a desired back pressure on the drilling fluid.

72. A system for forming a wellbore in a heated formation, comprising:

   drilling fluid;

   a drill bit configured to form an opening in the formation;
a drilling string coupled to the drill bit, the drilling string configured to transport drilling fluid to the drill bit and facilitate removal of drilling fluid and cuttings from the wellbore; and a pressure activated valve coupled to the drilling pipe, the pressure activated valve configured to maintain a high pressure on the drilling fluid flowing to the drill bit so that a portion of the drilling fluid directed to the drilling bit is in a liquid phase.

73. The system of claim 72, further comprising one or more chokes coupled to the drilling string, wherein at least one of the chokes is configured to maintain a high pressure on the drilling fluid flowing to the drill bit so that a portion of the drilling fluid is in a liquid phase.

74. The system of claim 73, wherein at least one of the chokes comprises a jet nozzle.

75. The system of claim 73, wherein at least one of the chokes comprises an orifice.

76. The system of claim 72, wherein the drilling fluid provided to the drill bit comprises a two-phase mixture of a non-condensable gas added to a liquid.

77. The system of claim 72, wherein the drilling fluid comprises nitrogen.

78. A conduit for flowing a refrigerant in a wellbore used to form a low temperature zone in a formation, comprising:

a plastic conduit;

an outer sleeve configured to couple to plastic conduit; and

an inner sleeve positioned in the outer sleeve, wherein the inner sleeve is in fluid communication with the plastic conduit, and wherein the inner sleeve comprises:

a first stop configured to limit insertion depth of the outer sleeve relative the inner sleeve;

one or more openings in the inner sleeve located below a lowermost position of the outer sleeve; and

a latch configured to couple to a casing that the conduit is to be positioned in; and wherein thermal contraction of the plastic conduit due to refrigerant flowing through the plastic conduit is compensated by the outer sleeve rising relative to the inner sleeve.

79. The conduit of claim 78, wherein the outer sleeve is a metal sleeve.

80. The conduit of claim 78, wherein the inner sleeve is a metal sleeve.

81. The conduit of claim 78, further comprising a plurality of slip rings coupled to the inner sleeve.

82. The conduit of claim 78, further comprising at least one shear pin positioned in openings in the inner sleeve and the outer sleeve to facilitate insertion of the conduit in the casing.

83. A freeze well for forming a low temperature zone, comprising:

a casing configured to be positioned in a wellbore, the casing comprising a closed bottom end;
a catch secured to the closed bottom end;

an inner conduit configured to be positioned in the casing, the inner conduit comprising:

a plastic conduit;

an outer sleeve coupled to the plastic conduit;

an inner sleeve positioned in the outer sleeve, wherein the inner sleeve is in fluid communication with the plastic conduit, and wherein a portion of the inner sleeve has one or more openings in communication with the casing; and

a latch coupled to a bottom portion of the inner sleeve, wherein the latch is configured to engage the catch to releasably couple the inner conduit to the casing.

84. The freeze well of claim 83, further comprising a plurality of slip rings coupled to the inner sleeve.

85. The freeze well of claim 83, further comprising at least one shear pin positioned in openings in the inner sleeve and the outer sleeve to facilitate insertion of the conduit in the casing.

86. A method of cooling a portion of a formation adjacent to a freeze well, comprising:

flowing refrigerant downward in an inner conduit positioned in a casing;

returning the refrigerant upwards in a space between the inner conduit and a casing; and

accommodating thermal contraction of the inner conduit using a bottom portion of the inner conduit, wherein an inner sleeve of the bottom portion is coupled to the casing, and wherein an outer sleeve is able to move upwards relative to the inner sleeve.

87. The method of claim 86, further comprising decoupling the inner sleeve from the casing to remove the inner conduit from the casing.

88. A method for installing a horizontal or inclined subsurface heater, comprising:

placing a heating section of a heater in a horizontal or inclined section of a wellbore with an installation tool;

uncoupling the tool from the heating section; and

mechanically and electrically coupling a lead-in section of the heater to the heating section of the heater, wherein the lead-in section is located in an angled or vertical section of the wellbore.

89. The method of claim 88, further comprising removing the tool from the wellbore after uncoupling the tool from the heating section.

90. The method of claim 88, wherein the lead-in section has an electrical resistance less than the heating section of the heater.

91. The method of claim 88, wherein the lead-in section is mechanically coupled to the heating section using a wet connect stab device.
92. The method of claim 88, wherein the heating section comprises a receptacle at one end for accepting and coupling to the lead-in section.

93. The method of claim 88, wherein the heater section is mechanically secured in the wellbore with the installation tool.

94. An electrical insulation system for a subsurface electrical conductor, comprising:
   - at least three electrical insulators coupled to the electrical conductor, each insulator comprising a metal piece at least partially surrounded by ceramic insulation, the metal piece being connected to the ceramic insulation, and each insulator being coupled to the electrical conductor by connecting the metal piece to the electrical conductor; and
   - the insulators being coupled to the exterior of the electrical conductor so that each insulator is separated from another insulator by a gap at or near the exterior of the electrical conductor.

95. The system of claim 94, wherein the gap allows debris to move along the exterior of the electrical conductor in between the insulators.

96. The system of claim 94, wherein the electrical conductor comprises a conductor used in a heater.

97. The system of claim 94, wherein the gap allows debris to move vertically along the exterior of the electrical conductor.

98. The system of claim 94, wherein the insulators are attached to the electrical conductor before the electrical conductor is installed in the subsurface.

99. The system of claim 94, wherein the electrical conductor is installed vertically in the subsurface.

100. The system of claim 94, wherein at least one metal piece is brazed to the ceramic insulation.

101. The system of claim 94, wherein at least one of the electrical insulators is coupled to the electrical conductor by welding or brazing the metal piece to the electrical conductor.

102. The system of claim 94, wherein at least one of the electrical insulators is coupled around a circumference of the electrical conductor.

103. A method for electrically insulating a subsurface electrical conductor, comprising:
   - coupling at least three electrical insulators around the circumference of the electrical conductor so that each insulator is separated from the another insulator by a gap around the outside surface of the electrical conductor;
   - wherein each insulator comprising a metal piece surrounded by ceramic insulation, the metal piece being brazed to the ceramic insulation, and each insulator being coupled to the heater by welding the metal piece to the electrical conductor.
104. A method for treating a subsurface formation using an electrically insulated electrical conductor, comprising:

providing at least one heater comprising:

at least three electrical insulators coupled to the electrical conductor, each
insulator comprising a metal piece at least partially surrounded by ceramic insulation, the
metal piece being connected to the ceramic insulation, and each insulator being coupled
to the electrical conductor by connecting the metal piece to the electrical conductor;
the insulators being coupled to the exterior of the electrical conductor so that each
insulator is separated from another insulator by a gap at or near the exterior of the
electrical conductor; and

heating at least a portion of the subsurface formation by providing electrical current to the
heater.

105. A method for assessing one or more temperatures of an electrically powered subsurface heater, comprising:

assessing an impedance profile of the electrically powered subsurface heater while the
heater is being operated in the subsurface; and

analyzing the impedance profile with a frequency domain algorithm to assess one or more
temperatures of the heater.

106. The method of claim 105, wherein the impedance profile is assessed using timed domain
reflectometer measurements.

107. The method of claim 105, wherein the frequency domain algorithm comprises partial
discharge measurement technology.

108. The method of claim 105, wherein the impedance profile comprises the impedance profile
along the length of the heater.

109. The method of claim 105, wherein the frequency domain algorithm utilizes laboratory
data for the heater to assess the temperature profile of the heater.

110. The method of claim 105, further comprising assessing a temperature profile of the
heater.

111. The method of claim 105, further comprising using one or more of the temperatures of the
heater to assess reactive power consumption of the heater in the subsurface.

112. The method of claim 105, further comprising using one or more of the temperatures of the
heater to assess real power consumption of the heater in the subsurface.

113. The method of claim 105, further comprising using one or more of the temperatures to
identify and/or predict failure locations along the length of the heater.

114. A method for forming a longitudinal subsurface heater, comprising:
longitudinally welding an electrically conductive sheath of an insulated conductor heater along at least one longitudinal strip of metal; and
forming the longitudinal strip into a tubular around the insulated conductor heater with the insulated conductor heater welded along the inside surface of the tubular.

115. The method of claim 114, wherein forming the longitudinal strip of metal into the tubular comprises rolling the strip of metal into the tubular.

116. The method of claim 114, further comprising electrically shorting a distal end of the tubular to a distal end of the sheath and a center conductor of the insulated conductor heater.

117. The method of claim 114, further comprising forming the tubular by welding the longitudinal lengths of the strip of metal together.

118. The method of claim 114, further comprising forming the tubular by welding the longitudinal lengths of the strip of metal together at a circumferential location away from the point of contact between the tubular and the insulated conductor heater.

119. The method of claim 114, wherein the tubular is formed from a plurality of longitudinal strips of metal.

120. The method of claim 114, wherein the insulated conductor heater comprises a center conductor at least partially surrounded by an electrical insulator, and the sheath at least partially surrounding the electrical insulator.

121. A method for forming a longitudinal subsurface heater, comprising:
longitudinally welding an electrically conductive sheath of an insulated conductor heater along an inside surface of a metal tubular.

122. The method of claim 121, wherein the tubular is formed from one or more longitudinal strips of metal.

123. The method of claim 121, further comprising electrically shorting a distal end of the tubular to a distal end of the sheath and a center conductor of the insulated conductor heater.

124. The method of claim 121, wherein the insulated conductor heater comprises a center conductor at least partially surrounded by an electrical insulator, and the electrically conductive sheath at least partially surrounding the electrical insulator.

125. A longitudinal subsurface heater, comprising:
an insulated conductor heater, comprising:
an electrical conductor;
an electrical insulator at least partially surrounding the electrical conductor; and
an electrically conductive sheath at least partially surrounding the electrical insulator;
a metal tubular at least partially surrounding the insulated conductor heater; and
wherein the sheath of the insulated conductor heater is longitudinally welded along an inside surface of the metal tubular.

126. The heater of claim 125, wherein a distal end of the tubular is electrically shorted to a distal end of the sheath and the electrical conductor of the insulated conductor heater.

127. The heater of claim 125, wherein the tubular is formed from one or more longitudinal strips of metal.

128. The heater of claim 125, wherein the tubular has been formed by welding longitudinal lengths of a strip of metal together.

129. The heater of claim 125, wherein the tubular is configured to allow fluids to flow through the tubular.

130. The heater of claim 125, wherein the metal tubular is ferromagnetic.

131. The heater of claim 125, wherein the electrical conductor comprises copper.

132. The heater of claim 125, wherein the electrical insulator comprises magnesium oxide.

133. The heater of claim 125, wherein the metal tubular is non-ferromagnetic, and the metal tubular is coated with thin electrically insulating coating.

134. The heater of claim 125, wherein the heater is a temperature limited heater.

135. A method for treating a subsurface formation using an electric heater, comprising:

  providing the electric heater to an opening in the subsurface formation, the electric heater comprising:

  an insulated conductor heater, comprising:

  an electrical conductor;

  an electrical insulator at least partially surrounding the electrical conductor; and

  an electrically conductive sheath at least partially surrounding the electrical insulator;

  a metal tubular at least partially surrounding the insulated conductor heater;

  wherein the sheath of the insulated conductor heater is longitudinally welded along an inside surface of the metal tubular; and

  heating the subsurface formation by providing electrical current to the electric heater.

136. The method of claim 135, further comprising providing at least one heat transfer fluid to the tubular.

137. The method of claim 135, further comprising heating the subsurface formation by providing time-varying electrical current to the electric heater.

138. A heating system for a subsurface formation, comprising:
three substantially u-shaped heaters, first ends of the heaters being electrically coupled to a single, three-phase wye transformer, second ends of the heaters being electrically coupled to each other and/or to ground;

wherein the three heaters enter the formation through a first common wellbore and exit the formation through a second common wellbore so that the magnetic fields of the three heaters at least partially cancel out in the common wellbores.

139. The system of claim 138, wherein at least two of the heaters have heating sections that are substantially parallel in a hydrocarbon layer of the formation.

140. The system of claim 138, wherein at least one of the three heaters comprises an exposed metal heating section.

141. The system of claim 138, wherein at least one of the three heaters comprises an insulated conductor heating section.

142. The system of claim 138, wherein at least one of the three heaters comprises a conductor-in-conduit heating section.

143. The system of claim 138, wherein the three heaters comprise 410 stainless steel in heating sections of the heaters, and copper in overburden sections of the heaters.

144. The system of claim 138, further comprising a ferromagnetic casing in the overburden section of the first common wellbore.

145. The system of claim 138, further comprising a ferromagnetic casing in the overburden section of the second common wellbore.

146. The system of claim 138, wherein each heater is coupled to one phase of the transformer.

147. The system of claim 138, further comprising multiples of three additional heaters entering through the first common wellbore.

148. The system of claim 138, further comprising multiples of three additional heaters entering through the first common wellbore and exiting through the second common wellbore.

149. The system of claim 138, wherein at least one of the heaters is used to directionally steer drilling of an opening in the formation used for at least one of the other heaters.

150. The system of claim 138, wherein the three heaters are electrically coupled together in the second common wellbore.

151. The system of claim 138, wherein the three heaters are located in three openings extending between the first common wellbore and the second common wellbore.

152. The system of claim 138, wherein at least one of the three heaters provides different heat outputs along the length of the heater.

153. The system of claim 138, wherein at least one of the three heaters has different materials along the length of the heater to provide different heat outputs along the length of the heater.
154. The system of claim 138, wherein at least one of the three heaters has different dimensions along the length of the heater to provide different heat outputs along the length of the heater.

155. A heating system for a subsurface formation, comprising:
   - a substantially u-shaped electrical conductor extending between a first wellbore and a second wellbore; and
   - a ferromagnetic tubular at least partially surrounding the electrical conductor and spaced from the electrical conductor;
   - wherein the electrical conductor, when energized with time-varying electrical current, induces electrical current flow in the skin depth of the ferromagnetic tubular.

156. The system of claim 155, wherein the tubular comprises carbon steel.

157. The system of claim 155, wherein the tubular comprises 410 stainless steel.

158. The system of claim 155, wherein the electrical conductor is the core of an insulated conductor.

159. The system of claim 155, wherein the tubular has a thickness of at least two times the skin depth of the ferromagnetic material in the tubular.

160. The system of claim 155, wherein the tubular is configured to provide different heat outputs along the length of the tubular.

161. The system of claim 155, wherein the tubular has different materials along the length of the tubular to provide different heat outputs along the length of the tubular.

162. The system of claim 155, wherein the tubular has different dimensions along the length of the tubular to provide different heat outputs along the length of the tubular.

163. The system of claim 155, further comprising coating the tubular with a corrosion resistant material.

164. The system of claim 155, wherein the tubular is between about 1.5” and about 5” in diameter.

165. A gas burner assembly, comprising:
   - an outer conduit;
   - an oxidant conduit positioned in the outer conduit, wherein exhaust returns to the surface in a space between the oxidant conduit and the outer conduit;
   - a plurality of oxidizers positioned in the oxidant conduit;
   - a plurality of fuel conduits positioned in the space between the oxidant conduit and the outer conduit; and
   - one or more taps from the fuel conduit that pass through the oxidant conduit to supply fuel to one or more mix chambers of the plurality of oxidizers.
166. The gas burner assembly of claim 165, further comprising one or more igniter supplies positioned in the space between the oxidant conduit and the outer conduit, and one or more igniter taps that pass through the oxidant conduit and into ignition chambers of the plurality of oxidizers.

167. The gas burner assembly of claim 165, further comprising one or more igniter supplies positioned in the oxidant conduit, and one or more igniter taps that pass from the one or more igniter supplies to the plurality of oxidizers.

168. The gas burner assembly of claim 165, wherein at least one oxidizer of the plurality of oxidizers comprises a mix chamber, wherein the mix chamber receives fuel from one of the plurality of fuel conduits, wherein the mix chamber has one or more openings that receive oxidant from the oxidant conduit, and wherein the mix chamber has an exit to an ignition chamber.

169. The gas burner assembly of claim 168, wherein the exit to the ignition chamber is located along a central axis of the oxidizer.

170. The gas burner assembly of claim 165, where each fuel conduit of the plurality of fuel conduits supplies fuel to a single oxidizer of the plurality of oxidizers.

171. The gas burner assembly of claim 165, where a fuel conduit of the plurality of fuel conduits supplies fuel to two or more oxidizers of the plurality of oxidizers.

172. A method of heating a portion of a subsurface formation, comprising:
   - flowing oxidant into an oxidant conduit to supply oxidant to a plurality of oxidizers positioned in the oxidant conduit;
   - flowing fuel into a plurality of fuel conduits, wherein the fuel conduits are located between the oxidant conduit and an outer conduit;
   - directing fuel from at least one of the fuel conduits to a mix chamber of each oxidizer;
   - mixing the fuel and oxidant in the mix chambers to form mixtures; and
   - combusting the mixtures to produce heat.

173. The method of claim 172, further comprising returning exhaust through a space between the oxidant conduit and the outer conduit.

174. The method of claim 172, wherein each fuel conduit supplies fuel to an oxidizer of the plurality of oxidizers.

175. The method of claim 172, wherein at least one fuel conduit supplies fuel to two or more oxidizers of the plurality of oxidizers.

176. The method of claim 172, further comprising initiating combustion of the mixtures with one or more igniters.

177. A method of forming a downhole gas burner, comprising:
coupling a plurality of oxidizers to an oxidant conduit;
placing a fuel tap through the oxidant conduit into a mix chamber of each oxidizer;
coupling the fuel taps to a plurality of fuel conduits;
coupling an igniter conduit to an ignition chamber of one or more of the oxidizers; and
placing the oxidant conduit, fuel conduits and igniter conduits in an outer conduit.

178. The method of claim 177, further comprising coiling the outer conduit on a reel.

179. The method of claim 177, wherein the igniter conduit is positioned inside of the oxidizer conduit.

180. The method of claim 177, wherein the igniter conduit is positioned outside of the oxidizer conduit.

181. The method of claim 177, wherein one or more of the oxidizers comprise catalyst so that the one or more oxidizers are self-igniting.

182. A method of heating a formation, comprising:
   providing fuel through a fuel conduit to a plurality of oxidizers positioned in a wellbore in the formation;
   combusting fuel from the fuel conduit and oxidant from an oxidant conduit in the oxidizers to produce heat that heats fuel in the fuel conduit; and
   mixing heated fuel from the fuel conduit with oxidant in a section of the oxidant conduit past an oxidizer of the plurality of oxidizers, wherein the heated fuel reacts with oxidant in the oxidant conduit to generate heat.

183. A method of treating a formation fluid, comprising:
   producing formation fluid from a subsurface in situ heat treatment process;
   separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises carbon dioxide, hydrogen sulfide, hydrocarbons, hydrogen, or mixtures thereof; and
   combusting at least a portion of the first gas stream to provide heat used to heat a treatment area of a formation.

184. The method of claim 183, wherein the combusting at least the portion of the first gas stream comprises combusting the gas in a plurality of oxidizer assemblies.

185. The method of claim 183, wherein combusting at least a portion of the first gas produces carbon dioxide and/or SO\textsubscript{x}.

186. The method of claim 183, wherein combusting at least a portion of the first gas stream produces carbon dioxide and/or SO\textsubscript{x}, and further comprising sequestering at least a portion of the carbon dioxide and/or SO\textsubscript{x}. 

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187. The method of claim 183, wherein combusting at least a portion of the first gas stream produces carbon dioxide, and providing at least a portion of the carbon dioxide to one or more fuel conduits of the one or more downhole burners.

188. A method of treating a formation fluid, comprising:

- providing formation fluid from a subsurface in situ heat treatment process;
- separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises carbon dioxide, hydrogen sulfide, hydrocarbons, hydrogen or mixtures thereof;
- separating molecular oxygen from air to form an molecular oxygen stream;
- combining the first gas stream with the molecular oxygen stream to form a combined stream comprising molecular oxygen and the first gas stream; and
- providing the combined stream to one or more downhole burners.

189. The method of claim 188, wherein separating the molecular oxygen from air comprises cryogenically distilling the air.

190. The method of claim 188, wherein separating the molecular oxygen from air comprises providing the air through one or more separation units operated above -180 °C at 0.101 MPa.

191. The method of claim 188, wherein separating air comprises forming a nitrogen stream.

192. The method of claim 191, further comprising providing the nitrogen to one or more barrier wells.

193. The method of claim 191, further comprising providing the nitrogen to one or more processing facilities.

194. A method of treating formation fluid, comprising:

- providing formation fluid from a subsurface in situ heat treatment process;
- separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises carbon dioxide, hydrogen sulfide, hydrocarbons, hydrogen, or mixtures thereof;
- applying current to water to form an oxygen stream and a hydrogen stream;
- combining the first gas stream with the oxygen stream to form a combined stream comprising molecular oxygen and the first gas stream; and
- providing the combined stream to one or more downhole burners.

195. The method of claim 194, wherein applying current comprising heating the water to a temperature of at least 600 °C.

196. The method of claim 195, wherein heating the water comprising applying energy from a using nuclear power source.
197. The method of claim 194, further comprising providing the hydrogen stream to one or more fuel conduits of the one or more downhole burners.

198. The method of claim 194, further comprising providing the hydrogen stream to one or more portions of the formation.

199. The method of claim 194, further comprising providing the hydrogen stream to one or more process facilities.

200. A system, comprising:

   a separating unit configured to receive formation fluid and separate the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises carbon dioxide, sulfur compounds, hydrocarbons, hydrogen, or mixtures thereof;

   a fuel conduit configured to receive the first gas stream and transport the first gas stream;

   a oxidizing fluid conduit configured to receive the oxidizing fluid and transport the oxidizing fluid; and

   one or more burners coupled to the fuel conduit and oxidizing fluid conduit, wherein at least one of the burners is configured to receive the first gas stream and/or the oxidizing fluid from the fuel and/or oxidizing fluid conduits and combust the first gas stream and/or the oxidizing fluid stream.

201. A method of treating formation fluid, comprising:

   providing formation fluid from a subsurface in situ heat treatment process;

   separating the formation fluid to produce a liquid stream and a gas stream, wherein the gas stream comprises hydrocarbons;

   providing the gas stream to a reformation unit;

   reforming the gas stream to produce a hydrogen gas stream; and

   providing the hydrogen gas stream to one or more downhole burners.

202. A method of heating a portion of a formation, comprising:

   placing fuel on a train;

   initiating combustion of the fuel on the train;

   pulling the train through a u-shaped opening in the formation;

   supplying oxygen to the opening through a conduit; and

   burning the fuel to provide heat to the formation.

203. The method of claim 202, wherein the fuel comprises coal.

204. The method of claim 202, wherein the fuel comprises biomass.

205. The method of claim 202, further comprising treating flue gas exiting the opening.

206. The method of claim 202, wherein initiating combustion of the fuel occurs at or near a transition from overburden to a portion of the formation that is to be heated.
207. A method for treating a hydrocarbon containing formation, comprising: 
providing heat to a section of the formation with one or more heaters in the section; 
producing fluids from the formation through a production well located in the section; and 
wherein the heaters are arranged in a geometric pattern around the production well, the 
heaters being arranged so that the density of heaters increases as the distance of the heaters from 
the production well increases.

208. The method of claim 207, further comprising reducing or turning off heating in the 
heaters nearest the production well when a temperature in at or near the production well reaches a 
temperature of about 100 °C.

209. The method of claim 207, further comprising reducing or turning off heating in the 
heaters nearest the production well when a temperature in at or near the production well reaches a 
temperature of about 200 °C.

210. The method of claim 207, further comprising turning on the heaters in a sequence with 
the heaters furthest from the production well being turned on first and the heaters nearest the 
production well being turned on last.

211. The method of claim 207, wherein increasing the density of heaters as the distance of the 
heaters from the production well increases provides less heating at or near the production well.

212. The method of claim 207, wherein the geometric pattern of heaters around the production 
well increases waste heat recovery from the formation by reducing the energy recovered in the 
produced fluids.

213. The method of claim 207, wherein the geometric pattern of heaters comprises an irregular 
hexagonal pattern of heaters.

214. A method for treating a tar sands formation with one or more karsted layers, comprising: 
providing heat from one or more heaters to at least one first karsted layer having a higher 
oil quality and being vertically above at least one second karsted layer with a lower oil quality; 
providing heat to the second karsted layer with the lower oil quality so that at least some 
hydrocarbons in the second karsted layer are mobilized, and at least some of the mobilized 
hydrocarbons in the second karsted layer move to the first karsted layer; and 
producing hydrocarbon fluids from the first karsted layer.

215. The method of claim 214, wherein the karsted layers are selectively heated so that more 
heat is provided to the first karsted layer than the second karsted layer.

216. The method of claim 214, further comprising providing more heat to the first karsted 
layer than the second karsted layer by having a higher heater density in the first karsted layer.
217. The method of claim 214, further comprising providing heat to the second karsted layer so that thermal expansion in the second karsted layer moves the mobilized hydrocarbons to the first karsted layer.

218. The method of claim 214, further comprising providing heat to the second karsted layer so that gas pressure in the second karsted layer moves the mobilized hydrocarbons to the first karsted layer.

219. The method of claim 214, further comprising providing heat to the first karsted layer to visbreak and/or pyrolyze at least some hydrocarbons in the first karsted layer.

220. The method of claim 214, wherein at least some of the produced hydrocarbon fluids from the first karsted layer comprise hydrocarbons from the second karsted layer.

221. The method of claim 214, further comprising providing heat from one or more heaters to a third karsted layer with a lower oil quality than the first karsted layer, the third karsted layer being vertically above the first karsted layer.

222. The method of claim 221, further comprising mobilizing at least some hydrocarbons in the third karsted layer and allowing the mobilized hydrocarbons to drain into the first karsted layer.

223. A method of treating a tar sands formation, comprising:

   providing heat to at least part of a layer in the formation from a plurality of heaters located in the formation;

   producing fluids from the formation;

   separating at least a portion of the hydrocarbons from the produced fluids, wherein a majority of condensable hydrocarbons in the produced fluids are separated from the produced fluids; and

   controlling operating conditions in the formation to inhibit a P-value of the separated hydrocarbons from decreasing below 1.1, wherein P-value is determined by ASTM Method D7060.

224. The method of claim 223, wherein controlling operating conditions comprises maintaining a pressure in the formation below a fracture pressure of the formation while allowing a portion of the portion to heat to at least a visbreaking temperature.

225. The method of claim 223, wherein controlling operating conditions comprises reducing a pressure in the formation to a selected pressure after at least a portion of the formation reaches a visbreaking temperature.

226. The method of claim 223, wherein controlling operating conditions comprises heating a portion of the formation to a temperature between about 200 °C and about 240 °C by allowing heat to transfer from the heaters to the portion.
227. The method of claim 223, wherein controlling operating conditions comprises reducing the pressure in the formation to between about 2000 kPa and about 10000 kPa.

228. The method of claim 223, wherein the separated hydrocarbons comprise mobilized hydrocarbon, visbroken hydrocarbons, pyrolyzed hydrocarbon, and/or mixtures thereof.

229. The method of claim 223, wherein producing fluids comprises producing a selected amount of fluids such that a pressure in the formation is maintained below the fracture pressure of the formation.

230. The method of claim 223, wherein the separated hydrocarbons have an API gravity of at least 10°.

231. The method of claim 223, wherein the separated hydrocarbons has an API gravity of at least 19°.

232. The method of claim 223, wherein the produced fluids comprise at least 85% by volume of hydrocarbon liquids and at most 15% by volume gases.

233. A method of treating a tar sands formation, comprising:
   providing heat to at least part of a layer in the formation from a plurality of heaters located in the formation;
   producing fluids from the formation;
   separating at least a portion of the hydrocarbons from the produced fluids, wherein a majority of condensable hydrocarbons in the produced fluids are separated from the produced fluids; and
   controlling operating conditions in the formation to inhibit a bromine factor of the separated hydrocarbons to increasing above 3%, wherein bromine number is determined by ASTM Method D 1159 on a hydrocarbon portion of the produced fluids have a boiling point of 246 °C.

234. The method of claim 233, wherein the bromine number is at most 1%.

235. The method of claim 233, wherein the bromine number is at most 0.5%.

236. The method of claim 233, wherein controlling operating conditions comprises reducing an amount of heat provided to the formation.

237. The method of claim 233, wherein controlling operating conditions comprises reducing pressure in the formation to between about 2000 kPa and about 10000 kPa.

238. The method of claim 233, wherein the separated hydrocarbons comprise mobilized hydrocarbon, visbroken hydrocarbons, pyrolyzed hydrocarbon, and/or mixtures thereof.

239. The method of claim 233, wherein the produced fluids comprise at least 85% by volume of hydrocarbon liquids and at most 15% by volume gases.

240. A method of treating a tar sands formation, comprising:
providing heat to at least part of a layer in the formation from a plurality of heaters located in the formation;
producing fluids from the formation;
separating at least a portion of the hydrocarbons from the produced fluids, wherein a majority of condensable hydrocarbons in the produced fluids are separated from the produced fluids; and
controlling operating conditions in the formation to inhibit a bromine factor of the separated hydrocarbons from increasing above 2% as 1-decene equivalent, wherein the percentage of olefins as 1-decene equivalent is measured using the Canadian Association of Petroleum Producers Olefin Test.

241. The method of claim 240, wherein controlling operating conditions comprises reducing an amount of heat provided to the formation.

242. The method of claim 240, wherein controlling operating conditions comprises reducing pressure in the formation to between about 2000 kPa and about 10000 kPa.

243. A method for treating a hydrocarbon containing formation, comprising:
providing heat to a first section of the formation from a plurality of heaters in the first section, the heaters being located in heater wells in the first section;
producing fluids through one or more production wells in a second section of the formation, the second section being substantially adjacent to the first section;
reducing or turning off the heat provided to the first section after a selected time;
providing an oxidation fluid through one or more of the heater wells in the first section;
providing heat to the first section and the second section through oxidation of at least some hydrocarbons in the first and second sections; and
producing fluids comprising at least some oxidation products through at least one of the production wells in the second section.

244. The method of claim 243, further comprising producing fluids comprising at least some oxidation products through one or more production wells located in a third section of the formation, the third section being substantially adjacent to the second section.

245. The method of claim 243, further comprising controlling the pressure in the formation to control the oxidation of hydrocarbons in the formation.

246. The method of claim 243, further comprising using at least some of the produced fluids to power one or more turbines at the surface of the formation.

247. A method of treating a tar sands formation, comprising:
providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;
allowing the heat to transfer from the heaters so that at least a portion of the formation reaches a selected temperature;

allowing fluids to gravity drain to a bottom portion of the layer;

producing a substantial portion of the drained fluids from one or more production wells located at or proximate the bottom portion of the layer, wherein at least a majority of the produced fluids are condensable hydrocarbons;

reducing the pressure in the formation to a selected pressure after the portion of the formation reaches the selected temperature and after producing a majority of the condensable hydrocarbons in the part of the hydrocarbon layer;

providing a solvation fluid to the formation, wherein the solvation fluid solvates at least a portion of remaining condensable hydrocarbons in the part of the hydrocarbon layer to form a mixture of solvation fluid and condensable hydrocarbons; and

producing the mixture.

248. The method of claim 247, wherein the selected temperature ranges between 200 °C and 240 °C.

249. The method of claim 247, wherein the solvation fluid comprises water.

250. The method of claim 247, wherein the solvation fluid comprises carbon disulfide.

251. The method of claim 247, wherein the solvation fluid comprises carbon dioxide.

252. The method of claim 247, wherein the solvation fluid comprises water, hydrocarbons, surfactants, polymers, carbon disulfide, caustic, alkaline water solutions, or mixtures thereof.

253. The method of claim 247, wherein the produced mixture comprises bitumen.

254. The method of claim 247, wherein the produced drained fluids comprise visbroken hydrocarbons.

255. The method of claim 247, wherein the produced drained fluids comprise about 85% by volume hydrocarbon liquids and 15% by volume gas.

256. The method of claim 247, further comprising controlling formation conditions to maintain a majority of the hydrocarbons as liquids in the formation.

257. The method of claim 247, wherein the produced mixture comprises hydrocarbon liquids have an API gravity of at least 10° but less than 25°.

258. The method of claim 247, further comprising separating at least a portion of the drained produced fluids from the produced fluids, wherein the separated hydrocarbon liquids have an API gravity between 19° and 25°, a viscosity of at most 350 cp at 5°C, a P-value of at least 1.1, and a bromine number of at most 2%, wherein P-value is determined using ASTM Method D7060 and bromine number is determined by ASTM Method D1159 on a portion of the separated hydrocarbons having a boiling range distribution between 204 °C and 343 °C.
259. The method of claim 247, further comprising separating at least a portion of the drained produced fluids from the produced fluids, wherein the separated hydrocarbon liquids have an API gravity between 19° and 25°, a viscosity ranging at most 350 cp at 5°C, a CAPP number of at most 2% as 1-decene equivalent, and a P-value of at least 1.1, wherein P-value is determined using ASTM Method D7060.

260. A method for treating a hydrocarbon formation, comprising:

- providing heat to a first portion of hydrocarbon layer in the formation from one or more heaters located in the formation;
- allowing the heat to transfer from the first portion to one or more portions of hydrocarbon layer in the formation;
- providing a solvation fluid to at least one of the portions of the hydrocarbon layer to solvate at least at least a portion of the formation fluids to form a mixture of solvation fluid and condensable hydrocarbons;
- allowing at least a portion of the mixture to flow to another portion of the formation; and
- producing at least some of the mixture from the formation.

261. The method of claim 260, wherein the solvation fluid comprises carbon disulfide.

262. The method of claim 260, wherein the solvation fluid comprises carbon dioxide.

263. The method of claim 260, wherein the solvation fluid comprises water.

264. The method of claim 260, wherein the solvation fluid comprises water, hydrocarbons, surfactants, polymers, carbon disulfide, or mixtures thereof.

265. The method of claim 260, wherein the solvation fluid comprises hydrocarbons produced from the first portion of the formation.

266. The method of claim 260, wherein the solvation fluid comprises hydrocarbons produced from the first portion of the formation and wherein the hydrocarbon have a boiling range distribution from about 50 °C to about 300 °C.

267. The method of claim 266, wherein the hydrocarbon have a boiling range distribution from about 50 °C to about 300 °C comprise aromatic compounds.

268. The method of claim 260, wherein the produced fluids comprise formation fluids and/or solvation fluid.

269. The method of claim 260, further comprising providing a pressurizing fluid to the other portion to move at least a portion of the fluids from the other portion of the formation and wherein the pressurizing fluid is carbon dioxide.

270. A method for treating a nahcolite containing subsurface formation, comprising:

- solution mining a nahcolite bed above a treatment area and a nahcolite bed below a treatment using one or more substantially horizontal solution mining wells in the nahcolite beds;
providing heat to the treatment area and the nahcolite beds using one or more heaters located in the formation;
converting the substantially horizontal solution mining wells to production wells;
producing gas hydrocarbons through at least one of the production wells in the nahcolite bed above the treatment area; and
producing liquid hydrocarbons through at least one of the production wells in the nahcolite bed below the treatment area.

271. A method of treating a formation fluid, comprising:
providing formation fluid from a subsurface in situ heat treatment process;
separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises at least 0.1% by volume of carbon oxides, sulfur compounds, hydrocarbons, hydrogen, or mixtures thereof; and
cryogenically separating the first gas stream to form a second gas stream and a third gas stream, wherein the second gas stream comprises methane and/or hydrogen and wherein the third gas stream comprises carbon oxide, hydrocarbons having a carbon number of at least 2, sulfur compounds, or mixtures thereof.

272. The method of claim 271, further comprising separating at least a portion of the H₂ from the second gas stream.

273. The method of claim 271, further comprising separating at least a portion of the hydrocarbons having a carbon number of at least 3 from the third gas stream.

274. The method of claim 271, further comprising separating the third gas stream to form an additional stream, wherein the additional stream comprises carbon oxide compounds, hydrocarbons having a carbon number of at most 2, sulfur compounds, or mixtures thereof; and sequestering the additional stream.

275. The method of claim 271, further comprising separating the third gas stream to form a fourth gas stream and a fifth gas stream, wherein the fourth gas stream comprises hydrocarbons having a carbon number of at most 2 and/or carbon oxides, and wherein the fifth gas stream comprises sulfur compounds.

276. The method of claim 271, further comprising separating the third gas stream to form a fourth gas stream and a fifth gas stream, wherein the fourth gas stream comprises hydrocarbons having a carbon number of at most 2 and/or carbon oxides, and wherein the fifth gas stream comprises sulfur compounds and/or hydrocarbons having a carbon number of at least 3.

277. The method of claim 276, further comprising separating the fifth gas stream into a stream comprising sulfur compounds and a stream comprising hydrocarbons having a carbon number of at least 3.
278. The method of claim 271, further comprising separating at least a portion of the hydrocarbons having a carbon number of at least 3 from the third gas stream, and providing the hydrocarbons having a carbon number of at least 3 to other processing facilities.

279. The method of claim 271, further comprising separating hydrocarbons having a carbon number of at most 2 from the third gas stream, and providing the hydrocarbons having a carbon number of at most 2 to an ammonia processing facilities.

280. The method of claim 271, further comprising separating hydrocarbons having a carbon number of at most 2 from the third gas stream, and providing the hydrocarbons having a carbon number of at most 2 to one or more barrier wells.

281. A system of treating formation fluid, comprising:

one or more separating units configured to receive formation fluid from a subsurface in situ heat treatment process and separate the formation fluid to form a liquid stream and a first gas stream, wherein the first gas stream comprises at least 0.1 mol% carbon dioxide, hydrogen sulfide, hydrocarbons, hydrogen, or mixtures thereof; and

one or more cryogenic separation units configured to cryogenically separate the first gas stream to form a second gas stream and a third gas stream, wherein the second gas stream comprises methane and/or H₂.

282. A method of treating a subsurface hydrocarbon formation, comprising:

providing a catalyst system in a carrier fluid to a least a first portion of the subsurface hydrocarbon formation, wherein the first portion has previously at least partially been subjected to an in situ heat treatment process;

introducing hydrocarbon fluid into the first portion;

contacting the hydrocarbon fluid with the catalyst system to produce a second fluid; and

producing the second fluid from the formation.

283. The method of claim 282, wherein the catalyst system comprises one or more catalysts, and wherein at least one of the catalysts comprises one or more metals from Columns 1 and 2 of the Periodic Table and/or one or more compounds of one or more metals from Columns 1 and 2 of the Periodic Table.

284. The method of claim 282, wherein the catalyst system comprises one or more catalysts, and wherein at least one of the catalysts comprises a one or more carbonates of one or more metals from Columns 1 and 2 of the Periodic Table.

285. The method of claim 282, wherein the catalyst system comprises one or more catalysts, and wherein at least one of the catalysts comprises one or more metals from Columns 6-10 of the Periodic Table and/or one or more compounds of one or more metals from Columns 6-10 of the Periodic Table.
286. The method of claim 282, wherein the catalyst system comprises dolomite.

287. The method of claim 282, wherein the first portion vaporizes at least a portion of the carrier fluid leaving at least a portion of the catalyst system in the formation.

288. The method of claim 282, wherein introducing the hydrocarbon fluid comprises driving formation fluid from an adjacent portion of the formation into the first portion.

289. The method of claim 282, wherein introducing the hydrocarbon fluid comprises injecting the hydrocarbon fluid into the first portion of the formation.

290. The method of claim 282, wherein the carrier fluid comprises steam, water, condensable hydrocarbons, in situ heat treatment process gas, or mixtures thereof.

291. The method of claim 282, wherein the formation fluid comprises bitumen.

292. The method of claim 282, wherein the produced mixture comprises liquid hydrocarbons having an API of at least 20°.

293. The method of claim 282, wherein the produced mixture comprises non-condensable hydrocarbons.

294. The method of claim 282, wherein the produced mixture comprises at most 0.25 grams of aromatics per gram of total hydrocarbons.

295. The method of claim 282, wherein the produced mixture comprises at least a portion of the catalyst system.

296. The method of claim 282, further comprising allowing formation fluid from a second portion of the subsurface hydrocarbon formation flow into the first portion.

297. The method of claim 282, further comprising providing one or more oxidants and heat to at least a portion of the formation containing one or more of the catalysts, wherein at least one of the oxidants in the presence of heat removes coke from the catalyst.

298. The method of claim 282, wherein contacting the hydrocarbon fluid with the catalyst system produces coke, and further comprising providing one or more oxidants to the portion of the formation containing coke; and allowing the coke to oxidize to form gas.

299. A method of forming a reaction zone in a subsurface formation, comprising:
   introducing a slurry into a heated portion of a formation previously subjected to an in situ heat treatment process;
   wherein the slurry comprises a catalyst system;
   providing hydrocarbon fluid to the heated portion of the formation; and
   contacting the catalyst system with the hydrocarbon fluid to produce a second fluid.

300. A method of treating a subsurface formation, comprising:
   providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;
allowing the heat to transfer from the heaters so that at least a portion of the formation reaches a selected temperature;
mobilizing fluids in the formation at the selected temperature;
producing at least a portion of the mobilized formation fluids;
providing a catalyst system to the portion of the formation;
contacting the at least a portion of the fluids remaining in the formation with the catalyst system to produce formation fluids; and
producing at least a portion of the formation fluids.

301. The method of claim 300, wherein the formation fluids comprise mobilized fluids, visbroken fluids, condensable hydrocarbons or mixtures thereof.

302. A method for treating a tar sands formation, comprising:
providing heat to at least part of a hydrocarbon layer in the tar sands formation from a plurality of heaters located in the formation;
allowing the heat to transfer from the heaters to at least a portion of the formation;
controlling a pressure in the portion of the formation such that the pressure remains below a fracture pressure of the formation overburden while allowing the portion of the formation to heat to a selected average temperature of at least about 280 °C and at most about 300 °C; and
reducing the pressure in the portion of the formation to a selected pressure after the portion of the formation reaches the selected average temperature.

303. The method of claim 302, wherein the fracture pressure is between about 1000 kPa and about 15000 kPa.

304. The method of claim 302, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is at most 300 °C.

305. The method of claim 302, wherein the selected pressure is between about 100 kPa and about 1000 kPa.

306. The method of claim 302, wherein the selected pressure is between about 200 kPa and about 800 kPa.

307. The method of claim 302, further comprising producing fluids from the formation.

308. The method of claim 302, further comprising producing fluids from the formation to control the pressure to remain below the fracture pressure.

309. The method of claim 302, wherein the selected average temperature is between about 285 °C and about 295 °C.

310. The method of claim 302, further comprising providing a drive fluid to the formation.

311. The method of claim 302, further comprising providing steam to the formation.
312. The method of claim 302, further comprising: producing fluids from the formation; reducing heat output from two or more of the heaters after a selected time; and continuing producing fluids from the formation after reducing the heat output from the two or more heaters.

313. A method for treating a hydrocarbon containing formation, comprising: providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation; allowing the heat to transfer from the heaters to at least a portion of the formation; controlling a pressure in the portion of the formation such that the pressure remains below a fracture pressure of the formation overburden while allowing the portion of the formation to heat to a selected average temperature range; producing at least some fluids from the formation to control the pressure to remain below the fracture pressure; and assessing the average temperature in the portion by analyzing at least some of the produced fluids.

314. The method of claim 313, further comprising reducing the pressure in the formation to a selected pressure after the portion of the formation reaches the selected average temperature range.

315. The method of claim 313, further comprising analyzing gases in the produced fluids to assess the average temperature in the portion.

316. The method of claim 313, further comprising assessing the average temperature in the portion based on, at least in part, a hydrocarbon isomer shift in the produced fluids.

317. The method of claim 313, further comprising assessing the average temperature in the portion based on, at least in part, a weight percentage of saturates in the produced fluids.

318. The method of claim 313, further comprising assessing the average temperature in the portion based on, at least in part, a weight percentage of n-C7 in the produced fluids.

319. The method of claim 313, wherein the selected average temperature range comprises a temperature range from about 280 °C to about 300 °C.

320. The method of claim 313, wherein the selected average temperature range is below the temperature at which substantial coking of hydrocarbons occurs in the formation.

321. The method of claim 313, further comprising providing steam to the formation.

322. The method of claim 313, wherein the formation comprises a tar sands formation.

323. A method for treating a tar sands formation, comprising:
providing heat to at least part of a hydrocarbon layer in the hydrocarbon containing formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

controlling a pressure in the portion of the formation such that the pressure remains below a fracture pressure of the formation overburden by producing at least some fluid from the formation;

assessing a hydrocarbon isomer shift of at least a portion of the fluid produced from the formation; and

reducing the pressure in the formation to a selected pressure when the assessed hydrocarbon isomer shift reaches a selected value.

324. The method of claim 323, wherein the average temperature in the portion is based on, at least in part, the hydrocarbon isomer shift.

325. The method of claim 323, wherein the hydrocarbon isomer shift comprises n-butane-\(\delta^{13}C_4\) percentage versus propane-\(\delta^{13}C_3\) percentage.

326. The method of claim 323, wherein the hydrocarbon isomer shift comprises n-pentane-\(\delta^{13}C_5\) percentage versus propane-\(\delta^{13}C_3\) percentage.

327. The method of claim 323, wherein the hydrocarbon isomer shift comprises n-pentane-\(\delta^{13}C_5\) percentage versus n-butane-\(\delta^{13}C_4\) percentage.

328. The method of claim 323, wherein the hydrocarbon isomer shift comprises i-pentane-\(\delta^{13}C_5\) percentage versus i-butane-\(\delta^{13}C_4\) percentage.

329. The method of claim 323, wherein the selected value of the hydrocarbon isomer shift corresponds to an average temperature between about 280 °C and about 300 °C.

330. The method of claim 323, further comprising analyzing gases in portion of the produced fluids to assess the hydrocarbon isomer shift in the portion.

331. The method of claim 323, further comprising heating the formation after reducing the pressure.

332. The method of claim 323, further comprising producing fluids from the formation after reducing the pressure.

333. The method of claim 323, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

334. The method of claim 323, further comprising providing steam to the formation.

335. The method of claim 323, wherein the formation comprises a tar sands formation.

336. A method for treating a hydrocarbon containing formation, comprising:
providing heat to at least part of a hydrocarbon layer in the hydrocarbon containing formation from a plurality of heaters located in the formation;
allowing the heat to transfer from the heaters to at least a portion of the formation;
controlling a pressure in the portion of the formation such the pressure remains below a fracture pressure of the formation overburden by producing at least some fluid from the formation;
assessing a weight percentage of saturates in at least a portion of the fluid produced from the formation; and
reducing the pressure in the formation to a selected pressure when the assessed weight percentage of saturates reaches a selected value.

337. The method of claim 336, wherein the average temperature in the portion is assessed based on, at least in part, the weight percentage of saturates.

338. The method of claim 336, wherein the selected value of the weight percentage of saturates corresponds to an average temperature between about 280 °C and about 300 °C.

339. The method of claim 336, further comprising analyzing gases in portion of the produced fluids to assess the weight percentage of saturates in the portion.

340. The method of claim 336, wherein the selected value of the weight percentage of saturates is about 30%.

341. The method of claim 336, wherein the selected value of the weight percentage of saturates is between about 25% and about 35%.

