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Remarks:
The references to the drawing(s) no. 1 to 17 are deemed to be deleted (Rule 56(4) EPC).

(54) Optimization of untreated oil shale geometry to control subsidence

(57) A method for developing hydrocarbons from a subsurface formation is provided. The subsurface formation may include oil shale. The method may include non-formation oxidatively heating portions of an organic-rich rock formation located in a development area, thereby pyrolyzing at least a portion of formation hydrocarbons located in a heated zone in the organic-rich rock formation into hydrocarbon fluids. The heat may be generated from one or more wellbores completed within the formation, such as a resistive heating element. At least one unheated zone is preserved within the organic-rich rock formation. This leaves a portion of the development area substantially unpyrolyzed. The unheated zone is sized or configured in order to substantially optimize that portion of the development area in which the organic-rich rock is pyrolyzed while controlling subsidence above the organic-rich rock formation.

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Description

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit of U.S. Provisional application 61/007,044 which was filed on December 10, 2007.

BACKGROUND OF THE INVENTION

Field of the Invention

[0002] The present invention relates to the field of hydrocarbon recovery from subsurface formations. More specifically, the present invention relates to the in situ recovery of hydrocarbon fluids from organic-rich rock formations including, for example, oil shale formations, coal formations and tar sands formations. The present invention also relates to methods for maximizing the recovery of shale oil while controlling surface subsidence during a production operation.

Background of the Invention

[0003] Certain geological formations are known to contain an organic matter known as "kerogen." Kerogen is a solid, carbonaceous material. When kerogen is imbedded in rock formations, the mixture is referred to as oil shale. This is true whether or not the mineral is, in fact, technically shale, that is, a rock formed from compacted clay.

[0004] Kerogen is subject to decomposing upon exposure to heat over a period of time. Upon heating, kerogen molecularly decomposes to produce oil, gas, and carbonaceous coke. Small amounts of water may also be generated. The oil, gas and water fluids are mobile within the rock matrix, while the carbonaceous coke remains essentially immobile.

[0005] Oil shale formations are found in various areas world-wide, including the United States. Oil shale formations tend to reside at relatively shallow depths. In the United States, oil shale is most notably found in Wyoming, Colorado, and Utah. These formations are often characterized by limited permeability. Some consider oil shale formations to be hydrocarbon deposits which have not yet experienced the years of heat and pressure thought to be required to create conventional oil and gas reserves.

[0006] The decomposition rate of kerogen to produce mobile hydrocarbons is temperature dependent. Temperatures generally in excess of 270° C (518° F) over the course of many months may be required for substantial conversion. At higher temperatures substantial conversion may occur within shorter times. When kerogen is heated, chemical reactions break the larger molecules forming the solid kerogen into smaller molecules of oil and gas. The thermal conversion process is referred to as pyrolysis or retorting.

[0007] Attempts have been made for many years to extract oil from oil shale formations. Near-surface oil shales have been mined and retorted at the surface for over a century. In 1862, James Young began processing Scottish oil shales. The industry lasted for about 100 years. Commercial oil shale retorting through surface mining has been conducted in other countries as well such as Australia, Brazil, China, Estonia, France, Russia, South Africa, Spain, and Sweden. However, the practice has been mostly discontinued in recent years because it proved to be uneconomical or because of environmental constraints on spent shale disposal. (See T.F. Yen, and G.V. Chilingarian, "Oil Shale," Amsterdam, Elsevier, p. 292, the entire disclosure of which is incorporated herein by reference.) Further, surface retorting requires mining of the oil shale, which limits application to very shallow formations.

[0008] In the United States, the existence of oil shale deposits in northwestern Colorado has been known since the early 1900's. While research projects have been conducted in this area from time to time, no serious commercial development has been undertaken. Most research on oil shale production has been carried out in the latter half of the 1900's. The majority of this research was on shale oil geology, geochemistry, and retorting in surface facilities.

[0009] In 1947, U.S. Pat. No. 2,732,195 issued to Ljungstrom. That patent, entitled "Method of Treating Oil Shale and Recovery of Oil and Other Mineral Products Therefrom," proposed the application of heat at high temperatures to the oil shale formation *in situ* to distill and produce hydrocarbons. The '195 Ljungstrom patent is incorporated herein by reference.

[0010] Ljungstrom coined the phrase "heat supply channels" to describe bore holes drilled into the formation. The bore holes received an electrical heat conductor which transferred heat to the surrounding oil shale. Thus, the heat supply channels served as heat injection wells. The electrical heating elements in the heat injection wells were placed within sand or cement or other heat-conductive material to permit the heat injection well to transmit heat into the surrounding oil shale while preventing the inflow of fluid. According to Ljungstrom, the "aggregate" was heated to between 500° and 1,000° C in some applications.

[0011] Along with the heat injection wells, fluid producing wells were also completed in near proximity to the heat injection wells. As kerogen was pyrolyzed upon heat conduction into the rock matrix, the resulting oil and gas would be recovered through the adjacent production wells.

[0012] Ljungstrom applied his approach of thermal conduction from heated wellbores through the Swedish Shale Oil Company. A full scale plant was developed that operated from 1944 into the 1950's. (See G. Salamonsson, "The Ljungstrom In Situ Method for Shale-Oil Recovery," 2nd Oil Shale and Cannel Coal Conference, v. 2, Glasgow, Scotland, Institute of Petroleum, London, p.

260-280 (1951), the entire disclosure of which is incorporated herein by reference.)

[0013] Additional *in situ* methods have been proposed. These methods generally involve the injection of heat and/or solvent into a subsurface oil shale. Heat may be in the form of heated methane (see U.S. Pat. No. 3,241,611 to J.L. Dougan), flue gas, or superheated steam (see U.S. Pat. No. 3,400,762 to D.W. Peacock). Heat may also be in the form of electric resistive heating, dielectric heating, radio frequency (RF) heating (U.S. Pat. No. 4,140,180, assigned to the ITT Research Institute in Chicago, Illinois) or oxidant injection to support *in situ* combustion. In some instances, artificial permeability has been created in the matrix to aid the movement of pyrolyzed fluids. Permeability generation methods include mining, rubblization, hydraulic fracturing (see U.S. Pat. No. 3,468,376 to M.L. Slusser and U.S. Pat. No. 3,513,914 to J. V. Vogel), explosive fracturing (see U.S. Pat. No. 1,422,204 to W. W. Hoover, et al.), heat fracturing (see U.S. Pat. No. 3,284,281 to R.W. Thomas), and steam fracturing (see U.S. Pat. No. 2,952,450 to H. Purre).

[0014] In 1989, U.S. Pat. No. 4,886,118 issued to Shell Oil Company, the entire disclosure of which is incorporated herein by reference. That patent, entitled "Conductively Heating a Subterranean Oil Shale to Create Permeability and Subsequently Produce Oil," declared that "[c]ontrary to the implications of ... prior teachings and beliefs ... the presently described conductive heating process is economically feasible for use even in a substantially impermeable subterranean oil shale." (col. 6, In. 50-54). Despite this declaration, it is noted that few, if any, commercial in *situ* shale oil operations have occurred other than Ljungstrom's application. The '118 patent proposed controlling the rate of heat conduction within the rock surrounding each heat injection well to provide a uniform heat front.

[0015] A need exists for improved processes for the production of shale oil. In addition, a need exists for improved methods for anticipating and controlling subsidence during a shale oil production operation. Still further, a need exists for methods that optimize the amount of rock that is treated so as to maximize the hydrocarbons recovered from an organic-rich rock formation.

SUMMARY OF THE INVENTION

[0016] The methods described herein have various benefits in improving the recovery of shale oil. In various embodiments, such benefits may include increased production of hydrocarbon fluids from an organic-rich rock formation, and controlling subsidence from a production operation.

[0017] A method for developing hydrocarbons from a subsurface formation in a development area is provided. The formation contains organic-rich rock. In one embodiment, the method includes heating portions of an organic-rich rock formation located in a development area through non-formation oxidative heat generation. The heating pyrolyzes at least a portion of formation hydrocarbons located in a heated zone in the organic rich rock into hydrocarbon fluids. The method also includes preserving at least one unheated zone within the organic-rich rock formation that is not heated. In this way, at least one zone is left within the formation that is substantially unpyrolyzed. In connection with the method, the at least one unheated zone is sized in order to substantially optimize the heated zone. In this way the likelihood of subsidence above the subsurface formation is controlled.

[0018] In one aspect, the organic-rich rock formation is comprised of solid hydrocarbons. Preferably, the solid hydrocarbons are kerogen.

[0019] The method is not limited to the manner in which heating of the formation hydrocarbons is carried out. In some embodiments the heating method includes a non-formation oxidative method. Non-formation oxidative means that an *in situ* combustion process which combusts in place formation hydrocarbons is not used as a source of heating for pyrolysis. For example, non-formation oxidative heat generation may comprise radiative and/or conductive heating by using an electrically resistive heating element in one or more heater wells, or by using one or more downhole burners within one or more heater wells. In the case of electrically resistive heating, the electricity used to generate heat in the electrically resistive heating element may be generated from combustion of previously *in situ* pyrolyzed formation hydrocarbons in, for example, an above-ground gas turbine. Similarly, the gas used for combustion in a downhole burner may have been completely or partially generated as a result of previous *in situ* pyrolysis of formation hydrocarbons. But in either case, in order to be non-formation oxidative the heat is not generated as a result of *in situ* combustion of the formation hydrocarbons in place in the organic-rich rock formation. Alternatively, non-formation oxidative heat generation may comprise heat generated (1) by passing an electrical current through an electrically resistive granular material residing within fractures in the organic-rich rock formation, or (2) by flowing a heated fluid through parallel propped vertical fractures within the organic-rich rock formation. These latter techniques are taught in WO 2005/010320 entitled "Methods of Treating a Subterranean Formation to Convert Organic Matter into Producible Hydrocarbons," and in patent publication WO 2005/045192 entitled "Hydrocarbon Recovery from Impermeable Oil Shales." As described above, the electricity used for generating heat within the electrically resistive granular material or for heating the heated fluid may be derived from the combustion of previously *in situ* pyrolyzed formation hydrocarbons. Moreover, the heated fluid may be heated through combustion of a fluid generated as a result of previous *in situ* pyrolysis of formation hydrocarbons. The Background and technical disclosures of these two patent publications are incorporated herein by reference.

[0020] Preferably, the step of controlling subsidence above the organic-rich rock formation comprises not exceeding a maximum subsidence criterion. The term "maximum subsidence criterion" means that one or more criteria are applied for quantifying or controlling subsidence. In one aspect, the maximum subsidence criterion is a measure of the difference in elevation before and after heating the formation. For example, the difference in elevation may be less than one foot. In another aspect, the maximum subsidence criterion is an absence of faulting above or adjacent the subsurface formation. For example, the absence of faulting may be an absence of faulting between the organic-rich rock formation and a ground water formation there above.

[0021] The size of the unheated region will vary depending upon the nature of the organic-rich rock formation under development. In one aspect, the at least one unheated zone represents no more than 50 percent of the development area. Alternatively, the at least one unheated zone represents no more than 25 percent of the development area. More preferably, the at least one unheated zone represents no more than 10 percent of the development area.

[0022] The method for developing hydrocarbons from a subsurface formation may also include the step of selecting a geometry for the at least one unheated zone within the development area. In one aspect, the at least one unheated zone defines an area that is at least 5 percent greater than an area considered to be a subsidence failure point for the selected geometry. In another aspect, the at least one unheated zone defines an area that is at least 10 percent greater than an area considered to be a subsidence failure point for the selected geometry.

[0023] Various specific configurations for the at least one unheated zone may be employed. In one aspect, a single large area that is essentially a four-sided polygon is left unheated. In another aspect, two or more smaller squares, rectangles, hexagons or rhomboids are left unheated, creating pillars. In yet another aspect, a plurality of small star-shaped areas is preserved from pyrolysis.

[0024] A method for developing hydrocarbons from a subsurface formation containing organic-rich rock while controlling subsidence in a development area is also provided. In one aspect, the method comprises:

(a) providing a finite element computer model of a subsurface zone within the organic-rich rock formation;
(b) providing for the computer model a designated heated area, and an unheated area located in the subsurface zone adjacent to the designated heated area, thereby providing a selected size ratio of the unheated area to the heated area within the subsurface zone;
(c) assigning geomechanical properties for the heated area and the unheated area;
(d) determining whether a subsidence failure point has been reached in rock above or adjacent the heated area at a first fluid pressure within the heated area;
(e) determining whether a subsidence failure point has been reached in rock above or adjacent the designated heated area at a second lower fluid pressure within the designated heated area, thus simulating a reduction of fluid pressure within the subsurface zone; and
(f) heating the subsurface formation in the designated heated area, thereby pyrolyzing at least a portion of formation hydrocarbons found in the organic rich rock into hydrocarbon fluids.

[0025] Preferably, the organic-rich rock formation is comprised of oil shale. The geomechanical properties may include the Poisson ratio, the modulus of elasticity, shear modulus, Lame' constant, V_p/V_s, or combinations thereof. The geomechanical properties may further, or in addition, include a Mohr-Coulomb failure criterion.

[0026] In one aspect, the step (e) of determining whether a subsidence failure point has been reached in the rock above or adjacent the designated heated area comprises determining whether a principal stress in the rock above or adjacent the designated heated area becomes tensile. Alternatively, the step (e) of determining whether a subsidence failure point has been reached in the rock above or adjacent the designated heated area comprises determining whether a shear stress in the rock above or adjacent the designated heated area exceeds the Mohr-Coulomb failure criterion.

[0027] The method may further include the steps of:

(f) increasing the size of the selected size ratio by increasing the size of the designated heated area relative to the unheated area, thereby providing a new selected size ratio;
(g) repeating steps (c) through (e) at the new selected size ratio; and
(h) confirming that the subsidence failure point has not been reached in the rock above or adjacent the designated heated area at the new selected size ratio.

[0028] A method for developing hydrocarbons from an organic-rich rock formation in a development area while controlling subsidence area is also provided. In one aspect, the method comprises:

(a) assigning an area of the subsurface formation to be heated, thereby providing a heated area;
(b) assigning an area of the subsurface formation to be left unheated, thereby providing an unheated area;
(c) providing an initial value for a geomechanical property of the heated area, the geomechanical property representing a softened condition of the subsurface formation in the heated area;
(d) assigning sequentially lower pore pressure values to the heated area;
(e) evaluating at least one of (1) the displacement of

rock above the heated area, or (2) the maximum principal stress in the unheated area adjacent the heated area at the initial value for the geomechanical property at each of the sequentially lower pore pressure values, in order to predict a likelihood of subsidence within the heated area.

[0029] Preferably, the subsurface formation is an oil shale formation. In one aspect, the method further comprises:

(f) providing a second value of the geomechanical property in order to simulate a further softening of the organic-rich rock relative to the initial value of the geomechanical property; and
(g) evaluating at least one of (1) the displacement of rock above the heated area, or (2) the maximum principal stress in the unheated area adjacent the heated area at the second value for the geomechanical property in order to predict a likelihood of subsidence within the heated area.

[0030] In another aspect, the method may further include:

(h) in response to step (g), if minimal likelihood of subsidence above the heated area is predicted, increasing a size of the heated area relative to a size of the unheated area; and
(i) repeating steps (c) through (g).

[0031] In yet another aspect, the unheated area defines a first configuration, and the method further comprises:

(h) in response to step (g), if minimal likelihood of subsidence above the heated area is predicted, changing the configuration of the subsurface formation to be left unheated to a second configuration; and
(i) repeating steps (c) through (g).

[0032] In yet another aspect, the area of the subsurface formation to be left unheated defines a first configuration, and the method further comprises:

(h) in response to step (g), if minimal likelihood of subsidence above the heated area is predicted, increasing a size of the heated area relative to a size of the unheated area using the same first configuration for the unheated area; and
(i) repeating steps (c) through (g).

[0033] A method of minimizing unpyrolyzed oil shale in a subsurface formation is also provided herein. In one embodiment, the method comprises:

providing a finite element model computer program;
designating for the program a first volume of the subsurface formation as being treated;
designating for the program a second volume of rock above and adjacent to the first volume as being untreated;
initializing the second volume in a stress state;
assigning a Young's modulus to the rock in the second volume;
assigning a Young's modulus to the first volume that is lower than the Young's modulus assigned to the second volume;
assigning a pore pressure within the first volume;
incrementally reducing the pore pressure to simulate pyrolysis of formation hydrocarbons in and the removal of fluids from the first volume; and
evaluating at least one of (1) the displacement of rock above the first volume, or (2) the maximum principal stress in the second volume in order to predict a likelihood of subsidence.

[0034] In this method, the pore pressure may be reduced to a value that approximates hydrostatic pressure. This reduction is preferably an incremental step reduction.

[0035] A method for developing hydrocarbons from an oil shale formation is also provided herein. In one aspect, the method includes:

mechanically characterizing geological forces acting upon the oil shale formation;
mechanically characterizing the oil shale formation after at least partial pyrolysis of the oil shale formation;
selecting a first prototype pillar geometry;
selecting a dimension for the first prototype pillar geometry representing a first selected percentage area of the oil shale formation;
running a subsidence model for the first prototype pillar geometry at the first selected percentage area; and
evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the first selected percentage area.

[0036] In one aspect the method further includes the steps of:

selecting a dimension for the first prototype pillar geometry representing a second selected percentage area of the oil shale formation;
running a subsidence model for the first prototype pillar geometry at the second selected percentage area; and
evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the second selected percentage area.

[0037] In one aspect the method further includes the steps of:

- selecting a second prototype pillar geometry;
- selecting a dimension for the second prototype pillar geometry representing the first selected percentage area of the oil shale formation;
- running a subsidence model for the second prototype pillar geometry at the first selected percentage area; and
- evaluating whether failure of the oil shale formation may occur at the selected second prototype pillar geometry and the first selected percentage area.

[0038] In one embodiment, evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the first selected percentage area comprises determining whether rock adjacent to the oil shale formation goes into a state of tension. Alternatively, evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the first selected percentage area comprises determining whether significant displacement of rock in the overburden occurs.

[0039] Finally, a method for importing hydrocarbons is offered herein. In one embodiment, the method includes locating a subsurface formation outside of the territorial boundaries of a first country, the subsurface formation containing organic rich rock, arranging to have hydrocarbon fluids loaded into a marine vessel, and arranging to have the marine vessel transport the hydrocarbon fluids to a terminal within the territorial boundaries of a second country such as the United States. The hydrocarbon fluids are produced as a result of non-formation oxidatively heating the subsurface formation across a development area, thereby pyrolyzing at least a portion of formation hydrocarbons in the organic rich rock into the hydrocarbon fluids.

[0040] In this method, heating the subsurface formation is conducted in a deliberate manner to control subsidence by preserving at least one unheated zone within the formation that is not heated, thereby leaving formation hydrocarbons in the organic rich rock in the at least one unheated zone unpyrolyzed, with the at least one unheated zone being located within the development area. Preferably, the organic-rich rock formation is comprised of oil shale.

BRIEF DESCRIPTION OF THE DRAWINGS

[0041] So that the present invention can be better understood, certain drawings, charts, graphs and flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

[0042] Figure 1 is a three-dimensional isometric view of an illustrative subsurface development area. The development area includes an organic-rich rock matrix that defines a subsurface formation.

[0043] Figure 2 is a flow chart demonstrating a general method of *in situ* thermal recovery of oil and gas from an organic-rich rock formation, in one embodiment.

[0044] Figure 3 is cross-sectional side view of an oil shale development indicating ground water flow.

[0045] Figure 4 provides a plan view of an illustrative heater well arrangement using more than one ring of heater wells surrounding a production well.

[0046] Figure 5 is a bar chart comparing one ton of Green River oil shale before and after a simulated *in situ,* retorting process.

[0047] Figure 6 is a process flow diagram of exemplary surface processing facilities for a subsurface formation development.

[0048] Figure 7 is a graph illustrating the Mohr-Coulomb principle of geomechanical stress.

[0049] Figure 8 is a flow chart showing steps that may be performed in connection with one embodiment of the methods disclosed herein.

[0050] Figure 9 shows another flow chart showing steps that may be performed in connection with an alternate embodiment of the methods disclosed herein.

[0051] Figure 10A is an example of a model geometry used for finite element modeling of formation stresses in a subsurface formation. The model represents one-quarter of a treated volume, plus an untreated area surrounding it.

[0052] Figure 10B is a diagram showing stresses acting on a rock system. The rock system includes a treated interval. Lateral stresses are indicated by arrows labeled "σ_x" and "σ_y." Vertical stresses due to the weight of the overburden are shown by arrows labeled "σ_z."

[0053] Figure 11 demonstrates steps that may be performed in connection with an alternate embodiment of the methods for developing hydrocarbons from a subsurface formation disclosed herein. Figure 11 presents in flow chart form an implementation of the model of Figure 10A.

[0054] Figures 12A through 12D display the results of a computer model in terms of the maximum principal stress acting on rocks within an oil shale development area. In these results, the post-treatment elastic modulus of the treated oil shale is 300 times lower than its pretreatment value.

[0055] In Figure 12A, the pore pressure in the subsurface treated volume is assumed to be 1,858 psi.

[0056] In Figure 12B, the pore pressure in the treated volume is assumed to be 1,458 psi. Thus, the pore pressure in the treated volume has been incrementally decreased to determine how stresses in the rocks surrounding the treated volume are modified.

[0057] Figure 12C represents a third pressure increment. Fluid pressure in the treated volume is further reduced to 1,058 psi. This represents another 400 psi incremental drop.

[0058] In Figure 12D, the pore pressure in the treated volume is further reduced to 658 psi. Thus, the pore pressure in the treated volume has been decreased to a level that is just above hydrostatic pressure. This represents a logical end point for the computer simulation.

[0059] Figures 13A through 13D display displacements calculated by the same computer model that was used to generate the stresses displayed in Figures 12A through 12D.

[0060] In Figure 13A, the pore pressure in the subsurface treated volume is assumed to be 1,858 psi.

[0061] In Figure 13B, the pore pressure in the treated volume is assumed to be 1,458 psi. Thus, the pore pressure in the treated volume has been incrementally decreased to determine the amount of displacement that will occur in the rocks surrounding the treated volume.

[0062] In Figure 13C, the pore pressure in the treated volume is further reduced to 1,058 psi.

[0063] In Figure 13D, the pore pressure in the treated volume is further reduced to 658 psi. Thus, the pore pressure in the treated volume has been decreased to a level that is just above hydrostatic pressure. Again, this represents a logical end point for the computer simulation.

[0064] Figure 14 is a graph wherein different plots are made of the fluid pressure in a treated volume (shown on the horizontal or "x" axis) against the maximum principal stress in a model formation (shown on the vertical or "y" axis). Four different runs representing different post-treatment elastic moduli for a treated volume are demonstrated.

[0065] Figure 15 demonstrates steps that may be performed in connection with an alternate embodiment of the methods for developing hydrocarbons from a subsurface formation disclosed herein. Figure 15 presents in flow chart form another implementation of the model of Figure 10A.

[0066] Figure 16 presents a map view of a shale oil development area, in one embodiment. The development area includes both heater wells and producers.

[0067] Figure 17 is a map view of an alternate shale oil development area. The development area again includes both heater wells and producers.

DETAILED DESCRIPTION OF CERTAIN EMBODIMENTS

Definitions

[0068] As used herein, the term "hydrocarbon(s)" refers to organic material with molecular structures containing carbon bonded to hydrogen. Hydrocarbons may also include other elements, such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur.

[0069] As used herein, the term "hydrocarbon fluids" refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions or at ambient conditions (15° C and 1 atm pressure). Hydrocarbon fluids may include, for example, oil, natural gas, coalbed methane, shale oil, pyrolysis oil, pyrolysis gas, a pyrolysis product of coal, and other hydrocarbons that are in a gaseous or liquid state.

[0070] As used herein, the terms "produced fluids" and "production fluids" refer to liquids and/or gases removed from a subsurface formation, including, for example, an organic-rich rock formation. Produced fluids may include both hydrocarbon fluids and non-hydrocarbon fluids. Production fluids may include, but are not limited to, pyrolyzed shale oil, synthesis gas, a pyrolysis product of coal, carbon dioxide, hydrogen sulfide and water (including steam). Produced fluids may include both hydrocarbon fluids and non-hydrocarbon fluids.

[0071] As used herein, the term "condensable hydrocarbons" means those 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.

[0072] As used herein, the term "non-condensable hydrocarbons" means those 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.

[0073] As used herein, the term "heavy hydrocarbons" refers to hydrocarbon fluids that are highly viscous at ambient conditions (15° C and 1 atm pressure). 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 degrees. Heavy oil, for example, generally has an API gravity of about 10-20 degrees, whereas tar generally has an API gravity below about 10 degrees. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15° C.

[0074] As used herein, the term "solid hydrocarbons" refers to any hydrocarbon material that is found naturally in substantially solid form at formation conditions. Nonlimiting examples include kerogen, coal, shungites, asphaltites, and natural mineral waxes.

[0075] As used herein, the term "formation hydrocarbons" refers to both heavy hydrocarbons and solid hydrocarbons that are contained in an organic-rich rock formation. Formation hydrocarbons may be, but are not limited to, kerogen, oil shale, coal, bitumen, tar, natural mineral waxes, and asphaltites.

[0076] As used herein, the term "tar" refers to 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 degrees. "Tar sands" refers to a formation that has tar in it.

[0077] As used herein, the term "kerogen" refers to a solid, insoluble hydrocarbon that principally contains carbon, hydrogen, nitrogen, oxygen, and sulfur. Oil shale contains kerogen.

[0078] As used herein, the term "bitumen" refers to a non-crystalline solid or viscous hydrocarbon material that is substantially soluble in carbon disulfide.

[0079] As used herein, the term "oil" refers to a hydrocarbon fluid containing a mixture of condensable hydrocarbons.

[0080] As used herein, the term "subsurface" refers to geologic strata occurring below the earth's surface.

[0081] As used herein, the term "hydrocarbon-rich formation" refers to any formation that contains more than trace amounts of hydrocarbons. For example, a hydrocarbon-rich formation may include portions that contain hydrocarbons at a level of greater than 5 percent by volume. The hydrocarbons located in a hydrocarbon-rich formation may include, for example, oil, natural gas, heavy hydrocarbons, and solid hydrocarbons.

[0082] As used herein, the term "organic-rich rock" refers to any rock matrix holding solid hydrocarbons and/or heavy hydrocarbons. Rock matrices may include, but are not limited to, sedimentary rocks, shales, siltstones, sands, silicilytes, carbonates, and diatomites.

[0083] As used herein, the term "formation" refers to any definable subsurface region. The formation may contain one or more hydrocarbon-containing layers, one or more non-hydrocarbon containing layers, an overburden, and/or an underburden of any geologic formation. An "overburden" and/or an "underburden" is geological material above or below the formation of interest. An overburden or underburden may include one or more different types of substantially impermeable materials. For example, overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate (i.e., an impermeable carbonate without hydrocarbons). An overburden and/or an underburden may include a hydrocarbon-containing layer that is relatively impermeable. In some cases, the overburden and/or underburden may be permeable.

[0084] As used herein, the term "organic-rich rock formation" refers to any formation containing organic-rich rock. Organic-rich rock formations include, for example, oil shale formations, coal formations, and tar sands formations.

[0085] As used herein, the term "pyrolysis" refers to the breaking of chemical bonds through the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone or by heat in combination with an oxidant. Pyrolysis may include modifying the nature of the compound by addition of hydrogen atoms which may be obtained from molecular hydrogen, or water. Heat may be transferred to a section of the formation to cause pyrolysis.

[0086] As used herein, the term "water-soluble minerals" refers to minerals that are soluble in water. Water-soluble minerals include, for example, nahcolite (sodium bicarbonate), soda ash (sodium carbonate), dawsonite ($NaAl(CO_3)(OH)_2$), or combinations thereof. Substantial solubility may require heated water and/or a non-neutral pH solution.

[0087] As used herein, the term "formation water-soluble minerals" refers to water-soluble minerals that are found naturally in a formation.

[0088] As used herein, the term "migratory contaminant species" refers to species that are both soluble or moveable in water or an aqueous fluid, and are considered to be potentially harmful or of concern to human health or the environment. Migratory contaminant species may include inorganic and organic contaminants. Organic contaminants may include saturated hydrocarbons, aromatic hydrocarbons, and oxygenated hydrocarbons. Inorganic contaminants may include metal contaminants, and ionic contaminants of various types that may significantly alter pH or the formation fluid chemistry. Aromatic hydrocarbons may include, for example, benzene, toluene, xylene, ethylbenzene, and tri-methylbenzene, and various types of polyaromatic hydrocarbons such as anthracenes, naphthalenes, chrysenes and pyrenes. Oxygenated hydrocarbons may include, for example, alcohols, ketones, phenols, and organic acids such as carboxylic acid. Metal contaminants may include, for example, arsenic, boron, chromium, cobalt, molybdenum, mercury, selenium, lead, vanadium, nickel or zinc. Ionic contaminants include, for example, sulfides, sulfates, chlorides, fluorides, ammonia, nitrates, calcium, iron, magnesium, potassium, lithium, boron, and strontium.

[0089] As used herein, the term "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 H_2 among other molecules.

[0090] As used herein, the term "subsidence" refers to a downward movement of an earth surface relative to an initial elevation of the surface.

[0091] As used herein, the term "thickness" of a layer refers to the distance between the upper and lower boundaries of a cross section of a layer, wherein the distance is measured normal to the average tilt of the cross section.

[0092] As used herein, the term "thermal fracture" refers to fractures created in a formation caused directly or indirectly by expansion or contraction of a portion of the formation and/or fluids within the formation, which in turn is caused by increasing/decreasing the temperature of the formation and/or fluids within the formation, and/or by increasing/decreasing a pressure of fluids within the formation due to heating. Thermal fractures may propagate into or form in neighboring regions significantly cooler than the heated zone.

[0093] As used herein, the term "hydraulic fracture" refers to a fracture at least partially propagated into a formation, wherein the fracture is created through injection of pressurized fluids into the formation. The fracture may be artificially held open by injection of a proppant material. Hydraulic fractures may be substantially horizontal in orientation, substantially vertical in orientation, or oriented along any other plane.

[0094] As used herein, the term "wellbore" refers to a hole in the subsurface made by drilling or insertion of a conduit into the subsurface. A wellbore may have a substantially circular cross section, or other cross-sectional shapes (e.g., circles, ovals, squares, rectangles, triangles, slits, or other regular or irregular shapes). As used herein, the term "well", when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

[0095] As used herein, the term "unheated" means that a rock formation has not been heated or otherwise energized to such an extent as would cause measurable pyrolysis of formation hydrocarbons located in an organic-rich formation.

[0096] Reciprocally, the term "heated" means a rock formation that has been heated or otherwise energized to such an extent as would cause measurable pyrolysis of formation hydrocarbons located in an organic-rich formation.

[0097] As used herein, the term "maximum subsidence criterion" means one or more criteria for quantifying and controlling subsidence.

[0098] Non-formation oxidative heating means that an *in situ* combustion process of formation hydrocarbons is not used for pyrolyzing an organic-rich rock formation. In this respect, the organic-rich rock formation is not artificially exposed to oxygen used to combust the in place formation hydrocarbons.

Description of Specific Embodiments

[0099] The inventions are described herein in connection with certain specific embodiments. However, to the extent that the following detailed description is specific to a particular embodiment or a particular use, such is intended to be illustrative only and is not to be construed as limiting the scope of the inventions.

[0100] As discussed herein, some embodiments of the inventions include or have application related to an *in situ* method of recovering natural resources. The natural resources may be recovered from a formation containing organic-rich rock, including, for example, an oil shale formation. The organic-rich rock may include formation hydrocarbons, including, for example, kerogen, coal, and heavy hydrocarbons. In some embodiments of the inventions the natural resources may include hydrocarbon fluids, including, for example, products of the pyrolysis of formation hydrocarbons such as shale oil. In some embodiments of the inventions the natural resources may also include water-soluble minerals, including, for example, nahcolite (sodium bicarbonate, or $2NaHCO_3$), soda ash (sodium carbonate, or Na_2CO_3), and dawsonite ($NaAl(CO_3)(OH)_2$).

[0101] **Figure 1** presents a perspective view of an illustrative oil shale development area **10.** A surface **12** of the development area **10** is indicated. Below the surface is an organic-rich rock formation **16.** The illustrative subsurface formation **16** contains formation hydrocarbons (such as, for example, kerogen) and possibly valuable water-soluble minerals (such as, for example, nahcolite). It is understood that the representative formation **16** may be any organic-rich rock formation, including a rock matrix containing coal or tar sands, for example. In addition, the rock matrix making up the formation **16** may be permeable, semipermeable or non-permeable. The present inventions are particularly advantageous in oil shale development areas initially having very limited or effectively no fluid permeability.

[0102] **Figure 1** presents a perspective view of an illustrative oil shale development area **10.** A surface **12** of the development area **10** is indicated. Below the surface is an organic-rich rock formation **16.** The illustrative subsurface formation **16** contains formation hydrocarbons (such as, for example, kerogen) and possibly valuable water-soluble minerals (such as, for example, nahcolite). It is understood that the representative formation **16** may be any organic-rich rock formation, including a rock matrix containing coal or tar sands, for example. In addition, the rock matrix making up the formation **16** may be permeable, semipermeable or non-permeable. The present inventions are particularly advantageous in oil shale development areas initially having very limited or effectively no fluid permeability.

[0103] In order to access formation **16** and recover natural resources therefrom, a plurality of wellbores is formed. Wellbores are shown at **14** in **Figure 1.** The representative wellbores **14** are essentially vertical in orientation relative to the surface **12.** However, it is understood that some or all of the wellbores **14** could deviate into an obtuse or even horizontal orientation. In the arrangement of **Figure 1,** each of the wellbores **14** is completed in the oil shale formation **16.** The completions may be either open or cased hole. The well completions may also include propped or unpropped hydraulic fractures emanating therefrom.

[0104] In the view of **Figure 1,** only seven wellbores **14** are shown. However, it is understood that in an oil shale development project, numerous additional wellbores **14** will most likely be drilled. The wellbores **14** may be located in relatively close proximity, being from 10 feet to up to 300 feet in separation. In some embodiments, a well spacing of 15 to 25 feet is provided. Typically, the wellbores **14** are also completed at shallow depths, being from 200 to 5,000 feet at total depth. In some embodiments the oil shale formation targeted for *in situ* retorting is at a depth greater than 200 feet below the surface or alternatively 400 feet below the surface. Alternatively, conversion and production of a shale oil formation occur at depths between 500 and 2,500 feet.

[0105] The wellbores **14** will be selected for certain functions and may be designated as heat injection wells, water injection wells, oil production wells and/or water-soluble mineral solution production wells. In one aspect, the wellbores **14** are dimensioned to serve two, three, or all four of these purposes. Suitable tools and equipment may be sequentially run into and removed from the wellbores **14** to serve the various purposes.

[0106] A fluid processing facility **17** is also shown schematically. The fluid processing facility **17** is equipped to receive fluids produced from the organic-rich rock formation **16** through one or more pipelines or flow lines **18.** The fluid processing facility **17** may include equipment suitable for receiving and separating oil, gas, and water produced from the heated formation. The fluid processing facility **17** may further include equipment for separating out dissolved water-soluble minerals and/or migratory contaminant species, including, for example, dissolved organic contaminants, metal contaminants, or ionic contaminants in the produced water recovered from the organic-rich rock formation **16.** The contaminants may include, for example, aromatic hydrocarbons such as benzene, toluene, xylene, and tri-methylbenzene. The contaminants may also include polyaromatic hydrocarbons such as anthracene, naphthalene, chrysene and pyrene. Metal contaminants may include species containing arsenic, boron, chromium, mercury, selenium, lead, vanadium, nickel, cobalt, molybdenum, or zinc. Ionic contaminant species may include, for example, sulfates, chlorides, fluorides, lithium, potassium, aluminum, ammonia, and nitrates.

[0107] In order to recover oil, gas, and sodium (or other) water-soluble minerals, a series of steps may be undertaken. **Figure 2** presents a flow chart demonstrating a method of *in situ* thermal recovery of oil and gas from an organic-rich rock formation **100,** in one embodiment. It is understood that the order of some of the steps from **Figure 2** may be changed, and that the sequence of steps is merely for illustration.

[0108] First, the oil shale (or other organic-rich rock) formation **16** is identified within the development area **10.** This step is shown in box **110.** Optionally, the oil shale formation may contain nahcolite or other sodium minerals. The targeted development area within the oil shale formation may be identified by measuring or modeling the depth, thickness and organic richness of the oil shale as well as evaluating the position of the organic-rich rock formation relative to other rock types, structural features (e.g. faults, anticlines or synclines), or hydrogeological units (i.e. aquifers). This is accomplished by creating and interpreting maps and/or models of depth, thickness, organic richness and other data from available tests and sources. This may involve performing geological surface surveys, studying outcrops, performing seismic surveys, and/or drilling boreholes to obtain core samples from subsurface rock. Rock samples may be analyzed to assess kerogen content and hydrocarbon fluid generating capability.

[0109] The kerogen content of the organic-rich rock formation may be ascertained from outcrop or core samples using a variety of data. Such data may include organic carbon content, hydrogen index, and modified Fischer assay analyses. Subsurface permeability may also be assessed via rock samples, outcrops, or studies of ground water flow. Furthermore the connectivity of the development area to ground water sources may be assessed.

[0110] Next, a plurality of wellbores **14** is formed across the targeted development area **10.** This step is shown schematically in box **115.** The purposes of the wellbores **14** are set forth above and need not be repeated. However, it is noted that for purposes of the wellbore formation step of box **115,** only a portion of the wells need be completed initially. For instance, at the beginning of the project heat injection wells are needed, while a majority of the hydrocarbon production wells are not yet needed. Production wells may be brought in once conversion begins, such as after 4 to 12 months of heating.