342. The method of claim 336, further comprising heating the formation after reducing the pressure.

343. The method of claim 336, further comprising producing fluids from the formation after reducing the pressure.

344. The method of claim 336, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

345. The method of claim 336, further comprising providing steam to the formation.

346. The method of claim 336, wherein the formation comprises a tar sands formation.

347. A method for treating a hydrocarbon containing formation, comprising:
providing heat to at least part of a hydrocarbon layer in the hydrocarbon containing formation from a plurality of heaters located in the formation;
allowing the heat to transfer from the heaters to at least a portion of the formation;
controlling a pressure in the portion of the formation such that the pressure remains below a fracture pressure of the formation overburden by producing at least some fluid from the formation;

assessing a weight percentage of n-C₇ in at least a portion of the fluid produced from the formation; and

reducing the pressure in the formation to a selected pressure when the assessed n-C₇ reaches a selected value.

348. The method of claim 347, wherein the average temperature in the portion is assessed based on, at least in part, the weight percentage of n-C₇.

349. The method of claim 347, wherein the selected value of the weight percentage of n-C₇ corresponds to an average temperature between 280 °C and 300 °C.

350. The method of claim 347, further comprising analyzing gases in portion of the produced fluids to assess the weight percentage of n-C₇ in the portion.

351. The method of claim 347, wherein the selected value of the weight percentage of n-C₇ is about 60%.

352. The method of claim 347, wherein the selected value of the weight percentage of n-C₇ is between about 50% and about 70%.

353. The method of claim 347, further comprising heating the formation after reducing the pressure.

354. The method of claim 347, further comprising producing fluids from the formation after reducing the pressure.

355. The method of claim 347, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

356. The method of claim 347, further comprising providing steam to the formation.

357. The method of claim 347, wherein the formation comprises a tar sands formation.

358. A method for treating a tar sands formation, comprising:

   providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

   allowing the heat to transfer from the heaters to at least a portion of the formation;

   assessing a viscosity of one or more zones of the hydrocarbon layer;

   varying a number of production wells in the zones based on the assessed viscosities,

   wherein the number of production wells in a first zone of the formation is greater than the number of production wells in a second zone of the formation if the viscosity in the first zone is greater than the viscosity in the second zone; and
producing fluids from the formation through the production wells.

359. The method of claim 358, further comprising providing a drive fluid to the formation.

360. The method of claim 358, further comprising providing steam to the formation.

361. The method of claim 358, further comprising varying the heating rates in the zones based on the assessed viscosities, wherein the heating rate in a first zone of the formation is greater than the heating rate in a second zone of the formation if the viscosity in the first zone is greater than the viscosity in the second zone.

362. The method of claim 358, further comprising varying the heater spacing in the zones based on the assessed viscosities, wherein the heater spacing in a first zone of the formation is denser than the heater spacing in a second zone of the formation if the viscosity in the first zone is greater than the viscosity in the second zone.

363. The method of claim 358, further comprising allowing fluids to drain from the first zone to the second zone.

364. The method of claim 358, further comprising producing fluids from at or near the bottom of the zones.

365. A method for treating a tar sands formation, comprising:

    providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

    allowing the heat to transfer from the heaters to at least a portion of the formation;

    assessing a viscosity of one or more zones of the hydrocarbon layer;

    varying the heating rates in the zones based on the assessed viscosities, wherein the heating rate in a first zone of the formation is greater than the heating rate in a second zone of the formation if the viscosity in the first zone is greater than the viscosity in the second zone; and

    producing fluids from the formation.

366. The method of claim 365, further comprising providing a drive fluid to the formation.

367. The method of claim 365, further comprising providing steam to the formation.

368. The method of claim 365, further comprising varying the heater spacing in the zones based on the assessed viscosities, wherein the heater spacing in a first zone of the formation is denser than the heater spacing in a second zone of the formation if the viscosity in the first zone is greater than the viscosity in the second zone.

369. The method of claim 365, further comprising allowing fluids to drain from the first zone to the second zone.

370. The method of claim 365, further comprising producing fluids from near the bottom of the zones.

371. A method for treating a tar sands formation, comprising:
providing heat to at least part of a hydrocarbon layer in the formation from a plurality of
heaters located in the formation;
assessing a viscosity of one or more zones of the hydrocarbon layer;
varying the heater spacing in the zones based on the assessed viscosities, wherein the
heater spacing in a first zone of the formation is denser than the heater spacing in a second zone
of the formation if the viscosity in the first zone is greater than the viscosity in the second zone;
allowing the heat to transfer from the heaters to the zones in the formation; and
producing fluids from one or more openings located in at least one selected zone to
maintain a pressure in the selected zone below a selected pressure.

372. The method of claim 371, wherein the selected zone is the first zone of the formation.

373. The method of claim 371, wherein the selected pressure is the fracture pressure of the
formation.

374. The method of claim 373, wherein the selected pressure is between about 1000 kPa and
about 15000 kPa.

375. The method of claim 371, wherein the selected pressure is a pressure below which
substantial hydrocarbon coking in the formation occurs when the average temperature in the
formation is less than 300 °C.

376. The method of claim 375, wherein the selected pressure is between about 100 kPa and
about 1000 kPa.

377. The method of claim 371, further comprising providing a drive fluid to the formation.

378. The method of claim 371, further comprising providing steam to the formation.

379. The method of claim 371, further comprising allowing fluids to drain from the first zone
to the second zone.

380. The method of claim 371, further comprising producing fluids from at or near the bottom
of the zones.

381. A method for treating a tar sands formation, comprising:
providing heat to at least part of a hydrocarbon layer in the formation from a plurality of
heaters located in the formation;
allowing the heat to transfer from the heaters to at least a portion of the formation; and
producing fluids from the formation through at least one production well that is located in
at least two zones in the formation, the first zone having an initial permeability of at least 1
darcy, the second zone having an initial of at most 0.1 darcy and the two zones are separated by a
substantially impermeable barrier.

382. The method of claim 381, wherein the substantially impermeable barrier has an initial
permeability of at most 10 μdarcy.
383. The method of claim 381, further comprising heating such that an average pressure in the two zones is within about 20% of each other.

384. The method of claim 381, further comprising heating such that an average viscosity in the two zones is within about 20% of each other.

385. The method of claim 381, wherein the at least one production well allows fluid communication between the zones.

386. The method of claim 381, further comprising providing a drive fluid to the formation.

387. The method of claim 381, further comprising providing steam to the formation.

388. The method of claim 381, further comprising controlling an average pressure in the formation such that the average pressure remains below a selected pressure.

389. The method of claim 388, wherein the selected pressure is the fracture pressure of the formation.

390. The method of claim 389, wherein the selected pressure is between about 1000 kPa and about 15000 kPa.

391. The method of claim 388, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

392. The method of claim 391, wherein the selected pressure is between about 100 kPa and about 1000 kPa.

393. A method for treating a tar sands formation, comprising:
   providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;
   allowing the heat to transfer from the heaters to at least a portion of the formation;
   wherein heat is transferred to at least two zones in the formation, at least two of the zones being separated by a substantially impermeable barrier, and one or more holes have been formed to connect the zones through the substantially impermeable barrier; and
   producing fluids from the formation.

394. The method of claim 393, wherein the substantially impermeable barrier has an initial permeability of at most 10 μdarcy.

395. The method of claim 393, further comprising heating such that an average pressure in the two zones is within about 20% of each other.

396. The method of claim 393, further comprising heating such that an average viscosity in the two zones is within about 20% of each other.

397. The method of claim 393, wherein the holes allow fluid communication between the zones.
398. The method of claim 393, further comprising providing a drive fluid to the formation.
399. The method of claim 393, further comprising providing steam to the formation.
400. The method of claim 393, further comprising controlling an average pressure in the formation such that the average pressure remains below a selected pressure.
401. The method of claim 400, wherein the selected pressure is the fracture pressure of the formation.
402. The method of claim 401, wherein the selected pressure is between about 1000 kPa and about 15000 kPa.
403. The method of claim 400, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.
404. The method of claim 403, wherein the selected pressure is between about 100 kPa and about 1000 kPa.
405. A method for treating a tar sands formation, comprising:
   providing a drive fluid to a first hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the first layer;
   allowing at least some of the mobilized hydrocarbons to flow into a second hydrocarbon containing layer of the formation;
   providing heat to the second layer from one or more heaters located in the second layer;
   and
   producing at least some hydrocarbons from the second layer of the formation.
406. The method of claim 405, further comprising providing the drive fluid to a third hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the third layer.
407. The method of claim 405, further comprising providing the drive fluid to a third hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the third layer, and allowing at least some of the mobilized hydrocarbons from the third layer to flow into the second layer.
408. The method of claim 405, wherein the first layer is above the second layer.
409. The method of claim 405, wherein the first layer is below the second layer.
410. The method of claim 405, wherein the first layer has a lower initial oil saturation than the second layer.
411. The method of claim 405, wherein the first layer has a higher initial water saturation than the second layer.
412. The method of claim 405, wherein the first layer has a lower initial porosity than the second layer.

413. The method of claim 405, wherein the first layer has a higher initial steam injectivity than the second layer.

414. The method of claim 405, further comprising increasing the steam injectivity of the second layer with the heat provided by the one or more heaters.

415. The method of claim 405, further comprising providing the drive fluid to the second layer after increasing the steam injectivity of the second layer with the heat provided by the one or more heaters.

416. The method of claim 405, further comprising producing hydrocarbons from the first layer.

417. The method of claim 405, further comprising using the produced hydrocarbons in a steam and electricity generation facility, wherein the facility provides steam as the drive fluid to the first layer of the formation, and electricity for at least some of the heaters in the second layer.

418. The method of claim 405, wherein the first layer and the second layer are separated by a substantially impermeable shale layer that inhibits the flow of hydrocarbons between the first and second layers.

419. The method of claim 418, further comprising increasing the permeability of the shale layer with the heat provided to the second layer such that hydrocarbons are allowed to flow between the first and second layers.

420. The method of claim 405, further comprising maintaining a pressure in the formation below a selected pressure.

421. The method of claim 420, wherein the selected pressure is the fracture pressure of the formation.

422. The method of claim 421, wherein the selected pressure is between about 1000 kPa and about 15000 kPa.

423. The method of claim 420, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

424. The method of claim 423, wherein the selected pressure is between about 100 kPa and about 1000 kPa.

425. A method for treating a tar sands formation, comprising:
- providing a drive fluid to a hydrocarbon containing layer of the tar sands formation to mobilize at least some hydrocarbons in the layer;
- producing at least some first hydrocarbons from the layer;
- providing heat to the layer from one or more heaters located in the formation; and
producing at least some second hydrocarbons from the layer of the formation, the second hydrocarbons comprising at least some hydrocarbons that are upgraded compared to the first hydrocarbons produced by using the drive fluid.

426. The method of claim 425, wherein the drive fluid is steam.

427. The method of claim 425, wherein at most about 20% of the oil in place is produced from the formation as first hydrocarbons using the provided drive fluid.

428. The method of claim 425, wherein at least about 25% of the oil in place is produced after providing heat to the formation from the one or more heaters.

429. The method of claim 425, further comprising heating the layer to a temperature between about 150 °C and about 270 °C using the drive fluid.

430. The method of claim 425, wherein the heaters used to provide heat are placed in the formation after the production of the first hydrocarbons using the drive fluid is at least 50% complete.

431. The method of claim 425, further comprising activating the heaters after the production of hydrocarbons using the drive fluid is at least 50% complete.

432. The method of claim 425, wherein the drive fluid is not uniformly provided throughout the layer.

433. The method of claim 425, further comprising continuing to provide the drive fluid while providing heat to the formation from the one or more heaters.

434. The method of claim 425, wherein the layer comprises at least two portions with different recoveries after producing the first hydrocarbons using the drive fluid.

435. The method of claim 434, wherein at least one of the portions has a recovery of at most about 10% of the oil in place and at least a second one of the portions has a recovery of at least about 30% of the oil in place.

436. The method of claim 435, further comprising providing more heat to the portion with the lower recovery than to the portion with the higher recovery.

437. The method of claim 425, wherein the layer is left dormant for at least about 1 year after production of the first hydrocarbons using the drive fluid and before heat is provided from the one or more heaters.

438. The method of claim 425, further comprising installing at least one of the heaters in a wellbore that has previously been used to provide the drive fluid into the layer.

439. The method of claim 425, further comprising heating the layer to a first average temperature using the drive fluid, and then heating the layer to a second average temperature using the one or more heaters, wherein the second average temperature is higher than the first average temperature.
440. The method of claim 439, wherein the second average temperature is at least about 250°C.

441. A method for treating a tar sands formation, comprising:

   providing heat to a hydrocarbon containing layer in the tar sands formation from one or more heaters located in the formation, wherein the hydrocarbon containing layer has been previously treated using a steam injection and production process; and

   producing at least some hydrocarbons from the layer of the formation, the produced hydrocarbons comprising at least some hydrocarbons that are upgraded compared to hydrocarbons produced by the steam injection and production process.

442. The method of claim 441, wherein at most about 20% of the oil in place is produced from the formation using the steam injection and production process.

443. The method of claim 441, wherein at least about 25% of the oil in place is produced after providing heat to the formation.

444. The method of claim 441, further comprising heating the layer to a temperature between about 150 °C and about 270 °C using the steam injection and production process.

445. The method of claim 441, wherein the heaters used to provide heat are placed in the formation after the steam injection and production process is at least 50% complete.

446. The method of claim 441, further comprising energizing the heaters after the steam injection and production process is at least 50% complete.

447. The method of claim 441, wherein hydrocarbons in the layer are not uniformly removed using the steam injection and production process.

448. The method of claim 441, further comprising resuming the steam injection and production process while providing heat to the formation from the one or more heaters.

449. The method of claim 441, wherein the layer comprises at least two portions with different recoveries after the steam injection and production process.

450. The method of claim 449, wherein at least one of the portions has a recovery of at most about 10% of the oil in place and at least a second one of the portions has a recovery of at least about 30% of the oil in place.

451. The method of claim 450, further comprising providing more heat to the portion with the lower recovery than the portion with the higher recovery.

452. The method of claim 441, wherein the layer is left dormant for at least about 1 year after the steam injection and production process and before heat is provided from the one or more heaters.

453. A method of heating a subsurface formation comprising:
supplying electricity to an insulated conductor positioned in a conduit to resistively heat at least a portion of the insulated conductor to a temperature that allows heat to transfer from the insulated conductor to a molten salt adjacent to at least a portion of the insulated conductor, wherein the temperature of the insulated conductor is above a melt temperature of the molten salt, wherein heat from the molten salt transfers to the conduit; and wherein heat transfers from the conduit to the formation.

454. The method of claim 453, further comprising inhibiting formation of hot spots at one or more high thermal load regions of the conduit by transferring heat using natural convection flow in the molten salt.

455. The method of claim 453, further comprising supplying a gas to the conduit above the molten salt, wherein the gas is carbon dioxide, nitrogen, helium or combinations thereof.

456. The method of claim 453, wherein at least a portion of the heat transferred to the formation mobilizes hydrocarbons in the formation.

457. The method of claim 453, wherein molten salt in the conduit inhibits deformation of the conduit.

458. The method of claim 453, further comprising mobilizing hydrocarbons in the formation with the heat transferred from the conduit.

459. The method of claim 453, further comprising mobilizing hydrocarbons in the formation with the heat transferred from the conduit, and producing mobilized hydrocarbons from the formation.

460. The method of claim 453, further comprising providing steam to the formation.

461. A heating system for a subsurface formation, comprising:
  a conduit located in an opening in the subsurface formation;
  at least one insulated conductor located in the conduit;
  a salt in the conduit adjacent to a portion of at least one insulated conductor, and wherein at least one insulated conductor is configured to resistively heat to a temperature sufficient to maintain the salt in a molten phase in the conduit.

462. The system of claim 461, further comprising a gas in the conduit above the salt, wherein the gas is carbon dioxide, nitrogen, helium or combinations thereof.

463. The system of claim 461, wherein the conduit includes cladding on an inner surface to inhibit corrosion of the conduit by the salt.

464. The system of claim 461, wherein the conduit includes cladding on an outer surface to inhibit corrosion of the conduit by formation fluid in the formation.

465. The system of claim 461, wherein the salt comprises a mixture of salts.

466. A heating system for a subsurface formation, comprising:
a wellbore in the formation;
a heat source in the wellbore; and
a salt between the formation and the heat source, wherein the salt is a liquid at a selected
operating temperature of the heat source.
467. The system of claim 466, wherein the heat source is an insulated conductor.
468. The system of claim 466, wherein the heat source is one or more gas burners.
469. The system of claim 466, wherein the material melts at a temperature greater than 350 °C.
470. The system of claim 466, further comprising a gas in the conduit above the salt, wherein
the gas is carbon dioxide, nitrogen, helium or combinations thereof.
471. A heating system for a subsurface formation, comprising:
a sealed conduit positioned in an opening in the formation, wherein a heat transfer fluid is
positioned in the conduit;
a heat source configured to provide heat to a portion of the sealed conduit to change phase
of the heat transfer fluid from a liquid to a vapor; and
wherein the vapor in the sealed conduit rises in the sealed conduit, condenses to transfer
heat to the formation and returns to the portion as a liquid.
472. The heating system of claim 471, wherein the heat source comprises one or more
downhole gas burners.
473. The heating system of claim 472, wherein at least a portion of exhaust gases from one of
the downhole gas burners passes between the sealed conduit and an outer conduit to the surface.
474. The heating system of claim 471, wherein the sealed conduit is oriented substantially
vertically in the formation.
475. The heating system of claim 471, wherein the sealed conduit is oriented substantially
horizontally in the formation with the sealed conduit angled upwards relative to horizontal.
476. The heating system of claim 471, wherein the sealed conduit is oriented substantially
horizontally in the formation with the sealed conduit angled downwards relative to horizontal.
477. The heating system of claim 471, wherein the heat source comprises one or more
electrical heaters.
478. The heating system of claim 471, wherein the heat transfer fluid comprises a molten
metal.
479. The heating system of claim 471, wherein the heat transfer fluid comprises molten salt.
480. A system for heating a subsurface formation, comprising:
a plurality of heaters positioned in the formation, the plurality of heaters configured to
heat a portion of the formation; and
a plurality of heat pipes positioned in the heated portion, wherein at least one of the heat pipes comprises a liquid heating portion, wherein heat from one or more of the plurality of heaters is configured to provide heat to the liquid heating portion sufficient to vaporize at least a portion of a liquid in the heat pipe, wherein the vapor rises in the heat pipe, condenses in the heat pipe, and transfers heat to the formation, and wherein condensed fluid flows back to the liquid heating portion.

481. The heating system of claim 480, wherein the plurality of heaters comprises one or more downhole gas burners.

482. The heating system of claim 481, wherein at least a portion of exhaust gases from one or more of the downhole gas burners passes between the heat pipe and an outer conduit to the surface.

483. The heating system of claim 480, wherein at least one heat pipe is oriented substantially vertically in the formation.

484. The heating system of claim 480, wherein at least one heat pipe is oriented substantially horizontally in the formation with the heat pipe angled upwards relative to horizontal.

485. The heating system of claim 480, wherein at least one heat pipe is oriented substantially horizontally in the formation with the heat pipe angled downwards relative to horizontal.

486. The heating system of claim 480, wherein the plurality of heaters comprises one or more electrical heaters.

487. The heating system of claim 480, wherein the liquid in one more heat pipes comprises molten metal.

488. The heating system of claim 480, wherein the liquid in one more heat pipes comprises molten salt.

489. A method for heating a subsurface formation, comprising:

heating portions of sealed conduits positioned in the formation using heat sources, wherein the heat sources vaporize heat transfer fluid in the sealed conduits, wherein the vapor rises in the sealed conduits, condenses to transfer heat to the sealed conduits, and flows back to the heated portions of the sealed conduits; and

allowing heat from the sealed conduits to transfer to the formation to heat a portion of the formation.

490. The method of claim 489, wherein one or more of the heat sources comprise gas burners.

491. The method of claim 489, wherein one or more of the heat sources comprise electrical heaters.

492. The method of claim 489, further comprising mobilizing hydrocarbons in the formation with the heat transferred from the sealed conduits.
493. The method of claim 489, further comprising mobilizing hydrocarbons in the formation with the heat transferred from the sealed conduits, and producing mobilized hydrocarbons from the formation.

494. A heating system for a subsurface formation, comprising:
   a first heater configuration, comprising:
   a conduit located in a first opening in the subsurface formation;
   three electrical conductors located in the conduit;
   a return conductor located inside the conduit, the return conductor being electrically coupled to the ends of the electrical conductors distal from the surface of the formation; and
   insulation located inside the conduit, the insulation being configured to electrically insulate the three electrical conductors, the return conductor, and the conduit from each other.

495. The system of claim 494, wherein each of the electrical conductors is coupled to one phase of a three-phase wye transformer.

496. The system of claim 494, wherein the return conductor is coupled to the neutral of a three-phase wye transformer.

497. The system of claim 494, wherein each of the electrical conductors is coupled to one phase of a single, three-phase wye transformer.

498. The system of claim 494, wherein the return conductor is coupled to the neutral of a single, three-phase wye transformer.

499. The system of claim 494, wherein each of the electrical conductors is coupled to one phase of a single, three-phase wye transformer, and the return conductor is coupled to the neutral of the single, three-phase wye transformer.

500. The system of claim 499, further comprising at least 4 additional heater configurations coupled to the single, three-phase wye transformer.

501. The system of claim 499, further comprising at least 10 additional heater configurations coupled to the single, three-phase wye transformer.

502. The system of claim 499, further comprising at least 25 additional heater configurations coupled to the single, three-phase wye transformer.

503. The system of claim 494, further comprising a second heater configuration, comprising:
   a conduit located in a second opening in the subsurface formation;
   three electrical conductors located in the conduit;
a return conductor located inside the conduit, the return conductor being
electrically coupled to the ends of the electrical conductors distal from the surface of the
formation; and

insulation located inside the conduit, the insulation being configured to
electrically insulate the three electrical conductors, the return conductor, and the conduit
from each other;

wherein the first heater configuration and the second heater configuration are
electrically coupled to a single, three-phase wye transformer.

504. The system of claim 503, further comprising a third heater configuration, comprising:

a conduit located in a third opening in the subsurface formation;

three electrical conductors located in the conduit;

a return conductor located inside the conduit, the return conductor being
electrically coupled to the ends of the electrical conductors distal from the surface of the
formation; and

insulation located inside the conduit, the insulation being configured to
electrically insulate the three electrical conductors, the return conductor, and the conduit
from each other;

wherein the first heater configuration, the second heater configuration, and the
third heater configuration are electrically coupled to the single, three-phase wye
transformer.

505. The system of claim 494, wherein the electrical conductors comprise resistive heating
portions located in a hydrocarbon layer in the formation, the hydrocarbon layer being configured
to be heated.

506. The system of claim 494, wherein the electrical conductors comprise resistive heating
portions located in a hydrocarbon layer in the formation, and a more electrically conductive
portion located in an overburden section of the formation.

507. The system of claim 494, wherein the electrical conductors are at least partially
surrounded by an insulation layer and an electrically conductive sheath, the sheath at least
partially surrounding the insulation layer.

508. The system of claim 494, wherein the insulation comprises two or more layers of
insulation in the conduit.

509. The system of claim 494, wherein the electrical conductors are the cores of insulated
cohductor heaters.

510. The system of claim 494, further comprising an outer tubular in the first opening, the first
heater configuration being located in the outer tubular.
511. A heating system for a subsurface formation, comprising:
   a three-phase wye transformer;
   at least five heaters, each heater comprising:
      a conduit located in a first opening in the subsurface formation;
      three electrical conductors located in the conduit, each electrical conductor being
electrically coupled to one phase of the transformer;
      a return conductor located inside the conduit, the return conductor being
electrically coupled to the ends of the electrical conductors distal from the surface of the
formation, and the return conductor being electrically coupled to the neutral of the
transformer; and
      insulation located inside the conduit, the insulation being configured to
electrically insulate the three electrical conductors, the return conductor, and the conduit
from each other.

512. A method for making a heater for a subsurface formation, comprising:
   coupling three heaters and a return conductor together, each of the three heaters
comprising an electrical conductor and an insulation layer at least partially surrounding the
electrical conductor;
   coupling additional insulation to the outside of the three heaters and the return conductor;
   forming a conduit around the additional insulation, the three heaters, and the return
conductor; and
   compacting the conduit against the additional insulation.

513. The method of claim 512, wherein the conduit is formed by rolling a metal plate into a
tubular shape around the additional insulation layer, the three heaters, and the return conductor,
and welding the lengthwise ends of the plate to form a tubular.

514. The method of claim 512, wherein the additional insulation comprises one or more
preformed blocks of insulation.

515. A method of treating a subsurface formation, comprising:
   applying electrical power to a first heater configuration in a subsurface wellbore to
provide heat, the first heater configuration comprising:
      a conduit located in a first opening in the subsurface formation;
      three electrical conductors located in the conduit;
      a return conductor located inside the conduit, the return conductor being
electrically coupled to the ends of the electrical conductors distal from the surface of the
formation; and
insulation located inside the conduit, the insulation being configured to
electrically insulate the three electrical conductors, the return conductor, and the conduit
from each other; and
allowing heat to transfer from the first heater configuration to at least part of the
subsurface formation.
516. The method of claim 515, further comprising mobilizing hydrocarbons in the subsurface
formation with the provided heat.
517. The method of claim 515, further comprising mobilizing hydrocarbons in the subsurface
formation with the provided heat, and producing at least some of the mobilized hydrocarbons
from the formation.
518. A heating system for a subsurface formation, comprising:
a plurality of substantially horizontally oriented or inclined heater sections located in a
hydrocarbon containing layer in the formation, wherein at least a portion of two of the heater
sections are substantially parallel to each other; and
wherein the ends of at least two of the heater sections in the layer are electrically coupled
to a substantially horizontal, or inclined, electrical conductor oriented substantially perpendicular
to the ends of the at least two heater sections.
519. The system of claim 518, wherein the substantially horizontal, or inclined, electrical
conductor is a neutral or a return for heater sections.
520. The system of claim 518, wherein the at least two heater sections are electrically coupled
in parallel.
521. The system of claim 518, wherein the at least two heater sections are electrically coupled
in series.
522. The system of claim 518, wherein the ends of the at least two heater sections are coupled
to the substantially horizontal, or inclined, conductor using a mousetrap coupling.
523. The system of claim 518, wherein the ends of the at least two heater sections are coupled
to the substantially horizontal, or inclined, conductor using molten metal.
524. The system of claim 518, wherein the ends of the at least two heater sections are coupled
to the substantially horizontal, or inclined, conductor using explosive bonding.
525. The system of claim 518, wherein the substantially horizontal, or inclined, conductor is a
tubular into which the ends of the at least two heater sections insert.
526. The system of claim 518, wherein at least one of the heater sections is configured to
automatically reduce its heat output when a selected temperature is reached in the heater section.
527. The system of claim 518, wherein at least a majority of at least two of the heater sections
are substantially parallel to each other.
528. A method, comprising:

forming a first wellbore in the formation, wherein a portion of the wellbore is oriented substantially horizontally or at an incline;

positioning an electrical conductor in the first wellbore;

forming at least two additional wellbores in the formation, wherein ends of the additional wellbores intersect with the first wellbore, and wherein at least a majority of a section of the first additional wellbore that passes through a hydrocarbon layer to be heat treated by an in situ heat treatment process is substantially parallel to at least a majority of a section of the second additional wellbore that passes through the hydrocarbon layer;

placing a heater section in at least one of the additional wellbores; and

coupling the heater section to the conductor in the first wellbore.

529. The method of claim 528, wherein the conductor in the first wellbore is a neutral or a return for heater section.

530. The method of claim 528, further comprising placing a second heater section in at least one of the other additional wellbores, and coupling the heater sections in the additional wellbores such that the heater sections are electrically coupled in parallel.

531. The method of claim 528, further comprising placing a second heater section in at least one of the other additional wellbores, and coupling the heater sections in the additional wellbores such that the heater sections are electrically coupled in series.

532. The method of claim 528, wherein the end of the heater section is coupled to the single conductor using a mousetrap coupling.

533. The method of claim 528, wherein the end of the heater section is coupled to the single conductor using molten metal.

534. The method of claim 528, wherein the end of the heater section is coupled to the single conductor using explosive bonding.

535. The method of claim 528, wherein the conductor in the first wellbore is a tubular into which the end of the heater section inserts.

536. The method of claim 528, further comprising providing heat to at least a portion of the formation using the heater section.

537. The method of claim 528, further comprising placing a second heater section in at least one of the other additional wellbores, and providing heat to at least a portion of the formation using the heater sections such that heat from the heater section superpositions heat from the second heater section in the formation.

538. The method of claim 528, wherein the heater section is configured to automatically reduce its heat output when a selected temperature is reached in the heater section.
539. A method of treating a hydrocarbon containing formation, comprising:
   providing heat from a plurality of substantially horizontally oriented or inclined heater
   sections located in a hydrocarbon containing layer in the formation, wherein at least a portion of
   two of the heater sections are substantially parallel to each other, and wherein the ends of at least
   two of the heater sections in the layer are electrically coupled to a substantially horizontal, or
   inclined, electrical conductor oriented substantially perpendicular to the ends of the at least two
   heater sections; and
   allowing the heat to transfer from the heaters to a portion of the formation.
540. A method for treating a nahcolite containing subsurface formation, comprising:
   removing water from a saline zone in or near the formation;
   heating the removed water using a steam and electricity cogeneration facility;
   providing the heated water to the nahcolite containing formation;
   producing a fluid from the nahcolite containing formation, the fluid comprising at least
   some dissolved nahcolite; and
   providing at least some of the fluid to the saline zone.
541. The method of claim 540, wherein the saline zone is up dip from the nahcolite containing
   formation.
542. The method of claim 540, wherein the saline zone comprises a zone in which nahcolite
   has been at least partially leached out by water present in the zone.
543. The method of claim 540, further comprising removing the water from the saline zone
   using a production well located in the saline zone.
544. The method of claim 543, further comprising using the production well to provide the
   fluid to the saline zone.
545. The method of claim 540, further comprising leaving a portion of the nahcolite containing
   formation as a wall of the formation to form a barrier to inhibit fluid flow into or out of the
   formation.
546. The method of claim 540, further comprising leaving a portion of the nahcolite containing
   formation as a supporting wall of the formation.
547. The method of claim 545, wherein the wall has a thickness of at least about 10 m.
548. The method of claim 540, further comprising using at least some of the heat of the
   produced fluid to heat the removed water in the steam and electricity cogeneration facility.
549. The method of claim 540, further comprising storing the fluid in the saline zone.
550. The method of claim 540, further comprising heating the nahcolite containing formation
   using heaters after removing at least some of the nahcolite from the formation.
551. The method of claim 550, wherein the heated water preheats the formation prior to heating with the heaters.

552. The method of claim 550, further comprising mobilizing hydrocarbons in the formation using the provided heat.

553. The method of claim 550, wherein electricity generated in the steam and electricity cogeneration facility is used to provide power to the heaters.

554. The method of claim 550, wherein steam generated in the steam and electricity cogeneration facility is used to provide steam to the formation.

555. The method of claim 550, wherein steam generated in the steam and electricity cogeneration facility is used to provide steam to a hydrocarbon containing formation.

556. The method of claim 550, further comprising producing at least some hydrocarbons from the formation while heating the formation.

557. The method of claim 556, further comprising using at least some of the produced hydrocarbons in the steam and electricity cogeneration facility.

558. The method of claim 550, further comprising using electricity from the steam and electricity cogeneration facility to provide electrical power to subsurface electrical heaters in the formation, and using steam from the facility to provide steam to the formation, and producing hydrocarbon fluids from the formation that have been heated by the heated water, the heaters, and/or the steam.

559. A method of heating a portion of a subsurface formation, comprising:
   introducing an oxidant into a wellbore through a first conduit;
   introducing coal and a carrier gas into the wellbore in a second conduit;
   passing at least a portion of the oxidant through one or more openings to mix the oxidant with the coal at one or more selected locations; and
   reacting the mixture of the coal and the oxidant to generate heat such that a portion of the generated heat transfers to the formation.

560. The method of claim 559, wherein the first conduit is at least partially positioned in the second conduit.

561. The method of claim 559, wherein the second conduit is at least partially positioned in the first conduit.

562. The method of claim 559, further comprising removing combustion gases from the formation through a third conduit, and wherein flow of combustion gases through the third conduit is countercurrent to flow of oxidant in the first conduit.

563. The method of claim 559, further comprising shielding at least one reaction zone where coal and oxidant react to stabilize the reaction zone.
564. A method of heating a portion of a subsurface formation, comprising:
   introducing an oxidant into a wellbore through a first conduit;
   introducing coal and a carrier gas into the wellbore in a second conduit;
   passing at least a portion of the coal and the carrier gas through one or more openings to
   mix the coal and the carrier gas with oxidant at one or more selected locations; and
   reacting the mixture of the coal and the oxidant to generate heat, wherein a portion of the
   generated heat transfers to the formation.
565. The method of claim 564, wherein the first conduit is at least partially positioned in the
   second conduit.
566. The method of claim 564, wherein the second conduit is at least partially positioned in the
   first conduit.
567. The method of claim 564, further comprising removing combustion gases from the
   formation through a third conduit, and wherein flow of combustion gases through the third
   conduit is countercurrent to flow of oxidant in the first conduit.
568. The method of claim 564, further comprising shielding at least one reaction zone where
   coal and oxidant react to stabilize the reaction zone.
569. A heater system for heating a subsurface formation, comprising:
   an oxidant conduit in a wellbore, wherein the oxidant conduit is configured to supply an
   oxidizing fluid;
   a fuel conduit having one or more openings, wherein the fuel conduit is configured to
   supply a fuel fluid comprising coal suspended in a carrier gas;
   a source of the carrier gas; and
   a source of the coal.
570. The system of claim 569, wherein the oxidant conduit is an inner conduit at least partially
   positioned in the fuel conduit.
571. The system of claim 569, wherein the fuel conduit is an inner conduit at least partially
   positioned in the oxidant conduit.
572. The system of claim 569, wherein the fuel conduit comprises an inner conduit at least
   partially positioned in the oxidant conduit, and wherein the heater system is configured to
   provide the fuel fluid at a higher pressure than the oxidant fluid.
573. The system of claim 569, wherein the fuel conduit comprises an inner conduit positioned
   in the oxidant conduit, and wherein the oxidant fluid is delivered at a higher pressure than the
   fuel fluid.
574. A method of heating a portion of a subsurface formation, comprising:
   heating fluidized material in the presence of an oxidizing fluid in a combustion unit;
passing the hot fluidized material through u-shaped conduits in a subsurface formation; and

transferring heat from the fluidized material to the u-shaped conduits, and from portions of the u-shaped conduits to a portion of the subsurface formation.

575. The method of claim 574, further comprising oxidizing a portion of the heating fluidized material in the u-shaped conduits.

576. The method of claim 574, further comprising providing a lift gas to a return portion of the conduit to gas lift material in the conduit out of the formation.

577. The method of claim 574, wherein the combustion unit comprises a fluidized combustor, and wherein at least a portion of the fluidized material comprises fluidized material from the combustion unit.

578. The method of claim 574, wherein the fluidized material comprises pulverized coal.

579. A method, comprising:

making coiled tubing at a coiled tubing manufacturing unit coupled to a coiled tubing transportation system; and

transporting one or more coiled tubing reels from the coiled tubing manufacturing unit to one or more moveable well drilling systems using the coiled tubing transportation system, wherein the coiled tubing transportation system runs from the tubing manufacturing unit to one or more movable well drilling systems, and then back to the coiled tubing manufacturing unit.

580. The method of claim 579, wherein making the coiled tubing comprises rolling plate metal to form tubing, welding the seam of the tubing, and coiling the coiled tubing on a reel.

581. The method of claim 579, wherein a reel of coiled tubing from the tubing manufacturing unit has a diameter of at least 15 m.

582. The method of claim 579, further comprising using at least some of the coiled tubing to drill and line a well to be drilled, or being drilled, by one or more of the movable well drilling systems.

583. The method of claim 579, further comprising providing utilities to one or more well drilling systems from one or more centralized utility units.

584. The method of claim 579, further comprising positioning one or more of the movable well drilling systems using a global positioning system.

585. The method of claim 579, further comprising a tracking system configured to actively assess locations of a position and/or state of one or more of the movable well drilling systems.

586. The method of claim 579, further comprising delivering coiled tubing reels from the coiled tubing manufacturing unit to the coiled tubing transportation system using one or more gantries.
587. The method of claim 579, further comprising returning empty reels from one or more of the drilling systems along the coiled tubing transportation system to the coiled tubing manufacturing unit.

588. The method of claim 579, further comprising drilling a subsurface heater wellbore using one or more of the well drilling systems.

589. A method for making coiled tubing for a wellbore in a formation, comprising:
    assessing properties of at least a first portion of a treatment area in the formation;
    making coiled tubing at a coiled tubing manufacturing unit based on, at least in part, one or more of the assessed properties of the first portion of the treatment area, wherein the coiled tubing manufacturing site is coupled to the first portion of the treatment area with a coiled tubing transportation system;
    transporting the coiled tubing from the coiled tubing manufacturing site to the first portion of the treatment area using a coiled tubing transportation system; and
    drilling a first wellbore using a movable wellbore drilling system and the coiled tubing.

590. The method of claim 589, wherein the coiled tubing transportation system comprises one or more gantries.

591. The method of claim 589, wherein the coiled tubing transportation system comprises a looped path from the tube manufacturing unit to one or more wellbore drilling areas, and from one or more of the wellbore drilling systems to the coiled tubing manufacturing unit.

592. The method of claim 589, wherein at least one moveable drilling system comprises a gantry.

593. The method of claim 589, further comprising drilling a heater wellbore using one or more of the well drilling systems.

594. The method of claim 589, further comprising drilling a subsurface heater wellbore using one or more of the well drilling systems, and installing a heating system in the heater wellbore.

595. A method for making coiled tubing and transporting such coiled tubing to a well, comprising:
    drilling at least a portion of a first well in a treatment area;
    assessing properties of the first well;
    making a first coiled tubing at a coiled tubing manufacturing unit based on, at least in part, the assessed properties of the first well, wherein the coiled tubing manufacturing unit is coupled to the first well with a coiled tubing transportation system;
    transporting the first coiled tubing from the coiled tubing manufacturing unit to the first well using the coiled tubing transportation system;
    drilling at least a portion of a second well in the treatment area;
assessing properties of the second well;
making a second coiled tubing at the coiled tubing manufacturing unit based on, at least
in part, the assessed properties of the second well, wherein the coiled tubing manufacturing unit
is coupled to the second well with the coiled tubing transportation system; and
transporting the second coiled tubing from the coiled tubing manufacturing unit to the
second well.

596. The method of claim 595, wherein the second coiled tubing comprises at least one
property different from properties of the first coiled tubing.

597. The method of claim 595, wherein the coiled tubing transportation system comprises one
or more gantries.

598. The method of claim 595, wherein the tubing transportation system comprises a loop
from the coiled tubing manufacturing unit to one or more wellbore drilling areas, and from one or
more wellbore drilling systems to the coiled tubing manufacturing unit.

599. A system for forming a wellbore, comprising:

   a drill tubular;
   a drill bit coupled to the drill tubular; and
   one or more cutting structures coupled to the drill tubular above the drill bit, wherein the
cutting structures are configured to remove at least a portion of formation that extends into the
wellbore formed by the drill bit.

600. The system of claim 599, wherein one or more of the cutting structures are positioned
away from the drill bit and oriented upwards to facilitate removal of formation extending in the
wellbore as the drill tubular is moved upwards.

601. The system of claim 599, wherein one or more of the cutting structures are positioned on
an outside portion of the drill tubular, and wherein the one or more cutting structures extend
radially beyond the drill tubular.

602. The system of claim 599, wherein one or more cutting structures are positioned away
from the drill bit and oriented downward to facilitate removal of formation extending in the
wellbore as the drill bit moves downwards.

603. The system of claim 599, further comprising one or more upward facing cutting structures
on the drill bit.

604. The system of claim 599, wherein one or more of the cutting structures are coupled to a
bottom hole assembly.

605. The system of claim 599, wherein one or more of the cutting structures are located at or
near a section of the drill tubular where the diameter of the drill tubular changes.

606. A method for forming a wellbore, comprising:
forming the wellbore in the formation using a drill bit; and
using cutting structures positioned above the drill bit to remove formation that expands into the wellbore.

607. The method of claim 606, wherein one or more of the cutting structures are oriented downwards to facilitate removal of formation extending into the wellbore as the drill bit is moved downwards.

608. The method of claim 606, wherein one or more of the cutting structures are oriented upwards to facilitate removal of formation extending into the wellbore when the drill bit is moved upwards in the wellbore.

609. The method of claim 606, wherein one or more of the cutting structures are coupled to a drill string at or near a change in diameter of the drill string.

610. The method of claim 606, wherein one or more of the cutting structures extend radially past a drill string coupled to the drill bit.

611. The method of claim 606, wherein at least a portion of the formation adjacent to the wellbore has been heated by heat sources.

612. The method of claim 606, wherein at least a portion of the formation adjacent to the wellbore has been heated by introduction of a hot fluid into the formation.

613. The method of claim 606, wherein at least a portion of the formation adjacent to the wellbore has been heated by combustion of hydrocarbons in the formation.

614. The method of claim 606, further comprising removing cuttings created by the cutting structures with circulated drilling fluid.

615. A method of forming a wellbore in a heated formation, comprising:

forming the wellbore in the heated formation using a bottom hole assembly; and

cutting formation with cutting structures to remove portions of the formation that expand into the wellbore after the wellbore is formed with the bottom hole assembly.

616. The method of claim 615, wherein one or more of the cutting structures are coupled to the bottom hole assembly.

617. The method of claim 615, wherein one or more of the cutting structures are oriented downwards to facilitate removal of formation extending into the wellbore as the drill bit is moved downwards.

618. The method of claim 615, wherein one or more of the cutting structures are oriented upwards to facilitate removal of formation extending into the wellbore when the drill bit is moved upwards in the wellbore.

619. A method of treating a tar sands formation, comprising:
providing heat to a first section of a hydrocarbon layer in the formation from a plurality of heaters located in the first section of the formation;
allowing the heat to transfer from the heaters so that at least a first section of the formation reaches a selected temperature;
allowing at least a portion of residual heat from the first section to transfer from the first section to a second section of the formation; and
mobilizing at least a portion of hydrocarbons in the second section by providing a solvation fluid and/or a pressurizing fluid to the second section of the formation.
620. The method of claim 619, wherein residual heat transfers from the first section to a second section by conduction and/or convection.
621. The method of claim 619, wherein superposition of heat from the plurality of heaters heats a majority of the first section.
622. The method of claim 619, wherein a minority of the heat transfers to the second section through superposition of heat from the plurality of heaters.
623. The method of claim 619, wherein the second section is outside of a perimeter of the heaters.
624. The method of claim 619, wherein a location of a heated area in the second section is greater than an average distance from the heaters in the first section.
625. The method of claim 619, wherein the second section is substantially horizontal to the first section.
626. The method of claim 619, wherein the second section is substantially vertical to the first section.
627. The method of claim 619, further comprising providing the solvation fluid and/or pressurizing fluid to a third section to mobilize at least a portion of the fluids from the third section of the formation.
628. The method of claim 619, further comprising providing the solvation fluid and/or pressurizing fluid to a third section to mobilize at least a portion of the fluids from the third section of the formation.
629. A method of treating a tar sands formation, comprising:
providing heat to at least part of the formation from a plurality of heaters located in the formation;
allowing the heat to transfer from the heaters so that at least a portion of the formation reaches a selected temperature;
allowing fluids to gravity drain to a bottom portion of the formation;
producing a substantial portion of the drained fluids from one or more production wells
located at or proximate the bottom portion of the formation, wherein at least a majority of the
produced fluids are condensible hydrocarbons;

reducing the pressure in the formation to a selected pressure after the portion of the
formation reaches the selected temperature and after producing a majority of the condensible
hydrocarbons in the portion of the formation;

providing a solvation fluid and/or a pressurizing fluid to the portion of the formation,
wherein the solvation fluid solvates at least a portion of remaining condensible hydrocarbons in
the part of the formation to form a mixture of solvation fluid and condensible hydrocarbons; and
mobilizing the mixture.

630. The method of claim 629, wherein the selected temperature is between 250 °C and 400
°C or between 200 °C and 240 °C.

631. The method of claim 629, wherein the solvation fluid comprises carbon disulfide, water,
hydrocarbons, surfactants, polymers, caustic, alkaline water solutions, sodium carbonate
solutions, or mixtures thereof.

632. The method of claim 629, wherein the pressurizing fluid comprises carbon dioxide and/or
methane.

633. The method of claim 629, further comprising producing the mobilized hydrocarbons, and
wherein the produced hydrocarbons comprise bitumen.

634. A hydrocarbon composition having:

an API gravity between 19° and 25°;

a viscosity of at most 350 cp at 5°C;

a P-value of at least 1.1, wherein P-value is determined using ASTM Method D7060; and

wherein the hydrocarbon composition comprises hydrocarbons having boiling range
distribution between 204 °C and 343 °C having a bromine number of at most 2%, and wherein
bromine number is determined by ASTM Method D1159.

635. The hydrocarbon composition of claim 634, wherein the hydrocarbon composition is
produced by a method, comprising:

providing heat to a first section of a hydrocarbon layer in the formation from a plurality of
heaters located in the first section of the formation;

allowing the heat to transfer from the heaters so that at least a first section of the
formation reaches a selected temperature;

allowing at least a portion of residual heat from the first section to transfer from the first
section to a second section of the formation; and
mobilizing at least a portion of hydrocarbons in the second section by providing a
solvation fluid and/or a pressurizing fluid to the second section of the formation.

636. A hydrocarbon composition having:
    an API gravity between 19° and 25° as determined by ASTM Method D1298;
    a viscosity ranging at most 350 cp at 5°C;
    a Canadian Association of Petroleum Producers number of at most 2% as 1-decene
equivalent; and
    a P-value of at least 1.1, wherein P-value is determined using ASTM Method D7060.

637. The hydrocarbon composition of claim 636, wherein the hydrocarbon composition is
produced by a method, comprising:
    providing heat to a first section of a hydrocarbon layer in the formation from a plurality of
heaters located in the first section of the formation;
    allowing the heat to transfer from the heaters so that at least a first section of the
formation reaches a selected temperature;
    allowing at least a portion of residual heat from the first section to transfer from the first
section to a second section of the formation; and
    mobilizing at least a portion of hydrocarbons in the second section by providing a
solvation fluid and/or a pressurizing fluid to the second section of the formation.

638. A method for treating a hydrocarbon formation, comprising:
    providing heat to a portion of the formation from one or more heaters located in the
formation;
    introducing a hydrogen donating solvation fluid to the portion of the formation;
    contacting at least a portion of the formation fluids with the hydrogen donating solvation
fluid at a temperature of at least 175 °C to produce a mixture comprising upgraded hydrocarbons,
formation fluids, hydrogen donating solvation, and dehydrogenated solvation fluid; and
    producing at least some of the mixture from the formation.