[0111] It is understood that petroleum engineers will develop a strategy for the best depth and arrangement for the wellbores **14,** depending upon anticipated reservoir characteristics, economic constraints, and work scheduling constraints. In addition, engineering staff will determine what wellbores **14** shall be used for initial formation **16** heating. This selection step is represented by box **120.**

[0112] Concerning heat injection wells, there are various methods for applying heat to the organic-rich rock formation **16.** The present methods are not limited to the heating technique employed unless specifically so stated in the claims. The heating step is represented generally by box **130.** Preferably, *for in situ* processes the heating of a production zone takes place over a period of months, or even four or more years.

[0113] The formation 16 is heated to a temperature sufficient to pyrolyze at least a portion of the oil shale in order to convert the kerogen to hydrocarbon fluids. The bulk of the target zone of the formation may be heated to between 270° C to 800° C. Alternatively, the targeted volume of the organic-rich formation is heated to at least 350° C to create production fluids. The conversion step is represented in **Figure 2** by box **135.** The resulting liquids and hydrocarbon gases may be refined into products which resemble common commercial petroleum products. Such liquid products include transportation fuels such as diesel, jet fuel, and naptha. Generated gases include light alkanes, light alkenes, H_2, CO_2, CO, and NH_3.

[0114] Conversion of the oil shale will create permeability in the oil shale section in rocks that were originally impermeable. Preferably, the heating and conversion processes of boxes **130** and **135,** occur over a lengthy period of time. In one aspect, the heating period is from three months to four or more years. Also as an optional part of box **135,** the formation **16** may be heated to a temperature sufficient to convert at least a portion of nahcolite, if present, to soda ash. Heat applied to mature the oil shale and recover oil and gas will also convert nahcolite to sodium carbonate (soda ash), a related sodium mineral. The process of converting nahcolite (sodium bicarbonate) to soda ash (sodium carbonate) is described herein.

[0115] In connection with the heating step **130,** the rock formation **16** may optionally be fractured to aid heat transfer or later hydrocarbon fluid production. The optional fracturing step is shown in box **125.** Fracturing may be accomplished by creating thermal fractures within the formation through application of heat. By heating the organic-rich rock and transforming the kerogen to oil and gas, the permeability of portions of the formation are increased via thermal fracture formation and subsequent production of a portion of the hydrocarbon fluids generated from the kerogen. Alternatively, a process known as hydraulic fracturing may be used. Hydraulic fracturing is a process known in the art of oil and gas recovery where a fracture fluid is pressurized within the wellbore above the fracture pressure of the formation, thus developing fracture planes within the formation to relieve the pressure generated within the wellbore. Hydraulic fractures may be used to create additional permeability in portions of the formation and/or be used to provide a planar source for heating.

[0116] As part of the hydrocarbon fluid production process **100,** certain wells **14** may be designated as oil and gas production wells. This step is depicted by box **140.** Oil and gas production might not be initiated until it is determined that the kerogen has been sufficiently retorted to allow maximum recovery of oil and gas from the formation **16**. In some instances, dedicated production wells are not drilled until after heat injection wells (box **130)** have been in operation for a period of several weeks or months. Thus, box **140** may include the formation of additional wellbores **14.** In other instances, selected heater wells are converted to production wells.

[0117] After certain wellbores **14** have been designated as oil and gas production wells, oil and/or gas is produced from the wellbores **14.** The oil and/or gas production process is shown at box **145.** At this stage (box **145),** any water-soluble minerals, such as nahcolite and converted soda ash may remain substantially trapped in the rock formation **16** as finely disseminated crystals or nodules within the oil shale beds, and are not produced. However, some nahcolite and/or soda ash may be dissolved in the water created during heat conversion (box **135**) within the formation.

[0118] Box **150** presents an optional next step in the oil and gas recovery method **100.** Here, certain wellbores **14** are designated as water or aqueous fluid injection wells. Aqueous fluids are solutions of water with other species. The water may constitute "brine," and may include dissolved inorganic salts of chloride, sulfates and carbonates of Group I and II elements of The Periodic Table of Elements. Organic salts can also be present in the aqueous fluid. The water may alternatively be fresh water containing other species. The other species may be present to alter the pH. Alternatively, the other species may reflect the availability of brackish water not saturated in the species wished to be leached from the subsurface. Preferably, the water injection wells are selected from some or all of the wellbores used for heat injection or for oil and/or gas production. However, the scope of the step of box **150** may include the drilling of yet additional wellbores **14** for use as dedicated water injection wells. In this respect, it may be desirable to complete water injection wells along a periphery of the development area **10** in order to create a boundary of high pressure.

[0119] Next, optionally water or an aqueous fluid is injected through the water injection wells and into the oil shale formation **16.** This step is shown at box **155.** The water may be in the form of steam or pressurized hot water. Alternatively the injected water may be cool and becomes heated as it contacts the previously heated formation. The injection process may further induce fracturing. This process may create fingered caverns and brecciated zones in the nahcolite-bearing intervals some distance, for example up to 200 feet out, from the water injection wellbores. In one aspect, a gas cap, such as nitrogen, may be maintained at the top of each "cavern" to prevent vertical growth.

[0120] Along with the designation of certain wellbores **14** as water injection wells, the design engineers may also designate certain wellbores **14** as water or water-soluble mineral solution production wells. This step is shown in box **160.** These wells may be the same as wells used to previously produce hydrocarbons or inject heat. These recovery wells may be used to produce an aqueous solution of dissolved water-soluble minerals and other species, including, for example, migratory contaminant species. For example, the solution may be one primarily of dissolved soda ash. This step is shown in box **165.** Alternatively, single wellbores may be used to both inject water and then to recover a sodium mineral solution. Thus, box **165** includes the option of using the same wellbores **14** for both water injection and solution production (Box **165).**

[0121] Temporary control of the migration of the migratory contaminant species, especially during the pyrolysis process, can be obtained via placement of the injection and production wells **14** such that fluid flow out of the heated zone is minimized. Typically, this involves placing injection wells at the periphery of the heated zone so as to cause pressure gradients which prevent flow inside the heated zone from leaving the zone.

[0122] **Figure 3** is a cross-sectional view of an illustrative oil shale formation that is within or connected to ground water aquifers and a formation leaching operation. Four separate oil shale formation zones are depicted **(23, 24, 25** and **26)** within the oil shale formation. The water aquifers are below the ground surface **27,** and are categorized as an upper aquifer **20** and a lower aquifer **22.** Intermediate the upper and lower aquifers is an aquitard **21.** It can be seen that certain zones of the formation are both aquifers or aquitards and oil shale zones. A plurality of wells **(28, 29, 30** and **31)** is shown traversing vertically downward through the aquifers. One of the wells is serving as a water injection well **31,** while another is serving as a water production well **30.** In this way, water is circulated **32** through at least the lower aquifer **22.**

[0123] **Figure 3** shows diagrammatically the water circulation **32** through an oil shale volume that was heated **33,** that resides within or is connected to an aquifer **22,** and from which hydrocarbon fluids were previously recovered. Introduction of water via the water injection well 31 forces water into the previously heated oil shale **33** so that water-soluble minerals and migratory contaminants species are swept to the water production well **30.** The water may then processed in a facility **34** wherein the water-soluble minerals (e.g. nahcolite or soda ash) and the migratory contaminants may be substantially removed from the water stream. Water is then reinjected into the oil shale volume **33** and the formation leaching is repeated. This leaching with water is intended to continue until levels of migratory contaminant species are at environmentally acceptable levels within the previously heated oil shale zone **33.** This may require 1 cycle, 2 cycles, 5 cycles 10 cycles or more cycles of formation leaching, where a single cycle indicates injection and production of approximately one pore volume of water. It is understood that there may be numerous water injection and water production wells in an actual oil shale development. Moreover, the system may include monitoring wells (**28** and **29**) which can be utilized during the oil shale heating phase, the shale oil production phase, the leaching phase, or during any combination of these phases to monitor for migratory contaminant species and/or water-soluble minerals.

[0124] In some fields, formation hydrocarbons, such as oil shale, may exist in more than one subsurface formation. In some instances, the organic-rich rock formations may be separated by rock layers that are hydrocarbon-free or that otherwise have little or no commercial value. Therefore, it may be desirable for the operator of a field under hydrocarbon development to undertake an analysis as to which of the subsurface, organic-rich rock formations to target or in which order they should be developed.

[0125] The organic-rich rock formation may be selected for development based on various factors. One such factor is the thickness of the hydrocarbon containing layer within the formation. Greater pay zone thickness may indicate a greater potential volumetric production of hydrocarbon fluids. Each of the hydrocarbon containing layers may have a thickness that varies depending on, for example, conditions under which the formation hydrocarbon containing layer was formed. Therefore, an organic-rich rock formation will typically be selected for treatment if that formation includes at least one formation hydrocarbon-containing layer having a thickness sufficient for economical production of produced fluids.

[0126] An organic-rich rock formation may also be chosen if the thickness of several layers that are closely spaced together is sufficient for economical production of produced fluids. For example, an *in situ* conversion process for formation hydrocarbons may include selecting and treating a layer within an organic-rich rock formation having a thickness of greater than about 5 meters, 10 meters, 50 m, or even 100 meters. In this manner, heat losses (as a fraction of total injected heat) to layers formed above and below an organic-rich rock formation may be less than such heat losses from a thin layer of formation hydrocarbons. A process as described herein, however, may also include selecting and treating layers that may include layers substantially free of formation hydrocarbons or thin layers of formation hydrocarbons.

[0127] The richness of one or more organic-rich rock formations may also be considered. Richness may depend on many factors including the conditions under which the formation hydrocarbon containing layer was formed, an amount of formation hydrocarbons in the layer, and/or a composition of formation hydrocarbons in the layer. A thin and rich formation hydrocarbon layer may be able to produce significantly more valuable hydrocarbons than a much thicker, less rich formation hydrocarbon layer. Of course, producing hydrocarbons from a formation that is both thick and rich is desirable.

[0128] The kerogen content of an organic-rich rock formation may be ascertained from outcrop or core samples using a variety of data. Such data may include organic carbon content, hydrogen index, and modified Fischer assay analyses. The Fischer Assay is a standard method which involves heating a sample of a formation hydrocarbon containing layer to approximately 500°C in one hour, collecting fluids produced from the heated sample, and quantifying the amount of fluids produced.

[0129] Subsurface formation permeability may also be assessed via rock samples, outcrops, or studies of ground water flow. Furthermore the connectivity of the development area to ground water sources may be assessed. Thus, an organic-rich rock formation may be chosen for development based on the permeability or porosity of the formation matrix even if the thickness of the formation is relatively thin.

[0130] Other factors known to petroleum engineers may be taken into consideration when selecting a formation for development. Such factors include depth of the perceived pay zone, stratigraphic proximity of fresh ground water to kerogen-containing zones, continuity of thickness, and other factors. For instance, the assessed fluid production content within a formation will also effect eventual volumetric production.

[0131] In producing hydrocarbon fluids from an oil shale field, it may be desirable to control the migration of pyrolyzed fluids. In some instances, this includes the use of injection wells, particularly around the periphery of the field. Such wells may inject water, steam, CO_2, heated methane, or other fluids to drive cracked kerogen fluids inwardly towards production wells. In some embodiments, physical barriers may be placed around the area of the organic-rich rock formation under development. One example of a physical barrier involves the creation of freeze walls. Freeze walls are formed by circulating refrigerant through peripheral wells to substantially reduce the temperature of the rock formation. This, in turn, prevents the pyrolyzation of kerogen present at the periphery of the field and the outward migration of oil and gas. Freeze walls will also cause native water in the formation along the periphery to freeze.

[0132] The use of subsurface freezing to stabilize poorly consolidated soils or to provide a barrier to fluid flow is known in the art. Shell Exploration and Production Company has discussed the use of freeze walls for oil shale production in several patents, including U.S. Pat. No. 6,880,633 and U.S. Pat. No. 7,032,660. Shell's '660 patent uses subsurface freezing to protect against groundwater flow and groundwater contamination during *in situ* shale oil production. Additional patents that disclose the use of so-called freeze walls are U.S. Pat. No. 3,528,252, U.S. Pat. No. 3,943,722, U.S. Pat. No. 3,729,965, U.S. Pat. No. 4,358,222, U.S. Pat. No. 4,607,488, and WO Pat. No. 98996480.

[0133] Another example of a physical barrier that may be used to limit fluid flow into or out of an oil shale field is the creation of grout walls. Grout walls are formed by injecting cement into the formation to fill permeable pathways. In the context of an oil shale field, cement would be injected along the periphery of the field. This prevents the movement of pyrolyzed fluids out of the field under development, and the movement of water from adjacent aquifers into the field.

[0134] As noted above, several different types of wells may be used in the development of an organic-rich rock formation, including, for example, an oil shale field. For example, the heating of the organic-rich rock formation may be accomplished through the use of heater wells. The heater wells may include, for example, electrical resistance heating elements. The production of hydrocarbon fluids from the formation may be accomplished through the use of wells completed for the production of fluids. The injection of an aqueous fluid may be accomplished through the use of injection wells. Finally, the production of an aqueous solution may be accomplished through use of solution production wells.

[0135] The different wells listed above may be used for more than one purpose. Stated another way, wells initially completed for one purpose may later be used for another purpose, thereby lowering project costs and/or decreasing the time required to perform certain tasks. For example, one or more of the production wells may also be used as injection wells for later injecting water into the organic-rich rock formation. Alternatively, one or more of the production wells may also be used as solution production wells for later producing an aqueous solution from the organic-rich rock formation.

[0136] In other aspects, production wells (and in some circumstances heater wells) may initially be used as dewatering wells (e.g., before heating is begun and/or when heating is initially started). In addition, in some circumstances dewatering wells can later be used as production wells (and in some circumstances heater wells). As such, the dewatering wells may be placed and/or designed so that such wells can be later used as production wells and/or heater wells. The heater wells may be placed and/or designed so that such wells can be later used as production wells and/or dewatering wells. The production wells may be placed and/or designed so that such wells can be later used as dewatering wells and/or heater wells. Similarly, injection wells may be wells that initially were used for other purposes (e.g., heating, production, dewatering, monitoring, etc.), and injection wells may later be used for other purposes. Similarly, monitoring wells may be wells that initially were used for other purposes (e.g., heating, production, dewatering, injection, etc.). Finally, monitoring wells may later be used for other purposes such as water production.

[0137] The wellbores for the various wells may be located in relatively close proximity, being from 10 feet to up to 300 feet in separation. Alternatively, the wellbores may be spaced from 30 to 200 feet or 50 to 100 feet. Typically, the wellbores are also completed at shallow depths, ranging from 200 to 5,000 feet at total depth. Alternatively, the wellbores may be completed at depths from 1,000 to 4,000 feet, or 1,500 to 3,500 feet. In some embodiments, the oil shale formation targeted for *in situ* retorting is at a depth greater than 200 feet below the surface. In alternative embodiments, the oil shale formation targeted for *in situ* retorting is at a depth greater than 500, 1,000, or 1,500 feet below the surface. In alternative embodiments, the oil shale formation targeted *for in situ* retorting is at a depth between 200 and 5,000 feet, alternatively between 1,000 and 4,000 ft, 1,200 and 3,700 feet, or 1,500 and 3,500 feet below the surface.

[0138] It is desirable to arrange the various wells for an oil shale field in a pre-planned pattern. For instance, heater wells may be arranged in a variety of patterns including, but not limited to triangles, squares, hexagons, and other polygons. The pattern may include a regular polygon to promote uniform heating through at least the portion of the formation in which the heater wells are placed. The pattern may also be a line drive pattern. A line drive pattern generally includes a first linear array of heater wells, a second linear array of heater wells, and a production well or a linear array of production wells between the first and second linear array of heater wells. Interspersed among the heater wells are typically one or more production wells. The injection wells may likewise be disposed within a repetitive pattern of units, which may be similar to or different from that used for the heater wells.

[0139] One method to reduce the number of wells is to use a single well as both a heater well and a production well. Reduction of the number of wells by using single wells for sequential purposes can reduce project costs. One or more monitoring wells may be disposed at selected points in the field. The monitoring wells may be configured with one or more devices that measure a temperature, a pressure, and/or a property of a fluid in the wellbore. In some instances, a heater well may also serve as a monitoring well, or otherwise be instrumented.

[0140] Another method for reducing the number of heater wells is to use well patterns. Regular patterns of heater wells equidistantly spaced from a production well may be used. The patterns may form equilateral triangular arrays, hexagonal arrays, or other array patterns. The arrays of heater wells may be disposed such that a distance between each heater well is less than about 70 feet (21 m). A portion of the formation may be heated with heater wells disposed substantially parallel to a boundary of the hydrocarbon formation.

[0141] In alternative embodiments, the array of heater wells may be disposed such that a distance between each heater well may be less than about 100 feet, or 50 feet, or 30 feet. Regardless of the arrangement of or distance between the heater wells, in certain embodiments, a ratio of heater wells to production wells disposed within a organic-rich rock formation may be greater than about 5, 8, 10, 20, or more.

[0142] In one embodiment, individual production wells are surrounded by at most one layer of heater wells. This may include arrangements such as 5-spot, 7-spot, or 9-spot arrays, with alternating rows of production and heater wells. In another embodiment, two layers of heater wells may surround a production well, but with the heater wells staggered so that a clear pathway exists for the majority of flow away from the further heater wells. Flow and reservoir simulations may be employed to assess the pathways and temperature history of hydrocarbon fluids generated *in situ* as they migrate from their points of origin to production wells.

[0143] **Figure 4** provides a plan view of an illustrative heater well arrangement using more than one layer of heater wells. The heater well arrangement is used in connection with the production of hydrocarbons from a shale oil development area **400.** In **Figure 4,** the heater well arrangement employs a first layer of heater wells **410,** surrounded by a second layer of heater wells **420.** The heater wells in the first layer **410** are referenced at **431,** while the heater wells in the second layer **420** are referenced at **432.**

[0144] A production well **440** is shown central to the well layers **410** and **420.** It is noted that the heater wells **432** in the second layer **420** of wells are offset from the heater wells **431** in the first layer **410** of wells, relative to the production well **440.** The purpose is to provide a flowpath for converted hydrocarbons that minimizes travel near a heater well in the first layer **410** of heater wells. This, in turn, minimizes secondary cracking of hydrocarbons converted from kerogen as hydrocarbons flow from the second layer of wells **420** to the production wells **440.**

[0145] In the illustrative arrangement of **Figure 4,** the first layer **410** and the second layer **420** each defines a 5-spot pattern. However, it is understood that other patterns may be employed, such as 3-spot or 6-spot patterns. In any instance, a plurality of heater wells **431** comprising a first layer of heater wells **410** is placed around a production well **440,** with a second plurality of heater wells **432** comprising a second layer of heater wells **420** placed around the first layer **410.**

[0146] The heater wells in the two layers also may be arranged such that the majority of hydrocarbons generated by heat from each heater well **432** in the second layer **420** are able to migrate to a production well **440** without passing substantially near a heater well **431** in the first layer **410.** The heater wells **431, 432** in the two layers **410, 420** further may be arranged such that the majority of hydrocarbons generated by heat from each heater well **432** in the second layer **420** are able to migrate to the production well **440** without passing through a zone of substantially increasing formation temperature.

[0147] One method to reduce the number of heater wells is to use well patterns that are elongated in a particular direction, particularly in the direction of most efficient thermal conductivity. Heat convection may be affected by various factors such as bedding planes and stresses within the formation. For instance, heat convection may be more efficient in the direction perpendicular to the least horizontal principal stress on the formation. In some instanced, heat convection may be more efficient in the direction parallel to the least horizontal principal stress.

[0148] In connection with the development of an oil shale field, it may be desirable that the progression of heat through the subsurface in accordance with steps **130** and **135** be uniform. However, for various reasons the heating and maturation of formation hydrocarbons in a subsurface formation may not proceed uniformly despite a regular arrangement of heater and production wells. Heterogeneities in the oil shale properties and formation structure may cause certain local areas to be more or less productive. Moreover, formation fracturing which occurs due to the heating and maturation of the oil shale can lead to an uneven distribution of preferred pathways and, thus, increase flow to certain production wells and reduce flow to others. Uneven fluid maturation may be an undesirable condition since certain subsurface regions may receive more heat energy than necessary where other regions receive less than desired. This, in turn, leads to the uneven flow and recovery of production fluids. Produced oil quality, overall production rate, and/or ultimate recoveries may be reduced.

[0149] To detect uneven flow conditions, production and heater wells may be instrumented with sensors. Sensors may include equipment to measure temperature, pressure, flow rates, and/or compositional information. Data from these sensors can be processed via simple rules or input to detailed simulations to reach decisions on how to adjust heater and production wells to improve subsurface performance. Production well performance may be adjusted by controlling backpressure or throttling on the well. Heater well performance may also be adjusted by controlling energy input. Sensor readings may also sometimes imply mechanical problems with a well or downhole equipment which requires repair, replacement, or abandonment.

[0150] In one embodiment, flow rate, compositional, temperature and/or pressure data are utilized from two or more wells as inputs to a computer algorithm to control heating rate and/or production rates. Unmeasured conditions at or in the neighborhood of the well are then estimated and used to control the well. For example, *in situ* fracturing behavior and kerogen maturation are estimated based on thermal, flow, and compositional data from a set of wells. In another example, well integrity is evaluated based on pressure data, well temperature data, and estimated *in situ* stresses. In a related embodiment the number of sensors is reduced by equipping only a subset of the wells with instruments, and using the results to interpolate, calculate, or estimate conditions at uninstrumented wells. Certain wells may have only a limited set of sensors (e.g., wellhead temperature and pressure only) where others have a much larger set of sensors (e.g., wellhead temperature and pressure, bottomhole temperature and pressure, production composition, flow rate, electrical signature, casing strain, etc.).

[0151] As noted above, there are various methods for applying heat to an organic-rich rock formation. For example, one method may include electrical resistance heaters disposed in a wellbore or outside of a wellbore. One such method involves the use of electrical resistive heating elements in a cased or uncased wellbore. Electrical resistance heating involves directly passing electricity through a conductive material such that resistive losses cause it to heat the conductive material. Other heating methods include the use of downhole combustors, *in situ* combustion, radio-frequency (RF) electrical energy, or microwave energy. Still others include injecting a hot fluid into the oil shale formation to directly heat it. The hot fluid may or may not be circulated. One method may include generating heat by burning a fuel external to or within a subsurface formation. For example, heat may be supplied by surface burners or downhole burners or by circulating hot fluids (such as methane gas or naphtha) into the formation through, for example, wellbores via, for example, natural or artificial fractures. Some burners may be configured to perform flameless combustion. Alternatively, some methods may include combusting fuel within the formation such as via a natural distributed combustor, which generally refers to a heater that uses an oxidant to oxidize at least a portion of the carbon in the formation to generate heat, and wherein the oxidation takes place in a vicinity proximate to a wellbore. The present methods are not limited to the heating technique employed unless so stated in the claims.

[0152] One method for formation heating involves the use of electrical resistors in which an electrical current is passed through a resistive material which dissipates the electrical energy as heat. This method is distinguished from dielectric heating in which a highfrequency oscillating electric current induces electrical currents in nearby materials and causes them to heat. The electric heater may include an insulated conductor, an elongated member disposed in the opening, and/or a conductor disposed in a conduit. An early patent disclosing the use of electrical resistance heaters to produce oil shale *in situ* is U.S. Pat. No. 1,666,488. The **'488** patent issued to Crawshaw in 1928. Since 1928, various designs for downhole electrical heaters have been proposed. Illustrative designs are presented in U.S. Pat. No. 1,701,884, U.S. Pat. No. 3,376,403, U.S. Pat. No. 4,626,665, U.S. Pat. No. 4,704,514, and U.S. Pat. No. 6,023,554).

[0153] A review of application of electrical heating methods for heavy oil reservoirs is given by R. Sierra and S.M. Farouq Ali, "Promising Progress in Field Application of Reservoir Electrical Heating Methods", Society of Petroleum Engineers Paper 69709, 2001. The entire disclosure of this reference is hereby incorporated by reference.

[0154] Certain previous designs *for in situ* electrical resistance heaters utilized solid, continuous heating elements (e.g., metal wires or strips). However, such elements may lack the necessary robustness for long-term, high temperature applications such as oil shale maturation. As the formation heats and the oil shale matures, significant expansion of the rock occurs. This leads to high stresses on wells intersecting the formation. These stresses can lead to bending and stretching of the wellbore pipe and internal components. Cementing (e.g., U.S. Pat. No. 4,886,118) or packing (e.g., U.S. Pat. No. 2,732,195) a heating element in place may provide some protection against stresses, but some stresses may still be transmitted to the heating element.

[0155] As an alternative, international patent publication WO 2005/010320 teaches the use of electrically conductive fractures to heat the oil shale. A heating element is constructed by forming wellbores and then hydraulically fracturing the oil shale formation around the wellbores. The fractures are filled with an electrically conductive material which forms the heating element. Calcined petroleum coke is an exemplary suitable conductant material. Preferably, the fractures are created in a vertical orientation along longitudinal, horizontal planes formed by horizontal wellbores. Electricity may be conducted through the conductive fractures from the heel to the toe of each well. The electrical circuit may be completed by an additional horizontal well that intersects one or more of the vertical fractures near the toe to supply the opposite electrical polarity. The WO 2005/010320 process creates an *"in situ* toaster" that artificially matures oil shale through the application of electric heat. Thermal conduction heats the oil shale to conversion temperatures in excess of 300° C causing artificial maturation.

[0156] International patent publication WO 2005/045192 teaches an alternative heating means that employs the circulation of a heated fluid within an oil shale formation. In the process of WO 2005/045192 supercritical heated naphtha may be circulated through fractures in the formation. This means that the oil shale is heated by circulating a dense, hot hydrocarbon vapor through sets of closely-spaced hydraulic fractures. In one aspect, the fractures are horizontally formed and conventionally propped. Fracture temperatures of 320° - 400° C are maintained for up to five to ten years. Vaporized naptha may be the preferred heating medium due to its high volumetric heat capacity, ready availability and relatively low degradation rate at the heating temperature. In the WO 2005/045192 process, as the kerogen matures, fluid pressure will drive the generated oil to the heated fractures, where it will be produced with the cycling hydrocarbon vapor.

[0157] The purpose for heating the organic-rich rock formation is to pyrolyze at least a portion of the solid formation hydrocarbons to create hydrocarbon fluids. The solid formation hydrocarbons may be pyrolyzed *in situ* by raising the organic-rich rock formation (or zones within the formation), to a pyrolyzation temperature. In certain embodiments, the temperature of the formation may be slowly raised through the pyrolysis temperature range. For example, an *in situ* conversion process may include heating at least a portion of the organic-rich rock formation to raise the average temperature of the zone above about 270° C at a rate less than a selected amount (e.g., about 10° C, 5° C; 3° C, 1° C, 0.5° C, or 0.1° C) per day. In a further embodiment, the portion may be heated such that an average temperature of the selected zone may be less than about 375° C or, in some embodiments, less than about 400°C. The formation may be heated such that a temperature within the formation reaches (at least) an initial pyrolyzation temperature (e.g., a temperature at the lower end of the temperature range where pyrolyzation begins to occur.

[0158] The pyrolysis temperature range may vary depending on the types of formation hydrocarbons within the formation, the heating methodology, and the distribution of heating sources. For example, a pyrolysis temperature range may include temperatures between about 270° C and about 900° C. Alternatively, the bulk of the target zone of the formation may be heated to between 300° to 600° C. In an alternative embodiment, a pyrolysis temperature range may include temperatures between about 270° C to about 500° C.

[0159] Preferably, *for in situ* processes the heating of a production zone takes place over a period of months, or even four or more years. Alternatively, the formation may be heated for one to fifteen years, alternatively, 3 to 10 years, 1.5 to 7 years, or 2 to 5 years. The bulk of the target zone of the formation may be heated to between 270° to 800° C. Preferably, the bulk of the target zone of the formation is heated to between 300° to 600° C. Alternatively, the bulk of the target zone is ultimately heated to a temperature below 400° C (752° F).

[0160] In certain embodiments of the methods of the present invention, downhole burners may be used to heat a targeted oil shale zone. Downhole burners of various design have been discussed in the patent literature for use in oil shale and other largely solid hydrocarbon deposits. Examples include U.S. Pat. No. 2,887,160; U.S. Pat. No. 2,847,071; U.S. Pat. No. 2,895,555; U.S. Pat. No. 3,109,482; U.S. Pat. No. 3,225,829; U.S. Pat. No. 3,241,615; U.S. Pat. No. 3,254,721; U.S. Pat. No. 3,127,936; U.S. Pat. No. 3,095,031; U.S. Pat. No. 5,255,742; and U.S. Pat. No. 5,899,269. Downhole burners operate through the transport of a combustible fuel (typically natural gas) and an oxidizer (typically air) to a subsurface position in a wellbore. The fuel and oxidizer react downhole to generate heat. The combustion gases are removed (typically by transport to the surface, but possibly via injection into the formation). Oftentimes, downhole burners utilize pipe-in-pipe arrangements to transport fuel and oxidizer downhole, and then to remove the flue gas back up to the surface. Some downhole burners generate a flame, while others may not.

[0161] The use of downhole burners is an alternative to another form of downhole heat generation called steam generation. In downhole steam generation, a combustor in the well is used to boil water placed in the wellbore for injection into the formation. Applications of the downhole heat technology have been described in F.M. Smith, "A Down-hole burner - Versatile tool for well heating," 25th Technical Conference on Petroleum Production, Pennsylvania State University, pp 275-285 (Oct. 19-21, 1966); H. Brandt, W.G. Poynter, and J.D. Hummell, "Stimulating Heavy Oil Reservoirs with Downhole Air-Gas Burners," World Oil, pp. 91-95 (Sept. 1965); and C.I. DePriester and A.J. Pantaleo, "Well Stimulation by Downhole Gas-Air Burner," Journal of Petroleum Technology, pp. 1297-1302 (Dec. 1963).

[0162] Downhole burners have advantages over electrical heating methods due to the reduced infrastructure cost. In this respect, there is no need for an expensive electrical power plant and distribution system. Moreover, there is increased thermal efficiency because the energy losses inherently experienced during electrical power generation are avoided.

[0163] Few applications of downhole burners exist due to various design issues. Downhole burner design issues include temperature control and metallurgy limitations. In this respect, the flame temperature can overheat the tubular and burner hardware and cause them to fail via melting, thermal stresses, severe loss of tensile strength, or creep. Certain stainless steels, typically with high chromium content, can tolerate temperatures up to ~700° C for extended periods. (See for example H.E. Boyer and T.L. Gall (eds.), Metals Handbook, "Chapter 16: Heat-Resistant Materials", American Society for Metals, (1985.) The existence of flames can cause hot spots within the burner and in the formation surrounding the burner. This is due to radiant heat transfer from the luminous portion of the flame. However, a typical gas flame can produce temperatures up to about 1,650° C. Materials of construction for the burners must be sufficient to withstand the temperatures of these hot spots. The heaters are therefore more expensive than a comparable heater without flames.

[0164] For downhole burner applications, heat transfer can occur in one of several ways. These include conduction, convection, and radiative methods. Radiative heat transfer can be particularly strong for an open flame. Additionally, the flue gases can be corrosive due to the CO_2 and water content. Use of refractory metals or ceramics can help solve these problems, but typically at a higher cost. Ceramic materials with acceptable strength at temperatures in excess of 900° C are generally high alumina content ceramics. Other ceramics that may be useful include chrome oxide, zirconia oxide, and magnesium oxide based ceramics. Additionally, depending on the nature of the downhole combustion NO_x generation may be significant.

[0165] Heat transfer in a pipe-in-pipe arrangement for a downhole burner can also lead to difficulties. The down going fuel and air will heat exchange with the up going hot flue gases. In a well there is minimal room for a high degree of insulation and hence significant heat transfer is typically expected. This cross heat exchange can lead to higher flame temperatures as the fuel and air become preheated. Additionally, the cross heat exchange can limit the transport of heat downstream of the burner since the hot flue gases may rapidly lose heat energy to the rising cooler flue gases.

[0166] In the production of oil and gas resources, it may be desirable to use the produced hydrocarbons as a source of power for ongoing operations. This may be applied to the development of oil and gas resources from oil shale. In this respect, when electrically resistive heaters are used in connection with *in situ* shale oil recovery, large amounts of power are required.

[0167] Electrical power may be obtained from turbines that turn generators. It may be economically advantageous to power the gas turbines by utilizing produced gas from the field. However, such produced gas must be carefully controlled so not to damage the turbine, cause the turbine to misfire, or generate excessive pollutants (e.g., NO_x).

[0168] One source of problems for gas turbines is the presence of contaminants within the fuel. Contaminants include solids, water, heavy components present as liquids, and hydrogen sulfide. Additionally, the combustion behavior of the fuel is important. Combustion parameters to consider include heating value, specific gravity, adiabatic flame temperature, flammability limits, autoignition temperature, autoignition delay time, and flame velocity. Wobbe Index (WI) is often used as a key measure of fuel quality. WI is equal to the ratio of the lower heating value to the square root of the gas specific gravity. Control of the fuel's Wobbe Index to a target value and range of, for example, ±10% or ±20% can allow simplified turbine design and increased optimization of performance.

[0169] Fuel quality control may be useful for shale oil developments where the produced gas composition may change over the life of the field and where the gas typically has significant amounts of CO_2, CO, and H_2 in addition to light hydrocarbons. Commercial scale oil shale retorting is expected to produce a gas composition that changes with time.

[0170] Inert gases in the turbine fuel can increase power generation by increasing mass flow while maintaining a flame temperature in a desirable range. Moreover inert gases can lower flame temperature and thus reduce NO_x pollutant generation. Gas generated from oil shale maturation may have significant CO_2 content. Therefore, in certain embodiments of the production processes, the CO_2 content of the fuel gas is adjusted via separation or addition in the surface facilities to optimize turbine performance.

[0171] Achieving a certain hydrogen content for low-BTU fuels may also be desirable to achieve appropriate burn properties. In certain embodiments of the processes herein, the H_2 content of the fuel gas is adjusted via separation or addition in the surface facilities to optimize turbine performance. Adjustment of H_2 content in non-shale oil surface facilities utilizing low BTU fuels has been discussed in the patent literature (e.g., U.S. Pat. No. 6,684,644 and U.S. Pat. No. 6,858,049, the entire disclosures of which are hereby incorporated by reference).

[0172] The process of heating formation hydrocarbons within an organic-rich rock formation, for example, by pyrolysis, may generate fluids. The heat-generated fluids may include water which is vaporized within the formation. In addition, the action of heating kerogen produces pyrolysis fluids which tend to expand upon heating. The produced pyrolysis fluids may include not only water, but also, for example, hydrocarbons, oxides of carbon, ammonia, molecular nitrogen, and molecular hydrogen. Therefore, as temperatures within a heated portion of the formation increase, a pressure within the heated portion may also increase as a result of increased fluid generation, molecular expansion, and vaporization of water. Thus, some corollary exists between subsurface pressure in an oil shale formation and the fluid pressure generated during pyrolysis. This, in turn, indicates that formation pressure may be monitored to detect the progress of a kerogen conversion process.

[0173] The pressure within a heated portion of an organic-rich rock formation depends on other reservoir characteristics. These may include, for example, formation depth, distance from a heater well, a richness of the formation hydrocarbons within the organic-rich rock formation, the degree of heating, and/or a distance from a producer well.

[0174] It may be desirable for the developer of an oil shale field to monitor formation pressure during development. Pressure within a formation may be determined at a number of different locations. Such locations may include, but may not be limited to, at a wellhead and at varying depths within a wellbore. In some embodiments, pressure may be measured at a producer well. In an alternate embodiment, pressure may be measured at a heater well. In still another embodiment, pressure may be measured downhole of a dedicated monitoring well.

[0175] The process of heating an organic-rich rock formation to a pyrolysis temperature range not only will increase formation pressure, but will also increase formation permeability. The pyrolysis temperature range should be reached before substantial permeability has been generated within the organic-rich rock formation. An initial lack of permeability may prevent the transport of generated fluids from a pyrolysis zone within the formation. In this manner, as heat is initially transferred from a heater well to an organic-rich rock formation, a fluid pressure within the organic-rich rock formation may increase proximate to that heater well. Such an increase in fluid pressure may be caused by, for example, the generation of fluids during pyrolysis of at least some formation hydrocarbons in the formation.

[0176] Alternatively, pressure generated by expansion of pyrolysis fluids or other fluids generated in the formation may be allowed to increase. This assumes that an open path to a production well or other pressure sink does not yet exist in the formation. In one aspect, a fluid pressure may be allowed to increase to or above a lithostatic stress. In this instance, fractures in the hydrocarbon containing formation may form when the fluid pressure equals or exceeds the lithostatic stress. For example, fractures may form from a heater well to a production well. The generation of fractures within the heated portion may reduce pressure within the portion due to the production of produced fluids through a production well.

[0177] Once pyrolysis has begun within an organic-rich rock formation, fluid pressure may vary depending upon various factors. These include, for example, thermal expansion of hydrocarbons, generation of pyrolysis fluids, rate of conversion, and withdrawal of generated fluids from the formation. For example, as fluids are generated within the formation, fluid pressure within the pores may increase. Removal of generated fluids from the formation may then decrease the fluid pressure within the near wellbore region of the formation.