639. A method for treating a tar sands formation with one or more karsted layers, comprising:
    providing heat from one or more heaters to at least one first karsted layer comprising
hydrocarbons and being vertically above at least one second karsted layer, wherein the second
karsted layer has a lower volume percent of hydrocarbons per volume percent of rock than the
first karsted layer;
    providing heat to the second karsted layer so that at least some hydrocarbons in the
second karsted layer are mobilized, and at least some of the mobilized hydrocarbons in the
second karsted layer move to the first karsted layer; and
    producing hydrocarbon fluids from the first karsted layer.
640. A gas burner assembly for heating a subsurface formation, comprising:
an oxidant conduit;
a fuel conduit; and
a plurality of oxidizers coupled to the oxidant conduit, wherein at least one of the
oxidizers comprises:
   a mix chamber for mixing fuel from the fuel conduit with oxidant from the
   oxidant conduit;
an igniter;
a shield, wherein the shield comprises a plurality of openings in communication
with the oxidant conduit; and
   at least one flame stabilizer coupled to the shield.

641. The assembly of claim 640, wherein at least one flame stabilizer comprises a ring
positioned in the shield downstream of a first set of openings in the shield, wherein the set of
openings are radially positioned in the shield at a longitudinal distance along the shield.

642. The assembly of claim 641, wherein the ring is substantially perpendicular to the shield.
643. The assembly of claim 641, wherein the ring is angled away from the set of openings.
644. The assembly of claim 641, wherein the ring is angled towards the set of openings.
645. The assembly of claim 640, wherein the shield comprises two or more sets of openings,
wherein a set of openings are radially positioned in the shield at specific longitudinal positions of
the shield, and wherein flame stabilizers comprising rings are positioned between sets of
openings.

646. The assembly of claim 640, wherein the shield comprises two or more sets of openings,
wherein a set of openings are radially positioned in the shield at specific longitudinal positions of
the shield, and wherein flame stabilizers comprising rings are positioned at an angle over the
openings.

647. The assembly of claim 640, wherein at least one flame stabilizer comprises a deflection
plate, wherein a portion of the deflection plate extends over an opening in the shield.
648. The assembly of claim 640, wherein the flame stabilizer alters the gas flow path in the
shield.

649. The assembly of claim 640, wherein the fuel conduit is positioned in the oxidant conduit.
650. The assembly of claim 640, wherein fuel in the fuel conduit comprises a decoking agent.
651. The assembly of claim 640, wherein the fuel conduit is positioned in the oxidant conduit.
652. The assembly of claim 640, wherein the fuel conduit is positioned adjacent to one or more
of the oxidizers, and wherein branches from the fuel conduit provide fuel to one or more of the
oxidizers.
653. The assembly of claim 640, wherein the flame stabilizer comprises a plurality of slots in the shield with extensions that direct gas flow into the shield in a desired direction.

654. A method of heating a subsurface formation, comprising:
   supplying fuel to a plurality of oxidizers;
   supplying oxidant to the plurality of oxidizers;
   mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of oxidizers to produce a combustible mixture;
   reacting the combustible mixture in the oxidizer to produce a flame; and
   using a flame stabilizer in the oxidizer to attach the flame to a shield.

655. The method of claim 654, using the flame stabilizer comprises passing gas in the oxidizer past a ring positioned in the shield.

656. The method of claim 654, wherein the ring is substantially perpendicular to the shield.

657. The method of claim 654, wherein the ring is angled in the shield.

658. The method of claim 654, wherein at least one flame stabilizer comprises an opening in the shield and an extension configured to direct gas flowing into the shield in a desired direction.

659. The method of claim 654, further comprising adding a coking inhibitor to the fuel.

660. A gas burner assembly for heating a subsurface formation, comprising:
   an oxidant conduit;
   a fuel conduit; and
   a plurality of oxidizers coupled to the oxidant conduit, wherein at least one of the oxidizers includes:
   a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;
   a catalyst chamber containing a catalyst, the catalyst configured to react a mixture from the mix chamber to produce reaction products at a temperature that is sufficient to ignite fuel and oxidant; and
   a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit.

661. The assembly of claim 660, wherein the shield comprises at least one flame stabilizer.

662. The assembly of claim 660, wherein oxidant supplied to the mix chamber comprises oxidant preheated by one or more previous oxidizers.

663. The assembly of claim 660, wherein the fuel conduit is positioned in the oxidant conduit.

664. The assembly of claim 660, wherein the fuel conduit is positioned adjacent to one or more of the oxidizers, and wherein branches from the fuel conduit provide fuel to one or more of the oxidizers.
665. A method of heating a subsurface formation, comprising:
supplying fuel to a plurality of oxidizers;
supplying oxidant to the plurality of oxidizers;
mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of
oxidizers to produce a first mixture;
passing the first mixture across a catalyst to produce reaction products at a temperature
sufficient to ignite fuel and oxidant; and
igniting a second mixture of fuel and oxidant to generate heat, wherein a portion of the
heat is transferred to the formation.
666. A gas burner assembly for heating a subsurface formation, comprising:
an oxidant conduit;
a fuel conduit positioned in the oxidant conduit; and
a plurality of oxidizers coupled to the fuel conduit, wherein at least one of the oxidizers
includes:
  a mix chamber for mixing fuel from the fuel conduit with an oxidant;
  an igniter in the mix chamber configured to ignite fuel and oxidant to preheat fuel
and oxidant;
  a catalyst chamber containing a catalyst, the catalyst configured to react preheated
fuel and oxidant from the mix chamber to produce reaction products at a temperature
sufficient to ignite fuel and oxidant; and
  a shield, wherein the shield comprises a plurality of openings in communication
with the oxidant conduit.
667. The assembly of claim 666, wherein the catalyst chamber comprises one or more
openings configured to allow oxidant, fuel, or a mixture thereof to contact the catalyst.
668. The assembly of claim 666, wherein the catalyst chamber comprises one or more
openings configured to allow the reaction products to exit the catalyst chamber and contact a
mixture of fuel and oxidant.
669. The assembly of claim 666, further comprising a water conduit positioned in the oxidant
conduit, the water conduit configured to deliver water that inhibits coking of fuel to the fuel
conduit before a first oxidizer in the gas burner assembly.
670. The assembly of claim 666, wherein the shield comprises at least one flame stabilizer.
671. The assembly of claim 666, wherein the igniter comprises a glow plug.
672. The assembly of claim 666, wherein the igniter comprises a temperature limited heating
element.
673. A method of heating a subsurface formation, comprising:
supplying fuel to a plurality of oxidizers;
supplying oxidant to the plurality of oxidizers;
mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of oxidizers to produce a first mixture;
using an igniter to ignite the first mixture and produce heat;
using the heat to preheat a second mixture;
passing the preheated second mixture over a catalyst to react the mixture and produce heat; and
using the heat to ignite a third mixture of oxidant and fuel to produce a flame in the oxidizer and generate heat, wherein at least a portion of the heat transfers to the formation.

674. The method of claim 673, wherein the igniter comprises a temperature limited heating element.

675. The method of claim 673, wherein the igniter comprises a glow plug.

676. A method of heating a subsurface formation, comprising:
supplying fuel to a plurality of oxidizers positioned in the subsurface formation via a fuel conduit;
supplying an oxidant to the plurality of oxidizers;
mixing a portion of the fuel with a portion of the oxidant;
combusting the fuel and oxidant mixture to produce heat that heats at least a portion of the subsurface formation; and
decoking the fuel conduit.

677. The method of claim 676, wherein decoking comprises injecting steam into the fuel conduit.

678. The method of claim 676, wherein the decoking comprises injecting water into the fuel conduit.

679. The method of claim 676, wherein the decoking fluid comprises decreasing a residence time of fuel in the fuel conduit.

680. The method of claim 676, wherein decoking comprises pumping a pig through the fuel conduit.

681. The method of claim 676, wherein decoking comprises insulating a portion of the fuel conduit.

682. The method of claim 676, wherein insulating a portion of the fuel conduit comprises coating a portion of the fuel conduit with an insulating layer and a conductive layer.

683. A downhole burner, comprising:
an oxidant conduit;
a fuel conduit positioned in the oxidant conduit;
an oxidizer coupled to the fuel conduit; and
an insulating sleeve positioned between the fuel conduit and the oxidizer;
wherein a portion of a fluid flowing through the oxidant conduit passes between the
insulating sleeve and fuel conduit to provide cooling to at least a portion of the fuel conduit that
passes through the oxidizer.

684. The burner of claim 683, wherein the insulating sleeve at least partially surrounds the fuel
conduit.

685. The burner of claim 683, further comprising a conductive layer surrounding the insulating
sleeve.

686. A method, comprising:
    providing oxidant in an oxidant conduit to an oxidizer;
    providing fuel through a fuel conduit to the oxidizer, wherein the fuel conduit is
    positioned in the oxidant conduit;
    reacting fuel from the fuel conduit and oxidant from the oxidant conduit in the oxidizer to
    produce heat; and
    flowing a portion of the oxidant in the oxidant conduit between an insulating sleeve and
    the fuel conduit to provide cooling to at least a portion of the fuel conduit passing through the
    oxidizer.

687. The method of claim 686, wherein the insulating sleeve at least partially surrounds the
fuel conduit.

688. The method of claim 686, wherein a conductive layer surrounds the insulating sleeve.

689. A method of heating a formation, comprising:
    providing fuel to a plurality of oxidizers;
    providing an oxidant to the plurality of oxidizers;
    reacting the oxidant and fuel in the oxidizers to produce heat to heat a portion of the
    formation; and
    reducing the amount of excess oxidant supplied to the oxidizers to less than about 50%
excess oxidant by weight.

690. The method of claim 689, further comprising reducing the amount of excess oxidant to
less than about 25%.

691. The method of claim 689, further comprising reducing the amount of excess oxidant to
less than about 10%.

692. A method of heating a formation, comprising:
    providing a plurality of oxidizers connected in series;
providing fuel to the plurality of oxidizers via a fuel conduit;
providing an oxidant to the plurality of oxidizers via an oxidant conduit;
reacting the oxidant and fuel in the oxidizers to produce heat to heat a portion of the formation; and
reducing the oxidant supplied via the oxidant conduit when the temperature in the fuel conduit reaches a specified temperature.

693. The method of claim 692, further comprising permitting unburned material to be oxidized in the oxidant conduit.

694. The method of claim 692, wherein the specified temperature is about 1200 °F.

695. The method of claim 692, wherein the specified temperature is about 1400 °F.

696. The method of claim 692, wherein the specified temperature is about 1600 °F.

697. A method of heating a formation, comprising:
providing a plurality of oxidizers comprising:
a first oxidizer;
one or more intermediate oxidizers connected in series; and
a last oxidizer;
providing fuel to the plurality of oxidizers via a fuel conduit;
providing an oxidant to the plurality of oxidizers via an oxidant conduit;
reacting the oxidant and fuel in the oxidizers to produce heat to heat a portion of the formation; and
reducing the oxidant supplied via the oxidant conduit so that the amount of oxygen in the oxidant supplied to the last oxidizer is minimized.

698. A gas burner, comprising:
an oxidant conduit;
a fuel conduit positioned in the oxidant conduit; and
an oxidizer configured to react fuel from the fuel conduit and oxidant from the oxidant conduit to produce heat, wherein the operating temperature of the oxidizer is configured to produce less than about 10 parts per million by weight of NOx from the gas burner.

699. The gas burner of claim 698, wherein the operating temperature of the oxidizer is configured by adding water to the fuel conduit.

700. The gas burner of claim 698, wherein the operating temperature of the oxidizer is configured by arranging openings in the oxidant conduit.

701. A method of heating a formation comprising:
providing oxidant in an oxidant conduit to an oxidizer;
providing fuel to the oxidizer;
reacting fuel and oxidant to produce heat, wherein at least a portion of the heat transfers to the formation; and
controlling flow of fuel and oxidant to produce less than about 10 parts per million by weight of NOx from the gas burner.

702. The method of claim 701, further comprising mixing water with the fuel.
703. The method of claim 701, further comprising arranging openings in the oxidant conduit.
704. A method of initiating heating in a gas burner assembly in a formation, comprising:
supplying fuel through a fuel conduit in the formation, and oxidant through an oxidant conduit to provide a first combustible mixture to a last oxidizer of a plurality of oxidizers;
initiating combustion in the last oxidizer of the plurality of oxidizers to provide an ignited oxidizer;
adjusting the supply of oxidant through the oxidant conduit to supply a second-to-last oxidizer next to the ignited oxidizer with a second combustible mixture while maintaining ignition of the ignited oxidizer; and
initiating combustion in the second-to-last oxidizer.

705. The method of claim 704, repeating adjusting the supply of oxidant to provide a combustible fuel and oxidant mixture to the next unignited oxidizer and initiating combustion in the unignited oxidizer until all oxidizers of the plurality of oxidizers are ignited.
706. The method of claim 704, wherein the fuel pressure is greater than the oxidant pressure at an oxidizer before initiating combustion in the oxidizer.
707. The method of claim 704, wherein the fuel comprises hydrogen.
708. The method of claim 704, wherein at least a portion of the hydrogen is produced using an in situ conversion process.
709. The method of claim 704, wherein at least a portion of the hydrogen is produced using a coal gasification process.
710. A method of initiating heating in a gas burner assembly in a formation, comprising:
supplying fuel through a fuel conduit in the formation, and oxidant through an oxidant conduit to provide a first combustible mixture to a first oxidizer of a plurality of oxidizers;
initiating combustion in the last oxidizer of the plurality of oxidizers to provide an ignited oxidizer;
adjusting the supply of oxidant through the oxidant conduit to supply a second oxidizer next to the ignited oxidizer with a second combustible mixture while maintaining ignition of the ignited oxidizer; and
initiating combustion in the second oxidizer.
711. The method of claim 710, further comprising repeating adjusting the supply of oxidant to provide a combustible fuel and oxidant mixture to the next unignited oxidizer and initiating combustion in the unignited oxidizer until all oxidizers of the plurality of oxidizers are ignited.

712. The method of claim 710, further comprising adjusting the fuel pressure by providing openings in the fuel conduit.

713. The method of claim 710, further comprising adjusting the fuel pressure by providing flow restrictions in the fuel conduit.

714. A gas burner assembly for heating a subsurface formation, comprising:
   an oxidant conduit;
   a fuel conduit; and
   a first oxidizer coupled to the oxidant conduit, the first oxidizer comprising:
       a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;
       an igniter; and
       a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit;
   a second oxidizer coupled to the oxidant conduit, the second oxidizer comprising:
       a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;
       an igniter; and
       a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit; and

wherein one or more of the plurality of openings of the first oxidizer are of a different size than the plurality of openings of the second oxidizer.

715. The gas burner assembly of claim 714, wherein at least one of the openings of the first oxidizer is of a different size than one or more other openings of the first oxidizer.

716. A gas burner assembly for heating a subsurface formation, comprising:
   an oxidant conduit;
   a fuel conduit;
   a first oxidizer coupled to the oxidant conduit, the first oxidizer comprising:
       a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;
       an igniter; and
       a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit;
a second oxidizer coupled to the oxidant conduit, the second oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter;

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit; and

wherein one or more of the plurality of openings of the first oxidizer are of a different geometry than the plurality of openings of the second oxidizer.

717. The gas burner assembly of claim 716, wherein at least one of the openings of the first oxidizer is of a different geometry than one or more other openings of the first oxidizer.

718. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit; and

a first oxidizer coupled to the oxidant conduit, the first oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a first group of openings angled across the thickness of the shield.

719. The gas burner assembly of claim 718, further comprising a second group of openings not angled across the thickness of the shield.

720. The gas burner assembly of claim 719, wherein the first group of openings are located on a portion of the shield away from the fuel conduit.

721. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit; and

a first oxidizer coupled to the oxidant conduit, the first oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit and a baffled section proximate to the openings.

722. The gas burner assembly of claim 721, further comprising a second oxidizer coupled to the oxidant conduit, the second oxidizer comprising:
a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;
an igniter; and
a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit; and
wherein one or more of the plurality of openings of the first oxidizer are of a different geometry than the plurality of openings of the second oxidizer.
723. A gas burner assembly for heating a subsurface formation, comprising:
an oxidant conduit;
a fuel conduit positioned in the oxidant conduit; and
a plurality of oxidizers coupled to the fuel conduit configured to react fuel from the fuel conduit and oxidant from the oxidant conduit;
wherein fuel supplied to a first oxidizer of the plurality of oxidizers is configured to pass into a heated region adjacent to the first oxidizer before entering the first oxidizer.
724. The gas burner of claim 723, further comprising a bypass conduit which forces fuel supplied to the first oxidizer to pass into the heated region before entering the first oxidizer.
725. The gas burner of claim 724, wherein the bypass conduit comprises a primary fuel hole upstream, of the first oxidizer and a secondary fuel hole inside the first oxidizer.
726. The gas burner of claim 723, wherein the fuel conduit is positioned in the oxidant conduit.
727. The gas burner of claim 723, wherein the fuel conduit is positioned adjacent to one or more of the oxidizers, and wherein branches from the fuel conduit provide fuel to one or more of the oxidizers.
728. The gas burner of claim 723, wherein the fuel conduit comprises one or more orifices to selectively control the pressure loss along the fuel conduit.
729. A method for heating a subsurface formation, comprising:
providing oxidant to a plurality of oxidizers;
providing fuel to the oxidizers through a fuel conduit;
passing the fuel conduit through a heated zone adjacent to a first oxidizer before providing fuel to the first oxidizer; and
reacting fuel and oxidant to produce heat, wherein at least a portion of the heat transfers to the formation.
730. The gas burner of claim 729, wherein the fuel conduit is positioned in the oxidant conduit.
731. The gas burner of claim 729, wherein the fuel conduit is positioned adjacent to one or more of the oxidizers, and wherein branches from the fuel conduit provide fuel to one or more of the oxidizers.

732. The gas burner of claim 729, wherein the fuel conduit comprises one or more orifices to selectively control the pressure loss along the fuel conduit.

733. A gas burner assembly for heating a subsurface formation, comprising:
   - an oxidant conduit;
   - a fuel conduit positioned in the oxidant conduit; and
   - a plurality of oxidizers coupled to the fuel conduit, wherein at least one of the oxidizers includes:
     - a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit; and
     - a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit, and wherein the fuel conduit comprises at least two fuel entries into the shield at different positions along a length of the fuel conduit.

734. The gas burner assembly of claim 733, wherein one of the oxidizers with the fuel conduit comprising at least two fuel entries into the shield at different positions along the length of the fuel conduit is a first oxidizer of the plurality of oxidizers.

735. A method of heating a subsurface formation, comprising:
   - supplying fuel to a plurality of oxidizers through a fuel conduit;
   - supplying oxidant to the plurality of oxidizers through an oxidant conduit;
   - mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of oxidizers to produce a combustible mixture;
   - reacting the combustible mixture in the oxidizer to produce a flame in a shield of the oxidizer; introducing additional fuel from the fuel conduit adjacent to the shield, and introducing additional oxidant through one or more openings in the shield to provide an extended length of the flame in the oxidizer; and
   - heating a portion of the formation using heat generated by the flame.

736. A method of initiating heating in a gas burner assembly in a formation, comprising:
   - supplying fuel of a first composition through a fuel conduit in the formation, and oxidant through an oxidant conduit;
   - initiating combustion in an oxidizer; and
   - adjusting the supply and composition of fuel in the conduit to supply fuel of a second composition to the formation.

737. The method of claim 736, wherein the first composition comprises hydrogen.
738. The method of claim 736, wherein the second composition comprises natural gas.

739. A method of initiating heating in a gas burner assembly in a formation, comprising:
   supplying fuel through a fuel conduit and oxidant through an oxidant conduit;
   igniting the burner using a fuel composition comprising hydrogen; and
   adjusting the composition of the fuel in the fuel conduit so that the fuel comprises natural gas.

740. A heating system for a subsurface formation, comprising:
   an electrical conductor;
   an insulation layer at least partially surrounding the electrical conductor; and
   a jacket comprising ferromagnetic material, the jacket at least partially surrounding the insulation layer, wherein the outside surface of the jacket is configured to be at little or no electric potential while the electrical conductor is conducting electricity and while the jacket is at temperatures below the Curie temperature of the ferromagnetic material.

741. The heating system of claim 740, wherein the jacket has a thickness of at least 2 times the skin depth of the ferromagnetic material at 50 °C below the Curie temperature of the ferromagnetic material.

742. The heating system of claim 740, wherein the jacket has a thickness of at least 3 times the skin depth of the ferromagnetic material at 50 °C below the Curie temperature of the ferromagnetic material.

743. The heating system of claim 740, wherein the heating system is configured such that a majority of electrical current passes through the jacket on the inside diameter of the jacket.

744. The heating system of claim 740, wherein the jacket and the electrical conductor are electrically coupled at distal ends of the jacket and the electrical conductor.

745. The heating system of claim 740, wherein the electrical conductor is copper.

746. The heating system of claim 740, wherein the jacket is formed from multiple layers of material.

747. The heating system of claim 740, wherein a majority of the heat generated by the heating system is generated in the jacket.

748. The heating system of claim 740, wherein the heating system is located in a wellbore such that the heating system provides heat to mobilize hydrocarbons in the subsurface formation.

749. A heating system for a subsurface formation, comprising:
   an electrical conductor;
   an insulation layer at least partially surrounding the electrical conductor; and
a jacket comprising ferromagnetic material, the jacket at least partially surrounding the insulation layer, wherein the jacket is configured to generate a majority of the heat in the heating system when a time-varying electrical current is applied to the heating system.

750. The heating system of claim 749, wherein the jacket has a thickness of at least 2 times the skin depth of the ferromagnetic material at 50 °C below the Curie temperature of the ferromagnetic material.

751. The heating system of claim 749, wherein the jacket has a thickness of at least 3 times the skin depth of the ferromagnetic material at 50 °C below the Curie temperature of the ferromagnetic material.

752. The heating system of claim 749, wherein the heating system is configured such that a majority of electrical current passes through the jacket on the inside diameter of the jacket.

753. The heating system of claim 749, wherein the jacket and the electrical conductor are electrically coupled at distal ends of the jacket and the electrical conductor.

754. The heating system of claim 749, wherein the electrical conductor is copper.

755. The heating system of claim 749, wherein the jacket is formed from multiple layers of material.

756. The heating system of claim 749, wherein a majority of the heat generated by the heating system is generated in the jacket.

757. The heating system of claim 749, wherein the heating system is located in a wellbore such that the heating system provides heat to mobilize hydrocarbons in the subsurface formation.

758. A method for heating a subsurface formation, comprising:

  providing electrical power to a heater located in an opening in the formation, the heater comprising:

  an electrical conductor;
  an insulation layer at least partially surrounding the electrical conductor; and
  a jacket comprising ferromagnetic material, the jacket at least partially surrounding the insulation layer, wherein the outside surface of the jacket is configured to be at little or no electrical potential while the electrical conductor is conducting electricity and while the jacket is at temperatures below the Curie temperature of the ferromagnetic material; and

  allowing heat to transfer from the heater to at least a portion of the subsurface formation.

759. The method of claim 758, wherein the jacket has a thickness of at least 2 times the skin depth of the ferromagnetic material.

760. The method of claim 758, wherein the jacket has a thickness of at least 3 times the skin depth of the ferromagnetic material.
761. The method of claim 758, wherein a majority of electrical current passes through the jacket on the inside diameter of the jacket while electrical power is being provided to the heater.

762. The method of claim 758, wherein the jacket and the electrical conductor are electrically coupled at distal ends of the jacket and the electrical conductor.

763. The method of claim 758, wherein the electrical conductor is copper.

764. The method of claim 758, wherein the jacket is formed from multiple layers of material.

765. The method of claim 758, further comprising generating a majority of the heat in the jacket.

766. The method of claim 758, further comprising using heat from the heater to mobilize hydrocarbons in the subsurface formation.

767. The method of claim 758, further comprising using heat from the heater to mobilize hydrocarbons in the subsurface formation, and producing hydrocarbons from the subsurface formation.

768. A heating system for a subsurface formation, comprising:

    an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and

    a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

    wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

769. The system of claim 768, wherein the electrical conductor comprises a substantially u-shaped electrical conductor.

770. The system of claim 768, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

771. The system of claim 768, wherein the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 500 °C.

772. The system of claim 768, wherein the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 700 °C.

773. The system of claim 768, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to the temperature of at least about 300 °C.

774. The system of claim 768, wherein the ferromagnetic conductor comprises carbon steel.

775. The system of claim 768, wherein the electrical conductor is the core of an insulated conductor.
776. The system of claim 768, wherein the ferromagnetic conductor has a thickness of at least
2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C
below the Curie temperature of the ferromagnetic material.
777. The system of claim 768, wherein the ferromagnetic conductor and the electrical
conductor are configured in relation to each other such that electrical current does not flow from
the electrical conductor to the ferromagnetic conductor, or vice versa.
778. The system of claim 768, wherein the ferromagnetic conductor is configured to provide
different heat outputs along at least a portion of the length of the ferromagnetic conductor.
779. The system of claim 768, wherein the ferromagnetic conductor has different materials
along at least a portion of the length of the ferromagnetic conductor that are configured to
provide different heat outputs along at least a portion of the length of the ferromagnetic
conductor.
780. The system of claim 768, wherein the ferromagnetic conductor has different dimensions
along at least a portion of the length of the ferromagnetic conductor that are configured to
provide different heat outputs along at least a portion of the length of the ferromagnetic
conductor.
781. The system of claim 768, further comprising a corrosion resistant material coating on at
least a portion of the ferromagnetic conductor.
782. The system of claim 768, wherein the ferromagnetic conductor is between about 3 cm and
about 13 cm in diameter.
783. The system of claim 768, wherein at least about 10 m of length of the ferromagnetic
conductor is positioned in a hydrocarbon containing layer in the subsurface formation.
784. The system of claim 768, wherein the electrical conductor is configured to flow electrical
current in one direction from the first electrical contact to the second electrical contact.
785. The system of claim 768, wherein the ferromagnetic conductor comprises a ferromagnetic
tubular.
786. The system of claim 768, wherein the ferromagnetic conductor comprises two or more
ferromagnetic layers, the ferromagnetic layers being separated by insulation layers, wherein the
electrical conductor, when energized with time-varying electrical current, induces sufficient
electrical current flow in each of the ferromagnetic layers such that the ferromagnetic layers
resistively heat.
787. The system of claim 768, wherein the electrical conductor is a substantially u-shaped
electrical conductor located in a u-shaped wellbore in the formation.
788. A method for heating a subsurface formation, comprising:
providing time-varying electrical current to an elongated electrical conductor located in
the subsurface formation, wherein the electrical conductor extends between at least a first
electrical contact and a second electrical contact;
inducing electrical current flow in a ferromagnetic conductor with the time-varying
electrical current in the electrical conductor, wherein the ferromagnetic conductor at least
partially surrounds and at least partially extends lengthwise around the electrical conductor; and
resistively heating the ferromagnetic conductor with the induced electrical current flow
such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.
789. The method of claim 788, further comprising allowing heat to transfer from the
ferromagnetic conductor to at least a portion of the subsurface formation.
790. The method of claim 788, further comprising resistively heating the ferromagnetic
conductor to a temperature of at least about 500 °C.
791. The method of claim 788, further comprising resistively heating the ferromagnetic
conductor to a temperature of at least about 700 °C.
792. The method of claim 788, further comprising resistively heating at least about 10 m of
length of the ferromagnetic conductor to the temperature of at least about 300 °C.
793. The method of claim 788, wherein the ferromagnetic conductor comprises carbon steel.
794. The method of claim 788, wherein the electrical conductor is the core of an insulated
conductor.
795. The method of claim 788, wherein the ferromagnetic conductor has a thickness of at least
2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C
below the Curie temperature of the ferromagnetic material.
796. The method of claim 788, wherein the ferromagnetic conductor and the electrical
conductor are configured in relation to each other such that electrical current does not flow from
the electrical conductor to the ferromagnetic conductor, or vice versa.
797. The method of claim 788, further comprising providing different heat outputs along at
least a portion of the length of the ferromagnetic conductor.
798. The method of claim 788, further comprising applying the electrical current to the
electrical conductor in one direction from the first electrical contact to the second electrical
contact.
799. The method of claim 788, wherein the electrical conductor is a substantially u-shaped
electrical conductor located in a u-shaped wellbore in the formation.
800. The method of claim 788, further comprising allowing heat to transfer from the
ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons
in the formation are mobilized.
801. The method of claim 788, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

802. The method of claim 788, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.

803. A heating system for a subsurface formation, comprising:

   - an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and

   - a ferromagnetic conductor, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

   wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats.

804. The system of claim 803, wherein the electrical conductor comprises a substantially u-shaped electrical conductor.

805. The system of claim 803, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

806. The system of claim 803, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

807. The system of claim 803, wherein the ferromagnetic conductor comprises carbon steel.

808. The system of claim 803, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

809. The system of claim 803, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

810. The system of claim 803, wherein the ferromagnetic conductor has different materials along at least a portion of the length of the ferromagnetic conductor that are configured to
provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

811. The system of claim 803, wherein the ferromagnetic conductor has different dimensions along at least a portion of the length of the ferromagnetic conductor that are configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

812. The system of claim 803, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.

813. The system of claim 803, wherein the ferromagnetic conductor is between about 3 cm and about 13 cm in diameter.

814. The system of claim 803, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

815. The system of claim 803, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

816. The system of claim 803, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

817. The system of claim 803, wherein the ferromagnetic conductor and the electrical conductor are electrically insulated from each other.

818. A method for heating a subsurface formation, comprising:

providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;

inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats.

819. The method of claim 818, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.

820. The method of claim 818, further comprising resistively heating at least about 10 m of length of the ferromagnetic conductor to a temperature of at least about 300 °C.

821. The method of claim 818, wherein the ferromagnetic conductor comprises carbon steel.
822. The method of claim 818, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

823. The method of claim 818, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.

824. The method of claim 818, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.

825. The method of claim 818, wherein the ferromagnetic conductor and the electrical conductor are electrically insulated from each other.

826. The method of claim 818, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

827. The method of claim 818, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

828. The method of claim 818, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.

829. A heating system for a subsurface formation, comprising:

an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and

a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

wherein the electrical conductor, when energized with time-varying electrical current, induces electrical current flow on the inside and outside surfaces of the ferromagnetic conductor such that the ferromagnetic conductor resistively heats.

830. The system of claim 829, wherein the electrical conductor comprises a substantially u-shaped electrical conductor.

831. The system of claim 829, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.
832. The system of claim 829, wherein the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

833. The system of claim 829, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

834. The system of claim 829, wherein the ferromagnetic conductor comprises carbon steel.

835. The system of claim 829, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

836. The system of claim 829, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

837. The system of claim 829, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

838. The system of claim 829, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

839. The system of claim 829, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

840. The system of claim 829, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

841. A method for heating a subsurface formation, comprising:

   providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;

   inducing electrical current flow on the inside and outside surfaces of a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

   resistively heating the ferromagnetic conductor with the induced electrical current flow.

842. The method of claim 841, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.

843. The method of claim 841, wherein at least about 10 m of length of the ferromagnetic conductor resistively heats to the temperature of at least about 300 °C.

844. The method of claim 841, wherein the ferromagnetic conductor comprises carbon steel.
845. The method of claim 841, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

846. The method of claim 841, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

847. The method of claim 841, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.

848. The method of claim 841, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.

849. The method of claim 841, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

850. The method of claim 841, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

851. The method of claim 841, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.

852. A heating system for a subsurface formation, comprising:

   an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and

   a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

   wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats; and

   wherein the ferromagnetic conductor is configured to have little or no induced current flow at temperatures at and above a selected temperature.

853. The system of claim 852, wherein the electrical conductor comprises a substantially u-shaped electrical conductor.
854. The system of claim 852, wherein the ferromagnetic conductor comprises a turndown ratio of at least about 5.

855. The system of claim 852, wherein the selected temperature is the Curie temperature of at least one ferromagnetic material in the ferromagnetic conductor.

856. The system of claim 852, wherein the selected temperature is the phase transformation temperature of at least one ferromagnetic material in the ferromagnetic conductor.

857. The system of claim 852, wherein the ferromagnetic conductor is configured to have induced current flow when the ferromagnetic conductor is at temperatures below the selected temperature.

858. The system of claim 852, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

859. The system of claim 852, wherein the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

860. The system of claim 852, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

861. The system of claim 852, wherein the ferromagnetic conductor comprises carbon steel.

862. The system of claim 852, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

863. The system of claim 852, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

864. The system of claim 852, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

865. The system of claim 852, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

866. The system of claim 852, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

867. The system of claim 852, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

868. A method for heating a subsurface formation, comprising:

   providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;
inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and resistively heating the ferromagnetic conductor with the induced electrical current flow, wherein the ferromagnetic conductor has little or no resistive heating at temperatures at and above a selected temperature.

869. The method of claim 868, wherein little or no electrical current flow is induced in the ferromagnetic conductor at temperatures at and above the selected temperature.

870. The method of claim 868, wherein the ferromagnetic conductor comprises a turndown ratio of at least about 5.

871. The method of claim 868, wherein the selected temperature is the Curie temperature of at least one ferromagnetic material in the ferromagnetic conductor.

872. The method of claim 868, wherein the selected temperature is the phase transformation temperature of at least one ferromagnetic material in the ferromagnetic conductor.

873. The method of claim 868, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.

874. The method of claim 868, wherein at least about 10 m of length of the ferromagnetic conductor resistively heats to the temperature of at least about 300 °C.

875. The method of claim 868, wherein the ferromagnetic conductor comprises carbon steel.

876. The method of claim 868, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

877. The method of claim 868, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

878. The method of claim 868, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.

879. The method of claim 868, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.

880. The method of claim 868, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

881. The method of claim 868, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons
in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

882. The method of claim 868, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superimposed in the formation and mobilizes hydrocarbons in the formation.

883. A system for heating a hydrocarbon containing formation, comprising:

a first elongated electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least two electrical contacts; and

a first ferromagnetic conductor, wherein the first ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the first electrical conductor;

wherein the first electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the first ferromagnetic conductor such that the first ferromagnetic conductor resistively heats;

a second elongated electrical conductor located in the subsurface formation, wherein the second electrical conductor extends between at least two electrical contacts; and

a second ferromagnetic conductor, wherein the second ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the second electrical conductor;

wherein the second electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the second ferromagnetic conductor such that the second ferromagnetic conductor resistively heats; and

wherein the first and second ferromagnetic conductors are configured to provide heat to the formation such that heat from the ferromagnetic conductors is superimposed in the formation.

884. The system of claim 883, wherein at least one of the ferromagnetic conductors is configured to resistively heat to a temperature of at least about 300 °C.

885. The system of claim 883, wherein at least one of the ferromagnetic conductors has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

886. The system of claim 883, wherein the ferromagnetic conductors and the electrical conductors are configured in relation to each other such that electrical current does not flow from the electrical conductors to the ferromagnetic conductors, or vice versa.
887. The system of claim 883, wherein at least one of the ferromagnetic conductors is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

888. The system of claim 883, wherein at least one of the electrical conductors is configured to flow electrical current in one direction from at least a first electrical contact to at least a second electrical contact.

889. The system of claim 883, wherein the first and second ferromagnetic conductors are configured to provide heat to the formation such that heat from the ferromagnetic conductors is superpositioned in the formation and hydrocarbons are mobilized in the formation between the ferromagnetic conductors.

890. A method for heating a hydrocarbon containing formation, comprising:
   providing time-varying electrical current to an elongated electrical conductor located in the formation;
   inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;
   resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats;
   allowing heat to transfer from the ferromagnetic conductor to at least a part of the formation; and
   mobilizing at least some hydrocarbons in the part of the formation.

891. The method of claim 890, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 300 °C.

892. The method of claim 890, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

893. The method of claim 890, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

894. The method of claim 890, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.

895. The method of claim 890, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.
896. The method of claim 890, wherein heat from the ferromagnetic conductor superpositions heat provided from at least one additional heater located in the formation.

897. The method of claim 890, wherein heat from the ferromagnetic conductor superpositions heat provided from at least one additional ferromagnetic conductor in the formation that resistively heats with induced electrical current flow.

898. A heating system for a subsurface formation, comprising:
   a first wellbore extending into the subsurface formation;
   a second wellbore extending into the subsurface formation; and
   three or more heaters extending between the first wellbore and the second wellbore, at least one heater comprising:
   an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and
   a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;
   wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

899. The system of claim 898, wherein each heater comprises:
   an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and
   a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;
   wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

900. The system of claim 898, wherein at least three of the heaters are located in separate wellbores extending between the first wellbore and the second wellbore.

901. The system of claim 898, wherein at least one of the heaters comprises a substantially u-shaped heater in the formation.

902. The system of claim 898, wherein ends of the three heaters in either the first or the second wellbore are electrically coupled to each other at or near the surface of the formation.

903. The system of claim 898, wherein the three heaters are electrically coupled to each other in a three-phase wye configuration.
904. The system of claim 898, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

905. The system of claim 898, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

906. The system of claim 898, wherein the ferromagnetic conductor comprises carbon steel.

907. The system of claim 898, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

908. The system of claim 898, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

909. The system of claim 898, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

910. The system of claim 898, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

911. The system of claim 898, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

912. The system of claim 898, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

913. A method for heating a subsurface formation, comprising:

- providing time-varying electrical current to three or more heaters extending between a first wellbore and a second wellbore, the first and second wellbores extending into the subsurface formation, wherein at least one of the heaters comprises an elongated electrical conductor and a ferromagnetic conductor at least partially surrounding and at least partially extending lengthwise around the electrical conductor;

- inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

- resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

914. The method of claim 913, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.

915. The method of claim 913, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 500 °C.
916. The method of claim 913, further comprising resistively heating at least about 10 m of the ferromagnetic conductor to the temperature of at least about 300 °C.
917. The method of claim 913, wherein the ferromagnetic conductor comprises carbon steel.
918. The method of claim 913, wherein the electrical conductor is the core of an insulated conductor.
919. The method of claim 913, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.
920. The method of claim 913, wherein the ferromagnetic conductor and the electrical conductor are electrically insulated from each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.
921. The method of claim 913, further comprising providing different heat outputs along the length of the ferromagnetic conductor.
922. The method of claim 913, further comprising applying the electrical current to the electrical conductor in one direction from the first wellbore to the second wellbore.
923. The method of claim 913, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.
924. The method of claim 913, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.
925. The method of claim 913, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.
926. A heating system for a subsurface formation, comprising:
   a first wellbore extending into the subsurface formation;
   a second wellbore extending into the subsurface formation;
   a third wellbore extending into the subsurface formation;
   a first heater located in the first wellbore, a second heater located in the second wellbore, and a third heater located in the third wellbore, at least one heater comprising:
      an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and
a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

927. The system of claim 926, wherein at least one of the wellbores comprises a substantially u-shaped wellbore in the formation.

928. The system of claim 926, wherein the first, second, and third wellbores are substantially parallel in the formation.

929. The system of claim 926, wherein the three heaters are electrically coupled to each other in a three-phase wye configuration.

930. The system of claim 926, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

931. The system of claim 926, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

932. The system of claim 926, wherein the ferromagnetic conductor comprises carbon steel.

933. The system of claim 926, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

934. The system of claim 926, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

935. The system of claim 926, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

936. The system of claim 926, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

937. The system of claim 926, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

938. The system of claim 926, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

939. A method for heating a subsurface formation, comprising:

providing time-varying electrical current to a first heater located in a first wellbore, a second heater located in a second wellbore, and a third heater located in a third wellbore, the first, second, and third wellbores extending into the subsurface formation, wherein at least one of
the heaters comprises an elongated electrical conductor and a ferromagnetic conductor at least partially surrounding and extending lengthwise around the electrical conductor;

inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

The method of claim 939, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.

The method of claim 939, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 500 °C.

The method of claim 939, further comprising resistively heating at least about 10 m of length of the ferromagnetic conductor to the temperature of at least about 300 °C.

The method of claim 939, wherein the ferromagnetic conductor comprises carbon steel.

The method of claim 939, wherein the electrical conductor is the core of an insulated conductor.

The method of claim 939, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

The method of claim 939, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

The method of claim 939, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.

The method of claim 939, further comprising applying the electrical current to the electrical conductor in one direction.

The method of claim 939, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

The method of claim 939, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

The method of claim 939, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic
conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.

952. A heating system for a subsurface formation, comprising:

an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;

an insulation layer at least partially surrounding the electrical conductor; and

a ferromagnetic sheath at least partially surrounding the insulation layer, the ferromagnetic sheath and the electrical conductor being configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic sheath, or vice versa;

wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic sheath such that the ferromagnetic sheath resistively heats.

953. The system of claim 952, wherein the ferromagnetic sheath is configured to provide heat to at least a portion of the subsurface formation.

954. The system of claim 952, wherein the electrical conductor is configured to induce electrical current flow on the inside and the outside surfaces of the ferromagnetic sheath.

955. The system of claim 952, wherein the electrical conductor, the insulation layer, and the ferromagnetic sheath are substantially physically contacting each other longitudinally.

956. The system of claim 952, wherein the electrical conductor, the insulation layer, and the ferromagnetic sheath comprise substantially u-shapes in the formation.

957. The system of claim 952, wherein the ferromagnetic sheath comprises carbon steel.

958. The system of claim 952, wherein the ferromagnetic sheath has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic sheath at 50 °C below the Curie temperature of the ferromagnetic material.

959. The system of claim 952, wherein the ferromagnetic sheath is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic sheath.

960. The system of claim 952, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic sheath.

961. The system of claim 952, further comprising an additional insulation layer at least partially surrounding the ferromagnetic sheath, and an additional ferromagnetic sheath substantially surrounding the additional insulation layer, wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the additional ferromagnetic sheath such that the additional ferromagnetic sheath resistively heats.
962. The system of claim 952, wherein the ferromagnetic sheath and the electrical conductor are electrically insulated from each other.

963. A method for heating a subsurface formation, comprising:
  providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;
  inducing electrical current flow in a ferromagnetic sheath with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic sheath at least partially surrounds an insulation layer that at least partially surrounds the electrical conductor, the ferromagnetic sheath and the electrical conductor being configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic sheath, or vice versa; and
  resistively heating the ferromagnetic sheath with the induced electrical current flow such that the ferromagnetic sheath resistively heats.

964. The method of claim 963, further comprising allowing heat to transfer from the ferromagnetic sheath to at least a portion of the subsurface formation.

965. The method of claim 963, further comprising resistively heating at least about 10 m of length of the ferromagnetic sheath to a temperature of at least about 300 °C.

966. The method of claim 963, wherein the ferromagnetic sheath comprises carbon steel.

967. The method of claim 963, wherein the ferromagnetic sheath has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

968. The method of claim 963, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic sheath.

969. The method of claim 963, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.

970. The method of claim 963, further comprising allowing heat to transfer from the ferromagnetic sheath to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

971. The method of claim 963, further comprising allowing heat to transfer from the ferromagnetic sheath to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

972. The method of claim 963, further comprising resistively heating at least one additional ferromagnetic sheath located in the formation, and providing heat from the ferromagnetic sheaths
such that heat from at least two of the ferromagnetic sheaths is superpositioned in the formation and mobilizes hydrocarbons in the formation.

973. A heating system for a subsurface formation, comprising:

- a first electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least a first electrical contact and a second electrical contact;
- a first insulation layer at least partially surrounding the first electrical conductor;
- a first ferromagnetic sheath at least partially surrounding the first insulation layer, the first ferromagnetic sheath and the first electrical conductor being configured in relation to each other such that electrical current does not flow from the first electrical conductor to the first ferromagnetic sheath, or vice versa;
- a second electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least the first electrical contact and the second electrical contact;
- a second insulation layer at least partially surrounding the second electrical conductor;
- a second ferromagnetic sheath at least partially surrounding the second insulation layer, the second ferromagnetic sheath and the second electrical conductor being configured in relation to each other such that electrical current does not flow from the second electrical conductor to the second ferromagnetic sheath, or vice versa; and
- a third insulation layer located between the first ferromagnetic sheath and the second ferromagnetic sheath;

wherein the first and second electrical conductors, when energized with time-varying electrical current, induce sufficient electrical current flow in the first and second ferromagnetic sheaths, respectively, such that the ferromagnetic sheaths resistively heat.

974. The system of claim 973, wherein the first and second electrical conductors are configured to be coupled to the same power source.

975. The system of claim 973, wherein the first and second electrical conductors are configured to conduct current in opposite directions.

976. The system of claim 973, wherein the third insulation layer is sandwiched between first ferromagnetic sheath and the second ferromagnetic sheath.

977. The system of claim 973, wherein the third insulation layer comprises a corrosion resistant material.

978. The system of claim 973, wherein at least one of the ferromagnetic sheaths is configured to provide heat to at least a portion of the subsurface formation.
979. The system of claim 973, wherein at least one of the electrical conductors is configured to induce electrical current flow on the inside and the outside surfaces of at least one of the ferromagnetic sheaths.

980. The system of claim 973, wherein the electrical conductors, the insulation layers, and the ferromagnetic sheaths are substantially physically contacting each other longitudinally.

981. The system of claim 973, wherein the electrical conductors, the insulation layers, and the ferromagnetic sheaths comprise substantially U-shapes in the formation.

982. The system of claim 973, wherein at least one of the ferromagnetic sheaths comprises carbon steel.

983. The system of claim 973, wherein at least one of the ferromagnetic sheaths has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic sheath at 50 °C below the Curie temperature of the ferromagnetic material.

984. The system of claim 973, wherein at least one of the ferromagnetic sheaths is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic sheath.

985. A method for heating a subsurface formation, comprising:

- providing time-varying electrical current to a first elongated electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least a first electrical contact and a second electrical contact;

- inducing electrical current flow in a first ferromagnetic sheath with the time-varying electrical current in the first electrical conductor, wherein the first ferromagnetic sheath at least partially surrounds a first insulation layer that at least partially surrounds the first electrical conductor, the first ferromagnetic sheath and the first electrical conductor being configured in relation to each other such that electrical current does not flow from the first electrical conductor to the first ferromagnetic sheath, or vice versa;

- resistively heating the first ferromagnetic sheath with the induced electrical current flow such that the first ferromagnetic sheath resistively heats;

- providing time-varying electrical current to a second elongated electrical conductor located in the subsurface formation, wherein the second electrical conductor extends between at least the first electrical contact and the second electrical contact;

- inducing electrical current flow in a second ferromagnetic sheath with the time-varying electrical current in the second electrical conductor, wherein the second ferromagnetic sheath at least partially surrounds a second insulation layer that at least partially surrounds the second electrical conductor, the second ferromagnetic sheath and the second electrical conductor being configured in relation to each other such that electrical current does not flow from the second electrical conductor to the second ferromagnetic sheath, or vice versa; and
resistively heating the second ferromagnetic sheath with the induced electrical current flow such that the second ferromagnetic sheath resistively heats;

wherein a third insulation layer is located between the first ferromagnetic sheath and the second ferromagnetic sheath.

986. The method of claim 985, further comprising providing time-varying current to the first and second electrical conductors from the same power source.

987. The method of claim 985, further comprising providing time-varying current to the first and second electrical conductors in opposite directions.

988. The method of claim 985, further comprising allowing heat to transfer from at least one of the ferromagnetic sheaths to at least a portion of the subsurface formation.

989. The method of claim 985, further comprising resistively heating at least about 10 m of length of at least one of the ferromagnetic sheaths to a temperature of at least about 300 °C.

990. The method of claim 985, wherein at least one of the ferromagnetic sheaths comprises carbon steel.

991. The method of claim 985, wherein at least one of the ferromagnetic sheaths has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

992. The method of claim 985, further comprising providing different heat outputs along at least a portion of the length of at least one of the ferromagnetic sheaths.