[0178] In certain embodiments, a mass of at least a portion of an organic-rich rock formation may be reduced due, for example, to pyrolysis of formation hydrocarbons and the production of hydrocarbon fluids from the formation. As such, the permeability and porosity of at least a portion of the formation may increase. Any *in situ* method that effectively produces oil and gas from oil shale will create permeability in what was originally a very low permeability rock. The extent to which this will occur is illustrated by the large amount of expansion that must be accommodated if fluids generated from kerogen are unable to flow. The concept is illustrated in **Figure 5.**

[0179] **Figure 5** provides a bar chart comparing one ton of Green River oil shale before **50** and after **51** a simulated *in situ,* retorting process. The simulated process was carried out at 2,400 psi and 750° F on oil shale having a total organic carbon content of 22 wt. % and a Fisher assay of 42 gallons/ton. Before the conversion, a total of 15.3 ft^3 of rock matrix 52 existed. This matrix comprised 7.2 ft^3 of mineral **53,** i.e., dolomite, limestone, etc., and 8.1 ft^3 of kerogen **54** imbedded within the shale. As a result of the conversion the material expanded to 26.1 ft^3 **55.** This represented 7.2 ft^3 of mineral **56** (the same number as before the conversion), 6.6 ft^3 of hydrocarbon liquid **57,** 9.4 ft^3 of hydrocarbon vapor 58, and 2.9 ft^3 of coke **59.** It can be seen that substantial volume expansion occurred during the conversion process. This, in turn, increases permeability of the rock structure.

[0180] In an embodiment, heating a portion of an organic-rich rock formation *in situ* to a pyrolysis temperature may increase permeability of the heated portion. For example, permeability may increase due to formation of thermal fractures within the heated portion caused by application of heat. As the temperature of the heated portion increases, water may be removed due to vaporization. The vaporized water may escape and/or be removed from the formation. In addition, permeability of the heated portion may also increase as a result of production of hydrocarbon fluids from pyrolysis of at least some of the formation hydrocarbons within the heated portion on a macroscopic scale.

[0181] Certain systems and methods described herein may be used to treat formation hydrocarbons in at least a portion of a relatively low permeability formation (e.g., in "tight" formations that contain formation hydrocarbons). Such formation hydrocarbons may be heated to pyrolyze at least some of the formation hydrocarbons in a selected zone of the formation. Heating may also increase the permeability of at least a portion of the selected zone. Hydrocarbon fluids generated from pyrolysis may be produced from the formation, thereby further increasing the formation permeability.

[0182] Permeability of a selected zone within the heated portion of the organic-rich rock formation may also rapidly increase while the selected zone is heated by conduction. For example, permeability of an impermeable organic-rich rock formation may be less than about 0.1 millidarcy before heating. In some embodiments, pyrolyzing at least a portion of organic-rich rock formation may increase permeability within a selected zone of the portion to greater than about 10 millidarcies, 100 millidarcies, 1 Darcy, 10 Darcies, 20 Darcies, or 50 Darcies. Therefore, a permeability of a selected zone of the portion may increase by a factor of more than about 10, 100, 1,000, 10,000, or 100,000. In one embodiment, the organic-rich rock formation has an initial total permeability less than 1 millidarcy, alternatively less than 0.1 or 0.01 millidarcies, before heating the organic-rich rock formation. In one embodiment, the organic-rich rock formation has a post heating total permeability of greater than 1 millidarcy, alternatively, greater than 10, 50 or 100 millidarcies, after heating the organic-rich rock formation.

[0183] In connection with heating the organic-rich rock formation, the organic-rich rock formation may optionally be fractured to aid heat transfer or hydrocarbon fluid production. In one instance, fracturing may be accomplished naturally by creating thermal fractures within the formation through application of heat. Thermal fracture formation is caused by thermal expansion of the rock and fluids and by chemical expansion of kerogen transforming into oil and gas. Thermal fracturing can occur both in the immediate region undergoing heating, and in cooler neighboring regions. The thermal fracturing in the neighboring regions is due to propagation of fractures and tension stresses developed due to the expansion in the hotter zones. Thus, by both heating the organic-rich rock and transforming the kerogen to oil and gas, the permeability is increased not only from fluid formation and vaporization, but also via thermal fracture formation. The increased permeability aids fluid flow within the formation and production of the hydrocarbon fluids generated from the kerogen.

[0184] In addition, a process known as hydraulic fracturing may be used. Hydraulic fracturing is a process known in the art of oil and gas recovery where a fracture fluid is pressurized within the wellbore above the fracture pressure of the formation, thus developing fracture planes within the formation to relieve the pressure generated within the wellbore. Hydraulic fractures may be used to create additional permeability and/or be used to provide an extended geometry for a heater well. The WO 2005/010320 patent publication incorporated above describes one such method.

[0185] It is preferred that thermal recovery of oil and gas be conducted before any solution mining of nahcolite or other water-soluble minerals present in the formation. Solution mining can generate large voids in a rock formation and collapse breccias in an oil shale development area. These voids and brecciated zones may pose problems for *in situ* and mining recovery of oil shale, further increasing the utility of supporting pillars.

[0186] In some embodiments, compositions and properties of the hydrocarbon fluids produced by an *in situ* conversion process may vary depending on, for example, conditions within an organic-rich rock formation. Controlling heat and/or heating rates of a selected section in an organic-rich rock formation may increase or decrease production of selected produced fluids.

[0187] In one embodiment, operating conditions may be determined by measuring at least one property of the organic-rich rock formation. The measured properties may be input into a computer executable program. At least one property of the produced fluids selected to be produced from the formation may also be input into the computer executable program. The program may be operable to determine a set of operating conditions from at least the one or more measured properties. The program may also be configured to determine the set of operating conditions from at least one property of the selected produced fluids. In this manner, the determined set of operating conditions may be configured to increase production of selected produced fluids from the formation.

[0188] Certain heater well embodiments may include an operating system that is coupled to any of the heater wells such as by insulated conductors or other types of wiring. The operating system may be configured to interface with the heater well. The operating system may receive a signal (e.g., an electromagnetic signal) from a heater that is representative of a temperature distribution of the heater well. Additionally, the operating system may be further configured to control the heater well, either locally or remotely. For example, the operating system may alter a temperature of the heater well by altering a parameter of equipment coupled to the heater well. Therefore, the operating system may monitor, alter, and/or control the heating of at least a portion of the formation.

[0189] In some embodiments, a heater well may be turned down and/or off after an average temperature in a formation may have reached a selected temperature. Turning down and/or off the heater well may reduce input energy costs, substantially inhibit overheating of the formation, and allow heat to substantially transfer into colder regions of the formation.

[0190] Temperature (and average temperatures) within a heated organic-rich rock formation may vary, depending on, for example, proximity to a heater well, thermal conductivity and thermal diffusivity of the formation, type of reaction occurring, type of formation hydrocarbon, and the presence of water within the organic-rich rock formation. At points in the field where monitoring wells are established, temperature measurements may be taken directly in the wellbore. Further, at heater wells the temperature of the immediately surrounding formation is fairly well understood. However, it is desirable to interpolate temperatures to points in the formation intermediate temperature sensors and heater wells.

[0191] In accordance with one aspect of the production processes of the present inventions, a temperature distribution within the organic-rich rock formation may be computed using a numerical simulation model. The numerical simulation model may calculate a subsurface temperature distribution through interpolation of known data points and assumptions of formation conductivity. In addition, the numerical simulation model may be used to determine other properties of the formation under the assessed temperature distribution. For example, the various properties of the formation may include, but are not limited to, permeability of the formation.

[0192] The numerical simulation model may also include assessing various properties of a fluid formed within an organic-rich rock formation under the assessed temperature distribution. For example, the various properties of a formed fluid may include, but are not limited to, a cumulative volume of a fluid formed in the formation, fluid viscosity, fluid density, and a composition of the fluid formed in the formation. Such a simulation may be used to assess the performance of a commercial-scale operation or small-scale field experiment. For example, a performance of a commercial-scale development may be assessed based on, but not limited to, a total volume of product that may be produced from a research-scale operation.

[0193] Some embodiments include producing at least a portion of the hydrocarbon fluids from the organic-rich rock formation. The hydrocarbon fluids may be produced through production wells. Production wells may be cased or uncased wells and drilled and completed through methods known in the art.

[0194] Some embodiments further include producing a production fluid from the organic-rich rock formation where the production fluid contains the hydrocarbon fluids and an aqueous fluid. The aqueous fluid may contain water-soluble minerals and/or migratory contaminant species. In such case, the production fluid may be separated into a hydrocarbon stream and an aqueous stream at a surface facility. Thereafter the water-soluble minerals and/or migratory contaminant species may be recovered from the aqueous stream. This embodiment may be combined with any of the other aspects of the invention discussed herein.

[0195] The produced hydrocarbon fluids may include a pyrolysis oil component (or condensable component) and a pyrolysis gas component (or non-condensable component). Condensable hydrocarbons produced from the formation will typically include paraffins, cycloalkanes, mono-aromatics, and di-aromatics as components. Such condensable hydrocarbons may also include other components such as tri-aromatics and other hydrocarbon species.

[0196] In certain embodiments, a majority of the hydrocarbons in the produced fluid may have a carbon number of less than approximately 25. Alternatively, less than about 15 weight % of the hydrocarbons in the fluid may have a carbon number greater than approximately 25. The non-condensable hydrocarbons may include, but are not limited to, hydrocarbons having carbon numbers less than 5.

[0197] In certain embodiments, the API gravity of the condensable hydrocarbons in the produced fluid may be approximately 20 or above (e.g., 25, 30, 40, 50, etc.). In certain embodiments, the hydrogen to carbon atomic ratio in produced fluid may be at least approximately 1.7 (e.g., 1.8, 1.9, etc.).

[0198] One embodiment of the invention includes an *in situ* method of producing hydrocarbon fluids with improved properties from an organic-rich rock formation. Applicants have surprisingly discovered that the quality of the hydrocarbon fluids produced from *in situ* heating and pyrolysis of an organic-rich rock formation may be improved by selecting sections of the organic-rich rock formation with higher lithostatic stress for *in situ* heating and pyrolysis.

[0199] The method may include *in situ* heating of a section of the organic-rich rock formation that has a high lithostatic stress to form hydrocarbon fluids with improved properties. The method may include creating the hydrocarbon fluid by pyrolysis of a solid hydrocarbon and/or a heavy hydrocarbon present in the organic-rich rock formation. Embodiments may include the hydrocarbon fluid being partially, predominantly or substantially completely created by pyrolysis of the solid hydrocarbon and/or heavy hydrocarbon present in the organic-rich rock formation. The method may include heating the section of the organic-rich rock formation by any method, including any of the methods described herein. For example, the method may include heating the section of the organic-rich rock formation by electrical resistance heating. Further, the method may include heating the section of the organic-rich rock formation through use of a heated heat transfer fluid. The method may include heating the section of the organic-rich rock formation to above 270° C. Alternatively, the method may include heating the section of the organic-rich rock formation between 270°C and 500° C.

[0200] The method may include heating *in situ* a section of the organic-rich rock formation having a lithostatic stress greater than 200 psi and producing a hydrocarbon fluid from the heated section of the organic-rich rock formation. In alternative embodiments, the heated section of the organic-rich rock formation may have a lithostatic stress greater than 400 psi. In alternative embodiments, the heated section of the organic-rich rock formation may have a lithostatic stress greater than 800 psi, greater than 1,000 psi, greater than 1,200 psi, greater than 1,500 psi or greater than 2,000 psi. Applicants have found that *in situ* heating and pyrolysis of organic-rich rock formations with increasing amounts of stress lead to the production of hydrocarbon fluids with improved properties.

[0201] The lithostatic stress of a section of an organic-rich formation can normally be estimated by recognizing that it will generally be equal to the weight of the rocks overlying the formation. The density of the overlying rocks can be expressed in units of psi/ft. Generally, this value will fall between 0.8 and 1.1 psi/ft and can often be approximated as 0.9 psi/ft. As a result the lithostatic stress of a section of an organic-rich formation can be estimated by multiplying the depth of the organic-rich rock formation interval by 0.9 psi/ft. Thus the lithostatic stress of a section of an organic-rich formation occurring at about 1,000 feet can be estimated to be about (0.9 psi/ft) multiplied by (1,000 feet) or about 900 psi. If a more precise estimate of lithostatic stress is desired the density of overlying rocks can be measured using wireline logging techniques or by making laboratory measurements on samples recovered from coreholes. The method may include heating a section of the organic-rich rock formation that is located at a depth greater than 200 feet below the earth's surface. Alternatively, the method may include heating a section of the organic-rich rock formation that is located at a depth greater than 500 feet below the earth's surface, greater than 1,000 feet below the earth's surface, greater than 1,200 feet below the earth's surface, greater than 1,500 feet below the earth's surface, or greater than 2,000 feet below the earth's surface.

[0202] The organic-rich rock formation may be, for example, a heavy hydrocarbon formation or a solid hydrocarbon formation. Particular examples of such formations may include an oil shale formation, a tar sands formation or a coal formation. Particular formation hydrocarbons present in such formations may include oil shale, kerogen, coal, and/or bitumen.

[0203] The hydrocarbon fluid produced from the organic-rich rock formation may include both a condensable hydrocarbon portion (e.g. liquid) and a non-condensable hydrocarbon portion (e.g. gas). The hydrocarbon fluid may additionally be produced together with non-hydrocarbon fluids. Exemplary non-hydrocarbon fluids include, for example, water, carbon dioxide, hydrogen sulfide, hydrogen, ammonia, and/or carbon monoxide.

[0204] The condensable hydrocarbon portion of the hydrocarbon fluid may be a fluid present within different locations associated with an organic-rich rock development project. For example, the condensable hydrocarbon portion of the hydrocarbon fluid may be a fluid present within a production well that is in fluid communication with the organic-rich rock formation. The production well may serve as a device for withdrawing the produced hydrocarbon fluids from the organic-rich rock formation. Alternatively, the condensable hydrocarbon portion may be a fluid present within processing equipment adapted to process hydrocarbon fluids produced from the organic-rich rock formation. Exemplary processing equipment is described herein. Alternatively, the condensable hydrocarbon portion may be a fluid present within a fluid storage vessel. Fluid storage vessels may include, for example, fluid storage tanks with fixed or floating roofs, knock-out vessels, and other intermediate, temporary or product storage vessels. Alternatively, the condensable hydrocarbon portion may be a fluid present within a fluid transportation pipeline. A fluid transportation pipeline may include, for example, piping from production wells to processing equipment or fluid storage vessels, piping from processing equipment to fluid storage vessels, or pipelines associated with collection or transportation of fluids to or from intermediate or centralized storage locations.

[0205] It is believed that lithostatic stress can affect the composition of produced fluids generated within an organic-rich rock via heating and pyrolysis. This implies that the composition of a produced hydrocarbon fluid can also be influenced by altering the lithostatic stress of the organic-rich rock formation. For example, the lithostatic stress of the organic-rich rock formation may be altered by choice of pillar geometries and/or locations and/or by choice of heating and pyrolysis formation region thickness and/or heating sequencing.

[0206] Pillars are regions within the organic-rich rock formation left unpyrolyzed at a given time to lessen or mitigate surface subsidence. Pillars may be regions within a formation surrounded by pyrolysis regions within the same formation. Alternatively, pillars may be part of or connected to the unheated regions outside the general development area. Certain regions that act as pillars early in the life of a producing field may be converted to producing regions later in the life of the field.

[0207] Typically in its natural state, the weight of a formation's overburden is fairly uniformly distributed over the formation. In this state the lithostatic stress existing at particular point within a formation is largely controlled by the thickness and density of the overburden. A desired lithostatic stress may be selected by analyzing overburden geology and choosing a position with an appropriate depth and position.

[0208] Although lithostatic stresses are commonly assumed to be set by nature and not changeable short of removing all or part of the overburden, lithostatic stress at a specific location within a formation can be adjusted by redistributing the overburden weight so it is not uniformly supported by the formation. For example, this redistribution of overburden weight may be accomplished by two exemplary methods. One or both of these methods may be used within a single formation. In certain cases, one method may be primarily used earlier in time whereas the other may be primarily used at a later time. Favorably altering the lithostatic stress experienced by a formation region may be performed prior to instigating significant pyrolysis within the formation region and also before generating significant hydrocarbon fluids. Alternately, favorably altering the lithostatic stress may be performed simultaneously with the pyrolysis.

[0209] A first method of altering lithostatic stress involves making a region of a subsurface formation less stiff than its neighboring regions. Neighboring regions thus increasingly act as pillars supporting the overburden as a particular region becomes less stiff. These pillar regions experience increased lithostatic stress whereas the less stiff regions experience reduced lithostatic stress. The amount of change in lithostatic stress depends upon a number of factors including, for example, the change in stiffness of the treated region, the size of the treated region, the pillar size, the pillar spacing, the rock compressibility, and the rock strength. In an organic-rich rock formation, a region within a formation may be made to experience mechanical weakening by pyrolyzing the region and creating void space within the region by removing produced fluids. In this way a region within a formation may be made less stiff than neighboring regions that have not experienced pyrolysis or have experienced a lesser degree of pyrolysis or production.

[0210] A second method of altering lithostatic stress involves causing a region of a subsurface formation to expand and push against the overburden with greater force than neighboring regions. This expansion may remove a portion of the overburden weight from the neighboring regions thus increasing the lithostatic stress experienced by the heated region and reducing the lithostatic stress experienced by neighboring regions. If the expansion is sufficient, horizontal fractures will form in the neighboring regions and the contribution of these regions to supporting the overburden will decrease. The amount of change in lithostatic stress depends upon a number of factors including, for example, the amount of expansion in the treated region, the size of the treated region, the pillar size, the pillar spacing, the rock compressibility, and the rock strength. A region within a formation may be made to expand by heating it so to cause thermal expansion of the rock. Fluid expansion or fluid generation can also contribute to expansion if the fluids are largely trapped within the region. The total expansion amount may be proportional to the thickness of the heated region. It is noted that if pyrolysis occurs in the heated region and sufficient fluids are removed, the heated region may mechanically weaken and thus may alter the lithostatic stresses experienced by the neighboring regions as described in the first exemplary method.

[0211] Some production procedures include *in situ* heating of an organic-rich rock formation that contains both formation hydrocarbons and formation water-soluble minerals prior to substantial removal of the formation water-soluble minerals from the organic-rich rock formation. In some embodiments of the invention there is no need to partially, substantially or completely remove the water-soluble minerals prior to *in situ* heating. For example, in an oil shale formation that contains naturally occurring nahcolite, the oil shale may be heated prior to substantial removal of the nahcolite by solution mining. Substantial removal of a water-soluble mineral may represent the degree of removal of a water-soluble mineral that occurs from any commercial solution mining operation as known in the art. Substantial removal of a water-soluble mineral may be approximated as removal of greater than 5 weight percent of the total amount of a particular water-soluble mineral present in the zone targeted for hydrocarbon fluid production in the organic-rich rock formation. In alternative embodiments, *in situ* heating of the organic-rich rock formation to pyrolyze formation hydrocarbons may be commenced prior to removal of greater than 3 weight percent, alternatively 7 weight percent, 10 weight percent or 13 weight percent of the formation water-soluble minerals from the organic-rich rock formation.