993. The method of claim 985, further comprising allowing heat to transfer from the ferromagnetic sheaths to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

994. The method of claim 985, further comprising allowing heat to transfer from the ferromagnetic sheaths to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

995. The method of claim 985, further comprising resistively heating at least two additional ferromagnetic sheaths located in the formation, and providing heat from the ferromagnetic sheaths such that heat from at least four of the ferromagnetic sheaths is superpositioned in the formation and mobilizes hydrocarbons in the formation.

996. A heating system for a subsurface formation, comprising:

an electrical conductor extending into the subsurface formation; and

a ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of an overburden section of the formation, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not
flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor comprises a plurality of straight, angled, or longitudinally spiral grooves or protrusions that increase the effective circumference of the ferromagnetic conduit;

wherein the straight, angled, or longitudinally spiral grooves or protrusions are configured to inhibit or reduce induction resistance heating in the ferromagnetic conductor.

997. The system of claim 996, wherein the grooves or protrusions extend substantially axially along the length of the ferromagnetic conductor.

998. The system of claim 996, wherein the grooves or protrusions increase the effective circumference of the ferromagnetic conductor at least about 2 times over the effective circumference of a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

999. The system of claim 996, wherein the grooves or protrusions reduce the induced electrical current flow in the ferromagnetic conductor as compared to a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1000. The system of claim 996, wherein the grooves or protrusions inhibit induced electrical current flow in the ferromagnetic conductor.

1001. The system of claim 996, wherein the grooves or protrusions are configured to reduce the effective resistance of the ferromagnetic conductor.

1002. The system of claim 996, wherein the grooves or protrusions comprise spiral grooves with a significant longitudinal component.

1003. The system of claim 996, wherein the grooves or protrusions are on the inside surface of the ferromagnetic conductor.

1004. The system of claim 996, wherein the grooves or protrusions are on the outside surface of the ferromagnetic conductor.

1005. The system of claim 996, wherein the grooves or protrusions are on both the inside and outside surfaces of the ferromagnetic conductor.

1006. The system of claim 996, wherein the electrical conductor is configured to provide current to an electric resistance heating system in the formation.

1007. The system of claim 996, further comprising a second ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of the subsurface formation, wherein the second ferromagnetic conductor is configured to provide heat to at least the portion of the subsurface formation when the second ferromagnetic conductor is either energized with time-varying electrical current or electrical current is induced in the second ferromagnetic conductor by the flow of time-varying electrical current in the electrical conductor.
1008. The system of claim 996, wherein the electrical conductor comprises a substantially u-shaped electrical conductor extending between a first wellbore and a second wellbore in the formation.

1009. The system of claim 996, wherein the ferromagnetic conductor comprises carbon steel.

1010. The system of claim 996, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.

1011. A method for providing current to an electrical resistance heater in a subsurface formation while inhibiting heating in an overburden section of the subsurface formation, comprising:

   providing time-varying electrical current to an electrical conductor extending through the overburden section of the formation into the subsurface formation; and

   inducing electrical current flow in a ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of the overburden section, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor comprises a plurality of straight, angled, or longitudinally spiral grooves or protrusions that increase the effective circumference of the ferromagnetic conduit.

1012. The method of claim 1011, wherein the grooves or protrusions increase the effective circumference of the ferromagnetic conductor at least about 2 times over the effective circumference of a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1013. The method of claim 1011, wherein the grooves or protrusions reduce the induced electrical current flow in the ferromagnetic conductor as compared to a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1014. The method of claim 1011, further comprising inhibiting induced electrical current flow in the ferromagnetic conductor with the grooves or protrusions.

1015. The method of claim 1011, wherein the grooves or protrusions comprise spiral grooves with a significant longitudinal component.

1016. The method of claim 1011, wherein the grooves or protrusions are on the inside surface of the ferromagnetic conductor.

1017. The method of claim 1011, wherein the grooves or protrusions are on the outside surface of the ferromagnetic conductor.

1018. The method of claim 1011, wherein the grooves or protrusions are on both the inside and outside surfaces of the ferromagnetic conductor.
1019. The method of claim 1011, further comprising providing current to an electric resistance heating system in the formation with the electrical conductor.

1020. The method of claim 1011, further comprising providing heat to at least a portion of the subsurface formation by applying the time-varying electrical current to a second ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of the formation.

1021. The method of claim 1011, further comprising providing heat to at least a portion of the subsurface formation by inducing electrical current flow in a second ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of the formation.

1022. The method of claim 1011, wherein the electrical conductor comprises a substantially u-shaped electrical conductor extending between a first wellbore and a second wellbore in the formation.

1023. The method of claim 1011, wherein the ferromagnetic conductor comprises carbon steel.

1024. The method of claim 1011, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.

1025. A heating system for a subsurface formation, comprising:

- a ferromagnetic conductor extending into the subsurface formation, wherein the ferromagnetic conductor is configured to resistively heat when electrical current is applied to, or induced in, the ferromagnetic conductor; and

- a plurality of straight, angled, or spiral grooves or protrusions located on at least one surface of the ferromagnetic conductor, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conduit.

1026. The system of claim 1025, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conductor by increasing the path length for the electrical current flow on the surface of the ferromagnetic conductor.

1027. The system of claim 1025, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conductor over the effective resistance of a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1028. The system of claim 1025, wherein the grooves or protrusions are positioned substantially radially on the ferromagnetic conductor.

1029. The system of claim 1025, wherein the grooves or protrusions are on the inside surface of the ferromagnetic conductor.

1030. The system of claim 1025, wherein grooves or protrusions are on the outside surface of the ferromagnetic conductor.
1031. The system of claim 1025, wherein the grooves or protrusions are on both the inside and outside surfaces of the ferromagnetic conductor.

1032. The system of claim 1025, wherein the ferromagnetic conductor is configured such that a majority of the resistive heat is generated in a skin depth of the ferromagnetic conductor at temperatures below the Curie temperature of the ferromagnetic conductor.

1033. The system of claim 1025, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the layer to be heated in the subsurface formation.

1034. The system of claim 1025, wherein the ferromagnetic conductor comprises carbon steel.

1035. The system of claim 1025, wherein the ferromagnetic conductor has a thickness of at least 2 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1036. The system of claim 1025, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.

1037. The system of claim 1025, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

1038. The system of claim 1025, further comprising an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor, and wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats.

1039. A method for heating a subsurface formation, comprising:

applying, or inducing, electrical current in a ferromagnetic conductor extending into the subsurface formation;

resistively heating the ferromagnetic conductor with the electrical current, wherein the ferromagnetic conductor comprises a plurality of straight, angled, or spiral grooves or protrusions located on at least one surface of the ferromagnetic conductor that increase the effective resistance of the ferromagnetic conduit; and

allowing heat to transfer from the ferromagnetic conductor to at least a part of the formation.

1040. The method of claim 1039, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 300 °C.

1041. The method of claim 1039, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.
1042. The method of claim 1039, wherein heat from the ferromagnetic conductor superpositions heat provided from at least one additional heater located in the formation.

1043. The method of claim 1039, wherein heat from the ferromagnetic conductor superpositions heat provided from at least one additional ferromagnetic conductor in the formation that resistively heats with electrical current flow.

1044. The method of claim 1039, further comprising mobilizing at least some hydrocarbons in the part of the formation.

1045. The method of claim 1039, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conductor by increasing the path length for the electrical current flow on the surface of the ferromagnetic conductor.

1046. The method of claim 1039, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conductor over the effective resistance of a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1047. The method of claim 1039, wherein the grooves or protrusions are positioned substantially radially on the ferromagnetic conductor.

1048. The method of claim 1039, wherein the grooves or protrusions are on the inside surface of the ferromagnetic conductor.

1049. The method of claim 1039, wherein grooves or protrusions are on the outside surface of the ferromagnetic conductor.

1050. The method of claim 1039, wherein the grooves or protrusions are on both the inside and outside surfaces of the ferromagnetic conductor.

1051. A variable voltage transformer, comprising:

   a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;

   a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;

   a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage; and

   wherein an electrical load is configured to be coupled to the multistep load tap changer to provide electrical power to the load with a selected voltage, the multistep load tap changer being configured to tap a selected voltage step in order to provide the selected voltage to the electrical load.
1052. The transformer of claim 1051, wherein the selected maximum percentage of the second voltage is 100%.

1053. The transformer of claim 1051, wherein the multistep load tap changer comprises a sliding tap that is configured to slide between voltage steps to tap the selected voltage step that provides the selected voltage to the electrical load.

1054. The transformer of claim 1051, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load.

1055. The transformer of claim 1051, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load in response to a change in the electrical load.

1056. The transformer of claim 1051, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load in response to a change in the electrical load so that the electrical load is provided with relatively constant current.

1057. The transformer of claim 1051, wherein the transformer is coupled to a control system configured to control the multistep load tap changer so that the multistep load tap changer switches the selected voltage step in response to a change in the electrical load.

1058. The transformer of claim 1051, further comprising a voltage measurement transformer coupled to the secondary winding, wherein the voltage measurement transformer is configured to assess the selected voltage provided to the electrical load.

1059. The transformer of claim 1051, further comprising a switch coupled to the secondary winding, wherein the switch is configured to electrically isolate the electrical load from the transformer when the switch is open.

1060. The transformer of claim 1051, further comprising a control power transformer coupled to the secondary winding, wherein the control power transformer is used to provide power to one or more controllers configured to operate the transformer.

1061. The transformer of claim 1051, further comprising a current transformer coupled to the secondary winding, wherein the current transformer is configured to assess electrical current passing through the secondary winding.

1062. The transformer of claim 1051, wherein the voltage steps comprise equally partitioned voltage steps.

1063. The transformer of claim 1051, wherein the voltage steps comprise non-equitably partitioned voltage steps.

1064. The transformer of claim 1051, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.
1065. The transformer of claim 1051, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1066. The transformer of claim 1051, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1067. The transformer of claim 1051, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.

1068. The transformer of claim 1051, wherein the transformer is configured to be mounted on a pole, a concrete pad, or part of a skid mounted assembly.

1069. The transformer of claim 1051, wherein the electrical load comprises a subsurface heater.

1070. The transformer of claim 1051, wherein the electrical load comprises a temperature limited heater.

1071. The transformer of claim 1051, wherein the electrical load comprises an insulated conductor heater.

1072. The transformer of claim 1051, wherein the electrical load comprises a conductor-in-conduit heater.

1073. A variable voltage transformer system for providing power to a three-phase electrical load, comprising:

   a first variable voltage transformer coupled to a first leg of three-phase electrical load; 
   a second variable voltage transformer coupled to a second leg of three-phase electrical load; 
   a third variable voltage transformer coupled to a third leg of three-phase electrical load; 
   wherein each of the first, second, and third variable voltage transformers comprise:

   a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding; 
   a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage; 
   a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage; and 

   wherein the corresponding leg of the three-phase electrical load is configured to be coupled to the multistep load tap changer to provide electrical power to the load with a selected voltage, the multistep load tap changer being configured to tap a selected voltage step in order to provide the selected voltage to the corresponding leg.
1074. The system of claim 1073, wherein the selected maximum percentage of the second voltage is 100%.

1075. The system of claim 1073, wherein the first, second, and third variable voltage transformers are coupled to a control system configured to keep the three legs of the three-phase electrical load in phase.

1076. The system of claim 1073, wherein the three legs of the three-phase electrical load are electrically coupled in a wye or delta configuration.

1077. The system of claim 1073, wherein the multistep load tap changer comprises a sliding tap that is configured to slide between voltage steps to tap the selected voltage step that provides the selected voltage to the corresponding leg.

1078. The system of claim 1073, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the corresponding leg.

1079. The system of claim 1073, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the corresponding leg in response to a change in the electrical load.

1080. The system of claim 1073, wherein the control system is configured to control the multistep load tap changers so that the multistep load tap changers switch the selected voltage steps in response to a change in the electrical load.

1081. The system of claim 1073, further comprising voltage measurement transformers coupled to the secondary windings, wherein the voltage measurement transformers are configured to assess the selected voltages provided to the corresponding legs.

1082. The system of claim 1073, further comprising switches coupled to the secondary windings, wherein the switches are configured to electrically isolate the electrical load from the transformers when the switches are open.

1083. The system of claim 1073, further comprising control power transformers coupled to the secondary windings, wherein the control power transformers are configured to provide power to one or more controllers operating the transformers.

1084. The system of claim 1073, further comprising current transformers coupled to the secondary windings, wherein the current transformers are configured to assess electrical current passing through the secondary windings.

1085. The system of claim 1073, wherein the voltage steps comprise equally partitioned voltage steps.

1086. The system of claim 1073, wherein the voltage steps comprise non-equally partitioned voltage steps.
1087. The system of claim 1073, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.

1088. The system of claim 1073, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1089. The system of claim 1073, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1090. The system of claim 1073, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.

1091. The system of claim 1073, wherein the transformers are configured to be mounted on a pole, a concrete pad, or part of a skid mounted assembly.

1092. The system of claim 1073, wherein the electrical load comprises a subsurface heater.

1093. The system of claim 1073, wherein the electrical load comprises a temperature limited heater.

1094. A variable voltage subsurface heating system, comprising:

   a voltage power source that provides a first voltage;

   a subsurface electrical load;

   a variable voltage transformer electrically coupled to the electrical load, the transformer comprising:

       a primary winding coupled to the voltage power source such that the first voltage is provided across the primary winding;

       a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;

       a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage; and

       wherein the electrical load is coupled to the multistep load tap changer to provide electrical power to the load with a selected voltage, the multistep load tap changer being configured to tap a selected voltage step in order to provide the selected voltage to the electrical load.

1095. The system of claim 1094, wherein the selected maximum percentage of the second voltage is 100%.
1096. The system of claim 1094, wherein the multistep load tap changer comprises a sliding tap that is configured to slide between voltage steps to tap the selected voltage step that provides the selected voltage to the electrical load.

1097. The system of claim 1094, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load.

1098. The system of claim 1094, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load in response to a change in the electrical load.

1099. The system of claim 1094, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load in response to a change in the electrical load so that the electrical load is provided with relatively constant current.

1100. The system of claim 1094, further comprising a control system coupled to the transformer and the electrical load, the control system being configured to control the multistep load tap changer so that the multistep load tap changer switches the selected voltage step in response to a change in the electrical load.

1101. The system of claim 1100, further comprising an optical fiber coupled to the electrical load and the control system, wherein the optical fiber is configured to provide data from the electrical load to the control system.

1102. The system of claim 1094, further comprising a voltage measurement transformer coupled to the secondary winding, wherein the voltage measurement transformer is configured to assess the selected voltage provided to the electrical load.

1103. The system of claim 1094, further comprising a switch coupled to the secondary winding, wherein the switch is configured to electrically isolate the electrical load from the transformer when the switch is open.

1104. The system of claim 1094, further comprising a control power transformer coupled to the secondary winding, wherein the control power transformer is configured to provide power to one or more controllers used for operating the transformer.

1105. The system of claim 1094, further comprising a current transformer coupled to the secondary winding, wherein the current transformer is configured to assess electrical current passing through the secondary winding.

1106. The system of claim 1094, wherein the voltage steps comprise equally partitioned voltage steps.

1107. The system of claim 1094, wherein the voltage steps comprise non-equispaced partitioned voltage steps.
1108. The system of claim 1094, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.

1109. The system of claim 1094, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1110. The system of claim 1094, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1111. The system of claim 1094, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.

1112. The system of claim 1094, wherein the transformer is configured to be mounted on a pole, a concrete pad, or part of a skid mounted assembly.

1113. The system of claim 1094, wherein the electrical load comprises a heater.

1114. The system of claim 1094, wherein the electrical load comprises a temperature limited heater.

1115. The system of claim 1094, wherein the electrical load comprises an insulated conductor heater.

1116. The system of claim 1094, wherein the electrical load comprises a conductor-in-conduit heater.

1117. A method for controlling voltage provided to an electrical heater, comprising:

    providing electrical power to the heater with a selected voltage using a variable voltage transformer, wherein the variable voltage transformer comprises:

    a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;

    a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;

    a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the selected voltage to the heater;

    assessing an electrical resistance of the heater over a selected period of time and assessing if there is a change in the electrical resistance of the heater over the selected period of time; and

    adjusting the selected voltage provided to the heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the selected voltage is changed in response to the change in the electrical resistance of the heater.
1118. The method of claim 1117, wherein the selected maximum percentage of the second voltage is 100%.

1119. The method of claim 1117, wherein the selected voltage is changed in response to the change in the electrical resistance of the heater such that the electrical current provided to the heater is relatively constant.

1120. The method of claim 1117, further comprising cycling the selected voltage provided to the heater so that the electrical current provided to the heater remains relatively constant.

1121. The method of claim 1117, further comprising assessing the electrical resistance of the heater by using a current transformer coupled to the secondary winding and a voltage transformer coupled to the secondary winding, wherein the electrical resistance is calculated by dividing a voltage assessed from the voltage transformer by a current assessed from the current transformer.

1122. The method of claim 1117, further comprising assessing the electrical resistance of the heater using an optical fiber coupled to the heater.

1123. The method of claim 1117, further comprising comparing the assessed electrical resistance of the heater to a theoretical electrical resistance of the heater and changing the selected voltage provided to the heater if there is a difference between the assessed and the theoretical resistances.

1124. The method of claim 1117, further comprising limiting a number of changes in the selected voltage over a period of time.

1125. The method of claim 1117, wherein the voltage steps comprise equally partitioned voltage steps.

1126. The method of claim 1117, wherein the voltage steps comprise non-equally partitioned voltage steps.

1127. The method of claim 1117, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.

1128. The method of claim 1117, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1129. The method of claim 1117, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1130. The method of claim 1117, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.

1131. The method of claim 1117, wherein the transformer is mounted on a pole, a concrete pad, or part of a skid mounted assembly.

1132. The method of claim 1117, wherein the electrical heater comprises ferromagnetic material.
1133. The method of claim 1117, wherein the electrical heater comprises a subsurface heater.
1134. The method of claim 1117, wherein the electrical heater comprises a temperature limited heater.
1135. The method of claim 1117, wherein the electrical heater comprises an insulated conductor heater.
1136. The method of claim 1117, wherein the electrical heater comprises a conductor-in-conduit heater.
1137. A method for controlling voltage provided to a subsurface electrical heater in a wellbore, comprising:
   providing electrical power to the heater with a first selected voltage using a variable voltage transformer, wherein the first selected voltage inhibits arcing in the wellbore, and wherein the variable voltage transformer comprises:
   a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;
   a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;
   a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the first selected voltage to the heater;
   assessing an electrical resistance of the heater;
   providing electrical power at the first selected voltage until the electrical resistance of the heater reaches a selected value;
   incrementally increasing the selected voltage provided to the heater to a second selected voltage after the electrical resistance of the heater reaches the selected value;
   assessing the electrical resistance of the heater over a selected period of time, and assessing if there is a change in the electrical resistance of the heater at the second selected voltage over the selected period of time; and
   adjusting the second selected voltage provided to the heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the second selected voltage is changed in response to the change in the electrical resistance of the heater.
1138. The method of claim 1137, wherein the selected maximum percentage of the second voltage is 100%.
1139. The method of claim 1137, wherein the second selected voltage is changed in response to the change in the electrical resistance of the heater such that the electrical current provided to the heater is relatively constant.

1140. The method of claim 1137, further comprising incrementally decreasing the selected voltage provided to the heater from the second selected voltage to zero voltage after a selected time period.

1141. The method of claim 1137, further comprising incrementally decreasing the selected voltage provided to the heater from the second selected voltage to zero voltage after the assessed electrical resistance reaches a second selected value.

1142. The method of claim 1137, further comprising cycling the second selected voltage provided to the heater so that the electrical current provided to the heater remains relatively constant.

1143. The method of claim 1137, further comprising assessing the electrical resistance of the heater by using a current transformer coupled to the secondary winding and a voltage transformer coupled to the secondary winding, wherein the electrical resistance is calculated by dividing a voltage assessed from the voltage transformer by a current assessed from the current transformer.

1144. The method of claim 1137, further comprising comparing the assessed electrical resistance of the heater to a theoretical electrical resistance of the heater and changing the second selected voltage provided to the heater if there is a difference between the assessed and the theoretical resistances.

1145. The method of claim 1137, wherein the voltage steps comprise equally partitioned voltage steps.

1146. The method of claim 1137, wherein the voltage steps comprise non-equally partitioned voltage steps.

1147. The method of claim 1137, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.

1148. The method of claim 1137, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1149. The method of claim 1137, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1150. The method of claim 1137, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.

1151. The method of claim 1137, wherein the transformer is mounted on a pole, a concrete pad, or part of a skid mounted assembly.
1152. The method of claim 1137, wherein the electrical heater comprises ferromagnetic material.

1153. The method of claim 1137, wherein the electrical heater comprises a temperature limited heater.

1154. The method of claim 1137, wherein the electrical heater comprises an insulated conductor heater.

1155. The method of claim 1137, wherein the electrical heater comprises a conductor-in-conduit heater.

1156. A method for controlling voltage provided to an electrical heater, comprising:

   providing electrical power to the heater with a selected voltage using a variable voltage transformer, wherein the variable voltage transformer comprises:

   a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;

   a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;

   a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the first selected voltage to the heater; assessing an electrical resistance of the heater at the selected voltage; and

   cycling the selected voltage provided to the heater by switching the selected voltage step tapped by the multistep load tap changer between at least two voltage steps such that the selected voltage is cycled between at least two voltages after a selected amount of time at each of the at least two voltages.

1157. The method of claim 1156, wherein the selected maximum percentage of the second voltage is 100%.

1158. The method of claim 1156, wherein the selected voltage is cycled between at least two voltages after the selected amount of time at each of the at least two voltages such that the heater is provided with an average voltage between the at least two voltages.

1159. The method of claim 1156, further comprising adjusting the selected voltage provided to the heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the selected voltage is changed in response to the change in the electrical resistance of the heater so that the electrical current provided to the heater is relatively constant.
1160. The method of claim 1156, further comprising determining the selected amount of time at a selected voltage based on the assessed resistance at the selected voltage.
1161. The method of claim 1156, further comprising adjusting the selected amounts of time at each of the least two voltages so that the average voltage is at a selected value.
1162. The method of claim 1161, further comprising basing the selected amounts of time at each of the least two voltages on the assessed resistances at the at least two voltages.
1163. The method of claim 1156, further comprising assessing the electrical resistance of the heater by using a current transformer coupled to the secondary winding and a voltage transformer coupled to the secondary winding, wherein the electrical resistance is calculated by dividing a voltage assessed from the voltage transformer by a current assessed from the current transformer.
1164. The method of claim 1156, further comprising limiting a number of changes in the selected voltage over a period of time.
1165. The method of claim 1156, wherein the voltage steps comprise equally partitioned voltage steps.
1166. The method of claim 1156, wherein the voltage steps comprise non-equally partitioned voltage steps.
1167. The method of claim 1156, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.
1168. The method of claim 1156, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.
1169. The method of claim 1156, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.
1170. The method of claim 1156, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.
1171. The method of claim 1156, wherein the transformer is mounted on a pole, a concrete pad, or part of a skid mounted assembly.
1172. The method of claim 1156, wherein the electrical heater comprises ferromagnetic material.
1173. The method of claim 1156, wherein the electrical heater comprises a subsurface heater.
1174. The method of claim 1156, wherein the electrical heater comprises a temperature limited heater.
1175. The method of claim 1156, wherein the electrical heater comprises an insulated conductor heater.
1176. The method of claim 1156, wherein the electrical heater comprises a conductor-in-conduit heater.
1177. A system for forming a subsurface wellbore, comprising:
   a drilling string configured to rotate at a first speed;
   a drill bit on an end of the drilling string, the drill being configured to form the wellbore;
   a first motor located on the drilling string configured to rotate the drill bit in a same
direction as the drilling string; and
   a second motor located near the end of the drilling string, the second motor being
configured to rotate a portion of the drilling string between the first motor and the second motor
in an opposite direction of the first motor.
1178. A system for forming a subsurface wellbore, comprising:
   a drilling string;
   a drill bit on an end of the drilling string, the drill being configured to form the wellbore;
   a first motor located on the drilling string configured to rotate the drill bit in a same
direction as the drilling string; and
   a non-rotating sensor located on the drilling string.
1179. A system for treating a subsurface hydrocarbon containing formation, comprising:
   one or more tunnels having an average diameter of at least 1 m, at least one tunnel being
connected to the surface; and
   two or more wellbores extending from the tunnel into at least a portion of the subsurface
hydrocarbon containing formation, at least two of the wellbores containing elongated heaters
configured to heat at least a portion of the subsurface hydrocarbon containing formation such that
at least some hydrocarbons are mobilized.
1180. The system of claim 1179, further comprising at least one shaft connecting at least one
tunnel to the surface.
1181. The system of claim 1179, further comprising at least one shaft connecting at least one
tunnel to the surface, wherein at least one shaft is substantially vertically oriented.
1182. The system of claim 1179, further comprising a production well located such that
mobilized fluids from the formation drain into the production well.
1183. The system of claim 1179, further comprising at least one steam injection wellbore
extending from at least one tunnel, the steam injection wellbore being connected to one or more
sources of steam, and at least one of the steam injection wellbores being configured to provide
steam to the subsurface hydrocarbon containing formation.
1184. The system of claim 1179, wherein at least one of the tunnels has an average diameter of
at least 2 m.
1185. The system of claim 1179, wherein the cross-sectional shape of at least one tunnel is
circular, oval, orthogonal, or irregular shaped.
1186. The system of claim 1179, wherein at least one of the heaters is an electric resistance heater, and a source of power is provided to the electric resistance heater from a conductor in at least one tunnel.

1187. The system of claim 1179, wherein at least one of the heaters is a gas burner, and a conduit carrying fuel gas for the gas burner is in at least one tunnel.

1188. The system of claim 1179, wherein at least one of the tunnels is substantially horizontal, and at least two of the wellbores extend at an angle from the tunnel.

1189. A method of treating a subsurface hydrocarbon containing formation, comprising:

   providing heat to the subsurface hydrocarbon containing formation to mobilize at least some of the hydrocarbons in the formation, the heat being provided from two or more elongated heaters in two or more wellbores extending from one or more tunnels having an average diameter of at least 1 m, at least one tunnel being connected to the surface; and

   providing heat to the subsurface hydrocarbon containing formation to mobilize at least some of the hydrocarbons in the formation, the heat being provided from two or more elongated heaters in two or more wellbores extending from one or more tunnels having an average diameter of at least 1 m, at least one tunnel being connected to the surface.

1190. A system for treating a subsurface hydrocarbon containing formation, comprising:

   one or more substantially horizontal or inclined tunnels extending from at least one shaft; and

   one or more heater sources located in one or more heater wellbores coupled to at least one of the substantially horizontal or inclined tunnels.

1191. The system of claim 1190, further comprising one or more power supplies coupled to one or more heat sources and at least one of the, at least one of the power supplies being configured to provide power to at least one of the heat sources.

1192. The system of claim 1190, further comprising one or more production wells coupled to one or more of the tunnels.

1193. The system of claim 1190, further comprising one or more impermeable barriers in the tunnels configured to seal the tunnels from formation fluids.

1194. A method for treating a subsurface hydrocarbon containing formation, comprising:

   providing one or more shafts;

   providing one or more substantially horizontal or inclined tunnels extending from at least one of the shafts;

   providing one or more wellbores from at least one of the tunnels; and

   providing one or more heat sources to at least one of the wellbores.
1195. The method of claim 1194, further comprising providing heat from at least one of the heat sources to at least a portion of a subsurface hydrocarbon containing formation to mobilize at least some hydrocarbons in the formation.

1196. The method of claim 1194, further comprising providing heat from at least one of the heat sources to at least a portion of a subsurface hydrocarbon containing formation, and producing formation fluids from the portion.

1197. The method of claim 1194, wherein at least one of the wellbores is a production wellbore.

1198. The method of claim 1194, further comprising providing one or more impermeable barriers to seal the tunnels from formation fluids.

1199. The method of claim 1194, further comprising sealing the shafts from the tunnels, after providing the heat sources, to inhibit fluids from flowing between the shafts and tunnels.

1200. The method of claim 1194, further comprising at least partially isolating heating sections of the heat sources from the tunnels such that fluids are inhibited from flowing between the heating sections and the tunnels.

1201. A system for treating a subsurface hydrocarbon containing formation, comprising:

one or more shafts;

at least two substantially horizontal or inclined tunnels extending from one or more of the shafts; and

a plurality of heaters located in at least one heater wellbore extending between at least two of the substantially horizontal tunnels, wherein electrical connections for the heat sources are located in at least one of the substantially horizontal tunnels.

1202. The system of claim 1201, wherein the heaters are connected to a bus bar with the electrical connections.

1203. The system of claim 1201, wherein the heater wellbore is directionally drilled between at least two of the substantially horizontal tunnels.

1204. A method for installing heaters in a subsurface hydrocarbon containing formation, comprising:

providing one or more shafts;

providing one or more substantially horizontal or inclined tunnels extending from at least one of the shafts;

providing at least one heater wellbore extending from at least one of the tunnels;

interconnecting the heater wellbore with at least one other of the tunnels;

providing one or more heaters the heater wellbore; and

electrically connecting to the heater in the tunnels.
1205. The method of claim 1204, further comprising forming the heater wellbore by directionally drilling from one tunnel to another tunnel.

1206. The method of claim 1204, further comprising electrically connecting the heater to a bus bar located in at least one of the tunnels.

1207. The method of claim 1204, further comprising manually electrically connecting to the heater in at least one of the tunnels.

1208. A system for treating a subsurface hydrocarbon containing formation, comprising:
   one or more substantially horizontal or inclined tunnels extending from one or more shafts; and
   a production system located in at least one of the tunnels, the production system being configured to produce fluids from the formation that collect in the tunnel.

1209. The system of claim 1208, wherein the production system tunnel is located to collect fluids in the formation by gravity drainage.

1210. The system of claim 1208, wherein the production system comprises a substantially vertical production wellbore coupled to the production system tunnel.

1211. A method for treating a subsurface hydrocarbon containing formation, comprising:
   providing one or more substantially horizontal or inclined tunnels extending from at least one shaft;
   allowing formation fluids to drain to at least one of the tunnels; and
   producing fluids from the drainage tunnel to the surface of the formation using a production system.

1212. The method of claim 1211, further comprising providing heat to the formation from at least one heat source located in a wellbore extending from at least one of the tunnels.

1213. A system for treating a subsurface hydrocarbon containing formation, comprising:
   one or more shafts;
   a first substantially horizontal or inclined tunnel extending from one or more of the shafts;
   a second substantially horizontal or inclined tunnel extending from one or more of the shafts; and
   two or more heat source wellbores extending from the first tunnel to the second tunnel, wherein the heat source wellbores are configured to allow heated fluid to flow through the wellbores from the first tunnel to the second tunnel.

1214. The system of claim 1213, further comprising a production system coupled to the second tunnel, the production system being configured to remove the heated fluids from the formation to the surface of the formation.
1215. The system of claim 1213, wherein the second tunnel is configured to collect heated fluids from at least two of the heat source wellbores.

1216. The system of claim 1213, wherein the production system comprises a vertical production wellbore coupled to the second tunnel.

1217. The system of claim 1213, wherein the production system comprises a lift system to move the heated fluids to the surface of the formation.

1218. A method for treating a subsurface hydrocarbon containing formation, comprising:
  providing heated fluids into two or more heat source wellbores extending from a first substantially horizontal or inclined tunnel to a second substantially horizontal or inclined tunnel;
  collecting the heated fluids in the second tunnel; and
  removing the heated fluids from the second tunnel to the surface of the formation.

1219. The method of claim 1218, further comprising providing heat to the formation from the heated fluids.

1220. The method of claim 1218, further comprising removing the heated fluids to the surface using a production system.

1221. The method of claim 1218, further comprising recirculating the heated fluids removed from the second tunnel back into the heat source wellbores.

1222. The method of claim 1218, further comprising reheating the removed heated fluids at the surface, and recirculating the reheated fluids into the heat source wellbores.

1223. A method for producing one or more crude products, comprising:
  producing formation fluid from a subsurface in situ heat treatment process;
  separating the formation fluid to produce a liquid stream and a gas stream;
  providing at least a portion of the liquid stream to a nanofiltration system to produce a retentate and a permeate, wherein the retentate comprises asphaltenes; and
  processing the permeate in one or more of processing units downstream of the nanofiltration system to form one or more crude products.

1224. The method of claim 1223, wherein the nanofiltration system is skid mounted.

1225. The method of claim 1223, wherein the nanofiltration system comprises one or more nanofiltration membranes.

1226. The method of claim 1223, wherein the nanofiltration system comprises one or more reverse osmosis type membranes.

1227. The method of claim 1223, wherein the membrane comprises a top layer made of a dense membrane and a support layer made of a porous membrane.

1228. The method of claim 1223, wherein the dense membrane is made from a polysiloxane.
1229. The method of claim 1223, wherein the nanofiltration system comprises one or more spirally wound modules.
1230. The method of claim 1223, wherein the nanofiltration system comprises one or more spirally wound modules, and wherein at least one of the spirally wound modules comprises a polysiloxane.
1231. The method of claim 1223, wherein the nanofiltration system comprises one or more ceramic membranes.
1232. The method of claim 1223, wherein the liquid stream is provided to the nanofiltration system continuously for at least 10 hours without cleaning a feed side of a membrane of the nanofiltration system.
1233. The method of claim 1223, wherein at least one of the processing units comprises a hydrotreating unit.
1234. The method of claim 1223, wherein at least one of the processing units comprises a selective hydrogenation unit.
1235. The method of claim 1223, wherein at least one of the processing units comprises a hydrotreating unit and the method further comprises contacting the permeate with one or more catalysts in the presence of hydrogen to produce a product suitable for transportation and/or refinery use.
1236. The method of claim 1223, wherein the in situ heat treatment process comprises heating a hydrocarbon containing formation with one or more heat sources.
1237. The method of claim 1223, wherein the formation fluid comprises mobilized fluids, visbroken fluids, pyrolyzed fluids, or mixtures thereof.
1238. The method of claim 1223, further comprising blending one or more of the crude products with other components to produce gasoline.
1239. The method of claim 1223, further comprising blending at least one of the crude products with other components to produce gasoline.
1240. The method of claim 1223, further comprising blending at least one of the crude products with other components to produce transportation fuel.
1241. A system for treating an in situ heat treatment fluid, comprising:
    a production well located in a formation, the production well configured to produce a formation fluid, wherein the formation fluid is produced using an in situ heat treatment process;
    a separation unit, the separation unit configured receive the formation fluid from the production well and the separation unit configured to separate the formation fluid into a liquid stream and a gas stream; and
a nanofiltration system configured to receive the liquid stream and the nanofiltration system configured to separate the liquid stream into a retentate and a permeate.

1242. A method for producing a diluent, comprising:
producing formation fluid from a subsurface in situ heat treatment process;
separating the formation fluid to produce a liquid stream and a gas stream; and
providing at least a portion of the liquid stream to a nanofiltration system to produce a diluent, wherein the diluent comprises aromatic compounds.

1243. A method for producing one or more crude products, comprising:
producing formation fluid from a subsurface in situ heat treatment process;
separating the formation fluid to produce a liquid stream and a gas stream;
providing at least a portion of the liquid stream to a nanofiltration system to produce a retentate and a permeate, wherein the retentate comprises asphaltenes;
processing the retentate in one or more of processing units downstream of the nanofiltration system to form one or more crude products; and
providing the permeate to a second nanofiltration system to produce a retentate and a permeate, wherein the permeate comprises aromatic compounds.

1244. The method of claim 1243, providing the permeate to one or more of processing units downstream of the nanofiltration system as a diluent.

1245. A method of treating a formation fluid, comprising:
providing formation fluid from a subsurface in situ heat treatment process;
separating the formation fluid to produce a first stream comprising at least 0.1% by volume of carbon oxides, sulfur compounds, hydrocarbons, or mixtures thereof;
cryogenically separating the first stream to form a second stream and a third stream wherein the second stream comprises methane and/or hydrogen and the third stream comprises hydrocarbons having a carbon number of at least 2, sulfur compounds, or mixtures thereof; and
cryogenically separating the third stream to form a fourth stream and a fifth stream by contacting the third stream with at least a portion of a stream comprising carbon dioxide, wherein the fourth stream comprises carbon dioxide and/or ethane and the fifth stream comprises hydrocarbons having a carbon number of at least 3, sulfur compounds, or mixtures thereof.

1246. The method of claim 1245, further comprising contacting the fifth stream comprising hydrocarbons having a carbon number of at least 3, sulfur compounds, or mixtures thereof with a hydrocarbon recovery stream to form a stream comprising hydrogen sulfide and a sixth stream.

1247. The method of claim 1246, wherein at least a portion of the hydrogen sulfide is provided to one or more oxidizers.
1248. The method of claim 1246, wherein the sixth stream comprises at most 30 ppm of hydrogen sulfide.

1249. The method of claim 1245, further comprising contacting the fourth stream comprising carbon dioxide and/or ethane with a hydrocarbon recovery stream to form a seventh stream comprising carbon dioxide and a eighth stream.

1250. The method of claim 1249, wherein at least a portion of the eighth stream is provided to the stream comprising carbon dioxide.

1251. The method of claim 1245, further comprising:

- contacting the fifth stream comprising hydrocarbons having a carbon number of at least 3, sulfur compounds, or mixtures thereof with a hydrocarbon recovery stream to form a stream comprising hydrogen sulfide and a sixth stream; and

- contacting the fourth stream comprising carbon dioxide and/or ethane with a hydrocarbon recovery stream to form a seventh stream comprising carbon dioxide and an eighth stream.

1252. The method of claim 1251, further comprising combining at least a portion of the sixth stream and at least a portion the eighth stream; and separating at least a portion of the hydrocarbons having a carbon number of at least 4 from the combined stream.

1253. The method of claim 1251, further comprising combining at least a portion of the sixth stream and at least a portion of the eighth stream; and separating at least a portion of the hydrocarbons having a carbon number of at least 2 from the combined stream.

1254. The method of claim 1251, further comprising combining at least a portion of the sixth stream and at least a portion of the eighth stream; and separating at least a portion of the hydrocarbons having a carbon number of at least 4 from the combined stream to form a ninth stream comprising the hydrocarbons having a carbon number of at least 4 and combining at least a portion of the ninth stream with at least a portion of a hydrocarbon recovery stream.

1255. The method of claim 1251, further comprising combining at least a portion of the sixth stream and at least a portion of the eighth stream; and separating at least a portion of the hydrocarbons having a carbon number of at least 4 from the combined stream to form a ninth stream comprising the hydrocarbons having a carbon number of at least 4 and expanding at least a portion of the ninth stream to remove at least a portion of the hydrocarbons having a carbon number of at least 5 and/or sulfur compounds.

1256. A system of treating formation fluid, comprising:

- one or more separating units configured to receive formation fluid from a subsurface in situ heat treatment process and separate the formation fluid to form a first stream comprising at least 0.1% by volume of carbon oxides, sulfur compounds, hydrocarbons, or mixtures thereof; and
one or more cryogenic separation units configured to cryogenically separate the first stream by contacting the first stream with at least a portion of a stream comprising carbon dioxide to form a second stream and a third stream, wherein the second stream comprises carbon dioxide and/or ethane and the third stream comprises hydrocarbons having a carbon number of at least 3, sulfur compounds, or mixtures thereof.

1257. A method of treating a formation fluid, comprising:

- providing formation fluid from a subsurface in situ heat treatment process;
- separating the formation fluid to produce a first stream, wherein the first stream comprises at least 0.1% by volume of carbon oxides, sulfur compounds, hydrocarbons, hydrogen, or mixtures thereof; and

- cryogenically separating the first stream to form a second stream and a third stream, wherein the second gas stream comprises methane and/or hydrogen and wherein the third gas stream comprises carbon oxide, hydrocarbons having a carbon number of at least 2, sulfur compounds, or mixtures thereof.

1258. The method of claim 1257, further comprising separating at least a portion of the H₂ from the second gas stream.

1259. The method of claim 1257, further comprising separating at least a portion of the hydrocarbons having a carbon number of at least 3 from the third gas stream.

1260. The method of claim 1257, further comprising separating the third gas stream to form an additional stream, wherein the additional stream comprises carbon oxide compounds, hydrocarbons having a carbon number of at most 2, sulfur compounds, or mixtures thereof; and sequestering the additional stream.

1261. The method of claim 1257, further comprising separating the third gas stream to form a fourth gas stream and a fifth gas stream, wherein the fourth gas stream comprises hydrocarbons having a carbon number of at most 2 and/or carbon oxides, and wherein the fifth gas stream comprises sulfur compounds.

1262. The method of claim 1257, further comprising separating the third gas stream to form a fourth gas stream and a fifth gas stream, wherein the fourth gas stream comprises hydrocarbons having a carbon number of at most 2 and/or carbon oxides, and wherein the fifth gas stream comprises sulfur compounds and/or hydrocarbons having a carbon number of at least 3.

1263. The method of claim 1262, further comprising separating the fifth gas stream into a stream comprising sulfur compounds and a stream comprising hydrocarbons having a carbon number of at least 3.

1264. A system of treating formation fluid, comprising:
one or more separating units configured to receive formation fluid from a subsurface in
situ heat treatment process and separate the formation fluid to form a liquid stream and a first gas
stream, wherein the first gas stream comprises at least 0.1 mol% carbon dioxide, hydrogen
sulfide, hydrocarbons, hydrogen, or mixtures thereof; and
one or more cryogenic separation units configured to cryogenically separate the first gas
stream to form a second gas stream and a third gas stream, wherein the second gas stream
comprises methane and/or H₂.

1265. A method for forming two or more wellbores in a subsurface formation, comprising:
forming a first wellbore in the formation;
directionally drilling a second wellbore in a selected relationship relative to the first
wellbore;
providing at least one magnetic field in the second wellbore using one or more magnets in
the second wellbore located on a drilling string used to drill the second wellbore;
sensing at least one magnetic field in the first wellbore using at least two sensors in the
first wellbore as the magnetic field passes by the at least two sensors while the second wellbore is
being drilled;
continuously assessing a position of the second wellbore relative to the first wellbore
using the sensed magnetic field; and
adjusting the direction of drilling of the second wellbore so that the second wellbore
remains in the selected relationship relative to the first wellbore.

1266. The method of claim 1265, wherein the second wellbore is formed substantially parallel
to the first wellbore.

1267. The method of claim 1265, further comprising moving the at least two sensors after
sensing the magnetic field so that the sensors are allowed to sense the magnetic field at a second
position while drilling the second wellbore.

1268. The method of claim 1265, further comprising providing at least two magnetic fields with
at least two magnets in the second wellbore.

1269. The method of claim 1265, wherein the at least two sensors are positioned in advance of
the sensed magnetic field so that the sensors sense the magnetic field as the magnetic field passes
the sensors.

1270. The method of claim 1265, wherein the at least two sensors are positioned in advance of
the sensed magnetic field so that the sensors may be set to "null" the background magnetic field
allowing direct measurement of the reference magnetic field as it passes the sensors.
1271. The method of claim 1265, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.

1272. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming at least a first wellbore in the formation;
   providing a current path and voltage signal to the first wellbore;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
   continuously sensing the voltage signal in the second wellbore;
   continuously assessing a position of the second wellbore relative to the first wellbore using the sensed voltage signal; and
   adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

1273. The method of claim 1272, further comprising:
   providing the current path and voltage signal to the first wellbore and a third wellbore, wherein the second wellbore is positioned substantially adjacent the first wellbore; and
   creating an electrical current and magnetic field signal.

1274. The method of claim 1272, further comprising providing the current path and voltage signal to the first wellbore to generate a known and optionally fixed current within the first wellbore.

1275. The method of claim 1272, further comprising resolving a reference magnetic field by counteracting a background magnetic field by sampling the background magnetic field at one or more fixed sampling frequencies.

1276. The method of claim 1272, further comprising counteracting effects of sensor movement and/or rotation in the second wellbore between sampling steps by using a calculated rotation of one or more assessed data sets to a reference attitude.

1277. The method of claim 1272, wherein the provided voltage signal creates a magnetic field.

1278. The method of claim 1272, wherein the second wellbore is formed substantially parallel to the first wellbore.

1279. The method of claim 1272, wherein the voltage signal comprises a pulsed direct current (DC) signal.

1280. The method of claim 1272, further comprising providing the voltage signal through an electrical conductor that is to be used as a heater in the first wellbore.
1281. The method of claim 1272, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.

1282. The method of claim 1272, further comprising automatically varying the voltage signal on the surface to generate a uniform current.

1283. The method of claim 1272, further comprising iteratively assessing the position of the second wellbore relative to the first wellbore using the sensed voltage signal.

1284. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming a first wellbore in the formation;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
   providing an electromagnetic wave in the second wellbore;
   continuously sensing the electromagnetic wave in the first wellbore using at least one electromagnetic antenna;
   continuously assessing a position of the second wellbore relative to the first wellbore using the sensed electromagnetic wave; and
   adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

1285. The method of claim 1284, wherein the second wellbore is formed substantially parallel to the first wellbore.

1286. The method of claim 1284, further comprising providing the electromagnetic wave using an electromagnetic sonde.

1287. The method of claim 1284, wherein the antenna is located in a heater that is to be used to provide heat in the first wellbore.

1288. The method of claim 1284, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.

1289. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming a first wellbore in the formation;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
   transmitting a first electromagnetic wave from a first transceiver in the first wellbore and sensing the first electromagnetic wave using a second transceiver in the second wellbore;
transmitting a second electromagnetic wave from the second transceiver in the second wellbore and sensing the second electromagnetic wave using the first transceiver in the first wellbore;
continuously assessing a position of the second wellbore relative to the first wellbore using the sensed first electromagnetic wave and the sensed second electromagnetic wave; and
adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.
1290. The method of claim 1289, further comprising assessing natural electromagnetic fields using a third transceiver positioned at a distal end of the first wellbore.
1291. The method of claim 1289, wherein the first transceiver is coupled to a surface of the formation.
1292. The method of claim 1289, wherein the first transceiver is directly coupled to a surface of the formation via a wire.
1293. The method of claim 1289, wherein the first transceiver is directly coupled to a surface of the formation via a wire.
1294. A method for forming two or more wellbores in a subsurface formation, comprising:
forming a plurality of first wellbores in the formation;
providing a plurality of electromagnetic waves in the first wellbores;
directionally drilling one or more second wellbores in a selected relationship relative to the first wellbores;
continuously sensing the electromagnetic waves in the first wellbores using at least one electromagnetic antenna in the second wellbores;
continuously assessing a position of the second wellbores relative to the first wellbores using the sensed electromagnetic waves; and
adjusting the direction of drilling of at least one of the second wellbores so that the second wellbore remains in the selected relationship relative to the first wellbores.
1295. The method of claim 1294, wherein at least one of the second wellbores is formed substantially perpendicular to at least one of the first wellbores.
1296. The method of claim 1294, further comprising providing the electromagnetic waves using electromagnetic sondes.
1297. The method of claim 1294, wherein the antenna is located in a heater that is to be used to provide heat in at least one of the second wellbores.
1298. The method of claim 1294, further comprising continuously adjusting the direction of drilling of at least one of the second wellbores using the continuously assessed position of the second wellbore relative to the first wellbore.
1299. A method for forming two or more wellbores in a subsurface formation, comprising:
forming a first wellbore in the formation;
assessing a position of the first wellbore;
drilling a second wellbore in a selected relationship relative to the first wellbore;
continuously assessing a position of the second wellbore relative to the first wellbore;
adjusting the direction of drilling of the second wellbore so that the second wellbore
remains in the selected relationship relative to the first wellbore;
drilling one or more additional wellbores in a selected relationship to the second
wellbore;
continuously assessing a position of at least one of the additional wellbores relative to the
first wellbore and/or the second wellbore; and
adjusting the direction of drilling of the at least one of the additional wellbores so that the
at least one of the additional wellbores remains in the selected relationship relative to the second
wellbore.

1300. The method of claim 1299, wherein the second wellbore is formed substantially
perpendicular to the first wellbore.

1301. The method of claim 1299, wherein at least one of the additional wellbores is formed
substantially parallel to the second wellbore.

1302. The method of claim 1299, wherein continuously assessing the position of the second
wellbore relative to the first wellbore, comprises:
transmitting a first electromagnetic wave from a first transceiver in the first wellbore and
sensing the first electromagnetic wave using a second transceiver in the second wellbore;
transmitting a second electromagnetic wave from the second transceiver in the second
wellbore and sensing the second electromagnetic wave using the first transceiver in the first
wellbore; and
continuously assessing the position of the second wellbore relative to the first wellbore
using the sensed first electromagnetic wave and the sensed second electromagnetic wave.

1303. The method of claim 1299, wherein continuously assessing the position of the at least one
of the additional wellbores relative to the second wellbore, comprises:
transmitting a first electromagnetic wave from a first transceiver in the first wellbore
and/or the second wellbore and sensing the first electromagnetic wave using a second transceiver
in the at least one of the additional wellbores;
transmitting a second electromagnetic wave from the second transceiver in the at least
one of the additional wellbores and sensing the second electromagnetic wave using the first
transceiver in the first wellbore and/or the second wellbore; and
continuously assessing the position of the at least one of the additional wellbores relative to the second wellbore using the sensed first electromagnetic wave and the sensed second electromagnetic wave.

1304. The method of claim 1299, wherein continuously assessing the position of the second wellbore relative to the first wellbore, comprises:

- providing a current path and voltage signal to the first wellbore;
- continuously sensing the voltage signal in the second wellbore; and
- continuously assessing the position of the second wellbore relative to the first wellbore using the sensed voltage signal.

1305. The method of claim 1299, wherein continuously assessing the position of at least one of the additional wellbores relative to the second wellbore, comprises:

- providing a current path and voltage signal to the first wellbore and/or the second wellbore;
- continuously sensing the voltage signal in at least one of the additional wellbores; and
- continuously assessing the position of at least one of the additional wellbores relative to the second wellbore using the sensed voltage signal.

1306. The method of claim 1299, further comprising assessing a position of the first wellbore relative to at least one additional wellbore in the formation to verify the position of the first wellbore.

1307. The method of claim 1299, further comprising assessing a position of the second wellbore relative to at least one additional wellbore in the formation to verify the position of the second wellbore.

1308. A method for forming two or more wellbores in a subsurface formation, comprising:

- forming a first wellbore in the formation;
- directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
- providing an electromagnetic field in the first wellbore using one or more magnets;
- continuously sensing the electromagnetic field in the first wellbore using at least one electromagnetic field sensor positioned in the second wellbore;
- continuously assessing a position of the second wellbore relative to the first wellbore using the sensed electromagnetic field; and
- adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.
1309. The method of claim 1308, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.

1310. A method for forming two or more wellbores in a subsurface formation, comprising:
   forming a first wellbore in the formation;
   directionally drilling a second wellbore in a selected relationship relative to the first wellbore;
   providing an electromagnetic field in the second wellbore using one or more magnets;
   continuously sensing the electromagnetic field in the second wellbore using at least one electromagnetic field sensor positioned in the first wellbore;
   continuously assessing a position of the second wellbore relative to the first wellbore using the sensed electromagnetic field; and
   adjusting the direction of drilling of the second wellbore so that the second wellbore remains in the selected relationship relative to the first wellbore.

1311. The method of claim 1310, further comprising continuously adjusting the direction of drilling of the second wellbore using the continuously assessed position of the second wellbore relative to the first wellbore.

1312. The method of claim 1310, further comprising calibrating the sensors to adjust for natural magnetic fields positioned adjacent the first wellbore.

1313. A method for forming a wellbore in a heated formation, comprising:
   flowing liquid cooling fluid to a bottom hole assembly in a wellbore in a heated formation; and
   vaporizing at least a portion of the liquid cooling fluid at or near a region to be cooled, wherein vaporizing the liquid cooling fluid absorbs heat from the region to be cooled.

1314. The method of claim 1313, further comprising returning the cooling fluid to the surface.

1315. The method of claim 1313, wherein the cooling fluid comprises drilling fluid.

1316. The method of claim 1313, wherein at least a majority of the cooling fluid is vaporized at or prior to reaching the bottom hole assembly.

1317. The method of claim 1313, wherein the vaporized cooling fluid is introduced into returning drilling fluid and cuttings.

1318. The method of claim 1313, wherein the formation has been heated or is being heated with one or more heat sources.

1319. The method of claim 1313, wherein the formation has been heated or is being heated to a temperature at least about 50 °C above ambient formation temperature.
1320. The method of claim 1313, wherein the vaporized cooling fluid returns to the surface without mixing with the drilling fluid.
1321. The method of claim 1313, further comprising maintaining the cooling fluid at sufficiently high pressure as the cooling fluid is flowing to the bottom hole assembly such that at least a portion of the drilling fluid is a liquid at or near the bottom hole assembly.
1322. The method of claim 1313, further comprising directing the cooling fluid in conventional flow circulation.
1323. The method of claim 1313, further comprising directing the cooling fluid in reverse flow circulation.
1324. The method of claim 1313, further comprising providing the cooling fluid to the bottom hole assembly as a two-phase mixture comprising a non-condensable gas in a liquid.
1325. The method of claim 1313, further comprising lifting the cuttings at least partially using pressure and velocity resulting from the phase change of cooling fluid to vapor.
1326. The method of claim 1313, further comprising controlling down hole pressure by maintaining a desired back pressure on the cooling fluid.
1327. The method of claim 1313, further comprising at least partially insulating the bottom hole assembly from the formation.
1328. The method of claim 1313, wherein the bottom hole assembly comprises one or more drilling bits with conduits for flow of the cooling fluid.
1329. The method of claim 1313, further comprising controlling a temperature at or near the bottom hole assembly by controlling vaporization of the cooling fluid.
1330. The method of claim 1313, further comprising operating a control valve at or near the bottom hole assembly, or a conduit carrying the cooling fluid, to control vaporization of the cooling fluid.
1331. A method for forming a wellbore in a heated formation, comprising:
   flowing a two-phase cooling fluid to a bottom hole assembly in a wellbore in the heated formation;
   vaporizing at least a portion of a liquid phase of the two-phase cooling fluid at or near a drill bit, wherein vaporizing the liquid phase cools the drill bit; and
   removing cuttings and the cooling fluid from the wellbore.
1332. The method of claim 1331, further comprising directing the cooling fluid down a drilling string to the drill bit using a circulation system.
1333. The method of claim 1331, further comprising directing the cooling fluid to a drill bit using reverse circulation.
1334. The method of claim 1331, further comprising lifting the cuttings partially using pressure and velocity resulting from the phase change of cooling fluid to vapor.

1335. The method of claim 1331, further comprising controlling down hole pressure by maintaining a desired back pressure on the cooling fluid.

1336. The method of claim 1331, wherein vaporizing at least a portion of the liquid phase comprises passing the liquid phase through one or more chokes to reduce the pressure of the liquid.

1337. A system for forming a wellbore in a heated formation, comprising:
   - cooling fluid;
   - a drill bit configured to form an opening in the heated formation;
   - a drilling string coupled to the drill bit, the drilling string configured to transport drilling fluid to the drill bit and facilitate removal of drilling fluid and cuttings from the wellbore;
   - a back pressure device coupled to the drilling pipe, the back pressure device configured to maintain a sufficiently high pressure on the cooling fluid flowing towards the drill bit so that at least a portion of the cooling fluid remains in a liquid phase, prior to the back pressure device; and
   wherein at least a portion of the cooling fluid is configured to vaporize after flowing through the back pressure device to provide cooling to a region.

1338. The system of claim 1337, wherein the back pressure device comprises one or more pressure activated valves.

1339. The system of claim 1337, wherein the back pressure device comprises one or more chokes.

1340. The system of claim 1337, wherein the cooling fluid is the drilling fluid.

1341. The system of claim 1337, wherein the cooling fluid is configured to be mixed with the drilling fluid after passing through the back pressure device.

1342. A method for installing a horizontal or inclined subsurface heater, comprising:
   - placing a heating section of a heater in a horizontal or inclined section of a wellbore with an installation tool;
   - uncoupling the tool from the heating section; and
   - mechanically and electrically coupling a lead-in section of the heater to the heating section of the heater, wherein the lead-in section is located in an angled or vertical section of the wellbore.

1343. The method of claim 1342, further comprising removing the tool from the wellbore after uncoupling the tool from the heating section.
1344. The method of claim 1342, wherein the lead-in section has an electrical resistance less than the heating section of the heater.
1345. The method of claim 1342, wherein the lead-in section is mechanically coupled to the heating section using a wet connect stab device.
1346. The method of claim 1342, wherein the heating section comprises a receptacle at one end for accepting and coupling to the lead-in section.
1347. The method of claim 1342, wherein the heater section is mechanically secured in the wellbore with the installation tool.
1348. The method of claim 1342, wherein the heater section is at least about 10 m in length.
1349. The method of claim 1342, wherein the lead-in section passes through an overburden of a subsurface formation.
1350. The method of claim 1342, wherein the heating section is placed in hydrocarbon containing layer of a subsurface formation.
1351. The method of claim 1342, further comprising providing electrical power to the heater.
1352. The method of claim 1342, further comprising providing electrical power to the heater, and providing heat to at least a portion of a subsurface formation from the heater.
1353. The method of claim 1342, further comprising providing electrical power to the heater, and providing heat to at least a portion of a subsurface formation from the heater such that heat from the heater superpositions heat from another heater in the subsurface formation.
1354. The method of claim 1342, further comprising providing electrical power to the heater, providing heat to at least a portion of a hydrocarbon containing formation from the heater, and allowing heat to mobilize and/or pyrolyze at least some hydrocarbons in the formation.
1355. The method of claim 1342, further comprising providing electrical power to the heater, providing heat to at least a portion of a hydrocarbon containing formation from the heater, allowing heat to mobilize and/or pyrolyze at least some hydrocarbons in the formation, and producing at least some of the mobilized and/or pyrolyzed hydrocarbons from the formation.
1356. A method for providing heat to a subsurface formation, comprising:

installing a heater comprising a heating section and a lead-in section into a wellbore in the subsurface formation, wherein the installation comprises:

placing the heating section of a heater in a horizontal or inclined section of the wellbore with an installation tool;
uncoupling the tool from the heating section;
mechanically and electrically coupling the lead-in section of the heater to the heating section of the heater, wherein the lead-in section is located in an angled or vertical section of the wellbore;
providing electrical power to the heater; and
providing heat to at least a portion of a subsurface formation from the heater.

1357. The method of claim 1356, wherein the lead-in section has an electrical resistance less than the heating section of the heater.

1358. The method of claim 1356, wherein the heater section is at least about 10 m in length.

1359. The method of claim 1356, wherein the lead-in section passes through an overburden of a subsurface formation.

1360. The method of claim 1356, wherein the heating section is placed in hydrocarbon containing layer of a subsurface formation.

1361. The method of claim 1356, further comprising providing heat to at least a portion of the subsurface formation from the heater such that heat from the heater superpositions heat from another heater in the subsurface formation.

1362. The method of claim 1356, further comprising providing heat to at least a portion of a hydrocarbon containing layer in the subsurface formation from the heater, and allowing heat to mobilize and/or pyrolyze at least some hydrocarbons in the layer.

1363. The method of claim 1356, further comprising providing heat to at least a portion of a hydrocarbon containing layer in the subsurface formation from the heater, allowing heat to mobilize and/or pyrolyze at least some hydrocarbons in the layer, and producing at least some of the mobilized and/or pyrolyzed hydrocarbons from the layer.

1364. A method for assessing one or more temperatures of an electrically powered subsurface heater, comprising:

   assessing an impedance profile of the electrically powered subsurface heater while the heater is being operated in the subsurface; and

   analyzing the impedance profile with a frequency domain algorithm to assess one or more temperatures of the heater.

1365. The method of claim 1364, wherein the impedance profile is assessed using timed domain reflectometer measurements.

1366. The method of claim 1364, wherein the frequency domain algorithm comprises partial discharge measurement technology.

1367. The method of claim 1364, wherein the impedance profile comprises the impedance profile along the length of the heater.

1368. The method of claim 1364, wherein the frequency domain algorithm utilizes laboratory data for the heater to assess the temperature profile of the heater.

1369. The method of claim 1364, further comprising assessing a temperature profile of the heater.
1370. The method of claim 1364, further comprising using one or more of the temperatures of the heater to assess reactive power consumption of the heater in the subsurface.

1371. The method of claim 1364, further comprising using one or more of the temperatures of the heater to assess real power consumption of the heater in the subsurface.

1372. The method of claim 1364, further comprising using one or more of the temperatures to identify and/or predict failure locations along the length of the heater.

1373. The method of claim 1364, further comprising using the heater to provide heat to at least a portion of a subsurface formation, and providing heat to mobilize hydrocarbons in the subsurface formation.

1374. The method of claim 1364, further comprising using the heater to provide heat to at least a portion of a subsurface formation, and providing heat to pyrolyze hydrocarbons in the subsurface formation.

1375. The method of claim 1364, further comprising using the heater to provide heat to at least a portion of a subsurface formation, providing heat to mobilize hydrocarbons in the subsurface formation, and producing at least some of the mobilized hydrocarbons from the formation.

1376. A method for forming a longitudinal subsurface heater, comprising:

   longitudinally welding an electrically conductive sheath of an insulated conductor heater along at least one longitudinal strip of metal; and

   forming the longitudinal strip into a tubular around the insulated conductor heater with the insulated conductor heater welded along the inside surface of the tubular.

1377. The method of claim 1376, wherein forming the longitudinal strip of metal into the tubular comprises rolling the strip of metal into the tubular.

1378. The method of claim 1376, further comprising electrically shorting a distal end of the tubular to a distal end of the sheath and a center conductor of the insulated conductor heater.

1379. The method of claim 1376, further comprising forming the tubular by welding the longitudinal lengths of the strip of metal together.

1380. The method of claim 1376, further comprising forming the tubular by welding the longitudinal lengths of the strip of metal together at a circumferential location away from the point of contact between the tubular and the insulated conductor heater.

1381. The method of claim 1376, wherein the tubular is formed from a plurality of longitudinal strips of metal.

1382. The method of claim 1376, wherein the insulated conductor heater comprises a center conductor at least partially surrounded by an electrical insulator, and the sheath at least partially surrounding the electrical insulator.

1383. A method for forming a longitudinal subsurface heater, comprising:
longitudinally welding an electrically conductive sheath of an insulated conductor heater along an inside surface of a metal tubular.

1384. The method of claim 1383, wherein the tubular is formed from one or more longitudinal strips of metal.

1385. The method of claim 1383, further comprising electrically shorting a distal end of the tubular to a distal end of the sheath and a center conductor of the insulated conductor heater.

1386. The method of claim 1383, wherein the insulated conductor heater comprises a center conductor at least partially surrounded by an electrical insulator, and the electrically conductive sheath at least partially surrounding the electrical insulator.

1387. A longitudinal subsurface heater, comprising:

an insulated conductor heater, comprising:

  an electrical conductor;

  an electrical insulator at least partially surrounding the electrical conductor; and

  an electrically conductive sheath at least partially surrounding the electrical insulator;

  a metal tubular at least partially surrounding the insulated conductor heater; and

  wherein the sheath of the insulated conductor heater is longitudinally welded along an inside surface of the metal tubular.

1388. The heater of claim 1387, wherein a distal end of the tubular is electrically shorted to a distal end of the sheath and the electrical conductor of the insulated conductor heater.

1389. The heater of claim 1387, wherein the tubular is formed from one or more longitudinal strips of metal.

1390. The heater of claim 1387, wherein the tubular has been formed by welding longitudinal lengths of a strip of metal together.

1391. The heater of claim 1387, wherein the tubular is configured to allow fluids to flow through the tubular.

1392. The heater of claim 1387, wherein the metal tubular is ferromagnetic.

1393. The heater of claim 1387, wherein the electrical conductor comprises copper.

1394. The heater of claim 1387, wherein the electrical insulator comprises magnesium oxide.

1395. The heater of claim 1387, wherein the metal tubular is non-ferromagnetic, and the metal tubular is coated with thin electrically insulating coating.

1396. The heater of claim 1387, wherein the heater is a temperature limited heater.

1397. A method for treating a subsurface formation using an electric heater, comprising:

  providing the electric heater to an opening in the subsurface formation, the electric heater comprising:
an insulated conductor heater, comprising:
  an electrical conductor;
  an electrical insulator at least partially surrounding the electrical
  conductor; and
  an electrically conductive sheath at least partially surrounding the
  electrical insulator;
  a metal tubular at least partially surrounding the insulated conductor heater;
  wherein the sheath of the insulated conductor heater is longitudinally welded
  along an inside surface of the metal tubular; and
  heating the subsurface formation by providing electrical current to the electric heater.

1398. The method of claim 1397, further comprising providing at least one heat transfer fluid to
the tubular.

1399. The method of claim 1397, further comprising heating the subsurface formation by
providing time-varying electrical current to the electric heater.

1400. A heating system for a subsurface formation, comprising:
  three substantially u-shaped heaters, first end portions of the heaters being electrically
coupled to a single, three-phase wye transformer, second end portions of the heaters being
electrically coupled to each other and/or to ground;
    wherein the three heaters enter the formation through a first common wellbore and exit
the formation through a second common wellbore so that the magnetic fields of the three heaters
at least partially cancel out in the common wellbores.

1401. The system of claim 1400, wherein at least two of the heaters have heating sections that
are at least partially substantially parallel in a hydrocarbon layer of the formation.

1402. The system of claim 1400, wherein at least one of the three heaters comprises an exposed
metal heating section.

1403. The system of claim 1400, wherein at least one of the three heaters comprises an insulated
conductor heating section.

1404. The system of claim 1400, wherein at least one of the three heaters comprises a
conductor-in-conduit heating section.

1405. The system of claim 1400, wherein the three heaters comprise 410 stainless steel in at
least part of the heating sections of the heaters, and copper in at least part of the overburden
sections of the heaters.

1406. The system of claim 1400, further comprising a ferromagnetic casing in at least part of
the overburden section of the first common wellbore.
1407. The system of claim 1400, further comprising a ferromagnetic casing in at least part of the overburden section of the second common wellbore.

1408. The system of claim 1400, wherein each heater is coupled to one phase of the transformer.

1409. The system of claim 1400, further comprising multiples of three additional heaters entering through the first common wellbore.

1410. The system of claim 1400, further comprising multiples of three additional heaters entering through the first common wellbore and exiting through the second common wellbore.

1411. The system of claim 1400, wherein at least one of the heaters is used to directionally steer drilling of an opening in the formation used for at least one of the other heaters.

1412. The system of claim 1400, wherein the three heaters are electrically coupled together in the second common wellbore.

1413. The system of claim 1400, wherein the three heaters are located in three openings extending between the first common wellbore and the second common wellbore.

1414. The system of claim 1400, wherein at least one of the three heaters provides different heat outputs along at least part of the length of the heater.

1415. The system of claim 1400, wherein at least one of the three heaters has different materials along at least part of the length of the heater to provide different heat outputs along at least part of the length of the heater.

1416. The system of claim 1400, wherein at least one of the three heaters has different dimensions along at least part of the length of the heater to provide different heat outputs along at least part of the length of the heater.

1417. The system of claim 1400, wherein at least a majority of the first common wellbore is vertical, substantially vertical, or vertically inclined, and at least a majority of the second common wellbore is vertical, substantially vertical, or vertically inclined.

1418. The system of claim 1400, wherein at least a majority of at least one of the three heaters is horizontal, substantially horizontal, or horizontally inclined.

1419. A method of heating a subsurface formation, comprising:

   providing heat from three substantially u-shaped heaters, wherein first end portions of the heaters are electrically coupled to a single, three-phase wye transformer, and second end portions of the heaters are electrically coupled to each other and/or to ground;

   wherein the three heaters enter the formation through a first common wellbore and exit the formation through a second common wellbore so that the magnetic fields of the three heaters at least partially cancel out in the common wellbores; and

   allowing the heat to transfer from the heaters to a portion of the formation.
1420. The method of claim 1419, further comprising mobilizing at least some hydrocarbons in the portion of the formation with the transferred heat.

1421. The method of claim 1419, further comprising mobilizing at least some hydrocarbons in the portion of the formation with the transferred heat, and producing at least some of the mobilized hydrocarbons.

1422. A heating system for a subsurface formation, comprising:
   an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and
   a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;
   wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

1423. The system of claim 1422, wherein the electrical conductor comprises a substantially u-shaped electrical conductor.

1424. The system of claim 1422, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

1425. The system of claim 1422, wherein the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 500 °C.

1426. The system of claim 1422, wherein the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 700 °C.

1427. The system of claim 1422, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to the temperature of at least about 300 °C.

1428. The system of claim 1422, wherein the ferromagnetic conductor comprises carbon steel.

1429. The system of claim 1422, wherein the electrical conductor is the core of an insulated conductor.

1430. The system of claim 1422, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1431. The system of claim 1422, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1432. The system of claim 1422, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.
1433. The system of claim 1422, wherein the ferromagnetic conductor has different materials along at least a portion of the length of the ferromagnetic conductor that are configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1434. The system of claim 1422, wherein the ferromagnetic conductor has different dimensions along at least a portion of the length of the ferromagnetic conductor that are configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1435. The system of claim 1422, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.

1436. The system of claim 768, wherein the ferromagnetic conductor is between about 3 cm and about 13 cm in diameter.

1437. The system of claim 1422, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

1438. The system of claim 1422, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

1439. The system of claim 1422, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

1440. The system of claim 1422, wherein the ferromagnetic conductor comprises two or more ferromagnetic layers, the ferromagnetic layers being separated by insulation layers, wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in each of the ferromagnetic layers such that the ferromagnetic layers resistively heat.

1441. The system of claim 1422, wherein the electrical conductor is a substantially u-shaped electrical conductor located in a u-shaped wellbore in the formation.

1442. A method for heating a subsurface formation, comprising:

   providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;

   inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

   resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.
1443. The method of claim 1442, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.
1444. The method of claim 1442, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 500 °C.
1445. The method of claim 1442, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 700 °C.
1446. The method of claim 1442, further comprising resistively heating at least about 10 m of length of the ferromagnetic conductor to the temperature of at least about 300 °C.
1447. The method of claim 1442, wherein the ferromagnetic conductor comprises carbon steel.
1448. The method of claim 1442, wherein the electrical conductor is the core of an insulated conductor.
1449. The method of claim 1442, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.
1450. The method of claim 1442, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.
1451. The method of claim 1442, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.
1452. The method of claim 1442, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.
1453. The method of claim 1442, wherein the electrical conductor is a substantially u-shaped electrical conductor located in a u-shaped wellbore in the formation.
1454. The method of claim 1442, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.
1455. The method of claim 1442, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.
1456. The method of claim 1442, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.
1457. A heating system for a subsurface formation, comprising:

an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and

a ferromagnetic conductor, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats.

1458. The system of claim 1457, wherein the electrical conductor comprises a substantially u-shaped electrical conductor.

1459. The system of claim 1457, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

1460. The system of claim 1457, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

1461. The system of claim 1457, wherein the ferromagnetic conductor comprises carbon steel.

1462. The system of claim 1457, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1463. The system of claim 1457, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1464. The system of claim 1457, wherein the ferromagnetic conductor has different materials along at least a portion of the length of the ferromagnetic conductor that are configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1465. The system of claim 1457, wherein the ferromagnetic conductor has different dimensions along at least a portion of the length of the ferromagnetic conductor that are configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1466. The system of claim 1457, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.
1467. The system of claim 1457, wherein the ferromagnetic conductor is between about 3 cm and about 13 cm in diameter.
1468. The system of claim 1457, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.
1469. The system of claim 1457, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.
1470. The system of claim 1457, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.
1471. The system of claim 1457, wherein the ferromagnetic conductor and the electrical conductor are electrically insulated from each other.
1472. A method for heating a subsurface formation, comprising:
   providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;
   inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and
   resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats.
1473. The method of claim 1472, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.
1474. The method of claim 1472, further comprising resistively heating at least about 10 m of length of the ferromagnetic conductor to a temperature of at least about 300 °C.
1475. The method of claim 1472, wherein the ferromagnetic conductor comprises carbon steel.
1476. The method of claim 1472, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.
1477. The method of claim 1472, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.
1478. The method of claim 1472, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.
1479. The method of claim 1472, wherein the ferromagnetic conductor and the electrical conductor are electrically insulated from each other.

1480. The method of claim 1472, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

1481. The method of claim 1472, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

1482. The method of claim 1472, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.

1483. A heating system for a subsurface formation, comprising:
   an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and
   a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;
   wherein the electrical conductor, when energized with time-varying electrical current, induces electrical current flow on the inside and outside surfaces of the ferromagnetic conductor such that the ferromagnetic conductor resistively heats.

1484. The system of claim 1483, wherein the electrical conductor comprises a substantially u-shaped electrical conductor.

1485. The system of claim 1483, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

1486. The system of claim 1483, wherein the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

1487. The system of claim 1483, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

1488. The system of claim 1483, wherein the ferromagnetic conductor comprises carbon steel.

1489. The system of claim 1483, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.
1490. The system of claim 1483, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1491. The system of claim 1483, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1492. The system of claim 1483, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

1493. The system of claim 1483, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

1494. The system of claim 1483, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

1495. A method for heating a subsurface formation, comprising:

providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;

inducing electrical current flow on the inside and outside surfaces of a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

resistively heating the ferromagnetic conductor with the induced electrical current flow.

1496. The method of claim 1495, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.

1497. The method of claim 1495, wherein at least about 10 m of length of the ferromagnetic conductor resistively heats to the temperature of at least about 300 °C.

1498. The method of claim 1495, wherein the ferromagnetic conductor comprises carbon steel.

1499. The method of claim 1495, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1500. The method of claim 1495, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1501. The method of claim 1495, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.
1502. The method of claim 1495, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.

1503. The method of claim 1495, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

1504. The method of claim 1495, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

1505. The method of claim 1495, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.

1506. A heating system for a subsurface formation, comprising:

an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and

a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats; and

wherein the ferromagnetic conductor is configured to have little or no induced current flow at temperatures at and above a selected temperature.

1507. The system of claim 1506, wherein the electrical conductor comprises a substantially u-shaped electrical conductor.

1508. The system of claim 1506, wherein the ferromagnetic conductor comprises a turndown ratio of at least about 5.

1509. The system of claim 1506, wherein the selected temperature is the Curie temperature of at least one ferromagnetic material in the ferromagnetic conductor.

1510. The system of claim 1506, wherein the selected temperature is the phase transformation temperature of at least one ferromagnetic material in the ferromagnetic conductor.
1511. The system of claim 1506, wherein the ferromagnetic conductor is configured to have induced current flow when the ferromagnetic conductor is at temperatures below the selected temperature.

1512. The system of claim 1506, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

1513. The system of claim 1506, wherein the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

1514. The system of claim 1506, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

1515. The system of claim 1506, wherein the ferromagnetic conductor comprises carbon steel.

1516. The system of claim 1506, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1517. The system of claim 1506, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1518. The system of claim 1506, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1519. The system of claim 1506, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

1520. The system of claim 1506, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

1521. The system of claim 1506, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

1522. A method for heating a subsurface formation, comprising:

   providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;

   inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

   resistively heating the ferromagnetic conductor with the induced electrical current flow, wherein the ferromagnetic conductor has little or no resistive heating at temperatures at and above a selected temperature.
1523. The method of claim 1522, wherein little or no electrical current flow is induced in the ferromagnetic conductor at temperatures at and above the selected temperature.

1524. The method of claim 1522, wherein the ferromagnetic conductor comprises a turndown ratio of at least about 5.

1525. The method of claim 1522, wherein the selected temperature is the Curie temperature of at least one ferromagnetic material in the ferromagnetic conductor.

1526. The method of claim 1522, wherein the selected temperature is the phase transformation temperature of at least one ferromagnetic material in the ferromagnetic conductor.

1527. The method of claim 1522, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.

1528. The method of claim 1522, wherein at least about 10 m of length of the ferromagnetic conductor resistively heats to the temperature of at least about 300 °C.

1529. The method of claim 1522, wherein the ferromagnetic conductor comprises carbon steel.

1530. The method of claim 1522, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1531. The method of claim 1522, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1532. The method of claim 1522, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1533. The method of claim 1522, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.

1534. The method of claim 1522, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

1535. The method of claim 1522, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

1536. The method of claim 1522, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.
1537. A system for heating a hydrocarbon containing formation, comprising:

a first elongated electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least two electrical contacts; and

a first ferromagnetic conductor, wherein the first ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the first electrical conductor;

wherein the first electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the first ferromagnetic conductor such that the first ferromagnetic conductor resistively heats;

a second elongated electrical conductor located in the subsurface formation, wherein the second electrical conductor extends between at least two electrical contacts; and

a second ferromagnetic conductor, wherein the second ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the second electrical conductor;

wherein the second electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the second ferromagnetic conductor such that the second ferromagnetic conductor resistively heats; and

wherein the first and second ferromagnetic conductors are configured to provide heat to the formation such that heat from the ferromagnetic conductors is superpositioned in the formation.

1538. The system of claim 1537, wherein at least one of the ferromagnetic conductors is configured to resistively heat to a temperature of at least about 300 °C.

1539. The system of claim 1537, wherein at least one of the ferromagnetic conductors has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1540. The system of claim 1537, wherein the ferromagnetic conductors and the electrical conductors are configured in relation to each other such that electrical current does not flow from the electrical conductors to the ferromagnetic conductors, or vice versa.

1541. The system of claim 1537, wherein at least one of the ferromagnetic conductors is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1542. The system of claim 1537, wherein at least one of the electrical conductors is configured to flow electrical current in one direction from at least a first electrical contact to at least a second electrical contact.

1543. The system of claim 1537, wherein the first and second ferromagnetic conductors are configured to provide heat to the formation such that heat from the ferromagnetic conductors is
superpositioned in the formation and hydrocarbons are mobilized in the formation between the ferromagnetic conductors.

1544. A method for heating a hydrocarbon containing formation, comprising:

providing time-varying electrical current to an elongated electrical conductor located in the formation;

inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats;

allowing heat to transfer from the ferromagnetic conductor to at least a part of the formation; and

mobilizing at least some hydrocarbons in the part of the formation.

1545. The method of claim 1544, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 300 °C.

1546. The method of claim 1544, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1547. The method of claim 1544, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1548. The method of claim 1544, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1549. The method of claim 1544, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.

1550. The method of claim 1544, wherein heat from the ferromagnetic conductor superpositions heat provided from at least one additional heater located in the formation.

1551. The method of claim 1544, wherein heat from the ferromagnetic conductor superpositions heat provided from at least one additional ferromagnetic conductor in the formation that resistively heats with induced electrical current flow.

1552. A heating system for a subsurface formation, comprising:

a first wellbore extending into the subsurface formation;

a second wellbore extending into the subsurface formation; and
three or more heaters extending between the first wellbore and the second wellbore, at least one heater comprising:

an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and

a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

1553. The system of claim 1552, wherein each heater comprises:

an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and

a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

1554. The system of claim 1552, wherein at least three of the heaters are located in separate wellbores extending between the first wellbore and the second wellbore.

1555. The system of claim 1552, wherein at least one of the heaters comprises a substantially u-shaped heater in the formation.

1556. The system of claim 1552, wherein ends of the three heaters in either the first or the second wellbore are electrically coupled to each other at or near the surface of the formation.

1557. The system of claim 1552, wherein the three heaters are electrically coupled to each other in a three-phase wye configuration.

1558. The system of claim 1552, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

1559. The system of claim 1552, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

1560. The system of claim 1552, wherein the ferromagnetic conductor comprises carbon steel.

1561. The system of claim 1552, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.
1562. The system of claim 1552, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1563. The system of claim 1552, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1564. The system of claim 1552, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1565. The system of claim 1552, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

1566. The system of claim 1552, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

1567. A method for heating a subsurface formation, comprising:

    providing time-varying electrical current to three or more heaters extending between a first wellbore and a second wellbore, the first and second wellbores extending into the subsurface formation, wherein at least one of the heaters comprises an elongated electrical conductor and a ferromagnetic conductor at least partially surrounding and at least partially extending lengthwise around the electrical conductor;

    inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

    resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

1568. The method of claim 1567, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.

1569. The method of claim 1567, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 500 °C.

1570. The method of claim 1567, further comprising resistively heating at least about 10 m of the ferromagnetic conductor to the temperature of at least about 300 °C.

1571. The method of claim 1567, wherein the ferromagnetic conductor comprises carbon steel.

1572. The method of claim 1567, wherein the electrical conductor is the core of an insulated conductor.

1573. The method of claim 1567, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.
1574. The method of claim 1567, wherein the ferromagnetic conductor and the electrical conductor are electrically insulated from each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1575. The method of claim 1567, further comprising providing different heat outputs along the length of the ferromagnetic conductor.

1576. The method of claim 1567, further comprising applying the electrical current to the electrical conductor in one direction from the first wellbore to the second wellbore.

1577. The method of claim 1567, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

1578. The method of claim 1567, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

1579. The method of claim 1567, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.

1580. A heating system for a subsurface formation, comprising:

- a first wellbore extending into the subsurface formation;
- a second wellbore extending into the subsurface formation;
- a third wellbore extending into the subsurface formation;
- a first heater located in the first wellbore, a second heater located in the second wellbore, and a third heater located in the third wellbore, at least one heater comprising:

  - an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact; and
  - a ferromagnetic conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor;

  wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.

1581. The system of claim 1580, wherein at least one of the wellbores comprises a substantially u-shaped wellbore in the formation.
1582. The system of claim 1580, wherein the first, second, and third wellbores are substantially parallel in the formation.

1583. The system of claim 1580, wherein the three heaters are electrically coupled to each other in a three-phase wye configuration.

1584. The system of claim 1580, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the subsurface formation.

1585. The system of claim 1580, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.

1586. The system of claim 1580, wherein the ferromagnetic conductor comprises carbon steel.

1587. The system of claim 1580, wherein at least about 10 m of length of the ferromagnetic conductor is configured to resistively heat to a temperature of at least about 300 °C.

1588. The system of claim 1580, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1589. The system of claim 1580, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.

1590. The system of claim 1580, wherein the ferromagnetic conductor is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic conductor.

1591. The system of claim 1580, wherein at least about 10 m of length of the ferromagnetic conductor is positioned in a hydrocarbon containing layer in the subsurface formation.

1592. The system of claim 1580, wherein the electrical conductor is configured to flow electrical current in one direction from the first electrical contact to the second electrical contact.

1593. A method for heating a subsurface formation, comprising:

   providing time-varying electrical current to a first heater located in a first wellbore, a second heater located in a second wellbore, and a third heater located in a third wellbore, the first, second, and third wellbores extending into the subsurface formation, wherein at least one of the heaters comprises an elongated electrical conductor and a ferromagnetic conductor at least partially surrounding and extending lengthwise around the electrical conductor;

   inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; and

   resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats to a temperature of at least about 300 °C.
1594. The method of claim 1593, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation.
1595. The method of claim 1593, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 500 °C.
1596. The method of claim 1593, further comprising resistively heating at least about 10 m of length of the ferromagnetic conductor to the temperature of at least about 300 °C.
1597. The method of claim 1593, wherein the ferromagnetic conductor comprises carbon steel.
1598. The method of claim 1593, wherein the electrical conductor is the core of an insulated conductor.
1599. The method of claim 1593, wherein the ferromagnetic conductor has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.
1600. The method of claim 1593, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa.
1601. The method of claim 1593, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.
1602. The method of claim 1593, further comprising applying the electrical current to the electrical conductor in one direction.
1603. The method of claim 1593, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.
1604. The method of claim 1593, further comprising allowing heat to transfer from the ferromagnetic conductor to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.
1605. The method of claim 1593, further comprising resistively heating at least one additional ferromagnetic conductor located in the formation, and providing heat from the ferromagnetic conductors such that heat from at least two of the ferromagnetic conductors is superpositioned in the formation and mobilizes hydrocarbons in the formation.
1606. A heating system for a subsurface formation, comprising:

   an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;

   an insulation layer at least partially surrounding the electrical conductor; and
a ferromagnetic sheath at least partially surrounding the insulation layer, the ferromagnetic sheath and the electrical conductor being configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic sheath, or vice versa;

wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic sheath such that the ferromagnetic sheath resistively heats.

1607. The system of claim 1606, wherein the ferromagnetic sheath is configured to provide heat to at least a portion of the subsurface formation.

1608. The system of claim 1606, wherein the electrical conductor is configured to induce electrical current flow on the inside and the outside surfaces of the ferromagnetic sheath.

1609. The system of claim 1606, wherein the electrical conductor, the insulation layer, and the ferromagnetic sheath are substantially physically contacting each other longitudinally.

1610. The system of claim 1606, wherein the electrical conductor, the insulation layer, and the ferromagnetic sheath comprise substantially u-shapes in the formation.

1611. The system of claim 1606, wherein the ferromagnetic sheath comprises carbon steel.

1612. The system of claim 1606, wherein the ferromagnetic sheath has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic sheath at 50 °C below the Curie temperature of the ferromagnetic material.

1613. The system of claim 1606, wherein the ferromagnetic sheath is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic sheath.

1614. The system of claim 1606, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic sheath.

1615. The system of claim 1606, further comprising an additional insulation layer at least partially surrounding the ferromagnetic sheath, and an additional ferromagnetic sheath substantially surrounding the additional insulation layer, wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the additional ferromagnetic sheath such that the additional ferromagnetic sheath resistively heats.

1616. The system of claim 1606, wherein the ferromagnetic sheath and the electrical conductor are electrically insulated from each other.

1617. A method for heating a subsurface formation, comprising:

providing time-varying electrical current to an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact;
inducing electrical current flow in a ferromagnetic sheath with the time-varying electrical current in the electrical conductor, wherein the ferromagnetic sheath at least partially surrounds an insulation layer that at least partially surrounds the electrical conductor, the ferromagnetic sheath and the electrical conductor being configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic sheath, or vice versa; and resistively heating the ferromagnetic sheath with the induced electrical current flow such that the ferromagnetic sheath resistively heats.

1618. The method of claim 1617, further comprising allowing heat to transfer from the ferromagnetic sheath to at least a portion of the subsurface formation.

1619. The method of claim 1617, further comprising resistively heating at least about 10 m of length of the ferromagnetic sheath to a temperature of at least about 300 °C.

1620. The method of claim 1617, wherein the ferromagnetic sheath comprises carbon steel.

1621. The method of claim 1617, wherein the ferromagnetic sheath has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1622. The method of claim 1617, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic sheath.

1623. The method of claim 1617, further comprising applying the electrical current to the electrical conductor in one direction from the first electrical contact to the second electrical contact.

1624. The method of claim 1617, further comprising allowing heat to transfer from the ferromagnetic sheath to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

1625. The method of claim 1617, further comprising allowing heat to transfer from the ferromagnetic sheath to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

1626. The method of claim 1617, further comprising resistively heating at least one additional ferromagnetic sheath located in the formation, and providing heat from the ferromagnetic sheaths such that heat from at least two of the ferromagnetic sheaths is superpositioned in the formation and mobilizes hydrocarbons in the formation.

1627. A heating system for a subsurface formation, comprising:

- a first electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least a first electrical contact and a second electrical contact;
- a first insulation layer at least partially surrounding the first electrical conductor;
a first ferromagnetic sheath at least partially surrounding the first insulation layer, the first ferromagnetic sheath and the first electrical conductor being configured in relation to each other such that electrical current does not flow from the first electrical conductor to the first ferromagnetic sheath, or vice versa;

a second electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least the first electrical contact and the second electrical contact;

a second insulation layer at least partially surrounding the second electrical conductor;

a second ferromagnetic sheath at least partially surrounding the second insulation layer, the second ferromagnetic sheath and the second electrical conductor being configured in relation to each other such that electrical current does not flow from the second electrical conductor to the second ferromagnetic sheath, or vice versa; and

a third insulation layer located between the first ferromagnetic sheath and the second ferromagnetic sheath;

wherein the first and second electrical conductors, when energized with time-varying electrical current, induce sufficient electrical current flow in the first and second ferromagnetic sheaths, respectively, such that the ferromagnetic sheaths resistively heat.

1628. The system of claim 1627, wherein the first and second electrical conductors are configured to be coupled to the same power source.

1629. The system of claim 1627, wherein the first and second electrical conductors are configured to conduct current in opposite directions.

1630. The system of claim 1627, wherein the third insulation layer is sandwiched between first ferromagnetic sheath and the second ferromagnetic sheath.

1631. The system of claim 1627, wherein the third insulation layer comprises a corrosion resistant material.

1632. The system of claim 1627, wherein at least one of the ferromagnetic sheaths is configured to provide heat to at least a portion of the subsurface formation.

1633. The system of claim 1627, wherein at least one of the electrical conductors is configured to induce electrical current flow on the inside and the outside surfaces of at least one of the ferromagnetic sheaths.

1634. The system of claim 1627, wherein the electrical conductors, the insulation layers, and the ferromagnetic sheaths are substantially physically contacting each other longitudinally.

1635. The system of claim 1627, wherein the electrical conductors, the insulation layers, and the ferromagnetic sheaths comprise substantially u-shapes in the formation.
1636. The system of claim 1627, wherein at least one of the ferromagnetic sheaths comprises carbon steel.

1637. The system of claim 1627, wherein at least one of the ferromagnetic sheaths has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic sheath at 50 °C below the Curie temperature of the ferromagnetic material.

1638. The system of claim 1627, wherein at least one of the ferromagnetic sheaths is configured to provide different heat outputs along at least a portion of the length of the ferromagnetic sheath.

1639. A method for heating a subsurface formation, comprising:

- providing time-varying electrical current to a first elongated electrical conductor located in the subsurface formation, wherein the first electrical conductor extends between at least a first electrical contact and a second electrical contact;

- inducing electrical current flow in a first ferromagnetic sheath with the time-varying electrical current in the first electrical conductor, wherein the first ferromagnetic sheath at least partially surrounds a first insulation layer that at least partially surrounds the first electrical conductor, the first ferromagnetic sheath and the first electrical conductor being configured in relation to each other such that electrical current does not flow from the first electrical conductor to the first ferromagnetic sheath, or vice versa;

- resistively heating the first ferromagnetic sheath with the induced electrical current flow such that the first ferromagnetic sheath resistively heats;

- providing time-varying electrical current to a second elongated electrical conductor located in the subsurface formation, wherein the second electrical conductor extends between at least the first electrical contact and the second electrical contact;

- inducing electrical current flow in a second ferromagnetic sheath with the time-varying electrical current in the second electrical conductor, wherein the second ferromagnetic sheath at least partially surrounds a second insulation layer that at least partially surrounds the second electrical conductor, the second ferromagnetic sheath and the second electrical conductor being configured in relation to each other such that electrical current does not flow from the second electrical conductor to the second ferromagnetic sheath, or vice versa; and

- resistively heating the second ferromagnetic sheath with the induced electrical current flow such that the second ferromagnetic sheath resistively heats;

- wherein a third insulation layer is located between the first ferromagnetic sheath and the second ferromagnetic sheath.

1640. The method of claim 1639, further comprising providing time-varying current to the first and second electrical conductors from the same power source.
1641. The method of claim 1639, further comprising providing time-varying current to the first and second electrical conductors in opposite directions.

1642. The method of claim 1639, further comprising allowing heat to transfer from at least one of the ferromagnetic sheaths to at least a portion of the subsurface formation.

1643. The method of claim 1639, further comprising resistively heating at least about 10 m of length of at least one of the ferromagnetic sheaths to a temperature of at least about 300 °C.

1644. The method of claim 1639, wherein at least one of the ferromagnetic sheaths comprises carbon steel.

1645. The method of claim 1639, wherein at least one of the ferromagnetic sheaths has a thickness of at least 2.1 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.

1646. The method of claim 1639, further comprising providing different heat outputs along at least a portion of the length of at least one of the ferromagnetic sheaths.

1647. The method of claim 1639, further comprising allowing heat to transfer from the ferromagnetic sheaths to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized.

1648. The method of claim 1639, further comprising allowing heat to transfer from the ferromagnetic sheaths to at least a portion of the subsurface formation such that hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons from the formation.

1649. The method of claim 1639, further comprising resistively heating at least two additional ferromagnetic sheaths located in the formation, and providing heat from the ferromagnetic sheaths such that heat from at least four of the ferromagnetic sheaths is superpositioned in the formation and mobilizes hydrocarbons in the formation.

1650. A heating system for a subsurface formation, comprising:

an electrical conductor extending into the subsurface formation; and

a ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of an overburden section of the formation, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor comprises a plurality of straight, angled, or longitudinally spiral grooves or protrusions that increase the effective circumference of the ferromagnetic conduit;

wherein the straight, angled, or longitudinally spiral grooves or protrusions are configured to inhibit or reduce induction resistance heating in the ferromagnetic conductor.
1651. The system of claim 1650, wherein the grooves or protrusions extend substantially axially along the length of the ferromagnetic conductor.
1652. The system of claim 1650, wherein the grooves or protrusions increase the effective circumference of the ferromagnetic conductor at least about 2 times over the effective circumference of a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.
1653. The system of claim 1650, wherein the grooves or protrusions reduce the induced electrical current flow in the ferromagnetic conductor as compared to a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.
1654. The system of claim 1650, wherein the grooves or protrusions inhibit induced electrical current flow in the ferromagnetic conductor.
1655. The system of claim 1650, wherein the grooves or protrusions are configured to reduce the effective resistance of the ferromagnetic conductor.
1656. The system of claim 1650, wherein the grooves or protrusions comprise spiral grooves with a significant longitudinal component.
1657. The system of claim 1650, wherein the grooves or protrusions are on the inside surface of the ferromagnetic conductor.
1658. The system of claim 1650, wherein the grooves or protrusions are on the outside surface of the ferromagnetic conductor.
1659. The system of claim 1650, wherein the grooves or protrusions are on both the inside and outside surfaces of the ferromagnetic conductor.
1660. The system of claim 1650, wherein the electrical conductor is configured to provide current to an electric resistance heating system in the formation.
1661. The system of claim 1650, further comprising a second ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of the subsurface formation, wherein the second ferromagnetic conductor is configured to provide heat to at least the portion of the subsurface formation when the second ferromagnetic conductor is either energized with time-varying electrical current or electrical current is induced in the second ferromagnetic conductor by the flow of time-varying electrical current in the electrical conductor.
1662. The system of claim 1650, wherein the electrical conductor comprises a substantially u-shaped electrical conductor extending between a first wellbore and a second wellbore in the formation.
1663. The system of claim 1650, wherein the ferromagnetic conductor comprises carbon steel.
1664. The system of claim 1650, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.
1665. A method for providing current to an electrical resistance heater in a subsurface formation while inhibiting heating in an overburden section of the subsurface formation, comprising:

providing time-varying electrical current to an electrical conductor extending through the overburden section of the formation into the subsurface formation; and

inducing electrical current flow in a ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of the overburden section, wherein the ferromagnetic conductor and the electrical conductor are configured in relation to each other such that electrical current does not flow from the electrical conductor to the ferromagnetic conductor, or vice versa, and wherein the ferromagnetic conductor comprises a plurality of straight, angled, or longitudinally spiral grooves or protrusions that increase the effective circumference of the ferromagnetic conduit.