[0212] The impact of heating oil shale to produce oil and gas prior to producing nahcolite is to convert the nahcolite to a more recoverable form (soda ash), and provide permeability facilitating its subsequent recovery. Water-soluble mineral recovery may take place as soon as the retorted oil is produced, or it may be left for a period of years for later recovery. If desired, the soda ash can be readily converted back to nahcolite on the surface. The ease with which this conversion can be accomplished makes the two minerals effectively interchangeable.

[0213] In some production processes, heating the organic-rich rock formation includes generating soda ash by decomposition of nahcolite. The method may include processing an aqueous solution containing water-soluble minerals in a surface facility to remove a portion of the water-soluble minerals. The processing step may include removing the water-soluble minerals by precipitation caused by altering the temperature of the aqueous solution.

[0214] The water-soluble minerals may include sodium. The water-soluble minerals may also include nahcolite (sodium bicarbonate), soda ash (sodium carbonate), dawsonite ($NaAl(CO_3)(OH)_2$), or combinations thereof. The surface processing may further include converting the soda ash back to sodium bicarbonate (nahcolite) in the surface facility by reaction with CO_2. After partial or complete removal of the water-soluble minerals, the aqueous solution may be reinjected into a subsurface formation where it may be sequestered. The subsurface formation may be the same as or different from the original organic-rich rock formation.

[0215] In some production processes, heating of the organic-rich rock formation both pyrolyzes at least a portion of the formation hydrocarbons to create hydrocarbon fluids and makes available migratory contaminant species previously bound in the organic-rich rock formation. The migratory contaminant species may be formed through pyrolysis of the formation hydrocarbons, may be liberated from the formation itself upon heating, or may be made accessible through the creation of increased permeability upon heating of the formation. The migratory contaminant species may be soluble in water or other aqueous fluids present in or injected into the organic-rich rock formation.

[0216] Producing hydrocarbons from pyrolyzed oil shale will generally leave behind some migratory contaminant species which are at least partially water-soluble. Depending on the hydrological connectivity of the pyrolyzed shale oil to shallower zones, these components may eventually migrate into ground water in concentrations which are environmentally unacceptable. The types of potential migratory contaminant species depend on the nature of the oil shale pyrolysis and the composition of the oil shale being converted. If the pyrolysis is performed in the absence of oxygen or air, the contaminant species may include aromatic hydrocarbons (e.g. benzene, toluene, ethylbenzene, xylenes), polyaromatic hydrocarbons (e.g. anthracene, pyrene, naphthalene, chrysene), metal contaminants (e.g. As, Co, Pb, Mo, Ni, and Zn), and other species such as sulfates, ammonia, Al, K, Mg, chlorides, flourides and phenols. If oxygen or air is employed, contaminant species may also include ketones, alcohols, and cyanides. Further, the specific migratory contaminant species present may include any subset or combination of the above-described species.

[0217] It may be desirable for a field developer to assess the connectivity of the organic-rich rock formation to aquifers. This may be done to determine if, or to what extent, *in situ* pyrolysis of formation hydrocarbons in the organic-rich rock formation may create migratory species with the propensity to migrate into an aquifer. If the organic-rich rock formation is hydrologically connected to an aquifer, precautions may be taken to reduce or prevent species generated or liberated during pyrolysis from entering the aquifer. Alternatively, the organic-rich rock formation may be flushed with water or an aqueous fluid after pyrolysis as described herein to remove water-soluble minerals and/or migratory contaminant species. In other embodiments, the organic-rich rock formation may be substantially hydrologically unconnected to any source of ground water. In such a case, flushing the organic-rich rock formation may not be desirable for removal of migratory contaminant species but may nevertheless be desirable for recovery of water-soluble minerals.

[0218] Following production of hydrocarbons from an organic-rich formation, some migratory contaminant species may remain in the rock formation. In such case, it may be desirable to inject an aqueous fluid into the organic-rich rock formation and have the injected aqueous fluid dissolve at least a portion of the water-soluble minerals and/or the migratory contaminant species to form an aqueous solution. The aqueous solution may then be produced from the organic-rich rock formation through, for example, solution production wells. The aqueous fluid may be adjusted to increase the solubility of the migratory contaminant species and/or the water-soluble minerals. The adjustment may include the addition of an acid or base to adjust the pH of the solution. The resulting aqueous solution may then be produced from the organic-rich rock formation to the surface for processing.

[0219] After initial aqueous fluid production, it may further be desirable to flush the matured organic-rich rock zone and the unmatured organic-rich rock zone with an aqueous fluid. The aqueous fluid may be used to further dissolve water-soluble minerals and migratory contaminant species. The flushing may optionally be completed after a substantial portion of the hydrocarbon fluids have been produced from the matured organic-rich rock zone. In some embodiments, the flushing step may be delayed after the hydrocarbon fluid production step. The flushing may be delayed to allow heat generated from the heating step to migrate deeper into surrounding unmatured organic-rich rock zones to convert nahcolite within the surrounding unmatured organic-rich rock zones to soda ash. Alternatively, the flushing may be delayed to allow heat generated from the heating step to generate permeability within the surrounding unmatured organic-rich rock zones. Further, the flushing may be delayed based on current and/or forecast market prices of sodium bicarbonate, soda ash, or both as further discussed herein. This method may be combined with any of the other aspects of the invention as discussed herein

[0220] Upon flushing of an aqueous solution, it may be desirable to process the aqueous solution in a surface facility to remove at least some of the migratory contaminant species. The migratory contaminant species may be removed through use of, for example, an adsorbent material, reverse osmosis, chemical oxidation, bio-oxidation, and/or ion exchange. Examples of these processes are individually known in the art. Exemplary adsorbent materials may include activated carbon, clay, or fuller's earth.

[0221] In certain areas with oil shale resources, additional oil shale resources or other hydrocarbon resources may exist at lower depths. Other hydrocarbon resources may include natural gas in low permeability formations (so-called "tight gas") or natural gas trapped in and adsorbed on coal (so called "coalbed methane"). In some embodiments with multiple shale oil resources it may be advantageous to develop deeper zones first and then sequentially shallower zones. In this way, wells will need not cross hot zones or zones of weakened rock. In other embodiments in may be advantageous to develop deeper zones by drilling wells through regions being utilized as pillars for shale oil development at a shallower depth.

[0222] Simultaneous development of shale oil resources and natural gas resources in the same area can synergistically utilize certain facility and logistic operations. For example, gas treating may be performed at a single plant. Likewise personnel may be shared among the developments.

[0223] **Figure 6** illustrates a schematic diagram of an embodiment of surface facilities **70** that may be configured to treat a produced fluid. The produced fluid **85** may be produced from the subsurface formation **84** though a production well **71** as described herein. The produced fluid may include any of the produced fluids produced by any of the methods as described herein. The subsurface formation **84** may be any subsurface formation, including, for example, an organic-rich rock formation containing any of oil shale, coal, or tar sands for example. A production scheme may involve quenching **72** produced fluids to a temperature below 300° F, 200° F, or even 100° F, separating out condensable components (i.e., oil **74** and water **75)** in an oil separator **73,** treating the non-condensable components **76** (i.e. gas) in a gas treating unit **77** to remove water **78** and sulfur species **79,** removing the heavier components from the gas (e.g., propane and butanes) in a gas plant **81** to form liquid petroleum gas (LPG) **80** for sale, and generating electrical power **82** in a power plant 88 from the remaining gas **83.** The electrical power **82** may be used as an energy source for heating the subsurface formation **84** through any of the methods described herein. For example, the electrical power **82** may be feed at a high voltage, for example 132 kV, to a transformer **86** and let down to a lower voltage, for example 6600 V, before being fed to an electrical resistance heater element located in a heater well **87** located in the subsurface formation **84.** In this way all or a portion of the power required to heat the subsurface formation **84** may be generated from the non-condensable portion of the produced fluids **85.** Excess gas, if available, may be exported for sale.

[0224] Produced fluids from *in situ* oil shale production contain a number of components which may be separated in surface facilities. The produced fluids typically contain water, noncondensable hydrocarbon alkane species (e.g., methane, ethane, propane, n-butane, isobutane), noncondensable hydrocarbon alkene species (e.g., ethene, propene), condensable hydrocarbon species composed of (alkanes, olefins, aromatics, and polyaromatics among others), CO_2, CO, H_2, H_2S, and NH_3.

[0225] In a surface facility, condensable components may be separated from non-condensable components by reducing temperature and/or increasing pressure.

Temperature reduction may be accomplished using heat exchangers cooled by ambient air or available water. Alternatively, the hot produced fluids may be cooled via heat exchange with produced hydrocarbon fluids previously cooled. The pressure may be increased via centrifugal or reciprocating compressors. Alternatively, or in conjunction, a diffuser-expander apparatus may be used to condense out liquids from gaseous flows. Separations may involve several stages of cooling and/or pressure changes.

[0226] Water in addition to condensable hydrocarbons may be dropped out of the gas when reducing temperature or increasing pressure. Liquid water may be separated from condensable hydrocarbons via gravity settling vessels or centrifugal separators. Demulsifiers may be used to aid in water separation.

[0227] Methods to remove CO_2, as well as other so-called acid gases (such as H_2S), from produced hydrocarbon gas include the use of chemical reaction processes and of physical solvent processes. Chemical reaction processes typically involve contacting the gas stream with an aqueous amine solution at high pressure and/or low temperature. This causes the acid gas species to chemically react with the amines and go into solution. By raising the temperature and/or lowering the pressure, the chemical reaction can be reversed and a concentrated stream of acid gases can be recovered.

[0228] Acid gas removal may also be effectuated through the use of distillation towers. Such towers may include an intermediate freezing section wherein frozen CO_2 and H_2S particles are allowed to form. A mixture of frozen particles and liquids fall downward into a stripping section, where the lighter hydrocarbon gasses break out and rise within the tower. A rectification section may be provided at an upper end of the tower to further facilitate the cleaning of the overhead gas stream.

[0229] In connection with the production of hydrocarbons from a rock matrix, particularly those of shallow depth, a concern may exist with respect to earth subsidence. This is particularly true in connection with the *in situ* heating of organic-rich rock where a portion of the matrix itself is thermally converted and removed. Initially, the formation may contain formation hydrocarbons in solid form, such as, for example, kerogen. The formation may also initially contain water-soluble minerals. Initially, the formation may also be substantially impermeable to fluid flow.

[0230] The *in situ* heating of the matrix pyrolyzes at least a portion of the formation hydrocarbons to create hydrocarbon fluids. In this respect, the *in situ* heating and production of oil and gas from oil shale converts a volumetrically significant portion of the heated oil shale to hydrocarbon fluids. This, in turn, creates permeability within a matured (pyrolyzed) organic-rich rock zone in the organic-rich rock formation. The combination of pyrolyzation and increased permeability permits hydrocarbon fluids to be produced from the formation. At the same time, the loss of supporting matrix material also creates the potential for subsidence.

[0231] In some instances, subsidence is sought to be controlled in order to avoid environmental or hydrogeological impact. In this respect, changing the contour and relief of the earth surface may change runoff patterns, affect vegetation patterns, and impact watersheds. In addition, subsidence has the potential of damaging production or heater wells formed in a production area. Such subsidence can create damaging hoop and compressional stresses on wellbore casings, cement jobs, and equipment downhole.

[0232] In order to evaluate the potential for subsidence, certain principles of geomechanics may first be considered. Application of geomechanical principles allows the stress response of rocks within and around a treated volume to be estimated.

[0233] Prior to heating, stresses will exist in the rocks within and around the treated volume. When the treated volume is heated, kerogen will be converted to hydrocarbon fluids. This will cause the rock in the treated volume to soften, or become less stiff. This softening in response to conversion can be mathematically described as a decrease in elastic modulus. When this happens, the rock will be less able to support the weight of its overburden.

[0234] For some time during and after heating, the overburden weight will be supported in the formation 16 by fluid pressure of the hydrocarbon fluids generated from kerogen conversion. However, this pore pressure will decrease as production takes place. As production from the formation 16 occurs and the supporting pressure in the rock declines, the softened rock in the treated volume will then be called upon to provide support for its overburden. This, in turn, creates a potential for subsidence.

[0235] As support for the overburden is transferred from the fluid pressure to the softened rock, stresses in the surrounding rock will be altered. Initially, the stress response of the surrounding rocks will be elastic and the principles of geomechanics permit the stress response to be estimated. Generally, if the stress response of the rocks around the treated interval remains elastic, the degree of subsidence will be minor. If, however, the stresses in rocks around the treated interval reach a failure condition, subsidence is likely to be more severe. A failure condition is a stress state that cannot be supported by the rock and which results in rock breakage.

[0236] One way to evaluate the potential for subsidence above a treated volume is to first estimate the stress response of the rocks within and around the treated volume assuming elastic behavior. The estimated stresses may then be used to determine if a designated failure criterion has been exceeded. Those of ordinary skill in the art understand that various criteria exist for the evaluation of rock failure. In the present methods, the empirical failure criteria are preferably evaluated in terms of "principal stresses". These are normal stresses referenced to a coordinate system in which all the shear stresses are equal to zero.

[0237] In connection with an evaluation of geomechanical stresses and failure criteria, it is generally recognized that rocks are strong in compression but weak in tension. This is particularly true for rocks with natural fractures. For these rocks, compressive stresses will tend to leave fractures closed, but tensile stresses will open the fractures and encourage fracture growth. By this criterion, any portion of a rock subjected to a tensile stress will fail.

[0238] Other failure criteria recognize that in addition to being weak in tension, rocks also have limited frictional strength. The Mohr-Coulomb failure criterion is an example. **Figure 7** presents a graph depicting a Mohr Coulomb failure line **700.** In **Figure 7,** the horizontal or **x-**axis represents the effective normal stress in the rock with compression being considered positive. The vertical or **y**-axis represents the shear stress in the rock. The normal stress increases with compression in the positive "**x**" direction, and decreases with tension in the negative "**x**" direction.

[0239] The Mohr Coulomb failure line **700** defines rock stress states at failure. To evaluate the failure criterion for a given stress state, the maximum and minimum principal stresses are plotted along the x-axis. A semi-circle is constructed whose center is along the x-axis at a value corresponding to the mean of the maximum and minimum principal stresses. If the semi-circle crosses the failure line, the stress state corresponds to a state at which rock failure will occur.

[0240] In practice, failure points may be determined by breaking core samples in compression under different confining pressures. The tri-axial compression laboratory test procedures and calculations to define the failure line **700** are known to those skilled in the art. When considering porous rocks with an internal pore fluid under pressure, the stresses correspond to "effective stresses." The "effective stress" on a porous rock is the normal total stress minus the pore fluid pressure. The measurement of "effective stress" and its use in mechanics is known to those skilled in the art.

[0241] The graph shown in **Figure 7** includes a failure line **700** and four Mohr Coulomb semicircles **710, 720, 730** and **740.** Semicircles **710, 720, 730** and **740** represent successive stress states in time. Curve **710** represents an initial pore pressure of 1,858 psi. Subsequent curves **720, 730** and **740** represent pore pressures in a treated oil shale volume that have been reduced by production. Curve **720** represents a pore pressure of 1,458 psi; curve **730** represents a pore pressure of 1,058 psi; and curve **740** represents a pore pressure of only 658 psi.

[0242] As shown by curve **740,** the semi-circle enlarges outwardly as pore pressure within the treated formation is reduced. This is a reflection of fluid production from within the formation. As the treated volume pore pressure is reduced, the stress state changes from a stable to an unstable state. It can be seen that curve **740** crosses over the failure line **700,** thus indicating that an unstable state has been reached.

[0243] The assumption of zero rock tensile strength and the Mohr-Coulomb failure line 700 represent two empirical failure criteria. However, other failure criteria exist such as the Drucker-Prager failure criteria, the Cam-clay model, and various other "critical state" models.

[0244] As applied to a formation where solid hydrocarbons such as kerogen are being pyrolyzed, tensile failure within a formation may be caused by two factors: (1) the removal of material from the subsurface formation due to pyrolysis; and (2) a reduction in pore pressure within the subsurface formation due to the ongoing removal of pyrolyzed hydrocarbon fluids over time. The pyrolysis may be non-formation oxidative. In one aspect, pyrolyzing is a result of electrically resistive heating of the subsurface formation.

[0245] In order to avoid tensile failure within a formation and to control subsidence due to pyrolysis and production, it is proposed to leave selected portions of the formation hydrocarbons substantially unpyrolyzed. This serves to preserve one or more unmatured, organic-rich rock zones. In some embodiments, the unmatured organic-rich rock zones may be shaped as substantially vertical pillars extending through a substantial portion of the thickness of the organic-rich rock formation.

[0246] **Figure 8** is a flow chart showing steps that may generally be performed in connection with one embodiment **800** of the methods disclosed herein. The steps represent one method for developing hydrocarbons from a subsurface formation containing organic-rich rock. As seen in **Figure 8,** the method **800** includes the step of heating the formation across a development area. This step is represented by Box **810.** The purpose for the heating step **810** is to pyrolyze at least a portion of the formation hydrocarbons in the organic rich rock into hydrocarbon fluids.

[0247] For purposes of the present disclosure, the development area represents the area that is subject to hydrocarbon development. The development area incorporates all of the projections of zones from the surface to the subsurface which are being heated or have been heated.

[0248] The method **800** of **Figure 8** also includes the step of preserving at least one unheated zone within the formation. This step is shown in Box **820.** The at least one unheated zone is located within the development area. The purpose of the preservation step **820** is to preserve at least one zone within the formation that is not heated. In this way, the formation hydrocarbons in the at least one unheated zone are left substantially unpyrolyzed. The at least one zone that is preserved is not heated, nor is it rubblized.

[0249] It is understood that there will be transition zones between heated and unheated zones. There will also be a complex temperature profile across a heated zone as the temperature varies between heater wells, producer wells, and unheated zones. Over time the temperature within a heated zone will even out but leave a transition zone of less heating. For purposes of this disclosure it is understood that the unheated zone is an area that is not heated or otherwise energized to such an extent as would cause measurable pyrolysis of the organic-rich formation.

[0250] The method **800** also provides the step of sizing an area of the at least one unheated zone. This step is presented in Box **830.** The purpose is to optimize that portion of the development area in which the formation hydrocarbons are pyrolyzed while controlling the likelihood of subsidence above the subsurface formation. Preferably, the at least one unheated zone represents no more than 50 percent of the development area. More preferably, the at least one unheated zone represents no more than 40 percent of the development area. More preferably still, the at least one unheated zone represents no more than 25, or even no more than 10 percent, of the development area.

[0251] It is preferred that the steps **810** through **830** be practiced in an organic-rich rock formation that is comprised of solid hydrocarbons. A particularly preferred example of solid hydrocarbons is kerogen.