1666. The method of claim 1665, wherein the grooves or protrusions increase the effective circumference of the ferromagnetic conductor at least about 2 times over the effective circumference of a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1667. The method of claim 1665, wherein the grooves or protrusions reduce the induced electrical current flow in the ferromagnetic conductor as compared to a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1668. The method of claim 1665, further comprising inhibiting induced electrical current flow in the ferromagnetic conductor with the grooves or protrusions.

1669. The method of claim 1665, wherein the grooves or protrusions comprise spiral grooves with a significant longitudinal component.

1670. The method of claim 1665, wherein the grooves or protrusions are on the inside surface of the ferromagnetic conductor.

1671. The method of claim 1665, wherein the grooves or protrusions are on the outside surface of the ferromagnetic conductor.

1672. The method of claim 1665, wherein the grooves or protrusions are on both the inside and outside surfaces of the ferromagnetic conductor.

1673. The method of claim 1665, further comprising providing current to an electric resistance heating system in the formation with the electrical conductor.

1674. The method of claim 1665, further comprising providing heat to at least a portion of the of the subsurface formation by applying the time-varying electrical current to a second ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of the formation.
1675. The method of claim 1665, further comprising providing heat to at least a portion of the subsurface formation by inducing electrical current flow in a second ferromagnetic conductor at least partially surrounding the electrical conductor in at least a portion of the formation.

1676. The method of claim 1665, wherein the electrical conductor comprises a substantially u-shaped electrical conductor extending between a first wellbore and a second wellbore in the formation.

1677. The method of claim 1665, wherein the ferromagnetic conductor comprises carbon steel.

1678. The method of claim 1665, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.

1679. A heating system for a subsurface formation, comprising:

   a ferromagnetic conductor extending into the subsurface formation, wherein the ferromagnetic conductor is configured to resistively heat when electrical current is applied to, or induced in, the ferromagnetic conductor; and

   a plurality of straight, angled, or spiral grooves or protrusions located on at least one surface of the ferromagnetic conductor, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conduit.

1680. The system of claim 1679, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conductor by increasing the path length for the electrical current flow on the surface of the ferromagnetic conductor.

1681. The system of claim 1679, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conductor over the effective resistance of a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1682. The system of claim 1679, wherein the grooves or protrusions are positioned substantially radially on the ferromagnetic conductor.

1683. The system of claim 1679, wherein the grooves or protrusions are on the inside surface of the ferromagnetic conductor.

1684. The system of claim 1679, wherein grooves or protrusions are on the outside surface of the ferromagnetic conductor.

1685. The system of claim 1679, wherein the grooves or protrusions are on both the inside and outside surfaces of the ferromagnetic conductor.

1686. The system of claim 1679, wherein the ferromagnetic conductor is configured such that a majority of the resistive heat is generated in a skin depth of the ferromagnetic conductor at temperatures below the Curie temperature of the ferromagnetic conductor.

1687. The system of claim 1679, wherein the ferromagnetic conductor is configured to provide heat to at least a portion of the layer to be heated in the subsurface formation.
1688. The system of claim 1679, wherein the ferromagnetic conductor comprises carbon steel.
1689. The system of claim 1679, wherein the ferromagnetic conductor has a thickness of at least 2 times the skin depth of the ferromagnetic material in the ferromagnetic conductor at 50 °C below the Curie temperature of the ferromagnetic material.
1690. The system of claim 1679, further comprising a corrosion resistant material coating on at least a portion of the ferromagnetic conductor.
1691. The system of claim 1679, wherein the ferromagnetic conductor comprises a ferromagnetic tubular.
1692. The system of claim 1679, further comprising an elongated electrical conductor located in the subsurface formation, wherein the electrical conductor extends between at least a first electrical contact and a second electrical contact, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor, and wherein the electrical conductor, when energized with time-varying electrical current, induces sufficient electrical current flow in the ferromagnetic conductor such that the ferromagnetic conductor resistively heats.
1693. A method for heating a subsurface formation, comprising:
applying, or inducing, electrical current in a ferromagnetic conductor extending into the subsurface formation;
resistively heating the ferromagnetic conductor with the electrical current, wherein the ferromagnetic conductor comprises a plurality of straight, angled, or spiral grooves or protrusions located on at least one surface of the ferromagnetic conductor that increase the effective resistance of the ferromagnetic conduit; and
allowing heat to transfer from the ferromagnetic conductor to at least a part of the formation.
1694. The method of claim 1693, further comprising resistively heating the ferromagnetic conductor to a temperature of at least about 300 °C.
1695. The method of claim 1693, further comprising providing different heat outputs along at least a portion of the length of the ferromagnetic conductor.
1696. The method of claim 1693, wherein heat from the ferromagnetic conductor superpositions heat provided from at least one additional heater located in the formation.
1697. The method of claim 1693, wherein heat from the ferromagnetic conductor superpositions heat provided from at least one additional ferromagnetic conductor in the formation that resistively heats with electrical current flow.
1698. The method of claim 1693, further comprising mobilizing at least some hydrocarbons in the part of the formation.
1699. The method of claim 1693, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conductor by increasing the path length for the electrical current flow on the surface of the ferromagnetic conductor.

1700. The method of claim 1693, wherein the grooves or protrusions increase the effective resistance of the ferromagnetic conductor over the effective resistance of a ferromagnetic conductor with smooth surfaces and the same inside and outside diameters.

1701. The method of claim 1693, wherein the grooves or protrusions are positioned substantially radially on the ferromagnetic conductor.

1702. The method of claim 1693, wherein the grooves or protrusions are on the inside surface of the ferromagnetic conductor.

1703. The method of claim 1693, wherein grooves or protrusions are on the outside surface of the ferromagnetic conductor.

1704. The method of claim 1693, wherein the grooves or protrusions are on both the inside and outside surfaces of the ferromagnetic conductor.

1705. A method of treating a formation fluid, comprising:
   providing formation fluid from a subsurface in situ heat treatment process;
   separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises carbon dioxide, hydrogen sulfide, hydrocarbons, hydrogen or mixtures thereof;
   separating molecular oxygen from air to form a molecular oxygen stream comprising molecular oxygen;
   combining the first gas stream with the molecular oxygen stream to form a combined stream comprising molecular oxygen and the first gas stream; and
   providing the combined stream to one or more downhole burners.

1706. The method of claim 1705, wherein separating the molecular oxygen from air comprises cryogenically distilling the air.

1707. The method of claim 1705, wherein separating the molecular oxygen from air comprises providing the air through one or more separation units operated above -180 °C at 0.101 MPa.

1708. The method of claim 1705, wherein separating air comprises forming a nitrogen stream.

1709. The method of claim 1708, further comprising providing at least some of the nitrogen from the nitrogen stream to one or more barrier wells.

1710. The method of claim 1708, further comprising providing at least some of the nitrogen from the nitrogen stream to one or more freeze wells.

1711. The method of claim 1708, further comprising providing at least some of the nitrogen from the nitrogen stream to one or more processing facilities.
1712. The method of claim 1705, further comprising:
    applying current to water to form the molecular oxygen stream, and a molecular hydrogen stream comprising molecular hydrogen.
1713. The method of claim 1712, further comprising heating the water to a temperature of at least about 500 °C to about 1000 °C.
1714. The method of claim 1712, further comprising heating the water by applying energy from a nuclear power source.
1715. The method of claim 1714, wherein the nuclear power source comprises a self-regulating nuclear reactor.
1716. The method of claim 1714, wherein the nuclear power source comprises a pebble bed nuclear reactor.
1717. The method of claim 1714, wherein the nuclear power source comprises a lead-cooled fast nuclear reactor.
1718. The method of claim 1714, wherein the nuclear power source comprises a supercritical-water-cooled nuclear reactor.
1719. The method of claim 1714, wherein the nuclear power source comprises a sodium-cooled fast nuclear reactor.
1720. The method of claim 1714, wherein the nuclear power source comprises a molten salt nuclear reactor.
1721. The method of claim 1712, further comprising providing at least some molecular hydrogen from the molecular hydrogen stream to one or more fuel conduits of the one or more downhole burners.
1722. The method of claim 1712, further comprising providing at least some molecular hydrogen from the molecular hydrogen stream to one or more portions of the formation.
1723. The method of claim 1712, further comprising providing at least some molecular hydrogen from the molecular hydrogen stream to one or more process facilities.
1724. A system, comprising:
    a separating unit configured to receive formation fluid from a subsurface in situ heat treatment process and separate the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises carbon dioxide, sulfur compounds, hydrocarbons, hydrogen, or mixtures thereof;
    a fuel conduit configured to receive the first gas stream and transport the first gas stream;
    an oxidizing fluid production system configured to apply current to water to form an oxidizing fluid;
an oxidizing fluid conduit configured to receive the oxidizing fluid and transport the oxidizing fluid; and
one or more downhole burners in or near the formation or another formation and coupled to the fuel conduit and oxidizing fluid conduit, wherein at least one of the burners is configured to receive the first gas stream and/or the oxidizing fluid from the fuel and/or oxidizing fluid conduits and combust the first gas stream and/or the oxidizing fluid stream, thereby heating at least a portion of the formation or another formation.

1725. The system of claim 1724, wherein the oxidizing fluid production system is configured to heat the water to a temperature of at least about 500 °C to about 1000 °C.

1726. The system of claim 1724, wherein the oxidizing fluid production system is configured to heat the water by applying energy from a nuclear power source.

1727. The system of claim 1726, wherein the nuclear power source comprises a self-regulating nuclear reactor.

1728. The system of claim 1726, wherein the nuclear power source comprises a pebble bed nuclear reactor.

1729. The system of claim 1726, wherein the nuclear power source comprises a lead-cooled fast nuclear reactor.

1730. The system of claim 1726, wherein the nuclear power source comprises a supercritical-water-cooled nuclear reactor.

1731. The system of claim 1726, wherein the nuclear power source comprises a sodium-cooled fast nuclear reactor.

1732. The system of claim 1726, wherein the nuclear power source comprises a molten salt nuclear reactor.

1733. A method of treating formation fluid, comprising:
- providing formation fluid from a subsurface in situ heat treatment process;
- separating the formation fluid to produce a liquid stream and a gas stream, wherein the gas stream comprises hydrocarbons;
- providing the gas stream to a reformation unit;
- reforming the gas stream to produce a hydrogen gas stream; and
- providing at least a portion of the hydrogen in the hydrogen gas stream to one or more downhole burners in or near the formation or another formation.

1734. A method for treating a hydrocarbon containing formation, comprising:
- providing heat input to a first section of the formation from one or more heat sources located in the first section; and
producing fluids from the first section through a production well located at or near the center of the first section;

wherein the heat sources are configured such that the average heat input per volume of formation in the first section increases with distance from the production well.

1735. The method of claim 1734, further comprising providing different heat outputs from the heat sources such that the average heat output from heat sources in the first section increases with distance from the production well.

1736. The method of claim 1734, further comprising arranging the heat sources such that the number of heat sources per volume of formation increases with distance from the production well.

1737. The method of claim 1734, further comprising:

providing heat input to a second section of the formation from one or more heat sources located in the second section, the second section being located adjacent to the first section; and producing fluids from the second section through a production well located at or near the center of the second section;

wherein the heat sources are configured such that the average heat input per volume of formation in the second section increases with distance from the production well in the second section.

1738. The method of claim 1734, further comprising:

providing heat input to a third section of the formation from one or more heat sources located in the third section, the third section being located adjacent to the first section; and producing fluids from the third section through a production well located at or near the center of the third section;

wherein the heat sources are configured such that the average heat input per volume of formation in the third section increases with distance from the production well in the third section.

1739. The method of claim 1734, further comprising producing hydrocarbons from the first section that are liquid hydrocarbons at 25 °C and 1 atm, wherein a majority of such liquid hydrocarbons are hydrocarbons originally in place in the first section.

1740. The method of claim 1734, wherein the heat sources comprise heaters.

1741. The method of claim 1734, further comprising providing heat input into the first section from the heat sources such that fluids moving from near heat sources located furthest from the production well in the first section to the production well are at least partially cooled.
1742. The method of claim 1734, further comprising mobilizing hydrocarbons with heat provided by the heat sources, and producing mobilized hydrocarbons through the production well.

1743. The method of claim 1734, further comprising providing heat to a portion of the formation near the production well with heat from mobilized fluids moving to the production well from the outside the portion near the production well.

1744. The method of claim 1734, further comprising reducing or turning off heating in the heat sources near the production well when a temperature at or near the production well reaches a temperature of at least about 100 °C.

1745. The method of claim 1734, further comprising turning on at least a majority of the heat sources in a sequence with at least a majority of the heat sources furthest from the production well being turned on before at least a majority of the heat sources nearest the production well are turned on.

1746. The method of claim 1734, further comprising turning off or reducing heat output from at least a majority of the heat sources in a sequence with at least a majority of the heat sources furthest from the production well having their heat output turned off or reduced before at least a majority of the heat sources nearest the production well have their heat output turned off or reduced.

1747. The method of claim 1734, further comprising providing the heat input into the formation from the heat sources such that the heat input to the formation per volume of formation in a first volume of the first section is less than the heat input to the formation per volume of formation in a second volume of the first section and the heat input to the formation per volume of formation in the second volume of the first section is less than the heat input to the formation per volume of a third volume of the first section, wherein the first volume substantially surrounds a production well located at or near the center of the section, the second volume substantially surrounds the first volume, and the third volume substantially surrounds the second volume.

1748. The method of claim 1747, wherein at least one heat source is located in the first volume, the second volume, and/or the third volume.

1749. The method of claim 1747, wherein at least two heat sources are located in the first volume, the second volume, and/or the third volume.

1750. The method of claim 1747, wherein at least three heat sources are located in the first volume, the second volume, and/or the third volume.

1751. The method of claim 1747, wherein the first volume is approximately equal in volume to the second volume and/or the third volume.
1752. The method of claim 1747, wherein the second volume is approximately equal in volume to the third volume.

1753. The method of claim 1747, wherein all of the heat sources located in the first volume are closer to the production well than any of the heat sources in the second volume.

1754. The method of claim 1747, wherein the average distance from the production well of heat sources located in the first volume is less than the average distance from the production well of heat sources located in the second volume.

1755. A method for treating a hydrocarbon containing formation, comprising:

    providing heat input to a first section of the formation from one or more heat sources located in the first section;

    providing the heat input into the formation from the heat sources such that the heat input to the formation per volume of formation in a first volume of the first section is less than the heat input to the formation per volume of formation in a second volume of the first section and the heat input to the formation per volume of formation in the second volume is less than the heat input to the formation per volume of a third volume of the first section, wherein the first volume substantially surrounds a production well located at or near the center of the section, the second volume substantially surrounds the first volume, and the third volume substantially surrounds the second volume; and

    producing fluids from the first section through the production well.

1756. The method of claim 1755, further comprising providing different heat outputs from the heat sources such that the average heat output from heat sources in the first volume is less than the average heat output of heat sources in the second volume.

1757. The method of claim 1755, further comprising arranging the heat sources such that the number of heat sources per volume of formation in the first volume is less than the number of heat sources per volume of formation in the second volume.

1758. The method of claim 1755, wherein the first volume has an average radial distance from the production well that is less than an average radial distance from the production well of the second volume.

1759. The method of claim 1755, wherein the heat sources comprise heaters.

1760. The method of claim 1755, further comprising providing heat input into the first section from the heat sources such that fluids moving from at or near the heat sources in the second volume to the production well are at least partially cooled.

1761. The method of claim 1755, further comprising mobilizing hydrocarbons with heat provided by the heat sources, and producing mobilized hydrocarbons through the production well.
1762. The method of claim 1755, further comprising providing heat to the portion of the formation between the first volume and the production well with heat from mobilized fluids moving to the production well from the second volume.

1763. The method of claim 1755, wherein the heat sources in the first volume are different types of heat sources than the heat sources in the second volume.

1764. The method of claim 1755, further comprising providing the heat input into the formation from the heat sources such that the heat output to the formation per volume of formation in a fourth volume of the first section is greater than the heat output to the formation per volume of formation in the third volume, wherein the fourth volume substantially surrounds the third volume.

1765. The method of claim 1755, further comprising reducing or turning off heating in the heat sources in the first volume when a temperature at or near the production well reaches a temperature of at least about 100 °C.

1766. The method of claim 1755, further comprising turning on at least a majority of the heat sources in a sequence with at least a majority of the heat sources furthest from the production well being turned on before at least a majority of the heat sources nearest the production well are turned on.

1767. The method of claim 1755, further comprising turning off or reducing heat output from at least a majority of the heat sources in a sequence with at least a majority of the heat sources furthest from the production well having their heat output turned off or reduced before at least a majority of the heat sources nearest the production well have their heat output turned off or reduced.

1768. The method of claim 1755, wherein at least one heat source is located in the first volume, the second volume, and/or the third volume.

1769. The method of claim 1755, wherein at least two heat sources are located in the first volume, the second volume, and/or the third volume.

1770. The method of claim 1755, wherein at least three heat sources are located in the first volume, the second volume, and/or the third volume.

1771. The method of claim 1755, wherein the first volume is approximately equal in volume to the second volume and/or the third volume.

1772. The method of claim 1755, wherein the second volume is approximately equal in volume to the third volume.

1773. The method of claim 1755, wherein all of the heat sources located in the first volume are closer to the production well than any of the heat sources in the second volume.
1774. The method of claim 1755, wherein the average distance from the production well of heat sources located in the first volume is less than the average distance from the production well of heat sources located in the second volume.

1775. A method for treating a hydrocarbon containing formation, comprising:
   providing heat to a first portion of the formation from a plurality of heaters in the first portion, at least two of the heaters being located in heater wells in the first portion;
   producing fluids through one or more production wells in a second portion of the formation, the second portion being at least partially substantially adjacent to the first portion;
   reducing or turning off the heat provided to the first portion after a selected time;
   providing an oxidizing fluid through one or more of the heater wells in the first portion;
   providing heat to the first portion and the second portion through oxidation of at least some hydrocarbons in the first portion and movement of the fluids heated by such oxidation from the first portion to the second portion; and
   producing fluids through at least one of the production wells in the second portion, the produced fluids comprising at least some oxidized hydrocarbons produced in the first portion.

1776. The method of claim 1775, further comprising producing fluids comprising at least some oxidation products through one or more production wells located in a third portion of the formation, the third portion being substantially adjacent to the second portion.

1777. The method of claim 1775, wherein one or more of the heaters are substantially horizontal or inclined.

1778. The method of claim 1775, further comprising controlling the pressure in the formation to at least partially control the oxidation of hydrocarbons in the formation.

1779. The method of claim 1775, wherein the oxidizing fluid comprises air, and further comprising using at least some of the produced fluids to power one or more turbines at the surface of the formation.

1780. The method of claim 1775, further comprising heating with heaters, producing, and providing heat through oxidation to a second or additional portions of the formation in a sequential manner.

1781. The method of claim 1775, further comprising injecting steam into the formation.

1782. A method for treating a subsurface formation, comprising:
   heating a first portion from one or more heaters located in the first portion;
   producing hydrocarbons from the first portion;
   reducing or turning off the heat provided to the first portion after a selected time;
injecting an oxidizing fluid in the first portion to cause a temperature of the first portion to increase sufficiently to oxidize hydrocarbons in the first portion and a third portion, the third portion being substantially below the first portion;

heating a second portion from heat transferred from the first portion and/or third portion and/or one or more heaters located in the second portion such that an average temperature in the second portion is at least about 100 °C, wherein the second portion is substantially adjacent to the first portion;

allowing hydrocarbons to flow from the second portion into the first portion and/or third portion;

discontinuing or reducing injection of the oxidizing fluid in the first portion; and

producing additional hydrocarbons from the first portion of the formation, the additional hydrocarbons comprising oxidized hydrocarbons from the first portion, at least some hydrocarbons from the second portion, at least some hydrocarbons from the third portion of the formation, or mixtures thereof, and wherein a temperature of the first portion is below 600 °C.

1783. The method of claim 1782, wherein the third portion is directly below the first portion.

1784. The method of claim 1782, wherein the second portion is directly adjacent to the first portion.

1785. The method of claim 1782, wherein producing comprises producing a majority of the hydrocarbons from the formation.

1786. The method of claim 1782, further comprising injecting steam into the formation.

1787. A method for treating a subsurface formation, comprising:

producing a majority of hydrocarbons from a first portion and/or a third portion by an in situ heat treatment process,

heating a second portion with one or more heaters to an average temperature of at least about 100 °C; the first portion and third portion being separated by the second portion;

reducing or turning off the heat provided to the first portion after a selected time;

injecting an oxidizing fluid in the first portion to cause a temperature of the first portion to increase sufficiently to oxidize hydrocarbons in the first portion;

injecting an oxidizing fluid and/or a drive fluid and/or creating a drive fluid in the third portion to cause at least some hydrocarbons to move from the third portion through the second portion to the first portion of the hydrocarbon layer;

reducing or discontinuing injection of the oxidizing fluid in the first portion; and

producing additional hydrocarbons and/or syngas from the first portion of the formation, the additional hydrocarbons and/or syngas comprising at least some hydrocarbons from the second and third portions of the formation.
1788. The method of claim 1787, wherein the oxidizing fluid comprises air and/or hydrocarbons produced from the first portion and/or the second portion.

1789. The method of claim 1787, wherein the drive fluid comprises steam, water, carbon dioxide, carbon monoxide, methane, pyrolyzed hydrocarbons, and/or air.

1790. The method of claim 1787, wherein the average temperature of the third portion ranges from 270 °C to 450 °C.

1791. The method of claim 1787, further comprising heating to create sufficient drive fluid in the third portion such that injecting drive fluid and/or oxidizing fluid in the third portion is discontinued.

1792. The method of claim 1787, further comprising heating a fourth portion and a fifth portion of the hydrocarbon formation with heaters, wherein the fourth portion is between the first and fifth portion and wherein a temperature of the fourth portion is less than a temperature than the first portion and a temperature of the fifth portion; and a producing hydrocarbons from the fifth portion.

1793. The method of claim 1792, further comprising reducing or discontinuing production in the fifth portion; and injecting an oxidizing fluid in the fifth portion to cause a temperature of the fifth portion to increase sufficiently to oxidize hydrocarbons in the fifth portion, wherein injecting occurs during moving hydrocarbons from the third portion to the first portion and producing additional hydrocarbons from the first portion.

1794. The method of claim 18, wherein a temperature of the first portion is below 450 °C, a temperature of the fourth portion is at least about 100 °C, and a temperature of the fifth portion is at least 450 °C.

1795. The method of claim 1792, further comprising:
   reducing or discontinuing production of additional hydrocarbons from the first portion;
   injecting and/or creating a drive fluid and/or an oxidizing fluid in the first portion to cause at least some hydrocarbons to move from the first portion through the fourth portion to the fifth portion of the hydrocarbon layer;
   reducing injection of the oxidizing fluid into the fifth portion; and
   producing additional hydrocarbons and/or syngas from the fifth portion of the formation, the additional hydrocarbons and/or syngas comprising at least some hydrocarbons from the first and fourth portions of the formation.

1796. The method of claim 1787, wherein the formation has a horizontal permeability that is higher than a vertical permeability so that the majority of hydrocarbons that move are moving substantially horizontally through the formation.
1797. The method of claim 1787, wherein the second portion has a larger volume than the first portion and/or the third portion.

1798. The method of claim 1787, wherein at least some of the heaters in the first portion are turned down and/or off after injecting oxidizing fluid in the first portion.

1799. The method of claim 1787, further comprising controlling the temperature and the pressure in the first portion and/or the third portion such that (a) at least a majority of the hydrocarbons in the first portion and/or the third portion are visbroken, (b) the pressure is below the fracture pressure of the first portion and/or the third portion, and (c) at least some hydrocarbons in the first portion and/or the third portion form a fluid comprising visbroken hydrocarbons that can be produced through a production well.

1800. The method of claim 1787, further comprising mobilizing at least some hydrocarbons in the second portion using heat provided from heaters located in the second portion, heat transferred from the first portion, and/or heat transferred from the third portion.

1801. The method of claim 1787, further comprising providing a catalyst system to the third portion prior to injecting and/or creating a drive fluid; and contacting the hydrocarbons in the third portion with the catalyst system to produce an in situ diluent.

1802. The method of claim 1801, wherein the in situ diluent comprises aromatic hydrocarbons; and further comprising solubilizing bitumen and/or heavy hydrocarbons in the third portion.

1803. The method of claim 1787, further comprising injecting steam into the formation.

1804. A method for treating a subsurface formation, comprising:

- producing at least one third of hydrocarbons from a first portion of the formation by an in situ heat treatment process, wherein an average temperature of the first portion is less than 350 °C;

- injecting an oxidizing fluid in the first portion to cause the average temperature of the first portion to increase sufficiently to oxidize hydrocarbons in the first portion and to raise the average temperature of the first portion to greater than 350 °C; and

- injecting a heavy hydrocarbon fluid in the first portion to form a diluent and/or drive fluid, the heavy hydrocarbon fluid comprising condensable hydrocarbons.

1805. The method of claim 1804, wherein the average temperature of the first portion is raised to a temperature ranging from 350 °C and 700 °C.

1806. The method of claim 1804, further comprising producing hydrocarbons from a second portion of the formation, the second portion being substantially adjacent to the first portion.

1807. The method of claim 1804, further comprising producing hydrocarbons from a second portion of the formation, the second portion being substantially adjacent to the first portion and
further causing the diluent and/or drive fluid to move into the second portion, thereby mobilizing at least some hydrocarbons in the second portion.

1808. The method of claim 1804, further comprising using the diluent and/or drive fluid to produce additional hydrocarbons from the first portion or from a section adjacent to the first section.

1809. The method of claim 1804, further comprising providing a catalyst system to the first portion.

1810. The method of claim 1804, further comprising providing a catalyst system to the first portion, the catalyst system being adapted to catalytically crack at least a portion of the condensable hydrocarbon in the heavy hydrocarbon fluid.

1811. The method of claim 1804, further comprising adding a catalyst to the first portion after at least one third of the hydrocarbons are produced from the first portion.

1812. The method of claim 1804, further comprising producing used catalyst from surface treatment facilities to the formation.

1813. The method of claim 1804, further comprising injecting steam into the formation.

1814. A method for treating a nahcolite containing subsurface formation, comprising:
   solution mining a first nahcolite bed above a hydrocarbon containing layer using a plurality of first solution mining wells;
   solution mining a second nahcolite bed below the hydrocarbon containing layer using a plurality of second solution mining wells;
   converting at least one of the first solution mining wells into a production well;
   heating the hydrocarbon containing layer using a plurality of heaters; and
   producing formation fluid from at least one converted first solution mining well.

1815. The method of claim 1814, wherein formation fluid produced from one or more converted first solution mining wells comprises vaporized formation fluid.

1816. The method of claim 1814, further comprising converting at least one of the second solution mining wells into a production well, and producing formation fluid from at least one converted second solution mining wells.

1817. The method of claim 1816, wherein formation fluid produced from one or more converted second solution mining wells comprises liquid formation fluid.

1818. The method of claim 1814, wherein a portion of at least one of the heaters extends into the second nahcolite bed.

1819. The method of claim 1814, wherein the hydrocarbon containing layer comprises oil shale.

1820. The method of claim 1814, wherein the heaters are configured to raise an average temperature of the hydrocarbon containing layer above a pyrolysis temperature.
1821. A method for treating a nahcolite containing subsurface formation, comprising:
   solution mining a first nahcolite bed above a hydrocarbon containing layer using a
   plurality of first solution mining wells;
   solution mining a second nahcolite bed below the hydrocarbon containing layer using a
   plurality of second solution mining wells;
   converting at least one of the second solution mining wells into a production well;
   heating the hydrocarbon containing layer using a plurality of heaters; and
   producing formation fluid from at least one converted second solution mining well.

1822. The method of claim 1821, wherein formation fluid produced from one or more converted
   first solution mining wells comprises vaporized formation fluid.

1823. The method of claim 1821, further comprising converting at least one of the second
   solution mining wells into a production well, and producing formation fluid from at least one
   converted second solution mining wells.

1824. The method of claim 1823, wherein formation fluid produced from one or more converted
   second solution mining wells comprises liquid formation fluid.

1825. The method of claim 1821, wherein a portion of at least one of the heaters extends into
   the second nahcolite bed.

1826. The method of claim 1821, wherein the hydrocarbon containing layer comprises oil shale.

1827. The method of claim 1821, wherein the heaters are configured to raise an average
   temperature of the hydrocarbon containing layer above a pyrolysis temperature.

1828. A method for treating a nahcolite containing subsurface formation, comprising:
   solution mining a first nahcolite bed above a treatment area using one or more solution
   mining wells positioned in the first nahcolite bed;
   solution mining a second nahcolite bed below the treatment using one or more solution
   mining wells in the second nahcolite bed;
   providing heat to the treatment area from heaters;
   converting one or more of the solution mining wells used to solution mine the first
   nahcolite bed to production wells;
   producing formation fluid through at least one production well in the first nahcolite bed.

1829. The method of claim 1828, wherein providing heat to the treatment area comprises raising
   an average temperature of the treatment area above a pyrolysis temperature of hydrocarbons in
   the treatment area.

1830. The method of claim 1828, further comprising converting one or more of the solution
   mining wells used to solution mine the second nahcolite bed to production wells.
1831. The method of claim 1830, further comprising producing formation fluid through at least one production well in the second nahcolite bed.

1832. The method of claim 1828, wherein the treatment area comprises an oil shale layer.

1833. The method of claim 1828, wherein the formation fluid produced from the first nahcolite bed comprises non-condensable hydrocarbons.

1834. A method of treating a gas stream, comprising:

in a first cryogenic zone, cryogenically separating a first gas stream to form a second gas stream and a third stream, wherein a majority of the second gas stream comprises methane and/or molecular hydrogen and a majority of the third stream comprises one or more carbon oxides, hydrocarbons having a carbon number of at least 2, one or more sulfur compounds, or mixtures thereof; and

in a second cryogenic zone, cryogenically contacting the third stream with a carbon dioxide stream to form a fourth stream and a fifth stream, wherein a majority of the fourth stream comprises one or more of the carbon oxides and hydrocarbons having a carbon number of at least 2, and a majority of the fifth stream comprises hydrocarbons having a carbon number of at least 3 and one or more of the sulfur compounds.

1835. The method of claim 1834, wherein the cryogenic separation in the first cryogenic zone comprises cryogenic distillation.

1836. The method of claim 1834, wherein the cryogenic separation in the second cryogenic zone comprises cryogenic distillation.

1837. The method of claim 1834, wherein the cryogenic separation in the first and second cryogenic zones comprises cryogenic distillation.

1838. The method of claim 1834, wherein the carbon dioxide stream is added to the third stream in or before the second cryogenic zone.

1839. The method of claim 1834, wherein one or more of the sulfur compounds comprises hydrogen sulfide and contacting the third stream with the carbon dioxide stream enhances the separation of the second stream from the third stream.

1840. The method of claim 1834, wherein one or more of the sulfur compounds is hydrogen sulfide.

1841. The method of claim 1834, further comprising compressing the first gas stream prior to cryogenically separating the first gas stream to produce a stream comprising hydrocarbon having a carbon number of at least 5 and the first gas stream.

1842. The method of claim 1834, further comprising separating formation fluid from a subsurface in situ heat treatment process to form a liquid stream and the first gas stream, wherein
the first gas stream comprises one or more carbon oxides, one or more sulfur compounds, hydrocarbons and/or molecular hydrogen.

1843. The method of claim 1834, further comprising, in a third cryogenic zone, cryogenically contacting the fourth stream with a hydrocarbon recovery stream to form a sixth stream and a seventh stream, a majority of the sixth stream comprising hydrocarbons having a carbon number of at least 2 and a majority of the seventh stream comprising carbon oxides.

1844. The method of claim 1834, further comprising, in a third cryogenic zone, cryogenically separating the fifth stream to form a stream comprising hydrogen sulfide and a stream comprising hydrocarbons having a carbon number of at least 3.

1845. The method of claim 1834, further comprising providing the fifth stream comprising the hydrocarbons having a carbon number of at least 3 to other processing facilities.

1846. The method of claim 1834, further comprising:

- in a third cryogenic zone, cryogenically separating the fourth stream to form a sixth stream and a seventh stream, the sixth stream comprising hydrocarbons having a carbon number of at least 2 and the seventh stream comprising one or more of the carbon oxides;

- in a fourth cryogenic zone, cryogenically separating the fifth stream to form a stream comprising hydrogen sulfide and a stream comprising hydrocarbons having a carbon number of at least 3;

- combining the sixth stream having a carbon number of at least 2 with the stream comprising hydrocarbons having a carbon number of at least 3 to form a combined stream;

- in a fifth cryogenic zone, cryogenically separating the combined stream to form a stream comprising hydrocarbons having a carbon number from 2 to 4 and a stream comprising hydrocarbons having a carbon number from 4 to 7; and

- providing at least a portion of the hydrocarbon stream comprising hydrocarbons having a carbon number ranging from 4 to 7 to the third cryogenic zone.

1847. A system of treating a gas stream, comprising:

- a first cryogenic separation zone configured receive a first gas stream and to cryogenically separate the first gas stream to form a second gas stream and a third gas stream, wherein the second gas stream comprises methane and/or hydrogen and the third gas stream comprises one or more carbon oxides, hydrocarbons having a carbon number of at least 2, and one or more sulfur compounds; and

- a second cryogenic separation zone configured to receive the third gas stream and carbon dioxide and wherein the second cryogenic separation unit is configured to cryogenically separate the third gas stream to from a fourth stream and fifth stream, wherein a majority of the fourth stream comprises one or more of the carbon oxides and hydrocarbons having a carbon number of
at least 2 and a majority of the fifth stream comprises hydrocarbons having a carbon number of at least 3 and one or more of the sulfur compounds.

1848. A method of treating a formation fluid, comprising:

separating formation fluid from a subsurface in situ heat treatment process to form a liquid stream and a first gas stream, wherein the first gas stream comprises one or more carbon oxides, one or more sulfur compounds, hydrocarbons, and/or molecular hydrogen;

in a first cryogenic zone, cryogenically separating the first gas stream to form a second gas stream and a third stream, wherein a majority of the second gas stream comprises methane and/or molecular hydrogen, and the third stream comprises hydrocarbons having a carbon number of at least 2, one or more sulfur compounds, one or more carbon oxides or mixtures thereof; and

in a second cryogenic zone, cryogenically separating the third gas stream to form a fourth stream and a fifth stream, wherein a majority the fourth stream comprises one or more carbon oxides and hydrocarbons having a carbon number of at most 2; and a majority of the fifth stream comprises hydrocarbons having a carbon number of at least 3 and/or one or more sulfur compounds.

1849. The method of claim 1848, further comprising separating the fifth stream to form a stream comprising one or more sulfur compounds and a stream comprising hydrocarbons having a carbon number of at least 3.

1850. The method of claim 1848, wherein the fourth gas stream further comprises hydrogen sulfide.

1851. The method of claim 1848, wherein the fourth stream further comprises hydrogen sulfide and the method comprises:

in a third cryogenic zone, cryogenically contacting at least a portion of the fourth stream with a hydrocarbons stream comprising hydrocarbons having a carbon number of at least 4 to form a sixth stream and a seventh stream, wherein a majority of the sixth stream comprises hydrogen sulfide and a majority of the seventh stream comprises hydrocarbons having a carbon number of at least 2.

1852. A method of heating a subsurface formation, comprising:

supplying fuel to a plurality of oxidizers positioned in the subsurface formation, at least a portion of the fuel being produced by cryogenically separating a gas stream using a method as claimed in claim 1 or 15;

supplying an oxidant to the plurality of oxidizers;

mixing a portion of the fuel with a portion of the oxidant; and
combusting the fuel and oxidant mixture to produce heat that heats at least a portion of the subsurface formation.

1853. The method of claim 1852, wherein cryogenically separating the gas stream produces a stream comprising carbon dioxide, and mixing at least a portion of the produced carbon dioxide with the oxidant.

1854. A variable voltage transformer, comprising:
   a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;
   a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;
   a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage; and
   wherein an electrical load is configured to be coupled to the multistep load tap changer to provide electrical power to the load with a selected voltage, the multistep load tap changer being configured to tap a selected voltage step in order to provide the selected voltage to the electrical load.

1855. The transformer of claim 1854, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load.

1856. The transformer of claim 1854, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load in response to a change in the electrical load so that the electrical load is provided with relatively constant current.

1857. The transformer of claim 1854, further comprising a control system coupled to the transformer, the control system configured to control the multistep load tap changer so that the multistep load tap changer switches the selected voltage step in response to a change in the electrical load.

1858. The transformer of claim 1854, further comprising a voltage measurement transformer coupled to the secondary winding, wherein the voltage measurement transformer is configured to assess the selected voltage provided to the electrical load.

1859. The transformer of claim 1854, further comprising a switch coupled to the secondary winding, wherein the switch is configured to electrically isolate the electrical load from the transformer.
1860. The transformer of claim 1854, further comprising a control power transformer coupled to the secondary winding, wherein the control power transformer is used to provide power to one or more controllers configured to operate the transformer.

1861. The transformer of claim 1854, further comprising a current transformer coupled to the secondary winding, wherein the current transformer is configured to assess electrical current passing through the secondary winding.

1862. The transformer of claim 1854, wherein the voltage steps comprise equally partitioned voltage steps.

1863. The transformer of claim 1854, wherein the voltage steps comprise non-equally partitioned voltage steps.

1864. The transformer of claim 1854, wherein the electrical load comprises a subsurface heater.

1865. A method for controlling voltage provided to an electrical heater, comprising:

- providing electrical power to the heater with a selected voltage using a variable voltage transformer, wherein the variable voltage transformer comprises:
  - a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;
  - a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;
  - a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the selected voltage to the heater;
- assessing change in electrical resistance of the heater over a selected period of time; and
- adjusting the selected voltage provided to the heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the selected voltage is changed in response to the change in the electrical resistance of the heater.

1866. The method of claim 1865, wherein the selected voltage is changed in response to the change in the electrical resistance of the heater such that the electrical current provided to the heater is relatively constant.

1867. The method of claim 1865, wherein the change in electrical resistance of the heater is assessed by using a current transformer coupled to the secondary winding and a voltage transformer coupled to the secondary winding, wherein the electrical resistance is calculated by
dividing a voltage assessed from the voltage transformer by a current assessed from the current transformer.

1868. The method of claim 1865, wherein the voltage steps comprise equally partitioned voltage steps.

1869. The method of claim 1865, wherein the voltage steps comprise non-equally partitioned voltage steps.

1870. The method of claim 1865, wherein the electrical heater comprises a subsurface heater.

1871. The method of claim 1865, further comprising assessing an electrical resistance of the heater by using; comparing the assessed electrical resistance to a theoretical electrical resistance of the heater; and changing the selected voltage provided to the heater if there is a substantial difference between the assessed electrical resistance and the theoretical electrical resistance.

1872. The method of claim 1865, further comprising limiting the number of changes in the selected voltage for a set period of time.

1873. The method of claim 1865, further comprising cycling the selected voltage provided to the heater so that the electrical current provided to the heater remains relatively constant.

1874. A variable voltage transformer system for providing power to a three-phase electrical load, comprising:

- a first variable voltage transformer coupled to a first leg of three-phase electrical load;
- a second variable voltage transformer coupled to a second leg of three-phase electrical load;
- a third variable voltage transformer coupled to a third leg of three-phase electrical load;

wherein each of the first, second, and third variable voltage transformers comprise:

- a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;
- a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;
- a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage; and

wherein the corresponding leg of the three-phase electrical load is configured to be coupled to the multistep load tap changer to provide electrical power to the load with a selected voltage, the multistep load tap changer being configured to tap a selected voltage step in order to provide the selected voltage to the corresponding leg.
1875. The system of claim 1874, wherein the selected maximum percentage of the second voltage is 100%.

1876. The system of claim 1874, wherein the first, second, and third variable voltage transformers are coupled to a control system configured to keep the three legs of the three-phase electrical load in phase.

1877. The system of claim 1874, wherein the three legs of the three-phase electrical load are electrically coupled in a wye or delta configuration.

1878. The system of claim 1874, wherein the multistep load tap changer comprises a sliding tap that is configured to slide between voltage steps to tap the selected voltage step that provides the selected voltage to the corresponding leg.

1879. The system of claim 1874, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the corresponding leg.

1880. The system of claim 1874, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the corresponding leg in response to a change in the electrical load.

1881. The system of claim 1874, wherein the control system is configured to control the multistep load tap changers so that the multistep load tap changers switch the selected voltage steps in response to a change in the electrical load.

1882. The system of claim 1874, further comprising voltage measurement transformers coupled to the secondary windings, wherein the voltage measurement transformers are configured to assess the selected voltages provided to the corresponding legs.

1883. The system of claim 1874, further comprising switches coupled to the secondary windings, wherein the switches are configured to electrically isolate the electrical load from the transformers when the switches are open.

1884. The system of claim 1874, further comprising control power transformers coupled to the secondary windings, wherein the control power transformers are configured to provide power to one or more controllers operating the transformers.

1885. The system of claim 1874, further comprising current transformers coupled to the secondary windings, wherein the current transformers are configured to assess electrical current passing through the secondary windings.

1886. The system of claim 1874, wherein the voltage steps comprise equally partitioned voltage steps.

1887. The system of claim 1874, wherein the voltage steps comprise non-equally partitioned voltage steps.
1888. The system of claim 1874, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.

1889. The system of claim 1874, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1890. The system of claim 1874, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1891. The system of claim 1874, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.

1892. The system of claim 1874, wherein the transformers are configured to be mounted on a pole, a concrete pad, or part of a skid mounted assembly.

1893. The system of claim 1874, wherein the electrical load comprises a subsurface heater.

1894. The system of claim 1874, wherein the electrical load comprises a temperature limited heater.

1895. A variable voltage subsurface heating system, comprising:

   a voltage power source that provides a first voltage;

   a subsurface electrical load;

   a variable voltage transformer electrically coupled to the electrical load, the transformer comprising:

       a primary winding coupled to the voltage power source such that the first voltage is provided across the primary winding;

       a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;

       a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage; and

       wherein the electrical load is coupled to the multistep load tap changer to provide electrical power to the load with a selected voltage, the multistep load tap changer being configured to tap a selected voltage step in order to provide the selected voltage to the electrical load.

1896. The system of claim 1895, wherein the selected maximum percentage of the second voltage is 100%.
1897. The system of claim 1895, wherein the multistep load tap changer comprises a sliding tap that is configured to slide between voltage steps to tap the selected voltage step that provides the selected voltage to the electrical load.

1898. The system of claim 1895, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load.

1899. The system of claim 1895, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load in response to a change in the electrical load.

1900. The system of claim 1895, wherein the multistep load tap changer is configured to switch the selected voltage step to change the selected voltage provided to the electrical load in response to a change in the electrical load so that the electrical load is provided with relatively constant current.

1901. The system of claim 1895, further comprising a control system coupled to the transformer and the electrical load, the control system being configured to control the multistep load tap changer so that the multistep load tap changer switches the selected voltage step in response to a change in the electrical load.

1902. The system of claim 1901, further comprising an optical fiber coupled to the electrical load and the control system, wherein the optical fiber is configured to provide data from the electrical load to the control system.

1903. The system of claim 1895, further comprising a voltage measurement transformer coupled to the secondary winding, wherein the voltage measurement transformer is configured to assess the selected voltage provided to the electrical load.

1904. The system of claim 1895, further comprising a switch coupled to the secondary winding, wherein the switch is configured to electrically isolate the electrical load from the transformer when the switch is open.

1905. The system of claim 1895, further comprising a control power transformer coupled to the secondary winding, wherein the control power transformer is configured to provide power to one or more controllers used for operating the transformer.

1906. The system of claim 1895, further comprising a current transformer coupled to the secondary winding, wherein the current transformer is configured to assess electrical current passing through the secondary winding.

1907. The system of claim 1895, wherein the voltage steps comprise equally partitioned voltage steps.

1908. The system of claim 1895, wherein the voltage steps comprise non-equally partitioned voltage steps.
1909. The system of claim 1895, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.

1910. The system of claim 1895, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1911. The system of claim 1895, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1912. The system of claim 1895, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.

1913. The system of claim 1895, wherein the transformer is configured to be mounted on a pole, a concrete pad, or part of a skid mounted assembly.

1914. The system of claim 1895, wherein the electrical load comprises a heater.

1915. The system of claim 1895, wherein the electrical load comprises a temperature limited heater.

1916. The system of claim 1895, wherein the electrical load comprises an insulated conductor heater.

1917. The system of claim 1895, wherein the electrical load comprises a conductor-in-conduit heater.

1918. A method for controlling voltage provided to an electrical heater, comprising:

providing electrical power to the heater with a selected voltage using a variable voltage transformer, wherein the variable voltage transformer comprises:

a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;

a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;

a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the selected voltage to the heater;

assessing an electrical resistance of the heater over a selected period of time and assessing if there is a change in the electrical resistance of the heater over the selected period of time; and

adjusting the selected voltage provided to the heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the selected voltage is changed in response to the change in the electrical resistance of the heater.
1919. The method of claim 1918, wherein the selected maximum percentage of the second voltage is 100%.
1920. The method of claim 1918, wherein the selected voltage is changed in response to the change in the electrical resistance of the heater such that the electrical current provided to the heater is relatively constant.
1921. The method of claim 1918, further comprising cycling the selected voltage provided to the heater so that the electrical current provided to the heater remains relatively constant.
1922. The method of claim 1918, further comprising assessing the electrical resistance of the heater by using a current transformer coupled to the secondary winding and a voltage transformer coupled to the secondary winding, wherein the electrical resistance is calculated by dividing a voltage assessed from the voltage transformer by a current assessed from the current transformer.
1923. The method of claim 1918, further comprising assessing the electrical resistance of the heater using an optical fiber coupled to the heater.
1924. The method of claim 1918, further comprising comparing the assessed electrical resistance of the heater to a theoretical electrical resistance of the heater and changing the selected voltage provided to the heater if there is a difference between the assessed and the theoretical resistances.
1925. The method of claim 1918, further comprising limiting a number of changes in the selected voltage over a period of time.
1926. The method of claim 1918, wherein the voltage steps comprise equally partitioned voltage steps.
1927. The method of claim 1918, wherein the voltage steps comprise non-equally partitioned voltage steps.
1928. The method of claim 1918, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.
1929. The method of claim 1918, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.
1930. The method of claim 1918, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.
1931. The method of claim 1918, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.
1932. The method of claim 1918, wherein the transformer is mounted on a pole, a concrete pad, or part of a skid mounted assembly.
1933. The method of claim 1918, wherein the electrical heater comprises ferromagnetic material.
1934. The method of claim 1918, wherein the electrical heater comprises a subsurface heater.
1935. The method of claim 1918, wherein the electrical heater comprises a temperature limited heater.
1936. The method of claim 1918, wherein the electrical heater comprises an insulated conductor heater.
1937. The method of claim 1918, wherein the electrical heater comprises a conductor-in-conduit heater.
1938. A method for controlling voltage provided to a subsurface electrical heater in a wellbore, comprising:

    providing electrical power to the heater with a first selected voltage using a variable voltage transformer, wherein the first selected voltage inhibits arcing in the wellbore, and wherein the variable voltage transformer comprises:

    a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;

    a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;

    a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the first selected voltage to the heater;

    assessing an electrical resistance of the heater;

    providing electrical power at the first selected voltage until the electrical resistance of the heater reaches a selected value;

    incrementally increasing the selected voltage provided to the heater to a second selected voltage after the electrical resistance of the heater reaches the selected value;

    assessing the electrical resistance of the heater over a selected period of time, and assessing if there is a change in the electrical resistance of the heater at the second selected voltage over the selected period of time; and

    adjusting the second selected voltage provided to the heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the second selected voltage is changed in response to the change in the electrical resistance of the heater.
1939. The method of claim 1938, wherein the selected maximum percentage of the second voltage is 100%.

1940. The method of claim 1938, wherein the second selected voltage is changed in response to the change in the electrical resistance of the heater such that the electrical current provided to the heater is relatively constant.

1941. The method of claim 1938, further comprising incrementally decreasing the selected voltage provided to the heater from the second selected voltage to zero voltage after a selected time period.

1942. The method of claim 1938, further comprising incrementally decreasing the selected voltage provided to the heater from the second selected voltage to zero voltage after the assessed electrical resistance reaches a second selected value.

1943. The method of claim 1938, further comprising cycling the second selected voltage provided to the heater so that the electrical current provided to the heater remains relatively constant.

1944. The method of claim 1938, further comprising assessing the electrical resistance of the heater by using a current transformer coupled to the secondary winding and a voltage transformer coupled to the secondary winding, wherein the electrical resistance is calculated by dividing a voltage assessed from the voltage transformer by a current assessed from the current transformer.

1945. The method of claim 1938, further comprising comparing the assessed electrical resistance of the heater to a theoretical electrical resistance of the heater and changing the second selected voltage provided to the heater if there is a difference between the assessed and the theoretical resistances.

1946. The method of claim 1938, wherein the voltage steps comprise equally partitioned voltage steps.

1947. The method of claim 1938, wherein the voltage steps comprise non-equispaced partitioned voltage steps.

1948. The method of claim 1938, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.

1949. The method of claim 1938, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1950. The method of claim 1938, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1951. The method of claim 1938, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.
1952. The method of claim 1938, wherein the transformer is mounted on a pole, a concrete pad, or part of a skid mounted assembly.

1953. The method of claim 1938, wherein the electrical heater comprises ferromagnetic material.

1954. The method of claim 1938, wherein the electrical heater comprises a temperature limited heater.

1955. The method of claim 1938, wherein the electrical heater comprises an insulated conductor heater.

1956. The method of claim 1938, wherein the electrical heater comprises a conductor-in-conduit heater.

1957. A method for controlling voltage provided to an electrical heater, comprising:

- providing electrical power to the heater with a selected voltage using a variable voltage transformer, wherein the variable voltage transformer comprises:
  - a primary winding configured to be coupled to a voltage power source that provides a first voltage across the primary winding;
  - a secondary winding electrically isolated from the primary winding, wherein the secondary winding is configured to step down the first voltage to a second voltage that is a preset percentage of the first voltage;
  - a multistep load tap changer coupled to the secondary winding, wherein the load tap changer divides the second voltage into a selected number of voltage steps, the voltage steps incremented from a selected minimum percentage of the second voltage to a selected maximum percentage of the second voltage, the multistep load tap changer tapping a selected voltage step in order to provide the first selected voltage to the heater;

  assessing an electrical resistance of the heater at the selected voltage; and

  cycling the selected voltage provided to the heater by switching the selected voltage step tapped by the multistep load tap changer between at least two voltage steps such that the selected voltage is cycled between at least two voltages after a selected amount of time at each of the at least two voltages.

1958. The method of claim 1957, wherein the selected maximum percentage of the second voltage is 100%.

1959. The method of claim 1957, wherein the selected voltage is cycled between at least two voltages after the selected amount of time at each of the at least two voltages such that the heater is provided with an average voltage between the at least two voltages.
1960. The method of claim 1957, further comprising adjusting the selected voltage provided to the heater by changing the selected voltage step tapped by the multistep load tap changer, wherein the selected voltage is changed in response to the change in the electrical resistance of the heater so that the electrical current provided to the heater is relatively constant.

1961. The method of claim 1957, further comprising determining the selected amount of time at a selected voltage based on the assessed resistance at the selected voltage.

1962. The method of claim 1957, further comprising adjusting the selected amounts of time at each of the least two voltages so that the average voltage is at a selected value.

1963. The method of claim 1962, further comprising basing the selected amounts of time at each of the least two voltages on the assessed resistances at the at least two voltages.

1964. The method of claim 1957, further comprising assessing the electrical resistance of the heater by using a current transformer coupled to the secondary winding and a voltage transformer coupled to the secondary winding, wherein the electrical resistance is calculated by dividing a voltage assessed from the voltage transformer by a current assessed from the current transformer.

1965. The method of claim 1957, further comprising limiting a number of changes in the selected voltage over a period of time.

1966. The method of claim 1957, wherein the voltage steps comprise equally partitioned voltage steps.

1967. The method of claim 1957, wherein the voltage steps comprise non-equally partitioned voltage steps.

1968. The method of claim 1957, wherein the second voltage preset percentage is between 5% and 20% of the first voltage.

1969. The method of claim 1957, wherein the selected minimum percentage of the second voltage is at least 25% of the second voltage.

1970. The method of claim 1957, wherein the selected minimum percentage of the second voltage is at least 50% of the second voltage.

1971. The method of claim 1957, wherein the selected minimum percentage of the second voltage is 0% of the second voltage.

1972. The method of claim 1957, wherein the transformer is mounted on a pole, a concrete pad, or part of a skid mounted assembly.

1973. The method of claim 1957, wherein the electrical heater comprises ferromagnetic material.

1974. The method of claim 1957, wherein the electrical heater comprises a subsurface heater.

1975. The method of claim 1957, wherein the electrical heater comprises a temperature limited heater.
1976. The method of claim 1977, wherein the electrical heater comprises an insulated conductor heater.


1978. A method of heating a portion of a subsurface formation, comprising:
   drawing fuel on a fuel carrier through an opening formed in the formation;
   supplying oxidant to the fuel at one or more locations in the opening; and
   combusting the fuel with the oxidant to provide heat to the formation.

1979. The method of claim 1978, further comprising initiating combustion of the fuel at one or more locations in the opening using one or more igniters.

1980. The method of claim 1978, wherein the fuel comprises coal, oil shale, or biomass.


1982. The method of claim 1978, further comprising drawing a clean-up bin through the opening to remove ash from the opening.

1983. The method of claim 1978, wherein initiating combustion of the fuel occurs at or near a transition from an overburden to a portion of the formation that is to be heated.

1984. The method of claim 1978, wherein supplying oxidant comprises passing oxidant into openings in one or more conduits positioned in the opening.

1985. The method of claim 1978, further comprising controlling the oxidant supplied to the fuel to control the heating of the formation.

1986. The method of claim 1978, wherein the opening one of a plurality of openings in the formation, and wherein the fuel carrier is configured to pass in a loop through two or more of the openings in the formation.

1987. The method of claim 1978, wherein the opening is a u-shaped opening, mine shaft, or tunnel.

1988. The method of claim 1978, wherein the heating provides sufficient heat to mobilize at least some hydrocarbons in the formation.

1989. The method of claim 1988, further comprising producing at least some mobilized hydrocarbons from the formation.

1990. The method of claim 1978, wherein the fuel carrier is one of a plurality of fuel carriers, and further comprising supplying fuel to the fuel carriers from one or more supply stations, and adjusting the amount of fuel supplied to one or more of the fuel carriers to control the heating of the formation.

1991. A system for heating a portion of a subsurface formation, comprising:
   an opening formed in the formation;
a conveyor positioned in the opening;
  fuel carriers coupled to the conveyor, wherein at least one fuel carrier is configured to hold fuel to be combusted in the opening; and

  one or more oxidant conduits positioned in the opening configured to supply oxidant to at least one fuel carrier at one or more locations in the opening.

1992. The system of claim 191, further comprising one or more clean-up bins coupled to the conveyor, at least one clean-up bin configured to remove ash from the opening.

1993. The system of claim 191, further comprising one or more igniters configured to initiate combustion of the fuel.

1994. The system of claim 191, further comprising one or more supply stations configured to supply fuel to the fuel carriers.

1995. The system of claim 191, further comprising one or more exhaust treatment systems configured to treat gases exiting the shaped opening.

1996. The system of claim 191, wherein the conveyor is configured to pass through two or more openings in the formation in a loop.

1997. The system of claim 191, wherein the opening is a u-shaped wellbore, mine shaft, or tunnel.

1998. A method of heating a subsurface formation, comprising:

  introducing molten salt into a first passageway of a conduit-in-conduit heater at a first location;

  passing the molten salt through the conduit-in-conduit heater in the formation to a second location, wherein heat transfers from the molten salt to a treatment area during passage of the molten salt through the conduit-in-conduit heater; and

  removing molten salt from the conduit-in-conduit heater at a second location spaced away from the first location.

1999. The method of claim 198, wherein introducing the molten salt into the first passageway comprises introducing the heat transfer fluid into an inner conduit of the conduit-in-conduit heater.

2000. The method of claim 198, wherein introducing the molten salt into the first passageway comprises introducing the molten salt into an inner conduit of the conduit-in-conduit heater, and passing the molten salt through a flow switcher to change the flow from the inner conduit to the annular region between the inner conduit and an outer conduit.

2001. The method of claim 2000, further comprising passing the molten salt through a second flow switcher to change the flow from the annular region between the inner conduit and the outer conduit to flow through the inner conduit.
2002. The method of claim 1998, further comprising introducing a heat transfer fluid into a second passageway of the conduit-in-conduit heater to ensure flowability of the molten salt in the first passageway.

2003. A method of heating a subsurface formation, comprising:

- introducing a secondary heat transfer fluid into a first passageway of a heater to preheat the heater;
- introducing a primary heat transfer fluid into a second passageway of the heater; and
- eliminating or reducing flow of the secondary heat transfer fluid into the first passageway after a temperature of the heater is sufficient to ensure flowability of the primary heat transfer fluid.

2004. The method of claim 2003, further comprising introducing a third heat transfer fluid into the second passageway of the heater prior to introducing the primary heat transfer fluid to preheat the second passageway, and removing at least a portion of the third heat transfer fluid from the second passageway.

2005. The method of claim 2004, wherein removing at least a portion of the third heat transfer fluid comprises displacing the third heat transfer fluid with the primary heat transfer fluid.

2006. A system for heating a subsurface formation, comprising:

- at least one fluid circulation system configured to provide hot heat transfer fluid to a plurality of heaters in the formation; and
- a plurality of heaters in the formation coupled to the circulation system, wherein at least one of the heaters comprises:
  - a first conduit;
  - a second conduit positioned in the first conduit; and
  - a first flow switcher configured to allow fluid flowing through the second conduit to flow through the annular region between the first conduit and the second conduit.

2007. The system of claim 2006, wherein one or more of the heater are L-shaped heaters.

2008. The system of claim 2006, wherein the heat transfer fluid flows through the second conduit adjacent to at least a portion of the overburden, and wherein the heat transfer fluid flows through an annular region between the first conduit and the second conduit adjacent to at least a portion of a treatment area.

2009. The system of claim 2006, wherein the at least one fluid circulation system comprises a first fluid circulation system near a first side of a treatment area and a second fluid circulation system near a second side of the treatment area, and wherein the first circulation system provides heated heat transfer fluid to entrances of a first set of heaters, and wherein the second treatment system receives heat transfer fluid from exits of the first set of heaters.
2010. A method for heating a subsurface formation, comprising:
    circulating a first heat transfer fluid through a heater positioned in the subsurface
formation to raise a temperature of the heater to a temperature that ensures flowability of a
second heat transfer fluid in the heater;
    stopping circulation of the first heat transfer fluid through the heater;
    circulating a second heat transfer fluid through the heater positioned in the subsurface
formation to raise the temperature of a heat treatment area adjacent to the heater.
2011. The method of claim 2010, wherein the heater comprises a conduit in the formation.
2012. The method of claim 2010, wherein the heater comprises a conduit-in-conduit heater, and
wherein the first heat transfer fluid flows through a first passageway through the heater and
wherein the second heat transfer fluid flows through a second passageway through the heater.
2013. A method for heating a subsurface formation, comprising:
    applying heat from a plurality of heaters to the formation; and
    allowing a portion of one or more of the heaters to move out of wellheads equipped with
sliding seals to accommodate thermal expansion of the heaters.
2014. The method of claim 2013, wherein applying heat from the plurality of heaters comprises
flowing heat transfer fluid through one or more heaters.
2015. The method of claim 2013, wherein the portion of a heater that moves out of a wellhead is
insulated.
2016. The method of claim 2013, further comprising fixing a heater relative to a wellhead
through which the heater passes after significant change in length of the heater due to thermal
expansion ceases.
2017. A method for heating a subsurface formation, comprising:
    applying heat from a plurality of heaters to the formation; and
    allowing a portion of one or more of the heaters to move out of wellheads using one or
more slip joints.
2018. The method of claim 2017, wherein at least a portion of at least one slip joint comprises at
least one sliding seal, wherein the sliding seal is spatially separated from heat.
2019. The method of claim 2017, wherein applying heat from the plurality of heaters comprises
flowing heat transfer fluid through one or more heaters.
2020. The method of claim 2017, wherein the portion of a heater that moves out of a wellhead is
insulated.
2021. The method of claim 2017, further comprising fixing a heater relative to a wellhead
through which the heater passes after significant change in length of the heater due to thermal
expansion ceases.
2022. A method for accommodating thermal expansion of a heater in a formation, comprising:
    heating a heater in the formation; and
    lifting a portion of the heater out of the formation to accommodate thermal expansion of the heater.
2023. The method of claim 2022, wherein at least a portion of at least one slip joint comprises at least one sliding seal, wherein the sliding seal is spatially separated from heat.
2024. The method of claim 2022, wherein applying heat from the plurality of heaters comprises flowing heat transfer fluid through one or more heaters.
2025. The method of claim 2022, wherein the portion of a heater that moves out of a wellhead is insulated.
2026. The method of claim 2022, further comprising fixing a heater relative to a wellhead through which the heater passes after significant change in length of the heater due to thermal expansion ceases.
2027. A system for heating a subsurface formation, comprising:
    a plurality of heaters positioned in the formation, the heaters configured to provide heat to the formation; and
    at least one lifter coupled to a portion of a heater, the lifter configured to lift portions of the heater out of the formation to accommodate thermal expansion of the heater.
2028. The system of claim 2027, wherein applying heat from the plurality of heaters comprises flowing heat transfer fluid through one or more heaters.
2029. The system of claim 2027, wherein at least one lifter comprises a hydraulic lifter.
2030. The system of claim 2027, further comprising measuring the strain of the heater near at least one lifter, and controlling the amount of lift applied to the heater from the lifter based on the measured strain.
2031. The system of claim 2027, further comprising measuring a first hydraulic pressure of a lifter coupled to a heater before heating the heater, and controlling the hydraulic pressure of the lifter after heating is initiated to maintain the hydraulic pressure of the lifter at least close to the first hydraulic pressure.
2032. The system of claim 2027, further comprising fixing a heater relative to a wellhead through which the heater passes after significant change in length of the heater due to thermal expansion ceases.
2033. A method of heating a subsurface formation, comprising:
    providing a heat transfer fluid to first portions of a first plurality of heaters that are at least partially oriented radially outwards from a first side of a treatment area to a second side of the treatment area;
flowing the heat transfer fluid radially outward in at least two of the heaters to provide heat to the subsurface formation; and
mobilizing at least a portion of the hydrocarbons in the formation being heated.

2034. The method of claim 2033, further comprising receiving the heat transfer fluid in second portions of the plurality of heaters, the second portions located on the second side of the treatment area.

2035. The method of claim 2034, further comprising changing the direction of heat transfer fluid flow by providing heat transfer fluid to the second portions of the first plurality of heaters and receiving the heat transfer fluid in the first portions of the first plurality of heaters.

2036. The method of claim 2033, further comprising providing heat transfer fluid to first portions of a plurality of a second plurality of heater wells on the second side of the treatment area; and flowing the heat transfer fluid inwards through the heaters towards the first side of the treatment area.

2037. The method of claim 2036, further comprising heating the heat transfer fluid provided to the second plurality of wellbores from at least one circulation system near the first portions of the second first plurality of wells.

2038. The method of claim 2033, further comprising heating the heat transfer fluid provided to the first plurality of wellbores from at least one circulation system near the first portions of the first plurality of wells.

2039. The method of claim 2033, wherein the average heat input per volume of formation near the first side of the treatment area is greater than an average heat input per volume of formation near the second side of the treatment area.

2040. A subsurface heating system, comprising:
at least one heat supply configured to heat a heat transfer fluid;
at least one fluid mover configured to move the heat transfer fluid through the heating system;
at least one storage tank for the heat transfer fluid coupled to the heat source; and
a first plurality of heaters, wherein portions of the first plurality of heater are located in the formation, wherein heat transfer fluid is provided to entrances of the first plurality of heaters, and wherein the heat transfer fluid in two adjacent heaters moves radially away from the heat transfer fluid entrance for at least portions of the lengths of the heaters.

2041. The system of claim 2040, wherein at least two of the heaters comprises L-shaped heaters, and wherein the heat transfer fluid flows in two adjacent L-shaped heaters moves radially towards the heat transfer fluid entrances for at least portions of the lengths of the heaters.
2042. The system of claim 2040, wherein at least one of the first plurality of heaters comprises an exit, wherein the heat transfer fluid passes through the exit of the heater, and wherein the entrance of the heater is on a first side of a treatment area and wherein the heater exit is on a second side of the heat treatment area.

2043. A method of heating a subsurface formation, comprising:

heating at least a section of the formation by circulating heat transfer fluid in a plurality of heaters, the heaters being configured such that the heat transfer fluid is at least partially heated at a first location and a second location, with the first location being proximate to first portions of a first set of heaters, and the second location being connected to second portions of the first set of heaters, with heat transfer fluid flowing from the first location through the first set of heaters to the second location.

2044. The method of claim 2043, further comprising a second set of heaters, and wherein heated heat transfer fluid flows from the second location through the second set of heaters to the first location.

2045. A method of heating a subsurface formation, comprising:

circulating a molten salt through heaters in the formation to heat a portion of the formation and coke hydrocarbons adjacent to portions of the heater;

providing openings in or more of the heaters to allow passage of fluid from the heaters into the formation adjacent to one or more coked portions of the heaters; and

flowing molten salt through openings to allow the molten salt to react with the coke to generate heat in the formation.

2046. The method of claim 2045, wherein providing openings in or more of the heaters comprises removing a liner from the heater.

2047. The method of claim 2045, wherein providing openings in or more of the heaters comprises perforating one or more of the heaters.

2048. The method of claim 2045, wherein the molten salt comprises a mixture of sodium nitrate and potassium nitrate.

2049. A method of treating a product stream, comprising:

producing a product stream comprising at least methane, hydrocarbons, and heavy hydrocarbons;

circulating a heat transfer fluid in piping in at least two wellbores to heat at least a portion of a formation, at least a portion of the heat transfer fluid being heated by heat provided from a nuclear reactor;

producing steam using heat from a nuclear reactor; and
using at least a portion of the steam to steam reform at least a portion of the product stream to make at least some molecular hydrogen.

2050. The method of claim 2049, further comprising using at least a portion of the molecular hydrogen to upgrade at least a portion of the product stream.

2051. The method of claim 2049, further comprising injecting at least a portion of the molecular hydrogen to the formation.

2052. The method of claim 2049, wherein product stream is produced from a surface upgrading process.

2053. The method of claim 2049, wherein product stream is produced from an in situ heat treatment process.

2054. The method of claim 2049, wherein product stream is produced from a subsurface steam heating process.

2055. The method of claim 2049, further comprising injecting at least a portion of the steam in a subsurface steam heating process.

2056. The method of claim 2049, wherein at least a portion of the methane is steam reformed.

2057. The method of claim 2049, further comprising mobilizing at least a portion of the hydrocarbons in the formation.

2058. The method of claim 2049, further comprising using at least a portion of steam for electrical generation.

2059. An in situ heat treatment system for producing hydrocarbons from a subsurface formation, comprising:

- a plurality of wellbores in the formation;
- piping positioned in at least two of the wellbores;
- a fluid circulation system coupled to the piping; and
- a self-regulating nuclear reactor configured to heat a heat transfer fluid circulated by the circulation system through the piping to heat the temperature of the formation to temperatures that allow for hydrocarbon production from the formation.

2060. The system of claim 2059, wherein the heat transfer fluid is a molten salt.

2061. The system of claim 2059, wherein the heat transfer fluid is a molten salt, wherein the molten salt is molten at a temperature of an activated self-regulating nuclear reactor.

2062. The system of claim 2059, wherein the heat transfer fluid is a molten salt, wherein the molten salt does not decompose within a temperature range of the self-regulating nuclear reactor.

2063. The system of claim 2059, wherein the heat transfer fluid is a molten salt, and wherein the molten salt is a nitrite salt or a combination of nitrite salts.
2064. The system of claim 2059, wherein the heat transfer fluid is a molten salt, and wherein the molten salt comprises about 15 to about 50 wt. % potassium nitrite salts and about 50 to about 80 wt. % sodium nitrite salts.

2065. The system of claim 2059, wherein the heat transfer fluid is a molten salt, and wherein the molten salt is a combination of lithium, sodium, and potassium nitrite salts.

2066. The system of claim 2059, wherein the heat transfer fluid is a molten salt, and wherein the molten salt is a nitrate salt or a combination of nitrate salts.

2067. The system of claim 2059, wherein the heat transfer fluid is a molten salt, and wherein the molten salt comprises about 15 to about 60 wt. % potassium nitrate salts and about 40 to about 80 wt. % sodium nitrate salts.

2068. The system of claim 2059, wherein the heat transfer fluid is a molten salt, and wherein the molten salt is a combination of sodium, and potassium nitrate salts.

2069. The system of claim 2059, wherein at least a portion of the heat transfer fluid circulates directly through the self-regulating nuclear reactor.

2070. The system of claim 2059, wherein the heat transfer fluid is heated with a second heat transfer fluid, wherein the heat transfer fluid and the second heat transfer fluid are molten salts.

2071. The system of claim 2059, wherein the heat transfer fluid is heated with a second heat transfer fluid, wherein the heat transfer fluid and the second heat transfer fluid are molten salts, wherein the second heat transfer fluid circulates directly through at least a portion of the self-regulating nuclear reactor.

2072. The system of claim 2059, wherein the self-regulating nuclear reactor sustains a temperature within a range of about 550 °C to about 600 °C.

2073. The system of claim 2059, wherein the self-regulating nuclear reactor sustains a temperature within a range of about 500 °C to about 650 °C.

2074. The system of claim 2059, wherein the self-regulating nuclear reactor decays at a rate of about 1/E.

2075. The system of claim 2059, wherein a spacing between at least a portion of the plurality of wellbores in the formation is at least partially correlated to a rate of decay of the self-regulating nuclear reactor.

2076. The system of claim 2059, wherein heat input to at least a portion of the formation over time at least approximately correlates to a rate of decay of the self-regulating nuclear reactor.

2077. The system of claim 2059, wherein the self-regulating nuclear reactor initially provides to at least a portion of the wellbores an energy output at about 300 watts/foot which decreases over a predetermined time period to about 120 watts/foot.
2078. The system of claim 2059, further comprising an at least second self-regulating nuclear reactor, wherein the second self-regulating nuclear reactor is coupled to the self-regulating nuclear reactor after a first period of time such that the energy output of the two coupled self-regulating nuclear reactors is at least as great as an initial output of the self-regulating nuclear reactor.

2079. The system of claim 2059, wherein the self-regulating nuclear reactor is modular.

2080. The system of claim 2059, wherein the self-regulating nuclear reactor comprises a core, and wherein the core comprises a metal hydride material.

2081. The system of claim 2059, wherein the self-regulating nuclear reactor comprises a core, and wherein the core comprises a powdered fissile metal hydride material.

2082. The system of claim 2059, wherein the self-regulating nuclear reactor is positioned underground in the formation.

2083. The system of claim 2059, wherein the self-regulating nuclear reactor is positioned underground in the formation below the overburden.

2084. The system of claim 2059, wherein the self-regulating nuclear reactor is positioned in or proximate to one or more tunnels.

2085. The system of claim 2059, wherein a temperature of the self-regulating nuclear reactor is controlled by controlling a pressure of hydrogen supplied to the self-regulating nuclear reactor.

2086. The system of claim 2059, wherein a temperature of the self-regulating nuclear reactor is controlled by controlling a pressure of hydrogen supplied to the self-regulating nuclear reactor, and wherein the pressure is regulated based upon a temperature of the heat transfer fluid entering at least one of the wellbores.

2087. The system of claim 2059, wherein a temperature of the self-regulating nuclear reactor is controlled by controlling a pressure of hydrogen supplied to the self-regulating nuclear reactor, and wherein the pressure is regulated based upon formation conditions.

2088. The system of claim 2059, wherein a temperature of the self-regulating nuclear reactor is reduced by introduction of a neutron-absorbing gas.

2089. The system of claim 2059, wherein a temperature of the self-regulating nuclear reactor is reduced by introduction of a neutron-absorbing gas, wherein the neutron-absorbing gas is xenon\textsuperscript{135}.

2090. The system of claim 2059, wherein a temperature of the self-regulating nuclear reactor is permanently reduced to ambient temperature upon introduction of a neutron-absorbing gas.

2091. The system of claim 2059, wherein a temperature of the self-regulating nuclear reactor is permanently reduced to ambient temperature upon introduction of a neutron-absorbing gas, wherein the neutron-absorbing gas is xenon\textsuperscript{135}. 

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2092. The system of claim 2059, wherein a temperature of the self-regulating nuclear reactor is controlled by a position of at least one control rod relative to a core of the self-regulating nuclear reactor.

2093. The system of claim 2059, wherein at least one of the wellbores is u-shaped.

2094. The system of claim 2059, wherein at least one of the wellbores is L-shaped.

2095. An in situ heat treatment system for producing hydrocarbons from a subsurface formation, comprising:

   a plurality of wellbores in the formation;

   at least one heater positioned in at least two of the wellbores; and

   a self-regulating nuclear reactor configured to provide energy to at least one of the heaters to increase the temperature of at least a portion of the formation to temperatures that allow for hydrocarbon production from the formation, wherein heat input to at least a portion of the formation over time at least approximately correlates to a rate of decay of the self-regulating nuclear reactor.

2096. The system of claim 2095, wherein a spacing between at least a portion of the plurality of wellbores in the formation is at least partially correlated to a rate of decay of the self-regulating nuclear reactor.

2097. The system of claim 2095, wherein the self-regulating nuclear reactor comprises a core, wherein the core comprises a powdered fissile metal hydride material.

2098. The system of claim 2095, wherein the self-regulating nuclear reactor decays at a rate of about 1/E.

2099. The system of claim 2095, wherein the self-regulating nuclear reactor initially provides to at least a portion of the wellbores an energy output at about 300 watts/foot which decreases over time to about 120 watts/foot.

2100. The system of claim 2095, wherein the self-regulating nuclear reactor initially provides to at least a portion of the wellbores an energy output at about 300 watts/foot which decreases over a predetermined time period to about 120 watts/foot.

2101. The system of claim 2095, wherein the self-regulating nuclear reactor initially provides to at least a portion of the wellbores an energy output at about 300 watts/foot which decreases over a predetermined time period to about 120 watts/foot, wherein the predetermined period of time ranges from about 4 to about 8 years.

2102. The system of claim 2095, wherein the self-regulating nuclear reactor initially provides to at least a portion of the wellbores an energy output at about 300 watts/foot which decreases over a predetermined time period to about 120 watts/foot, wherein the predetermined period of time ranges from about 5 to about 7 years.
2103. The system of claim 2095, wherein the self-regulating nuclear reactor is configured to provide energy to at least one of the heaters to increase the temperature of at least a portion of the formation to within a range of about 300 °C to about 400 °C.

2104. The system of claim 2095, wherein the self-regulating nuclear reactor is configured to provide energy to at least one of the heaters to increase the temperature of at least a portion of the formation to within a range of about 300 °C to about 400 °C within a predetermined time period, wherein the predetermined period of time ranges from about 4 to about 8 years.

2105. The system of claim 2095, wherein the self-regulating nuclear reactor is configured to provide energy to at least one of the heaters to increase the temperature of at least a portion of the formation to within a range of about 300 °C to about 400 °C within a predetermined time period, wherein the predetermined period of time ranges from about 5 to about 7 years.

2106. The system of claim 2095, wherein the spacing between at least a portion of the plurality of wellbores in the formation ranges between about 8 meters to about 11 meters.

2107. The system of claim 2095, wherein the spacing between at least a portion of the plurality of wellbores in the formation ranges between about 9 meters to about 10 meters.

2108. The system of claim 2095, wherein the spacing between at least a portion of the plurality of wellbores in the formation ranges between about 9.4 meters to about 9.8 meters.

2109. The system of claim 2095, wherein the self-regulating nuclear reactor is configured to provide thermal energy to at least one of the heaters using a heat transfer fluid.

2110. The system of claim 2095, wherein the self-regulating nuclear reactor is configured to provide thermal energy to at least one of the heaters using a heat transfer fluid, wherein the heat transfer fluid comprises a molten salt.

2111. An in situ heat treatment system for producing hydrocarbons from a subsurface formation, comprising:

   a plurality of wellbores in the formation;
   at least one heater positioned in at least two of the wellbores;
   a first self-regulating nuclear reactor configured to provide energy to at least one of the heaters to heat the temperature of the formation to temperatures that allow for hydrocarbon production from the formation; and
   at least a second self-regulating nuclear reactor, wherein the second self-regulating nuclear reactor is coupled to the first self-regulating nuclear reactor after a first period of time such that the total energy output of the first and second self-regulating nuclear reactors is at least as great as to an initial output of the first self-regulating nuclear reactor.

2112. The system of claim 2111, wherein the self-regulating nuclear reactor comprises a core, wherein the core comprises a powdered fissile metal hydride material.
2113. An in situ heat treatment system for producing hydrocarbons from a subsurface formation, comprising:

- a plurality of wellbores in the formation;
- at least one heater positioned in at least two of the wellbores; and
- a self-regulating nuclear reactor configured to provide energy to at least one of the heaters to heat the temperature of the formation to temperatures that allow for hydrocarbon production from the formation, wherein a temperature of the self-regulating nuclear reactor is controlled by controlling a pressure of hydrogen supplied to the self-regulating nuclear reactor, and wherein the pressure is regulated based upon formation conditions.

2114. The system of claim 2113, wherein the self-regulating nuclear reactor comprises a core, wherein the core comprises a powdered fissile metal hydride material.

2115. The system of claim 2113, wherein a temperature of the self-regulating nuclear reactor is reduced by introduction of a neutron-absorbing gas.

2116. The system of claim 2113, wherein a temperature of the self-regulating nuclear reactor is reduced by introduction of a neutron-absorbing gas, wherein the neutron-absorbing gas is xenon\textsuperscript{135}.

2117. The system of claim 2113, wherein a temperature of the self-regulating nuclear reactor is permanently reduced to ambient temperature upon introduction of a neutron-absorbing gas.

2118. The system of claim 2113, further comprising a system to convert nitrite to nitrate salts, or vice versa.

2119. The system of claim 2113, wherein a temperature of the self-regulating nuclear reactor is permanently reduced to ambient temperature upon introduction of a neutron-absorbing gas, wherein the neutron-absorbing gas is xenon\textsuperscript{135}.

2120. A method of heating a subsurface formation, comprising:

- heating a heat transfer fluid using a self-regulating nuclear reactor with a core that comprises a metal hydride material; and
- circulating the heated heat transfer fluid through piping positioned in at least two of a plurality of wellbores using a fluid circulation system, wherein the plurality of wellbores are positioned in a formation.

2121. The method of claim 2120, further comprising producing hydrocarbons from the formation.

2122. The method of claim 2120, further comprising controlling a temperature of the self-regulating nuclear reactor by controlling a pressure of hydrogen supplied to the self-regulating nuclear reactor.

2123. The method of claim 2120, further comprising:
controlling a temperature of the self-regulating nuclear reactor by controlling a pressure of hydrogen supplied to the self-regulating nuclear reactor; and
regulating the pressure of hydrogen supplied to the self-regulating nuclear reactor based upon a temperature of the heat transfer fluid entering at least one of the wellbores.
2124. The method of claim 2120, further comprising:
controlling a temperature of the self-regulating nuclear reactor by controlling a pressure of hydrogen supplied to the self-regulating nuclear reactor; and
regulating the pressure of hydrogen supplied to the self-regulating nuclear reactor based upon formation conditions.
2125. The method of claim 2120, further comprising:
introducing a neutron-absorbing gas; and
reducing a temperature of the self-regulating nuclear reactor.
2126. The method of claim 2120, further comprising:
introducing a neutron-absorbing gas, wherein the neutron-absorbing gas comprises xenon\textsuperscript{135}; and
reducing a temperature of the self-regulating nuclear reactor.
2127. The method of claim 2120, further comprising:
introducing a neutron-absorbing gas; and
permanently reducing a temperature of the self-regulating nuclear reactor to ambient temperature.
2128. The method of claim 2120, further comprising:
introducing a neutron-absorbing gas, wherein the neutron-absorbing gas comprises xenon\textsuperscript{135}; and
permanently reducing a temperature of the self-regulating nuclear reactor to ambient temperature.
2129. The method of claim 2120, further comprising:
controlling a temperature of the self-regulating nuclear reactor by positioning at least one control rod relative to a core of the self-regulating nuclear reactor.
2130. The method of claim 2120, wherein the heat transfer fluid comprises a nitrite salt, and further comprising:
heating a second heat transfer fluid; and
circulating the heated second heat transfer fluid through the piping positioned in the wellbores upon at least a portion of the formation attaining a first temperature as a result of the heated heat transfer fluid.
2131. The method of claim 2120, wherein the heat transfer fluid is a molten salt.
2132. The method of claim 2120, wherein the heat transfer fluid is a molten salt, wherein the molten salt is molten at a temperature of an activated self-regulating nuclear reactor.

2133. The method of claim 2120, wherein the heat transfer fluid is a molten salt, wherein the molten salt does not decompose within a temperature range of the self-regulating nuclear reactor.

2134. The method of claim 2120, wherein the heat transfer fluid is a molten salt, and wherein the molten salt is a nitrite salt or a combination of nitrite salts.

2135. The method of claim 2120, wherein the heat transfer fluid is a molten salt, and wherein the molten salt comprises about 15 to about 50 wt. % potassium nitrite salts and about 50 to about 80 wt. % sodium nitrite salts.

2136. The method of claim 2120, wherein the heat transfer fluid is a molten salt, and wherein the molten salt is a combination of lithium, sodium, and potassium nitrite salts.

2137. The method of claim 2120, wherein the heat transfer fluid is a molten salt, and wherein the molten salt is a nitrate salt or a combination of nitrate salts.

2138. The method of claim 2120, wherein the heat transfer fluid is a molten salt, and wherein the molten salt comprises about 15 to about 60 wt. % potassium nitrate salts and about 40 to about 80 wt. % sodium nitrate salts.

2139. The method of claim 2120, wherein the heat transfer fluid is a molten salt, and wherein the molten salt is a combination of sodium, and potassium nitrate salts.

2140. The method of claim 2120, further comprising controlling a temperature of the self-regulating nuclear reactor to be about 550 °C to about 600 °C.

2141. The method of claim 2120, further comprising controlling a temperature of the self-regulating nuclear reactor to be about 500 °C to about 650 °C.

2142. The method of claim 2120, further comprising:

   producing hydrocarbons from the formation;
   separating at least a portion of heavy hydrocarbons from the produced hydrocarbons; and
   pyrolyzing at least a portion of the separated heavy hydrocarbons.

2143. The method of claim 2142, further comprising producing steam using the pyrolyzed heavy hydrocarbons.

2144. The method of claim 2143, further comprising producing electricity using the steam.

2145. The method of claim 2120, further comprising:

   discontinuing circulation of the heated heat transfer fluid though the piping positioned in
   the wellbores when the self-regulating nuclear reactor has decayed to at least a third of the self-
   regulating nuclear reactor's initial energy output; and
   producing steam using the heat transfer fluid.

2146. The method of claim 2120, further comprising:
discontinuing circulation of the heated heat transfer fluid though the piping positioned in the wellbores when the self-regulating nuclear reactor has decayed to at least a third of the self-regulating nuclear reactor's initial energy output;

producing steam using the heat transfer fluid; and

injecting steam into the formation.

2147. The method of claim 2146, further comprising producing electricity using the produced steam.

2148. The method of claim 2146, further comprising producing hydrogen using the produced steam.

2149. A method of producing hydrogen, comprising:

 circulating a heat transfer fluid using a circulation system;

 using a self-regulating nuclear reactor, heating the heat transfer fluid to temperatures that allow for steam production; and

 producing hydrogen from the steam.

2150. The method of claim 2149, wherein the self-regulating nuclear reactor comprises a core, wherein the core comprises a powdered fissile metal hydride material.

2151. The method of claim 2149, further comprising combining the steam with methane.

2152. The method of claim 2149, wherein the hydrogen is produced at a facility coupled to a subsurface formation from which hydrocarbons are being produced.

2153. The method of claim 2149, further comprising introducing the hydrogen in a subsurface formation to mobilize or convert hydrocarbons in situ.

2154. The method of claim 2149, wherein the hydrogen is introduced in a subsurface formation to upgrade hydrocarbons in situ.

2155. The method of claim 2149, further comprising using electrolysis to produce hydrogen from the steam.

2156. A method of heating a subsurface formation, comprising:

 heating a first heat transfer fluid;

 circulating the heated first heat transfer fluid through piping positioned in at least two of a plurality of wellbores using a fluid circulation system, wherein the plurality of wellbores are positioned in a formation;

 heating at least a portion of a formation to a first temperature;

 heating a second heat transfer fluid;

 replacing the first heat transfer fluid positioned in the wellbores with the second heat transfer fluid; and
heating the portion of the formation to a second temperature, wherein the second temperature is higher than the first temperature.

2157. The method of claim 2156, further comprising:
recirculating the first heat transfer fluid through piping positioned in at least two of the wellbores using the fluid circulation system; and
heating the first heat transfer fluid using the formation heated by the second heat transfer fluid.

2158. The method of claim 2156, further comprising:
recirculating the first heat transfer fluid through piping positioned in at least two of the wellbores using the fluid circulation system;

transferring the heated first heat transfer fluid from the formation to at least a portion of at least one additional formation; and

heating the portion of at least one of the additional formations using the heated first heat transfer fluid.

2159. The method of claim 2156, wherein the first heat transfer fluid and/or the second heat transfer fluid comprise molten salts.

2160. The method of claim 2156, wherein the first heat transfer fluid and the second heat transfer fluid comprise molten salts with different temperature ranges.

2161. A method of heating a subsurface formation, comprising:
heating a heat transfer fluid using a self-regulating nuclear reactor;
circulating the heated heat transfer fluid through piping positioned in at least two of a plurality of wellbores using a fluid circulation system, wherein the plurality of wellbores are positioned in a formation;

discontinuing circulation of the heated heat transfer fluid though the piping positioned in the wellbores when the self-regulating nuclear reactor has decayed to at least a third of the self-regulating nuclear reactor’s initial energy output; and
producing steam using the heat transfer fluid.

2162. The method of claim 2161, further comprising producing electricity using the produced steam.

2163. The method of claim 2161, further comprising producing hydrogen using the produced steam.

2164. A system for treating a subsurface hydrocarbon containing formation, comprising:
one or more tunnels having an average diameter of at least 1 m, at least one tunnel being connected to the surface; and

two or more wellbores extending from the tunnel into at least a portion of the subsurface hydrocarbon containing formation, at least two of the wellbores containing elongated heat sources configured to heat at least a portion of the subsurface hydrocarbon containing formation such that at least some hydrocarbons are mobilized.

2165. The system of claim 2164, further comprising at least one shaft connecting at least one tunnel to the surface.

2166. The system of claim 2164, further comprising at least one shaft connecting at least one tunnel to the surface, wherein at least one shaft is substantially vertically oriented.

2167. The system of claim 2164, further comprising a production well located such that mobilized fluids from the formation drain into the production well.

2168. The system of claim 2164, further comprising at least one steam injection wellbore extending from at least one tunnel, the steam injection wellbore being connected to one or more sources of steam, and at least one of the steam injection wellbores being configured to provide steam to the subsurface hydrocarbon containing formation.

2169. The system of claim 2164, wherein at least one of the tunnels has an average diameter of at least 2 m.

2170. The system of claim 2164, wherein the cross-sectional shape of at least one tunnel is circular, oval, orthogonal, or irregular shaped.

2171. The system of claim 2164, wherein at least one of the heat sources is an electric resistance heater, and a source of power is provided to the electric resistance heater from a conductor in at least one tunnel.

2172. The system of claim 2164, wherein at least one of the heat sources is a gas burner, and a conduit carrying fuel gas for the gas burner is in at least one tunnel.

2173. The system of claim 2164, wherein at least two of the heat sources are configured to allow electrical current flow between the heat sources to heat the formation.

2174. The system of claim 2164, wherein at least one of the tunnels is substantially horizontal, and at least two of the wellbores extend at an angle from the tunnel.

2175. A method of treating a subsurface hydrocarbon containing formation, comprising:

providing heat to the subsurface hydrocarbon containing formation to mobilize at least some of the hydrocarbons in the formation, the heat being provided from two or more elongated heaters in two or more wellbores extending from one or more tunnels having an average diameter of at least 1 m, at least one tunnel being connected to the surface; and
providing heat to the subsurface hydrocarbon containing formation to mobilize at least some of the hydrocarbons in the formation, the heat being provided from two or more elongated heaters in two or more wellbores extending from one or more tunnels having an average diameter of at least 1 m, at least one tunnel being connected to the surface.

2176. A system for treating a subsurface hydrocarbon containing formation, comprising:

one or more substantially horizontal or inclined tunnels extending from at least one shaft; and

one or more heater sources located in one or more heater wellbores coupled to at least one of the substantially horizontal or inclined tunnels.

2177. The system of claim 2176, further comprising one or more power supplies coupled to one or more heat sources and at least one of the, at least one of the power supplies being configured to provide power to at least one of the heat sources.

2178. The system of claim 2176, further comprising one or more production wells coupled to one or more of the tunnels.

2179. The system of claim 2176, further comprising one or more impermeable barriers in the tunnels configured to seal the tunnels from formation fluids.

2180. A method for treating a subsurface hydrocarbon containing formation, comprising:

providing one or more shafts;

providing one or more substantially horizontal or inclined tunnels extending from at least one of the shafts;

providing one or more wellbores from at least one of the tunnels; and

providing one or more heat sources to at least one of the wellbores.

2181. The method of claim 2180, further comprising providing heat from at least one of the heat sources to at least a portion of a subsurface hydrocarbon containing formation to mobilize at least some hydrocarbons in the formation.

2182. The method of claim 2180, further comprising providing heat from at least one of the heat sources to at least a portion of a subsurface hydrocarbon containing formation, and producing formation fluids from the portion.

2183. The method of claim 2180, wherein at least one of the wellbores is a production wellbore.

2184. The method of claim 2180, further comprising providing one or more impermeable barriers to seal the tunnels from formation fluids.

2185. The method of claim 2180, further comprising sealing the shafts from the tunnels, after providing the heat sources, to inhibit fluids from flowing between the shafts and the tunnels.
2186. The method of claim 2180, further comprising at least partially isolating heating sections of the heat sources from the tunnels such that fluids are inhibited from flowing between the heating sections and the tunnels.

2187. A system for treating a subsurface hydrocarbon containing formation, comprising:
   one or more shafts;
   at least two substantially horizontal or inclined tunnels extending from one or more of the shafts; and
   a plurality of heat sources located in at least one heat source wellbore extending between at least two of the substantially horizontal tunnels, wherein electrical connections for the heat sources are located in at least one of the substantially horizontal tunnels.

2188. The system of claim 2187, wherein the heat sources comprise electrical heaters connected to a bus bar with the electrical connections.

2189. The system of claim 2187, wherein the heat source wellbore is directionally drilled between at least two of the substantially horizontal tunnels.

2190. A method for installing heaters in a subsurface hydrocarbon containing formation, comprising:
   providing one or more shafts;
   providing one or more substantially horizontal or inclined tunnels extending from at least one of the shafts;
   providing at least one heater wellbore extending from at least one of the tunnels; interconnecting the heater wellbore with at least one other of the tunnels;
   providing one or more heaters into the heater wellbore; and
   electrically connecting to at least one of the heaters in the tunnels.

2191. The method of claim 2190, further comprising forming the heater wellbore by directionally drilling from one tunnel to at least one other tunnel.

2192. The method of claim 2190, further comprising electrically connecting the heater to a bus bar located in at least one of the tunnels.

2193. The method of claim 2190, further comprising manually electrically connecting to the heater in at least one of the tunnels.

2194. A system for treating a subsurface hydrocarbon containing formation, comprising:
   one or more substantially horizontal or inclined tunnels extending from one or more shafts; and
   a production system located in at least one of the tunnels, the production system being configured to produce fluids from the formation that collect in the tunnel.
2195. The system of claim 2194, wherein the production system tunnel is located to collect fluids in the formation by gravity drainage.

2196. The system of claim 2194, wherein the production system comprises a substantially vertical production wellbore coupled to the production system tunnel.

2197. A method for treating a subsurface hydrocarbon containing formation, comprising:

   providing one or more substantially horizontal or inclined tunnels extending from at least one shaft;

   allowing formation fluids to drain to at least one of the tunnels; and

   producing fluids from the drainage tunnel to the surface of the formation using a production system.

2198. The method of claim 2197, further comprising providing heat to the formation from at least one heat source located in a wellbore extending from at least one of the tunnels.

2199. A system for treating a subsurface hydrocarbon containing formation, comprising:

   one or more shafts;

   a first substantially horizontal or inclined tunnel extending from one or more of the shafts;

   a second substantially horizontal or inclined tunnel extending from one or more of the shafts; and

   two or more heat source wellbores extending from the first tunnel to the second tunnel, wherein the heat source wellbores are configured to allow heated fluid to flow through the wellbores from the first tunnel to the second tunnel.

2200. The system of claim 2199, further comprising a production system coupled to the second tunnel, the production system being configured to remove the heated fluids from the formation to the surface of the formation.

2201. The system of claim 2199, wherein the second tunnel is configured to collect heated fluids from at least two of the heat source wellbores.

2202. The system of claim 2199, wherein the production system comprises a vertical production wellbore coupled to the second tunnel.

2203. The system of claim 2199, wherein the production system comprises a lift system to move the heated fluids to the surface of the formation.