[0252] One step for method **800** is to select a geometry for the at least one unheated zone within the development area. This step is represented in Box **840** of **Figure 8.** It is understood that "geometry" may indicate a designated size, a designated configuration, or a selected location within the development area. For instance, the unheated zone may have a configuration that represents a single circle, square, rectangle or star. Alternatively, the unheated zone may represent a plurality of circles, squares, rectangles, hexagons, rhomboids or stars that serve as separate support pillars. In any event, the at least one unheated zone may define an area that is at least 5 percent greater than an area considered to be a subsidence failure point for the selected geometry. Alternatively, the at least one unheated zone defines an area that is at least 10 percent greater than an area considered to be a subsidence failure point for the selected size or area.

[0253] In one aspect, the at least one unheated zone defines a single, contiguous unheated zone within the development area. The contiguous unheated zone has pyrolyzed zones located therein. Alternatively, the at least one unheated zone defines at least two unheated zones. The at least two unheated zones may be non-contiguous.

[0254] **Figure 16** presents a map view of a shale oil development area **1600,** in one embodiment. The illustrative development area **1600** is defined by a surface boundary or perimeter **1605.** Within the boundary **1605,** a plurality of heater wells **1610** have been formed. The heater wells **1610** may employ downhole combustion heaters. Alternatively, the heater wells **1610** may have resistive heater elements. Alternatively still, the heater wells 1610 may receive injections of heated fluids for circulation. In any instance, the heater wells 1610 serve to heat a subsurface formation made up of solid hydrocarbons for the purpose of pyrolyzing oil shale or other solid hydrocarbons into hydrocarbon fluids.

[0255] Associated with each heater well **1610** is a heating profile **1615.** The heating profiles **1615** are in the form of circles, and indicate a scope of heating within the subsurface formation around the individual heater wells **1610.** More specifically, the profiles **1615** show the extent of formation heating to a pyrolysis temperature. It is understood that heating a formation is a process that takes time. As heat is first applied downhole, the heating profiles will be small. As heat continues to be applied downhole, a heat front moves away from the respective heater wells **1610.** In the stage depicted in **Figure 16,** a pyrolysis heat profile has emanated away from the respective heater wells **1610,** and the various heat profiles have begun to overlap. Continued formation heating will cause further overlapping of the heat profiles **1615,** producing more complete pyrolysis across a subsurface formation.

[0256] The development area **1600** also includes a plurality of production wells or producers **1620.** The producers **1620** serve to deliver pyrolyzed hydrocarbon fluids under pressure to the surface. In the arrangement of **Figure 16,** the ratio between heater wells **1610** and producers **1620** is about 1:1. However, other heater well **1610** and production well **1620** arrangements may be used to generate different ratios.

[0257] In accordance with embodiments of the present methods, a portion of the formation is left unheated in order to preserve one or more unheated zones. Such unheated zones are indicated in **Figure 16** by cross-hatching at **1630.** In the arrangement of **Figure 16,** the unheated zones **1630** comprise separate or non-contiguous stars or portions thereof. However, the unheated zones **1630** may optionally be interconnected. The unheated zones **1630** are preserved in a virgin state and are not pyrolyzed, burned or rubblized.

[0258] The unheated zones **1630** serve as pillars. In this respect, alteration of solid rock formations through the pyrolysis process creates a potential for subsidence at the surface. The unheated zones **1630** preferably prevent significant surface subsidence by supporting the rock layers overlying the subsurface formation or formations that are undergoing pyrolysis.

[0259] **Figure 17** is an alternate view of a shale oil development area **1700.** The development area **1700** is defined by a surface boundary or perimeter **1705.** The perimeter **1705** may be of any configuration. In the illustrative view of **Figure 17,** the perimeter **1705** is four-sided, forming a development area that is a rectangle.

[0260] Within the perimeter **1705,** a plurality of heater wells **1710** have been formed. The heater wells **1710** are completed in a subsurface formation containing solid hydrocarbons. As with heater wells **1610,** heater wells **1710** serve to heat the subsurface formation for the purpose of pyrolyzing solid hydrocarbons into hydrocarbon fluids. Any method of heating may be used.

[0261] Associated with each heater well **1710** is a heating profile **1715.** Circles **1715** are provided around the heater wells **1710** indicating a scope of heating within the subsurface formation. More specifically, the circles **1715** show the extent of formation heating at a pyrolysis temperature. It is again understood that heating a formation is a process that takes time. As heat is first applied downhole, the heating profile is very small. As heat continues to be applied, a heat front moves away from the respective heater wells **1710.** In the stage depicted in **Figure 17,** a pyrolysis heat profile has emanated away from the respective heater wells **1710,** and the various heat profiles have begun to overlap. Continued formation heating will cause further overlapping of the heat profiles **1715,** producing more complete pyrolysis.

[0262] The development area **1700** also includes a plurality of production wells or producers **1720.** The producers **1720** serve to deliver pyrolyzed hydrocarbon fluids under pressure to the surface. In the arrangement of **Figure 17,** the heater wells **1710** and producers **1720** form a four-spot pattern. However, other heater well **1710** and production well **1720** arrangements may be used to generate different patterns or well ratios.

[0263] In accordance with certain embodiments of the present methods, a portion of the formation is left unheated. This serves to create or preserve at least one unheated zone. Such unheated zones are indicated in **Figure 17** by crosshatching at **1730.** In the arrangement of **Figure 17,** the unheated zones **1730** comprise separate or non-contiguous four-sided polygons. However, the unheated zones **1730** may optionally be interconnected. The unheated zones **1730** are preserved in a virgin state and are not pyrolyzed, burned or rubblized.

[0264] As with unheated zones **1630,** the unheated zones **1730** serve as pillars. In this respect, alteration of solid rock formations through the pyrolysis process creates a potential for subsidence at the surface. The unheated zones **1730** preferably prevent significant surface subsidence by supporting the rock layers overlying the subsurface formation or formations that are undergoing pyrolysis.

[0265] It is also understood that in both development area **1600** of **Figure 16** and development area **1700** of **Figure 17,** a large number of heater wells and production wells may be employed. Thus, for example, the development areas **1600** or **1700** may be indicative of small sections in a much larger development area.

[0266] The step **840** of selecting a geometry may optionally comprise the steps of drilling at least one cooling well through each of the one or more unheated zones **1630** or **1730.** A cooling fluid is then injected into each cooling well (not shown). The cooling fluid serves to inhibit pyrolysis within the unheated zones. It is preferred that the cooling fluid be a gas at ambient conditions.

[0267] In one embodiment, each cooling well comprises a downhole piping assembly for circulating unheated fluid. The unheated fluid may optionally be chilled at the earth surface. In one aspect, the unheated fluid is a cooling fluid that is chilled below ambient air temperature prior to injection into the downhole piping assembly. The cooling fluid is circulated through the tubular member, to the completion depth, and back up the wellbore through the annular region.

[0268] In one embodiment, each cooling well is completed at or below a depth of the subsurface formation, and comprises a wellbore, an elongated tubular member within the wellbore, and an expansion valve in fluid communication with the tubular member. The cooling fluid travels through the tubular member to inhibit heating within the subsurface formation. The expansion valve is preferably positioned in the tubular member at or above the depth of the kerogen.

[0269] In one embodiment, the cooling well further comprises an annular region formed between the elongated tubular member and a diameter of the wellbore. The cooling fluid is then circulated through the tubular member, to the completion depth (that is, to at least the subsurface formation), and back up the wellbore through the annular region.

[0270] In some instances, the subsurface formation comprises *in situ* water. It is then anticipated that the cooling fluid will cool the subsurface formation sufficient to freeze at least a portion of the *in situ* water.

[0271] It is believed that a plurality of smaller pillars (such as unheated zones **1630)** provide greater stability to the formation than one or two larger pillars. Therefore, as an alternative, the one or more unheated zones may define at least five non-contiguous, unheated zones that serve as pillars to minimize subsidence. Alternatively, if only a few unheated zones are used, then the unheated zones may be proportionally larger zones (such as unheated zones 1730). The heating rate and distribution of heat within the formation may be designed and implemented to leave sufficient unmatured pillars to prevent subsidence.

[0272] A number of methods are provided herein for the step **830** of sizing the cumulative area of the at least one unheated zone. Before discussing the various methods and the factors that are considered, it should be noted that the purpose for sizing the area of the unheated zone is to control subsidence while maximizing hydrocarbon production. Stated another way, it is desirable to optimize that portion of the hydrocarbon development area in which the organic rich rock is pyrolyzed while controlling subsidence above the subsurface formation.

[0273] The concept of "controlling" subsidence does not mean that subsidence is eliminated, but rather refers to the idea of anticipating when subsidence may occur under various geometries of unheated zones, and then attempting to maintain a degree of subsidence that is within an amount that can be tolerated. The amount of subsidence that can be tolerated in a development area will vary depending upon the location and environmental sensitivity of the area. For instance, the amount that can be tolerated may be determined by the owner or manager of the surface rights and the owner or operator of the underlying mineral rights in the development area.

[0274] Ideally, no subsidence would occur at all, meaning that the difference in elevation before and the after heating and production of hydrocarbons is imperceptible. However, in one aspect, the difference in elevation is less than three feet. More preferably, the difference in elevation is less than one foot or, even more preferably, less than six inches. What is considered to be a "significant" amount of subsidence is dependent on the needs and desires of the operator, the land owner, or any governmental entity.

[0275] In the present disclosure, the concept of "substantially optimizing" a portion of a development area in which organic rich rock is pyrolyzed is offered. This concept does not necessarily mean that a heated area is maximized. In one aspect, "substantially optimizing" means that an area is within 5% of the maximum amount of area that can be heated while avoiding significant subsidence. In another aspect, "substantially optimizing" means that an area is within 10% of the maximum amount of area that can be heated while avoiding significant subsidence.

[0276] Various factors may be considered in connection with the step **830** of sizing the cumulative area of the at least one unheated zone. In one embodiment, the step of sizing the area of the at least one unheated zone comprises considering at least one of richness of the organic rich rock, the thickness of the subsurface formation, and the permeability of the subsurface formation. Alternatively, or in addition, the step of sizing the area of the at least one unheated zone includes considering geomechanical properties of the subsurface formation. Such geomechanical properties may include, for example, the Poisson ratio, the modulus of elasticity, shear modulus, a Lame' constant, or combinations thereof.

[0277] In one embodiment, the step of sizing the area of the at least one unheated zone is performed using a computer model. The computer model may be, for example, a finite element model. The finite element model assumes that during the heating process, oil and gas are generated in sufficient volumes to keep the average fluid pressure in the heated areas at or near lithostatic pressure. After heating is ended and generation begins to decline, the average fluid pressure will decrease with fluid production until an approximately hydrostatic condition is reached. It is during this pressure decline that subsidence is most likely to occur. In one aspect, the model tracks the stresses in rocks adjacent to the treated volume during this period.

[0278] The computer model generally considers the treated volume to be homogeneous, rather than attempting to describe the details of the pyrolysis process on the scale of individual heater wells and flow paths. In one aspect, the model assumes that artificial fractures were formed in the area under development as part of the formation heating process. It also assumes that the organic-rich rock acts as a linearly elastic, isotropic solid.

[0279] When using a computer model, the method **800** may include the step of assigning for the computer model an initial post-treatment modulus of elasticity for the area that has been pyrolyzed. In one aspect, the initial post-treatment modulus of elasticity is lower than a modulus of elasticity for the formation in an untreated state. The initial post-treatment modulus of elasticity may be empirically determined through field tests. Alternatively, the initial modulus of elasticity may be empirically determined through laboratory tests on one or more core samples.

[0280] When using a computer model, the method **800** may include the step of assigning for the computer model a first fluid pressure in the heated area. The method 800 then includes confirming that a subsidence failure point has not been reached at the first fluid pressure. A second lower fluid pressure may then be assigned in the heated area. The method 800 then further includes determining whether a subsidence failure point has been reached at the second lower fluid pressure. This progression may be repeated until the fluid pressure is reduced to a point that approximates hydrostatic pressure. This effectively simulates the reduction of fluid pressure within the formation towards a hydrostatic pressure level. At each progression, the model is reviewed to determine whether there is a likelihood of subsidence in the rock above the organic-rich rock.

[0281] When using a computer model, the method **800** may include the step of assigning for the computer model a second lower post-treatment modulus of elasticity for the heated area, and then assigning a new first fluid pressure in the heated area. In one aspect, the second post-treatment modulus of elasticity is at least 5 times lower than the pre-treatment modulus of elasticity. Alternatively, the second modulus of elasticity is at least 10, 20 or 30 times lower than the pre-treatment modulus of elasticity. In any event, the method **800** then includes confirming that a subsidence failure point has not been reached at the first fluid pressure.

[0282] If the subsidence failure point has not been reached at the first fluid pressure, then a new second lower fluid pressure may be assigned in the heated area. The method **800** then includes determining whether the subsidence failure point has been reached at the second lower fluid pressure. This progression of lower fluid pressures may again be repeated to simulate the reduction of fluid pressure within the formation towards a hydrostatic pressure level.

[0283] In the above methods, the step of confirming that a subsidence failure point has not been reached may comprise confirming that a maximum principal stress does not present a likelihood of faulting within the at least one unheated zone. Alternatively, or in addition, the step of confirming that a subsidence failure point has not been reached may comprise confirming that a Mohr-Coulomb criterion does not present a likelihood of faulting within the at least one unheated zone. Such Mohr-Coulomb criterion is where stresses exceed the Mohr-Coulomb failure line. Alternatively, or in addition, the step of confirming that a subsidence failure point has not been reached may comprise confirming that unacceptable vertical displacement is not taking place at the surface above the organic-rich rock formation. Alternatively, the step of confirming that a subsidence failure point has not been reached may comprise determining when a portion of the rock around a heated zone goes into tension.

[0284] The method **800** may also include the step of selecting a first size ratio between an at least one heated area and an at least one unheated area. In this instance, the method **800** may further comprise increasing the size of the selected size ratio by increasing the size of the first heated area relative to the second area to be left unheated. In this way, a second selected size ratio is provided.

[0285] It is noted that the first and second size ratios are preferably calculated by using the same configuration for the pyrolyzed area in both ratios. However, in connection with the step of selecting a second size ratio, a different configuration may be used. For instance, the configuration at the first size ratio may be a square, whereas the configuration at the second size ratio is a rectangle. In this instance, the second size ratio may in fact be substantially similar to the first size ratio when using the new configuration.

[0286] In one aspect, the configuration comprises a plurality of substantially circular heated areas, leaving a plurality of unheated zones there between. In another aspect, the configuration comprises a plurality of four-sided polygons that are unheated. In any instance, the above-described steps concerning assigning sequentially lower pore pressures, and then confirming that no subsidence failure condition has occurred may be repeated at the new selected size ratio or configuration.

[0287] Referring back to **Figures 16** and **17,** it is noted that a size ratio of the heated areas (represented by the heat fronts **1615 / 1715**) to the unheated areas (represented by unheated zones **1630 / 1730**) is implied. In **Figure 16,** the cumulative area of the unheated areas **1630** is about 50% of the overall development area **1600.** In **Figure 17,** the cumulative area of the unheated areas **1730** is about 35% of the overall development area **1700.** These percentages will decrease as additional heating takes place towards maturity. Therefore, the operator should be mindful of the optimum portion of the development area in which organic rich rock is pyrolyzed while still controlling subsidence above the subsurface formation.

[0288] In one aspect, substantially optimizing that portion of the development area in which the organic rich rock is pyrolyzed comprises identifying a maximum area of heating while still controlling subsidence above the subsurface formation, and then reducing the size of the area of heating by 1 to 10 percent of the maximum area of heating. In another aspect, substantially optimizing a portion of the development area in which the organic rich rock is pyrolyzed comprises identifying a maximum area of heating while still controlling subsidence above the subsurface formation, and then reducing the size of the area of heating by 1 to 5 percent of the maximum area of heating.

[0289] **Figure 9** presents another flow chart showing steps that may be performed in connection with an alternate embodiment **900** of the present inventions. The method 900 employs a computer model such as a finite element computer model in order to analyze possible subsidence in a subsurface formation as a result of pyrolysis and production activities. Box **910** shows the step of providing a finite element mesh for a computer model.

[0290] The method **900** also includes the step of selecting an initial post-treatment modulus of elasticity. This is represented at Box **920.** The initial post-treatment modulus of elasticity is selected to represent the modulus of elasticity for the subsurface area sought to be developed through pyrolysis and production. The initial modulus of elasticity may be empirically determined through field tests. Alternatively, the initial modulus of elasticity may be empirically determined through laboratory tests on one or more core samples. The initial modulus of elasticity is lower than the modulus of elasticity for the organic-rich rock in an untreated state. In this embodiment, the rock under investigation is initialized in a softened condition.

[0291] The method **900** further includes the step of selecting a size ratio between a heated area and an unheated area within the subsurface formation. This is shown at Box **930.** It is noted that the heated area need not be one single or contiguous area, but may be a plurality of separate unheated zones that serve as pillars. The unheated area thus represents the cumulative area of the unheated zones.

[0292] As an option associated with selecting a size ratio, the operator may determine the shape or shapes of the unheated areas that provide optimum support for the overburden. Further, the operator may determine the location of the unheated areas within the development area for providing optimum support for the overburden.

[0293] The method **900** also includes the step of assigning a first fluid pressure in the area that has been heated, or pyrolyzed. This is indicated at Box **940.** The fluid pressure simulates the degree of pore pressure within the area after treatment.

[0294] The method **900** next includes determining a likelihood of subsidence above the heated area at the first fluid pressure. The purpose is to confirm that a subsidence failure point has not been reached at the first fluid pressure. This determination step is indicated at Box **950.** Various ways may be used to determine the likelihood of subsidence above the heated area. These include, for example, monitoring the displacement of rock above the heated area, or confirming that the maximum principal stress in the unheated area adjacent the heated area does not exceed a failure criterion.

[0295] As a next step, the method **900** includes assigning for the computer model a second lower fluid pressure in the heated area. This step is shown at Box **960.** By stepping down the fluid pressure in the computer model, the production of hydrocarbon and other fluids in the subsurface formation is simulated. Stated another way, stepping the fluid pressure down serves to simulate the production of oil and gas after conversion of the formation hydrocarbons in the organic rich rock at the initial post-treatment modulus of elasticity for the selected size ratio.

[0296] A likelihood of subsidence above the heated area is next determined at the second lower fluid pressure. This is shown at Box **970.** The purpose of determination step **970** is to confirm that rock displacement or maximum principal stress or some other chosen criteria at the second lower fluid pressure does not present a likelihood of subsidence above the heated area at the selected size ratio.

[0297] After determining that subsidence is not likely from steps **910** through **970,** the size ratio of the heated versus unheated areas may be adjusted. Box **980** indicates the step of increasing the size of the selected size ratio. This is done by increasing the size of the heated area relative to the unheated area. Thus, a second size ratio is provided. From there, steps **940** through **970** may be repeated at the second size ratio. This is shown at Box **990.** From step **990** it is determined whether subsidence above the heated area at the second size is likely.