2204. A method for treating a subsurface hydrocarbon containing formation, comprising:

   providing heated fluids into two or more heat source wellbores extending from a first substantially horizontal or inclined tunnel to a second substantially horizontal or inclined tunnel;

   collecting the heated fluids in the second tunnel; and

   removing the heated fluids from the second tunnel to the surface of the formation.
2205. The method of claim 2204, further comprising providing heat to the formation from the heated fluids.

2206. The method of claim 2204, further comprising removing the heated fluids to the surface using a production system.

2207. The method of claim 2204, further comprising recirculating the heated fluids removed from the second tunnel back into the heat source wellbores.

2208. The method of claim 2204, further comprising reheating the removed heated fluids at the surface, and recirculating the reheated fluids into the heat source wellbores.

2209. A system for treating a subsurface hydrocarbon containing formation, comprising:

one or more shafts;

a first substantially horizontal or inclined tunnel extending from one or more of the shafts;

a second substantially horizontal or inclined tunnel extending from one or more of the shafts; and

two or more heat source wellbores extending from the first tunnel to the second tunnel, wherein the heat source wellbores are configured to allow electrical current to flow between the heat source wellbores.

2210. The system of claim 2209, wherein the electrical current flow between the heat source wellbores is configured to resistively heat the formation.

2211. A method for treating a subsurface hydrocarbon containing formation, comprising:

providing electrical current into two or more heat source wellbores extending from a first substantially horizontal or inclined tunnel to a second substantially horizontal or inclined tunnel;

allowing electrical current to flow between the heat source wellbores; and

heating the formation.

2212. The method of claim 2211, further comprising heating the formation such that at least some hydrocarbons in the formation are mobilized.

2213. The method of claim 2211, further comprising heating the formation such that at least some hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons.

2214. A system for treating a subsurface hydrocarbon containing formation, comprising:

one or more shafts;

a first substantially horizontal or inclined tunnel extending from one or more of the shafts;

a second substantially horizontal or inclined tunnel extending from one or more of the shafts; and

at least one heat source wellbore extending from the first tunnel; and

at least one heat source wellbore extending from the second tunnel;
wherein the heat source wellbores are configured to allow electrical current to flow between the heat source wellbores.

2215. The system of claim 2214, wherein the electrical current flow between the heat source wellbores is configured to resistively heat the formation.

2216. A method for treating a subsurface hydrocarbon containing formation, comprising:
   providing electrical current into two or more heat source wellbores, at least one wellbore extending from a first substantially horizontal or inclined tunnel, and at least one wellbore extending from a second substantially horizontal or inclined tunnel;
   allowing electrical current to flow between the heat source wellbores; and
   heating the formation.

2217. The method of claim 2216, further comprising heating the formation such that at least some hydrocarbons in the formation are mobilized.

2218. The method of claim 2216, further comprising heating the formation such that at least some hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons.

2219. A system for forming a subsurface wellbore, comprising:
   a drilling string configured to rotate at a first speed;
   a bottom hole assembly comprising a drill bit, the drill bit being configured to form the wellbore;
   a first motor configured to rotate the drill bit in a same direction as the drilling string; and
   a second motor located near the end of the drilling string, the second motor being configured to rotate a portion of the bottom hole assembly in a direction opposite to that of the drilling string.

2220. A method for forming a subsurface wellbore, comprising:
   operating a drilling string in a first direction of rotation; and
   operating a motor located near the end of the drilling string in a direction of rotation opposite that of the drilling string.

2221. The method of claim 2220, further comprising controlling a drill bit by changing at least one of the rotation speed of the drilling string or the rotation speed of the motor.

2222. The method of claim 2220, further comprising controlling a rotation of at least a portion of a bottom hole assembly coupled to the drilling string.

2223. A system for forming a subsurface wellbore, comprising:
   a drilling string;
   a drill bit on an end of the drilling string, the drill being configured to form the wellbore;
a first motor located on the drilling string configured to rotate the drill bit in a same
direction as the drilling string; and
a non-rotating sensor located on the drilling string.

2224. A method for forming a subsurface wellbore, comprising:
controlling rotation of a sensor located on a drilling string; and
controlling the drilling string based on data from the sensor.

2225. The method of claim 2224, wherein controlling the rotation of the sensor located on a
drilling string comprises inhibiting rotation of the sensor.

2226. A system for forming a subsurface wellbore, comprising:
a rack and pinion system comprising a chuck drive system, wherein chuck drive system is
configured to operate a drilling string; and
an automatic position control system comprising at least one measurement sensor coupled
to the rack and pinion system, wherein the auto-position control system is configured to control
the rack and pinion system to determine a position of the drilling string.

2227. A method for forming a subsurface wellbore, comprising:
receiving position data about a drilling string from at least one measurement sensor
coupled to an automatic position control system; and
controlling the drilling string using a rack and pinion system based on the position data
from the at least one measurement sensor.

2228. A system for forming a subsurface wellbore, comprising:
a bottom drive system configured to couple to an existing tubular of a drilling string at
least partially in the wellbore and to control a drilling operation in the wellbore, the bottom drive
system comprising a circulating sleeve configured to accept a new tubular during the drilling
operation; and
a top drive system configured to couple with the new tubular and to assume control of the
drilling operation when the new tubular is coupled to the existing tubular.

2229. The system of claim 2228, wherein the bottom drive system is configured to move up to
the top of the new tubular while the top drive system is controlling the drilling operation and to
assume control of the drilling operation from the top drive system.

2230. The system of claim 2228, further comprising a tubular handling system configured to
position the new tubular for coupling with the top drive system.

2231. A method for adding a new tubular to a drilling string, comprising:
coupling a top end of the new tubular to a top drive system;
positioning a bottom end of the new tubular in an opening of a circulating sleeve of a
bottom drive system while the bottom drive system controlling a drilling operation;
while the drilling operation continues, coupling the new tubular to an existing tubular to form a coupled tubular;

transferring control of the drilling operation from the bottom drive system to the top drive system;

while the drilling operation continues, moving the bottom drive system up the coupled tubular towards the top drive system;

while the drilling operation continues, coupling the bottom drive system to a top portion of the coupled tubular;

transferring control of the drilling operation from the top drive system to the bottom drive system; and

disconnecting the top drive system from the coupled tubular.

2232. A method for treating a hydrocarbon containing formation, comprising:

providing heat to a first portion of the formation using a heater, wherein the heating section of the heater is at least partially located in a substantially horizontal or inclined portion of a wellbore and is located in or proximate to a hydrocarbon containing layer of the formation, and wherein the heating section has a length that is at most 1/2 the length of the horizontal or inclined portion of the wellbore; and

moving at least a portion of the heating section in the wellbore such that heat is provided to a second portion of the formation, wherein the second portion is horizontally displaced from the first portion of the formation.

2233. The method of claim 2232, wherein the wellbore is a u-shaped wellbore.

2234. The method of claim 2232, wherein the wellbore is an L-shaped wellbore.

2235. The method of claim 2232, further comprising moving the heating section in the wellbore such that the heating section provides heat to a third portion of the formation, wherein the third portion is horizontally displaced from the first and second portions of the formation.

2236. The method of claim 2232, wherein the second portion is adjacent to the first portion.

2237. The method of claim 2232, wherein the heating section is moved from heating the first portion to heating the second portion after a selected time period of heating of the first portion.

2238. The method of claim 2232, wherein the heating section is moved from heating the first portion to heating the second portion after at least some hydrocarbons in the first portion are mobilized.

2239. The method of claim 2232, wherein the heating section is moved from heating the first portion to heating the second portion after at least some hydrocarbons in the first portion are pyrolyzed.
2240. The method of claim 2232, further comprising moving the heating section by moving at least a portion of the heater in the wellbore.

2241. The method of claim 2232, further comprising moving the heating section by pulling at least a portion of the heater through the wellbore.

2242. The method of claim 2232, wherein the wellbore is a u-shaped wellbore, the method further comprising moving the heating section by moving at least a portion of the heater through the wellbore from at or near one end of the wellbore to at or near the other end of the wellbore.

2243. The method of claim 2232, further comprising mobilizing at least some hydrocarbons in the first portion, and producing at least some of the mobilized hydrocarbons.

2244. The method of claim 2232, further comprising pyrolyzing at least some hydrocarbons in the first portion, and producing at least some of the pyrolyzed hydrocarbons.

2245. The method of claim 2232, wherein the heating section has a length that is at most ¼ the length of the horizontal or inclined portion of the wellbore.

2246. The method of claim 2232, wherein the heating section has a length that is at most 1/5 the length of the horizontal or inclined portion of the wellbore.

2247. The method of claim 2232, wherein the heater comprises an electrical resistance heater.

2248. The method of claim 2232, wherein the heater comprises an oxidation heater.

2249. The method of claim 2232, wherein the heater comprises a circulating fluid heater.

2250. The method of claim 2232, further comprising providing steam to at least a portion of the formation.

2251. A method for treating a hydrocarbon containing formation, comprising:

   providing heat to a first portion of the formation using a first heater, wherein the heating section of the first heater is at least partially located in a substantially horizontal or inclined portion of a wellbore and is located in or proximate to a hydrocarbon containing layer of the formation, and wherein the heating section of the first heater has a length that is at most ½ the length of the horizontal or inclined portion of the wellbore;

   providing heat to a second portion of the formation using a second heater, wherein the heating section of the second heater is at least partially located in a substantially horizontal or inclined portion of the wellbore and is located in or proximate to the hydrocarbon containing layer of the formation, and wherein the heating section of the second heater has a length that is at most ½ the length of the horizontal or inclined portion of the wellbore;

   wherein the first portion and the second portion of the formation are horizontally displaced from each other in the formation; and

   moving at least a portion of the heating section of the first heater in the wellbore such that heat is provided to a third portion of the formation, wherein the third portion is horizontally
displaced from the first portion of the formation and the second portion of the formation, and wherein the third portion is closer to the first portion than the second portion.

2252. The method of claim 2251, further comprising moving at least a portion of the heating section of the second heater in the wellbore such that heat is provided to a fourth portion of the formation, wherein the fourth portion is horizontally displaced from the first portion of the formation and the second portion of the formation, and wherein the fourth portion is closer to the second portion than the first portion.

2253. The method of claim 2252, wherein the fourth portion is substantially the same distance from the second portion as the third portion is from the first portion.

2254. The method of claim 2251, wherein the wellbore is a u-shaped wellbore.

2255. The method of claim 2251, wherein the wellbore is an L-shaped wellbore.

2256. The method of claim 2251, wherein the second portion is adjacent to the first portion.

2257. The method of claim 2251, wherein the heating section of the first heater is moved from heating the first portion to heating the third portion after at least some hydrocarbons in the first portion are mobilized.

2258. The method of claim 2251, wherein the heating section of the first heater is moved from heating the first portion to heating the third portion after at least some hydrocarbons in the first portion are pyrolyzed.

2259. The method of claim 2251, further comprising moving the heating section of the first heater by moving at least a portion of the heater in the wellbore.

2260. The method of claim 2251, further comprising moving the heating section of the first heater by pulling at least a portion of the heater through the wellbore.

2261. The method of claim 2251, further comprising mobilizing at least some hydrocarbons in the first portion, and producing at least some of the mobilized hydrocarbons.

2262. The method of claim 2251, further comprising pyrolyzing at least some hydrocarbons in the first portion, and producing at least some of the pyrolyzed hydrocarbons.

2263. The method of claim 2251, further comprising providing steam to at least a portion of the formation.

2264. A heater, comprising:

- a conduit;

three insulated electrical conductors located in the conduit, at least one of the three insulated conductors comprising an electrical conductor at least partially surrounded by an insulation layer and an electrically conductive sheath at least partially surrounding the insulation layer; and
one or more layers of electrical insulation at least partially surrounding the three insulated electrical conductors in the conduit, the one or more layers of electrical insulation being configured to electrically isolate the insulated electrical conductors from the conduit.

2265. The heater of claim 2264, wherein the one or more layers of electrical insulation comprises one or more layers of tape comprising ceramic fibers.

2266. The heater of claim 2264, wherein the one or more layers of electrical insulation comprises high temperature ceramic fiber rope.

2267. The heater of claim 2264, wherein the one or more layers of electrical insulation are configured to withstand operating temperatures of at least about 750 °C.

2268. The heater of claim 2264, wherein the heater has a length of at least about 100 m.

2269. The heater of claim 2264, wherein the heater is configured to operate at a voltage of at least about 4000 V.

2270. The heater of claim 2264, wherein the electrically conductive sheath comprises corrosion resistant material.

2271. The heater of claim 2264, wherein the conduit comprises corrosion resistant material.

2272. A method for making a heater for a subsurface formation, comprising:

at least partially covering three insulated electrical conductors with one or more layers of electrical insulation, at least one of the insulated electrical conductors comprising:

an electrical conductor;

an insulation layer at least partially surrounding the electrical conductor; and

an electrically conductive sheath at least partially surrounding the insulation layer;

forming a conduit around the one or more layers of electrical insulation and the three insulated electrical conductors.

2273. The method of claim 2272, further comprising installing the heater in an opening in the subsurface formation.

2274. The method of claim 2272, further comprising installing the heater in an opening in the subsurface formation, and energizing the heater to provide at least some heat to the subsurface formation.

2275. The method of claim 2272, further comprising spooling the conduit on a reel.

2276. The method of claim 2272, wherein forming the conduit around the one or more layers of electrical insulation and the three insulated electrical conductors comprises bending a plate around the one or more layers of electrical insulation and the three insulated electrical conductors and welding the seam.

2277. The method of claim 2272, wherein at least one insulated conductor comprises one or more heater sections configured to provide heat to heat subsurface formation adjacent to the
heater sections, and one or more other sections configured to transport electricity to the heater sections with relatively small heat losses.

2278. A method for treating a subsurface formation using an electric heater, comprising:

providing electricity to the electric heater positioned in an opening in the subsurface formation, the electric heater comprising:

a conduit;

three insulated electrical conductors located in the conduit, at least one of the three insulated conductors comprising an electrical conductor at least partially surrounded by an insulation layer and an electrically conductive sheath at least partially surrounding the insulation layer; and

one or more layers of electrical insulation at least partially surrounding the three insulated electrical conductors in the conduit, the one or more layers of electrical insulation being configured to electrically isolate the insulated electrical conductors from the conduit; and

resistively heating one or more sections of one or more of the three electrical conductors; and

heating the subsurface formation from the conduit.

2279. The method of claim 2278, further comprising heating the subsurface formation such that at least some hydrocarbons in the formation are mobilized.

2280. The method of claim 2278, further comprising heating the subsurface formation such that at least some hydrocarbons in the formation are pyrolyzed.

2281. The method of claim 2278, further comprising heating the subsurface formation such that at least some hydrocarbons in the formation are mobilized, and producing at least some of the mobilized hydrocarbons through a production well.

2282. The method of claim 2278, further comprising heating the subsurface formation such that at least some hydrocarbons in the formation are pyrolyzed, and producing at least some of the pyrolyzed hydrocarbons through a production well.

2283. The method of claim 2278, further comprising heating the subsurface formation by providing time-varying electrical current to the electric heater.

2284. A method for making a coiled insulated conductor heater configured to heat a subsurface formation, comprising:

pushing the insulated conductor heater longitudinally inside a flexible conduit using pressure, wherein one or more cups coupled to the outside of the insulated conductor heater, the cups being configured to maintain at least some pressure inside at least a portion of the flexible conduit as the insulated conductor heater is pushed inside the flexible conduit; and
coiling the flexible conduit and the insulated conductor heater onto a coiled tubing rig.

2285. The method of claim 2284, wherein the cups are flexible cups.

2286. The method of claim 2284, wherein the cups comprise elastomeric cups.

2287. The method of claim 2284, wherein the cups provide little or no mechanical resistance to the movement of the insulated conductor heater inside the flexible conduit.

2288. The method of claim 2284, wherein one or more of the cups are configured to at least partially burn or melt when the insulated conductor heater is energized.

2289. The method of claim 2284, wherein the insulated conductor heater is at least about 10 m in length.

2290. A coiled insulated conductor heater system configured to heat a subsurface formation, comprising:

a flexible conduit;

an insulated conductor heater located longitudinally inside the flexible conduit; and

one or more cups coupled to the outside of the insulated conductor heater, the cups being configured to maintain pressure inside the flexible conduit; and

wherein the flexible conduit and the insulated conductor heater are configured to be coiled onto a coiled tubing rig.

2291. The system of claim 2290, wherein the cups are flexible cups.

2292. The system of claim 2290, wherein the cups comprise elastomeric cups.

2293. The system of claim 2290, wherein the cups provide little or no mechanical resistance to the movement of the insulated conductor heater inside the flexible conduit.

2294. The system of claim 2290, wherein the cups are configured to burn up when the insulated conductor heater is energized.

2295. The system of claim 2290, wherein the insulated conductor heater is at least about 10 m in length.

2296. A method for installing a horizontal or inclined subsurface insulated conductor heater, comprising:

installing a flexible conduit and an insulated conductor heater into a subsurface wellbore by uncoiling the flexible conduit and the insulated conductor heater from a coiled tubing rig, wherein the insulated conductor heater is located longitudinally inside the flexible conduit, and one or more cups are coupled to the outside of the insulated conductor heater, the cups being configured to maintain pressure inside the flexible conduit; and

removing the flexible conduit from the insulated conductor heater with the coiled tubing rig while leaving the insulated conductor heater installed in the subsurface wellbore.

2297. The method of claim 2296, wherein the cups are flexible cups.
2298. The method of claim 2296, wherein the cups comprise elastomeric cups.
2299. The method of claim 2296, wherein the cups provide little or no mechanical resistance to
the movement of the insulated conductor heater inside the flexible conduit.
2300. The method of claim 2296, wherein one or more of the cups are configured to at least
partially burn or melt when the insulated conductor heater is energized.
2301. The method of claim 2296, further comprising placing a guide string on an end of the
flexible conduit and insulated conductor heater assembly.
2302. The method of claim 2296, further comprising placing a guide string on an end of the
flexible conduit and insulated conductor heater assembly, and using the guide string to guide the
installation of the flexible conduit and insulated conductor heater assembly into the subsurface
wellbore.
2303. The method of claim 2296, wherein the insulated conductor heater is at least about 10 m
in length.
2304. The method of claim 2296, further comprising stopping removal of the flexible conduit at
a bend in the subsurface wellbore, and pumping plugging material through the flexible conduit to
the bend in the subsurface wellbore, wherein the plugging material is configured to plug the
subsurface wellbore around the insulated conductor heater at the bend in the subsurface wellbore.
2305. The method of claim 2296, wherein the insulated conductor heater is placed in a
hydrocarbon containing layer of the subsurface formation.
2306. A method for heating a subsurface formation, comprising:

    providing heat from an insulated conductor heater to at least a portion of the formation,

wherein the insulated conductor heater has been installed in the formation by:

    installing a flexible conduit and the insulated conductor heater into a subsurface
    wellbore by uncoiling the flexible conduit and the insulated conductor heater from a
    coiled tubing rig, wherein the insulated conductor heater is located longitudinally inside
    the flexible conduit, and one or more cups are coupled to the outside of the insulated
    conductor heater, the cups being configured to maintain pressure inside the flexible
    conduit; and

    removing the flexible conduit from the insulated conductor heater with the coiled
    tubing rig while leaving the insulated conductor heater installed in the subsurface
    wellbore.

2307. The method of claim 2306, wherein the cups are flexible cups.
2308. The method of claim 2306, wherein the cups comprise elastomeric cups.
2309. The method of claim 2306, wherein the cups provide little or no mechanical resistance to
the movement of the insulated conductor heater inside the flexible conduit.
2310. The method of claim 2306, further comprising at least partially burning or melting one or more of the cups.

2311. The method of claim 2306, wherein the insulated conductor heater is at least about 10 m in length.

2312. The method of claim 2306, further comprising mobilizing at least some hydrocarbons in the formation with the provided heat, and producing at least some of the mobilized hydrocarbons from the formation.

2313. The method of claim 2306, further comprising pyrolyzing at least some hydrocarbons in the formation with the provided heat, and producing at least some of the pyrolyzed hydrocarbons from the formation.

2314. A method of positioning wellbores for forming a double barrier for at least a portion of a treatment area, comprising:

   forming a plurality of first barrier wells in the formation for the first barrier, wherein a substantially constant spacing separates adjacent first barrier wells;

   analyzing the formation to determine the principal fracture direction of at least one layer of the formation;

   determining an offset distance of the second barrier wells relative to the first barrier wells based on the principal fracture direction to limit a maximum separation distance between a closest barrier well and a theoretical fracture extending between the first barrier and the second barrier along the principal fracture direction to a distance of less than one half of the spacing that separates adjacent first barrier wells; and

   forming a plurality of second barrier wells in the formation for the second barrier to a side of the first barrier wells by a substantially constant separation distance, wherein the second barrier wells are offset from the first barrier wells by a distance that is at least substantially the same as the offset distance.

2315. The method of claim 2314, wherein the first barrier wells are freeze wells.

2316. The method of claim 2314, wherein the second barrier wells are freeze wells.

2317. The method of claim 2314, further comprising forming the first barrier.

2318. The method of claim 2314, further comprising forming the second barrier.

2319. The method of claim 2314, wherein the offset distance is chosen to limit the maximum separation distance between a closest barrier well and a theoretical fracture extending between the first barrier and the second barrier along the principal fracture direction to a distance of about one fourth of the spacing that separates adjacent first barrier wells.

2320. A method of positioning wellbores for forming a double barrier for at least a portion of a treatment area, comprising:
forming a plurality of first barrier wells in the formation for the first barrier, wherein a substantially constant spacing separates adjacent first barrier wells;

analyzing the formation to determine the principal direction of water flow in at least one layer of the formation;

determining an offset distance of the second barrier wells relative to the first barrier wells based on the principal direction of water flow in at least one layer to limit a maximum separation distance between a closest barrier well and a theoretical breach extending from the first barrier to the second barrier along the principal direction of water flow to a distance of less than one half of the spacing that separates adjacent first barrier wells; and

forming a plurality of second barrier wells in the formation for the second barrier to a side of the first barrier wells by a substantially constant separation distance, wherein the second barrier wells are offset from the first barrier wells by a distance that is at least substantially the same as the offset distance.

2321. The method of claim 2320, wherein the first barrier wells are freeze wells.

2322. The method of claim 2320, wherein the second barrier wells are freeze wells.

2323. The method of claim 2320, further comprising forming the first barrier.

2324. The method of claim 2320, further comprising forming the second barrier.

2325. The method of claim 2320, wherein the offset distance is chosen to limit the maximum separation distance between a closest barrier well and a theoretical breach extending from the first barrier to the second barrier along the principal direction of water flow to a distance of about one fourth of the spacing that separates adjacent first barrier wells.

2326. A method of treating a hydrocarbon formation, comprising:

providing heat to the hydrocarbon formation from a plurality of heaters;

allowing the heat to transfer from the heaters so that at least a section the formation reaches a selected temperature; the section comprising hydrocarbons having an API gravity below 10°;

providing a solution comprising water to the section, wherein a temperature of the solution is at least 250 °C;

maintaining a pressure of the formation such that the water remains a liquid at 250 °C;

contacting at least a some of the hydrocarbons in the section having an API gravity below 10° to produce hydrocarbon fluids; and

mobilizing the hydrocarbon fluids in the section, wherein the hydrocarbon fluids comprise hydrocarbons having an API gravity of at least 10°.

2327. The method of claim 2326, wherein the hydrocarbons comprise bitumen.
2328. The method of claim 2326, wherein the section comprises kerogen and heating the kerogen produces the heavy hydrocarbons.

2329. The method of claim 2326, wherein the section comprises kerogen and heating the kerogen produces bitumen.

2330. The method of claim 2326, wherein maintaining a pressure comprises controlling the pressure of the formation at a range from 5,000 kPa to 15,000 kPa.

2331. The method of claim 2326, wherein the temperature of the solution ranges from 250 °C and 350 °C and pressure is maintained from 5000 kPa and 15,000 kPa.

2332. The method of claim 2326, wherein the viscosity of the hydrocarbon fluids is at least 100 centipoise at 15 °C.

2333. The method of claim 2326, further comprising producing at least a portion of the mobilized hydrocarbon fluids.

2334. The method of claim 2326, wherein the solution further comprises one or more aromatic compounds.

2335. The method of claim 2326, wherein the solution further comprises one or more phenol compounds.

2336. The method of claim 2326, wherein the solution further comprises one or more creosol compounds.

2337. A method of treating an oil shale formation, comprising:

   providing heat to the oil shale formation from a plurality of heaters, at least a portion of the oil shale formation comprising kerogen;

   allowing the heat to transfer from the heaters such that at least some of the kerogen in the section is transformed to hydrocarbons comprising bitumen;

   providing a solution comprising water to the section; wherein a temperature of the solution is at least 250 °C;

   maintaining a pressure of the formation such that the water remains a liquid at 250 °C;

   contacting at least a some of the hydrocarbons comprising bitumen with the solution; and

   mobilizing hydrocarbon fluids in the section, wherein the hydrocarbon fluids comprise hydrocarbons having viscosity less than bitumen.

2338. A method of treating a hydrocarbon formation, comprising:

   providing heat to the hydrocarbon formation from a plurality of heaters; at least one of the heaters being located in a heater well in the section;

   allowing the heat to transfer from the heaters so that at least a section the formation reaches a selected temperature;
providing a solution comprising water to the section to the heater well; the heater well comprising hydrocarbons having an API gravity below 10° and wherein a temperature of the solution is at least 250 °C;

maintaining a pressure of the heater well such that the water remains a liquid at 250 °C;

contacting at least a some of the hydrocarbons in the heater well having an API gravity below 10° to produce hydrocarbon fluids; and

mobilizing the hydrocarbon fluids in the section, wherein the hydrocarbon fluids comprise hydrocarbons having an API gravity of at least 10°.

2339. A system for treating a subsurface formation, comprising:

a plurality of conduits at least partially located in a portion of a hydrocarbon containing formation, wherein at least part of two of the conduits are aligned in relation to each other such that electrical current will flow from a first conduit to a second conduit, and wherein first and second conduits comprise electrically conductive material and at least one of the first and second conduits is perforated or configured to be perforated; and

a power supply coupled to the first and second conduits, the power supply configured to electrically excite at least one of the conductive sections such that current flows between the first conduit and the second conduit in the formation and heats at least a portion of the formation between the two conduits.

2340. The system of claim 2339, wherein at least a portion of the first and second conduits are substantially horizontally oriented or inclined in the formation.

2341. The system of claim 2339, wherein at least a portion of the first and second conduits are substantially parallel to each other.

2342. The system of claim 2339, wherein at least a portion of the first and second conduits are perforated.

2343. The system of claim 2339, wherein the conductive material is copper.

2344. The system of claim 2339, wherein at least one of the first and second conduits is a pipe.

2345. The system of claim 2339, wherein at least one of the first and second conduits comprises heat treated copper.

2346. The system of claim 2339, wherein at least one of the first and second conduits comprises a first layer comprising carbon steel and a second layer comprising copper, and at least a portion of the second layer substantially surrounds or partially surrounds a portion of the first layer.

2347. The system of claim 2339, wherein at least one of the first and second conduits comprises an overburden section and the overburden section comprises one or more ferromagnetic materials.
2348. The system of claim 2339, wherein at least one of the first and second conduits comprises an overburden section and the overburden section comprises at least 15 wt% manganese.
2349. The system of claim 2339, wherein at least one of the first and second conduits comprises an overburden section and the overburden section comprises one or more ferromagnetic materials, and one or more of the ferromagnetic materials comprises at least 10 wt% manganese.
2350. The system of claim 2339, wherein at least one of the first and second conduits comprises an overburden section and the overburden section comprises one or more ferromagnetic materials; and one or more of the ferromagnetic materials comprises at least 10 wt% manganese, at least 5 wt% carbon, and at least 1 wt% chromium.
2351. The system of claim 2339, wherein at least one of the first and second conduits is located in a wellbore comprising one or more electrical insulators.
2352. The system of claim 2339, wherein the first conduit is located in a first wellbore and the second conduit is located in a second wellbore.
2353. The system of claim 2339, further comprising a fluid injection system configured to inject fluid through at least some of the perforations and into the formation.
2354. The system of claim 2353, wherein the fluid comprises a drive fluid.
2355. The system of claim 2353, wherein the fluid comprises a foaming composition.
2356. A method for treating a subsurface formation, comprising:

   providing electrical current to a first conduit in a section of the formation such that electrical current flows from the first conduit to a second conduit in the section of the formation, the electrical current flowing through at least a portion of the formation to heat at least part of the formation; and

   injecting a drive fluid through perforations in the first conduit such that the drive fluid flows through the perforations and moves formation fluids towards the second conduit and/or another section of the formation.
2357. The method of claim 2356, further comprising positioning the first conduit in the section of the formation, wherein the first conduit is oriented substantially horizontally or at an incline and wherein the first conduit comprises electrically conductive material.
2358. The method of claim 2356, further comprising positioning the second conduit in the section of the formation, wherein the second conduit is aligned in relation to the first conduit such that electrical current flows between the first and second conduits.
2359. The method of claim 2356, further comprising electrically exciting electrically conductive material in the first and/or second conduit to create the electrical current flow.
2360. The method of claim 2356, further comprising creating increased fluid injectivity in at least portion of the section between the first and second conduits.
2361. The method of claim 2356, further comprising perforating at least a portion of the first conduit and/or the second conduit.

2362. The method of claim 2356, further comprising producing at least a portion of the mobilized formation fluids from the formation.

2363. The method of claim 2356, further comprising perforating at least a portion of the first or second conduit, and producing at least a portion of the mobilized formation fluids from the perforated first or second conduit.

2364. The method of claim 2356, wherein the first conduit comprises a conductive portion that is at least 10 meters from a conductive portion of the second conduit.

2365. The method of claim 2356, wherein the drive fluid is steam and/or water.

2366. The method of claim 2356, further comprising injecting a foaming composition, and injecting a pressurizing fluid at a rate sufficient to foam the foaming composition.

2367. The method of claim 2356, further comprising injecting a pre-foamed composition.

2368. The method of claim 2356, further comprising injecting a foaming composition, wherein the foaming composition comprises a surfactant.

2369. The method of claim 2356, wherein at least a portion of the first conduit is positioned in a shale layer of the formation.

2370. The method of claim 2356, wherein the first conduit is located in a first wellbore and the second conduit is located in a second wellbore.

2371. A system for treating a subsurface formation, comprising:

   a first conductor at least partially located in a portion of a hydrocarbon containing formation, wherein the first conductor comprises a first section, a second section, and an electrical insulator positioned between the two sections to electrically isolate the sections, the first and second sections comprising electrically conductive material;

   a grounded conductor at least partially positioned in relation to the first conductor such that electrical current flows from the first section of the first conductor to the ground conductor through at least one portion of the formation and electrical current flows from the ground conductor to the second section of the first conductor through at least another portion of the formation; and

   a power supply coupled to the first conductor, the power supply configured to electrically excite the electrically conductive material of the first section such that electrical current flows from the first section to the ground conductor, and back to the electrically conductive material of the second section, and wherein the current flow through the formation is sufficient to heat at least a portion of the formation between the first conductor and the ground conductor.
2372. The system of claim 2371, wherein at least a portion the first conductor and/or the ground conductor are substantially horizontally oriented or inclined in the formation.

2373. The system of claim 2371, wherein at least a portion of the first conductor and the ground conductor are substantially parallel to each other.

2374. The system of claim 2371, wherein at least a portion of the electrical insulator has a length of at least 10 meters.

2375. The system of claim 2371, wherein an average distance between the conductive portions of the first conductor and the ground conductor is at least 10 meters.

2376. The system of claim 2371, wherein the first conductor comprises a conduit.

2377. The system of claim 2371, wherein the first conductor comprises a perforated conduit.

2378. The system of claim 2371, wherein at least one of the conductors comprises a first layer comprising carbon steel and a second layer comprising copper, and at least a portion of the second layer substantially surrounds or partially surrounds a portion of the first layer.

2379. The system of claim 2371, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials.

2380. The system of claim 2371, wherein at least one of the conductors comprises an overburden section and the overburden section comprises at least 15 wt% manganese.

2381. The system of claim 2371, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials, and one or more of the ferromagnetic materials comprises at least 10 wt% manganese.

2382. The system of claim 2371, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials; and one or more of the ferromagnetic materials comprises at least 10 wt% manganese, at least 5 wt% carbon, and at least 1 wt% chromium.

2383. The system of claim 2371, wherein at least one of the conductors is located in a wellbore comprising one or more electrical insulators.

2384. The system of claim 2371, wherein the first conductor is located in a first wellbore and the ground conductor is located in a second wellbore.

2385. The system of claim 2371, wherein at least one of the conductors comprises a perforated conduit, the system further comprising a fluid injection system configured to inject fluid through at least some of the perforations and into the formation.

2386. The system of claim 2385, wherein the fluid comprises a drive fluid.

2387. The system of claim 2385, wherein the fluid comprises a foaming composition.

2388. A method for treating a subsurface formation, comprising:
2389. providing electrical current to a first conductor in a section of the formation such that electrical current flows from a first section of the first conductor, through at least a portion of the formation, to a ground conductor, and from the ground conductor, through at least another portion of the formation, to a second section of the first conductor, wherein the first section and the second section are electrically isolated;
2390. heating at least a portion of the formation between the first conductor and the ground conductor with heat generated from the electrical current flow; and
2391. mobilizing at least some hydrocarbons in the heated portion of the formation.
2392. The method of claim 2388, further comprising positioning the first conductor substantially horizontally or at an incline in the formation.
2393. The method of claim 2388, further comprising positioning the ground conductor substantially horizontally oriented or at an incline in the formation.
2394. The method of claim 2388, further comprising creating increased fluid injectivity in at least portion of the section between the first conductor and the ground conductor.
2395. The method of claim 2388, further comprising perforating at least a portion of the first conductor and/or the ground conductor.
2396. The method of claim 2388, further comprising producing at least a portion of the mobilized formation fluids from the formation.
2397. The method of claim 2388, further comprising perforating at least a portion of the first conductor or the ground conductor, and producing at least a portion of the mobilized formation fluids from the perforated first or second conductor.
2398. The method of claim 2388, further comprising injecting a foaming composition, and injecting a pressurizing fluid at a rate sufficient to foam the foaming composition in the section.
2399. The method of claim 2388, further comprising injecting a pre-foamed composition.
2400. The method of claim 2388, further comprising injecting a foaming composition, wherein the foaming composition comprises a surfactant.
2401. The method of claim 2388, wherein at least a portion of the first conductor is positioned in a shale layer of the formation.
2402. The method of claim 2388, wherein the first conductor is located in a first wellbore and the ground conductor is located in a second wellbore.
2403. A system for treating a subsurface formation, comprising:
    a first conductor at least partially located in a portion of a hydrocarbon containing formation, wherein the first conductor comprises a first section, a second section, and an electrical insulator positioned between the two sections to electrically isolate the sections, the first and second sections comprising electrically conductive material;
a second conductor at least partially positioned in relation to the first conductor such that electrical current flows from the first section of the first conductor to a first section of the second conductor through at least a portion of the formation and electrical current flows from a second section of the second conductor to the second section of the first conductor through at least a portion of the formation, the first and second sections of the second conductor being electrically isolated; and

a power supply coupled to the first conductor, the power supply configured to electrically excite the electrically conductive material of the first section of the first conductor such that electrical current flows from the first section of the first conductor to the first section of the second conductor, and the same or a different power supply configured to electrically excite the electrically conductive material of the second section of the second conductor such that electrical current flows from the second section of the second conductor to the second section of the first conductor.

2404. The system of claim 2403, wherein the first conductor and/or the second conductor are substantially horizontally oriented or inclined in the formation.

2405. The system of claim 2403, wherein the first conductor and the second conductor are substantially parallel to each other.

2406. The system of claim 2403, wherein an average distance between the conductive portions of the first conductor and the second conductor is at least 10 meters.

2407. The system of claim 2403, wherein the first conductor comprises a conduit.

2408. The system of claim 2403, wherein the first conductor comprises a perforated conduit.

2409. The system of claim 2403, wherein at least one of the conductors comprises a first layer comprising carbon steel and a second layer comprising copper, and at least a portion of the second layer substantially surrounds or partially surrounds a portion of the first layer.

2410. The system of claim 2403, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials.

2411. The system of claim 2403, wherein at least one of the conductors comprises an overburden section and the overburden section comprises at least 15 wt% manganese.

2412. The system of claim 2403, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials, and one or more of the ferromagnetic materials comprises at least 10 wt% manganese.

2413. The system of claim 2403, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials; and one or more of the ferromagnetic materials comprises at least 10 wt% manganese, at least 5 wt% carbon, and at least 1 wt% chromium.
2414. The system of claim 2403, wherein at least one of the conductors is located in a wellbore comprising one or more electrical insulators.

2415. The system of claim 2403, wherein the first conductor is located in a first wellbore and the second conductor is located in a second wellbore.

2416. The system of claim 2403, wherein at least one of the conductors comprises a perforated conduit, the system further comprising a fluid injection system configured to inject fluid through at least some of the perforations and into the formation.

2417. The system of claim 2416, wherein the fluid comprises a drive fluid.

2418. The system of claim 2416, wherein the fluid comprises a foaming composition.

2419. A method for treating a subsurface formation, comprising:

   providing electrical current to a first conductor in a section of the formation such that electrical current flows from a first section of the first conductor, through at least a portion of the formation, to first section of a second conductor;

   providing electrical current to the second conductor such that electrical current flows from a second section of the second conductor, through at least a portion of the formation, to a second section of the first conductor;

   wherein the first sections and the second sections of the first conductor and the second conductor are electrically isolated;

   heating at least a portion of the formation between the first conductor and the second conductor with heat generated from the electrical current flow; and

   mobilizing at least some hydrocarbons in the heated portion of the formation.

2420. The method of claim 2419, further comprising positioning the first conductor substantially horizontally or at an incline in the formation.

2421. The method of claim 2419, further comprising positioning the second conductor substantially horizontally oriented or at an incline in the formation.

2422. The method of claim 2419, further comprising creating increased fluid injectivity in at least portion of the section between the first conductor and the second conductor.

2423. The method of claim 2419, further comprising perforating at least a portion of the first conductor and/or the second conductor.

2424. The method of claim 2419, further comprising producing at least a portion of the mobilized formation fluids from the formation.

2425. The method of claim 2419, further comprising perforating at least a portion of the first conductor or the second conductor, and producing at least a portion of the mobilized formation fluids from the perforated first or second conductor.
2426. The method of claim 2419, further comprising injecting a foaming composition, and injecting a pressurizing fluid at a rate sufficient to foam the foaming composition in the section.

2427. The method of claim 2419, further comprising injecting a pre-foamed composition.

2428. The method of claim 2419, further comprising injecting a foaming composition, wherein the foaming composition comprises a surfactant.

2429. The method of claim 2419, wherein at least a portion of the first conductor is positioned in a shale layer of the formation.

2430. The method of claim 2419, wherein the first conductor is located in a first wellbore and the second conductor is located in a second wellbore.

2431. A system for treating a subsurface formation, comprising:

   a wellbore at least partially located in a hydrocarbon containing formation, the wellbore comprising a substantially vertical portion and at least two substantially horizontally oriented or inclined portions coupled to the vertical portion;

   a first conductor at least partially positioned in a first of the two substantially horizontal oriented or inclined portions of the wellbore, wherein at least the first conductor comprises electrically conductive material; and

   a power supply coupled to at least the first conductor, the power supply configured to electrically excite the electrically conductive materials of the first conductor such that current flows between the electrically conductive materials in the first conductor, through at least a portion of the formation, to a second conductor and heats at least a portion of the formation between the two substantially horizontally oriented or inclined portions of the wellbore.

2432. The system of claim 2431, wherein at least a portion of the first conductor and the second conductor are substantially parallel to each other.

2433. The system of claim 2431, wherein the second conductor is a ground conductor.

2434. The system of claim 2431, wherein the second conductor is at least partially positioned in a second of the two substantially horizontal oriented or inclined portion of the wellbore.

2435. The system of claim 2431, wherein an average distance between the conductive portions of the first conductor and the second conductor is at least 10 meters.

2436. The system of claim 2431, wherein the first conductor comprises a conduit.

2437. The system of claim 2431, wherein the first conductor comprises a perforated conduit.

2438. The system of claim 2431, wherein the second conductor comprises a perforated conduit.

2439. The system of claim 2431, wherein at least one of the conductors comprises a first layer comprising carbon steel and a second layer comprising copper, and at least a portion of the second layer substantially surrounds or partially surrounds a portion of the first layer.
2440. The system of claim 2431, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials.

2441. The system of claim 2431, wherein at least one of the conductors comprises an overburden section and the overburden section comprises at least 15 wt% manganese.

2442. The system of claim 2431, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials, and one or more of the ferromagnetic materials comprises at least 10 wt% manganese.

2443. The system of claim 2431, wherein at least one of the conductors comprises an overburden section and the overburden section comprises one or more ferromagnetic materials; and one or more of the ferromagnetic materials comprises at least 10 wt% manganese, at least 5 wt% carbon, and at least 1 wt% chromium.

2444. The system of claim 2431, wherein at least one of the conductors is located in a wellbore comprising one or more electrical insulators.

2445. The system of claim 2431, wherein at least one of the conductors comprises a perforated conduit, the system further comprising a fluid injection system configured to inject fluid through at least some of the perforations and into the formation.

2446. The system of claim 2445, wherein the fluid comprises a drive fluid.

2447. The system of claim 2445, wherein the fluid comprises a foaming composition.

2448. A method for treating a subsurface formation, comprising:

2449. providing electrical current to a first conductor in a first substantially horizontal or inclined position in a section of the formation such that electrical current flows from the first conductor to a second conductor located in a second substantially horizontal or inclined position in the section of the formation, wherein the first conductor and the second conductor are located in wellbore sections that extend from a common wellbore; and

2450. heating a least a portion of the hydrocarbon layer between the first and second conduits with heat generated by the electrical current flow.

2451. The system of claim 2448, wherein the first conductor extends from the vertical portion of the common wellbore, wherein at least a portion of the first conduit extends horizontally or inclined from the vertical portion and the first conductor comprises electrically conductive material.

2452. The system of claim 2448, wherein the second conductor extends from the vertical portion of the common wellbore, wherein at least a portion of the second conductor is substantially parallel to the first conductor; and wherein the second conductor comprises electrically conductive material.
2453.  The method of claim 2448, further comprising creating increased fluid injectivity in at least portion of the section between the first conductor and the second conductor.

2454.  The method of claim 2448, further comprising perforating at least a portion of the first conductor and/or the second conductor.

2455.  The method of claim 2448, further comprising mobilizing at least some hydrocarbons in the formation with the generated heat.

2456.  The method of claim 2455, further comprising producing at least a portion of mobilized formation fluids from the formation.

2457.  The method of claim 2448, further comprising injecting a foaming composition, and injecting a pressurizing fluid at a rate sufficient to foam the foaming composition in the section.

2458.  The method of claim 2448, further comprising injecting a pre-foamed composition.

2459.  The method of claim 2448, further comprising injecting a foaming composition, wherein the foaming composition comprises a surfactant.

2460.  The method of claim 2448, wherein at least a portion of the first conductor is positioned in a shale layer of the formation.

2461.  The method of claim 2448, wherein the second conductor is a ground conductor.

2462.  A method for treating subsurface formation, comprising:

   providing a hydrocarbon-containing feed stream produced from an in situ heat treatment process;

   treating at least a portion of the hydrocarbon-containing feed stream with one or more aqueous acid compounds to produce an aqueous stream comprising organonitrogen compounds; and

   providing at least a portion of the aqueous stream comprising organonitrogen compounds to at least a portion of a formation that has been at least partially treated by an in situ-heat treatment process.

2463.  The method of claim 2339, wherein at least a part of the formation in which the stream comprising organonitrogen compounds is injected comprises nahcolite.

2464.  The method of claim 2339, wherein at least a part of the formation in which the stream comprising organonitrogen compounds is injected comprises nahcolite has been treated using an in situ heat treatment process.

2465.  The method of claim 2339, wherein at least a part of the formation in which the stream comprising organonitrogen compounds is injected comprises nahcolite, and wherein the stream comprising organonitrogen compounds is used as a source of fluid for solution mining.
2466. The method of claim 2339, wherein the treating of the treating of the hydrocarbon-containing stream with one or more aqueous acid compounds also produces a liquid stream, the liquid stream comprising non-organonitrogen hydrocarbons.

2467. The method of claim 2339, wherein the treating of the treating of the hydrocarbon-containing stream with one or more aqueous acid compounds also produces a non-aqueous stream, the non-aqueous stream comprising non-organonitrogen hydrocarbons; and further comprising hydrotreating at least a portion of the non-aqueous stream.

2468. The method of claim 2339, further comprising heating at least a portion of the aqueous stream comprising organonitrogen hydrocarbons to a temperature sufficient to at least form some non-nitrogen containing hydrocarbons.

2469. The method of claim 2339, further comprising heating at least a portion of the aqueous stream comprising organonitrogen hydrocarbons to a temperature sufficient to at least form some non-nitrogen containing hydrocarbons, and producing at least some of the non-nitrogen containing hydrocarbons from the formation.

2470. The method of claim 2339, further comprising separating solids from at least a portion of the hydrocarbon-containing feed stream prior to treatment with at least one aqueous acid compound.

2471. The method of claim 2339, further comprising separating solids from at least a portion of the hydrocarbon-containing feed stream prior to treatment with at least one aqueous acid compound, and injecting the solids in the formation.

2472. The method of claim 2339, wherein the formation comprises oil shale.

2473. A method for treating a subsurface formation, comprising:
   - injecting a stream comprising organonitrogen compounds into a nahcolite containing formation that has been treated using an in situ heat treatment process to remove at least some of the nahcolite from the formation;
   - producing formation fluids from the formation.

2474. The method of claim 2473, wherein the stream comprising organonitrogen compounds is produced using an in situ heat treatment process.

2475. The method of claim 2473, wherein removal of the nahcolite comprises solution mining the nahcolite and at least a portion of the stream comprising organonitrogen compounds is used as a fluid for the solution mining.

2476. The method of claim 2473, wherein the treating of the treating of the hydrocarbon-containing stream with one or more aqueous acid compounds also produces a liquid stream, the liquid stream comprising non-organonitrogen hydrocarbons.
2477. The method of claim 2473, wherein the treating of the treating of the hydrocarbon-containing stream with one or more aqueous acid compounds also produces a non-aqueous stream, the non-aqueous stream comprising non-organonitrogen hydrocarbons, and further comprising hydrotreating at least a portion of the non-aqueous stream.

2478. The method of claim 2473, further comprising heating at least a portion of the aqueous stream comprising organonitrogen hydrocarbons to a temperature sufficient to at least form some non-nitrogen containing hydrocarbons.

2479. The method of claim 2473, further comprising heating at least a portion of the aqueous stream comprising organonitrogen hydrocarbons to a temperature sufficient to at least form some non-nitrogen containing hydrocarbons, and producing at least some of the non-nitrogen containing hydrocarbons from the formation.

2480. The method of claim 2473, further comprising separating solids from at least a portion of the hydrocarbon-containing feed stream prior to treatment with at least one aqueous acid compound.

2481. The method of claim 2473, further comprising separating solids from at least a portion of the hydrocarbon-containing feed stream prior to treatment with at least one aqueous acid compound, and injecting the solids in the formation.
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