[0298] The steps **940** through **990** may be repeated at third, fourth, or additional increased size ratios until unacceptable rock displacement is anticipated. Preferably, these steps are performed by assuming a modulus of elasticity that is significantly softer than the rock in its untreated or unheated condition. In this way, the area of the treated interval is maximized while avoiding a likelihood of subsidence. The steps may be performed manually or via an automated routine.

[0299] In an alternative embodiment, after determining that subsidence is not likely from steps **910** through **970,** the configuration of the unheated areas may be adjusted. From there, steps **940** through **970** may be repeated for the new configuration. It is then determined whether subsidence above the heated area at the new configuration is likely.

[0300] **Figure 10A** is an example of a model geometry **3200** used for finite element modeling of formation stresses. The model **3200** is designed to determine whether a pillar of untreated oil shale can adequately mitigate subsidence. The model **3200** represents one-quarter of a treated volume, plus an untreated area surrounding it. The lateral extent of the model **3200** is constant and measures 1,200 feet by 1,200 feet. The treated volume in the model **3200** is square. However, this is merely exemplary, and could represent a quarter of a circle or another shape.

[0301] The model **3200** has a treated interval **3210.** The lateral dimensions of the treated interval **3210** are preferably varied in test runs to determine a minimum size that prevents subsidence. In one aspect, the size of the treated interval is varied from 840 feet down to 480 feet in width. The thickness of the treated interval **3210** may also be adjusted. In one model the thickness of the treated interval **3200** may be 180 feet.

[0302] The treated interval **3200** may also be placed at different depths, reflecting the depth of a targeted organic-rich rock in a development area. In the illustrative model of **Figure 10A,** the treated interval **3210** is at a depth of 2,000 feet, meaning that an overburden **3220** of 2,000 feet is assumed. An underburden **3230** of 820 feet is also assumed in the model **3200.**

[0303] **Figure 10B** presents a diagram showing stresses acting on the treated interval **3210** of **Figure 10A.** The initial loading of the finite element model **3200** is shown schematically. Lateral stresses are indicated by arrows labeled "σ_x" and "σ_y." Vertical stresses corresponding to the weight of overlying rocks are shown by arrows labeled "σ_z." It can be seen that lateral stresses "σ_x" and "σ_y." increase with depth. Together, the "σ_x", "σ_y.", and "σ_z." stresses define the *in situ* stress for rocks in the development area.

[0304] The "σ_x" and "σ_y." stresses vary linearly, and are not necessarily equal. For instance, it can be seen that lateral stress, "σ_x" increases with depth. The "σ_z" stress is predominantly a function of the weight of the overburden 3220. The "σ_z" stress will increase with depth throughout the section.

[0305] Referring generally to both **Figure 10A** and **10B,** the model **3200** may be built using different elements. In the illustrative model **3200,** the model is built using 20-noded brick elements. Laterally a 10 by 10 mesh may be used, making the elements 120 feet on a side. Elements in the treated interval **3210** may have various sizes. In the model **3200,** the elements are 60 feet in thickness. This means that three elements are provided vertically for the treated zone **3210.** Overburden **3220** and underburden **3230** elements are made to be 200 feet thick and 164 feet thick, respectively, though they may be any convenient thicknesses. Elements within the treated interval **3210** are designated as pore-pressure elements, while elements outside of the treated interval **3210** are designated as stress-only elements.

[0306] It is desirable to test the stresses acting above and below the treated interval **3210** by changing the size of the treated interval **3210.** Therefore, as noted the size of the treated interval **3210** may be varied from run to run by changing the number of elements designated as pore-pressure elements or, alternatively, by varying the size of the elements.

[0307] According to the model **3200,** pressure exists in the treated interval **3210.** The pressure is in the form of fluid pressure, referred to as "pore pressure." In each run for the computer model **3200,** and as demonstrated more fully in **Figures 12A** through **12D** and **13A** through **13D,** the fluid pressure in the treated interval 3210 may be decreased in 50-psi increments.

[0308] To simulate the response of the treated interval **3200** after heating, the computer model may be assigned a geomechanical property. In one aspect, the geomechanical property is an initial post-treatment modulus of elasticity. A separate value is assigned to the rocks in the treated interval **3210** and to the untreated rocks in the surrounding formations. The untreated rocks are assigned properties similar to organic-rich rock comprised of unconverted oil shale. In connection with the model **3200,** the Young's modulus may be 2.3e6 psi, and the Poisson ratio may be 0.2.

[0309] For the treated interval **3210,** it is assumed that heating softens the oil shale. More specifically, heating causes pyrolysis in the oil shale which in turn creates formation fluids. The fluids are then removed as part of a production process. Preferably, laboratory tests are conducted to estimate the post-heating mechanical properties of oil shale in the treated interval **3210.** This allows for the mechanical integrity of the treated interval **3210** to be predetermined so that a more accurate model may be run. Computer runs may then be performed that assume a softened condition of the treated interval **3210.** For example, an initial run may be made that assumes a Young's modulus that is 5 times, or alternatively, 10 times lower than the untreated value of 2.3e6 psi. The Poisson ratio of the treated interval **3210** may also be assumed as 0.2.

[0310] After assuming a reduced pressure state of the treated interval **3210,** a computer run is made. During the run, the pressure within the treated interval **3210** is incrementally reduced. For example, an initial pore pressure of approximately 1,900 psi may be assumed. Then, the pressure is incrementally reduced to a value of approximately 600 psi, or another value that approximates hydrostatic pressure. During this run, if it is determined that the untreated rocks around or above the treated interval **3210** are able to withstand the removal of fluids from the treated interval **3210** at a given geometry, then a subsequent run may be made that assumes a still greater amount of production. In one aspect, a new Young's modulus is used that is 30 times lower than the untreated value of 2.3e6 psi. During this run, the pressure within the treated interval **3210** is again incrementally reduced. This sequence may be repeated at even lower elasticity values, such as a Young's modulus that is 100 times lower than the untreated value of 2.3e6 psi, or even 300 times lower than the untreated value of 2.3e6 psi. A modulus of elasticity range of 10 to 300 times lower than the untreated rock effectively spans the range from slight production (where the treated interval can support a portion of its overburden) to a state where the treated volume behaves almost as if it were excavated.

[0311] **Figure 11** presents in flow chart form an implementation of the model **3200** of **Figure 10A** as discussed above. The method **1100** demonstrates steps that may be performed in connection with an alternate embodiment of the methods disclosed herein. The method **1100** again relates to developing hydrocarbons from a subsurface formation containing organic-rich rock. Preferably, the organic-rich rock formation is comprised of solid hydrocarbons. Preferably, the solid hydrocarbons comprise kerogen.

[0312] The method **1100** employs the finite element computer model **3200** in order to analyze possible subsidence above the treated interval **3210** as a result of pyrolysis and production activities. Box **1110** shows the step of providing a finite element computer model. The purpose of the step **1110** is to simulate the production of hydrocarbon fluids from the subsurface formation at a given model geometry.

[0313] In connection with method **1100,** areas are assigned to the computer model **3200.** The areas represent a heated area and an unheated area within a development area. This step is shown at Box **1120.** In the illustrative model **3200,** the heated area represents one-quarter of a treated volume, and is represented by treated interval **3210.** The unheated area is understood to be adjacent the treated interval **3210,** but is not shown. Initially, the unheated area may represent approximately 50% of the development area. The heated area **3210** versus an adjacent unheated area defines a size ratio.

[0314] A geomechanical property is assigned for the heated area **3210.** The geomechanical property may be, for example, an initial post-treatment modulus of elasticity. This step is represented by Box **1130.** The initial post-treatment modulus of elasticity may be empirically determined through field tests. Alternatively, the initial post-treatment modulus of elasticity may be empirically determined through laboratory tests on one or more core samples. Alternatively still, the initial post-treatment modulus of elasticity may be estimated from previous field tests.

[0315] Next, it is determined whether a subsidence failure point has been reached in the overburden **3220** above the heated area **3210.** This is indicated at Box **1140.** In this instance, one determines whether the principal stress in the rock above the heated area **3210** becomes tensile. This represents a subsidence failure point. The subsidence failure point is determined at a first fluid pressure assigned within the heated area **3210.**

[0316] If a subsidence failure point has not been reached at the first fluid pressure level, then the method **1100** also includes determining whether a subsidence failure point has been reached in the overburden **3220** above the heated area **3210** at a second fluid pressure assigned within the heated area **3210.** This is indicated at Box **1150.** This again may involve a determination as to whether the principal stress in the rock above the heated area **3210** goes into a state of tension.

[0317] It is preferred that the step **1150** be repeated at sequentially lower fluid pressures until a subsidence failure point is reached, or until the fluid pressure reaches a level that approximates hydrostatic pressure. This is shown at Box **1160.** In one aspect, the fluid pressure is sequentially dropped in 50 psi increments to a hydrostatic pressure level. By stepping down or reducing the fluid pressure within the formation, one is able to simulate the production of fluids from the heated area **3210.** This production is reflective of solid hydrocarbons having been pyrolyzed within the heated area **3210** and subsequently removed.

[0318] Other failure criteria besides the maximum principal stress being tensile may be analyzed in order to determine whether a subsidence failure point has been reached. For example, the step of determining whether a subsidence failure point has been reached in the rock above the heated area may comprise determining whether a shear stress in the rock above the heated area **3210**

or, perhaps, adjacent the heated area, exceeds a Mohr-Coulomb failure criterion. Such criteria may also include the Drucker-Prager failure criteria, the Cam-clay model, or various other "critical state" models.

[0319] In one embodiment, the method **1100** further includes increasing the size of the selected size ratio by increasing the size of the heated area **3210** relative to the unheated area. In this way, a new size ratio is provided. This step is indicated at Box **1170.** Steps **1140** through **1160** may then be repeated at the new size ratio. This step is shown at Box **1180.** The purpose is to determine whether (or to confirm that) a subsidence failure point has been reached in the rock above the heated area **3210** at the new selected size ratio. Where maximum principal stress is used as a geomechanical property, this may involve determining whether a likelihood of faulting exists within the unheated zone **3210.** This, in turn, may involve considering whether the overburden **3220** rock has gone into a state of substantial tension.

[0320] As discussed above, the pore pressure within the treated interval **3210** may be incrementally reduced to simulate the production of fluids from the organic-rich rock formation. Again, production is reflective of solid hydrocarbons having been pyrolyzed within the heated area **3210,** and then removed. **Figures 12A** through **12D** present calculated stresses for increments **12A, 12B, 12A, 12D** from a model run **3400** wherein pore pressure in a treated volume **3410** is incrementally decreased. The model **3400** shows a treated volume **3410** within a development area **3405.** An overburden **3407** is provided over the treated volume **3410** extending to the surface, and an underburden **3409** below the treated volume **3410.** In this model **3400,** the treated volume **3410** is laterally 840 feet by 840 feet (1,680 feet x 1,680 feet on a full pattern).

[0321] The model **3400** is tilted in each **Figure** to provide a better interior view for the treated volume **3410.** In other words, **Figures 12A, 12B, 12C** and **12D** provide isometric views of a formation model that is substantially vertical, but is shown leaning merely for illustrative purposes. In addition, the rock representing the treated volume **3410** is actually removed. This allows a better view of the stresses in the untreated portion **3420** around the treated volume **3410.** However, this too is for illustrative purposes as it is understood that rock is present, particularly at the beginning **12A** of the model run.

[0322] The model **3400** is initialized in a stress state reflecting the uplift and tectonics in the Piceance Basin. Different mechanical properties are used in the model **3400** for the treated volume **3410** and for the untreated portion **3420.** The rock in the untreated portion **3420** is preferably assigned properties similar to unconverted oil shale. The Young's modulus may be, for example, 2.3e6 psi, and the Poisson ratio may be 0.2.

[0323] For the treated volume **3410,** it is assumed that heating softens the oil shale. The model **3400** represents a single run with a post-heating modulus of elasticity for the treated volume **3410** that is softer than the modulus of elasticity for the untreated portion **3420** around the treated volume **3410,** including the overburden **3407.** In the illustrative model **3400,** the modulus of elasticity was 300 times softer than the modulus of elasticity for the untreated rock **3420.** However, other factors may be used. This corresponds to the treated volume **3410** behaving almost as if it were excavated. The treated volume **3410** was also assigned an initial porosity of 25%.

[0324] In connection with the model run **3400,** the fluid pressure in the treated volume **3410** was decreased in 50-psi increments. It is noted that pressure increments **12A, 12B, 12C, 12D** do not show each 50-psi increment, but only show incremental pressure reductions of 400-psi.

[0325] The model **3400** shows vertical stress profiles (measured in pounds per square foot) acting on the treated volume **3410.** The model **3400** also shows horizontal stress profiles (measured in pounds per square foot) acting around the treated volume **3410.** The stress profiles represent the maximum principal stress, which is the most tensional stress acting on the rock. Maximum principal stress is indicated by shades of gray, with greater compression levels (that is, more negative stress) being shown in darker shades. The maximum principal stress ranges from 0.0 lb/ft^2 to -4.0e5 lb/ft^2 (0 to -400,000 lb/ft^2).

[0326] In **Figures 12A** through **12D** the maximum principal stresses developed in the rocks **3407** and **3420** surrounding the treated volume **3410** is monitored as the fluid pressure declines. In model **3400** portions of the rocks **3407** and **3420** surrounding the treated volume **3410** are monitored so as to detect whether tensional stresses develop. If tensional stresses arise that exceed the strength of the rocks **3407** and **3420,** particularly in the overburden **3407,** faulting is likely to occur, potentially causing subsidence. If faulting does not occur, the elastic response of the rocks **3407** and **3420** surrounding the treated volume **3410** will likely prevent noticeable subsidence from occurring.

[0327] In the pressure increment **12** of **Figure 12A,** it can be seen that the stress level is horizontally constant at the various depths. The rock in the overburden **3407** has not entered a state of tension, and there is minimal likelihood of faulting above the treated interval **3410.** It should be noted that this does not mean that subsidence in the overburden **3405** cannot occur. However, it does mean that there will not be catastrophic subsidence as a result of faulting.

[0328] **Figure 12B** represents a second pressure increment **12B.** In **Figure 12B,** fluid pressure in the treated volume **3410** is reduced to 1,458 psi. This is a 400 psi drop. In the pressure increment **12B,** it can be seen that the stresses are less compressive below the surface, but no tensile stress conditions are observed. Thus, there is little or no likelihood of faulting above the treated interval **3410.**

[0329] **Figure 12C** represents a third pressure increment **12C.** In **Figure 12C,** fluid pressure in the treated volume **3410** is further reduced to 1,058 psi. This represents another **400** psi incremental pressure drop. In the pressure increment **12C,** it can be seen that the stresses are again less compressive, but again no tensile stress conditions are observed. Particularly, the maximum principal stress values above and adjacent the treated interval **3410** remain low. Thus, there is again little to no likelihood of faulting above the treated interval **3410.**

[0330] **Figure 12D** represents a fourth pressure increment **12D.** In **Figure 12D,** fluid pressure in the treated volume **3410** is further reduced to 658 psi. This represents still another 400 psi reduction. This amount is very close to hydrostatic pressure.

[0331] In the pressure increment **12D** of **Figure 12D,** it can be seen that the stresses are again less compressive. Close examination indicates that several very small areas directly adjacent to the treated interval are experiencing tensile stresses. However, even in this increment there actually are no tensile stresses calculated at element integration points. It is understood that the interpolation of stresses to model nodes for presentation creates artifacts that may result in small areas which appear to be in tension adjacent to the treated volume. However, these artifacts are of no consequence.

[0332] The pressure increments **12A, 12B, 12C, 12D** indicate that only at the lowest fluid pressure (658 psi) are there any tensile stresses in the model **3400.** However, even at the lowest increment **12D** there is little likelihood of subsidence, and certainly no suggestion of wholesale faulting. Therefore, a subsidence failure point at this modulus of elasticity parameter and this particular geometry is not detected.

[0333] **Figures 13A** through **13D** represent the same computer model as used to generate increments **12A** through **12D.** However, **Figures 13A** through **13D** present calculated displacements instead of stresses **3500** to detect subsidence in an oil shale development area **3505.** More specifically, model **3500** determines rock displacement above a treated volume **3510.** The model **3500** shows displacement of rock, measured in feet. The range of displacement is from 1.0 foot to -1.0 foot. Displacement is indicated by shades of gray, with negative displacement being shown in darker shades. These displacements are calculated based on an assumption of elastic behavior of the rocks. As expected, elastic behavior (no failure) leads to only small displacements and subsidence.

[0334] As with **Figures 12A** through **12D, Figures 13A** through **13D** present pressure increments **13A, 13B, 13C, 13D** wherein pore pressure in the treated volume **3510** is incrementally decreased to determine the effect on rock displacement above the treated volume **3510.** The model **3500** shows the treated volume **3510** within the development area **3505.** An overburden **3507** is provided over the treated volume **3510** extending to the surface, and an underburden **3509** below the treated volume **3510.** In this model **3500,** the treated volume **3510** is again laterally 840 feet by 840 feet (1,680 feet by 1,680 feet on a full pattern).

[0335] As with model **3400,** the model **3500** is tilted in each **Figure** to provide a better interior view for the treated volume **3510.** In other words, **Figures 13A, 13B, 13C** and **13D** provide isometric views of a formation model that is substantially vertical, but is shown leaning merely for illustrative purposes. In addition, the rock representing the treated volume **3510** is again removed to allow for a better view of the stresses in the untreated portion **3520** around the treated volume **3510.** This too is for illustrative purposes.

[0336] As discussed above, each pressure increment **13A, 13B, 13C, 13D** assumes an untreated portion **3520** adjacent the treated volume **3510.** Different mechanical properties were used in the model **3500** for the treated volume **3510** and for the untreated portion **3520.** As noted, for the treated volume **3510,** it was assumed that heating would soften the oil shale. In this respect, the Young's modulus was increased to a factor that is 300 times above the value assigned to the untreated rock **3520.**

[0337] In the model runs, the fluid pressure in the treated volume **3510** was decreased in 50-psi increments. It is noted that pressure increments **13A, 13B, 13C, 13D** do not show each 50-psi increment, but only show increments of 400-psi pressure reductions. In **Figures 13A** through **13D,** displacement appearing in the overburden **3507** above the treated volume **3510** is monitored as the fluid pressure declines.

[0338] **Figure 13A** represents the pressure increment **13A** at an initial state. In accordance with the model, fluid pressure in the treated volume **3510** was initialized at 1,858 psi. In the pressure increment **13A,** it can be seen that no displacement has taken place at any level within the overburden **3407.** The shading in the overburden **3507** is monochromatic. Thus, there is no subsidence anticipated at the initial state.

[0339] **Figure 13B** represents the second pressure increment **13B.** In **Figure 13B,** fluid pressure in the treated volume **3510** is reduced to 1,458 psi. It can be seen that some slight negative displacement is beginning to take place below the surface and immediately above the treated volume **3510.** However, the overburden **3507** remains stable and no catastrophic subsidence above the treated volume **3510** is anticipated.

[0340] **Figure 13C** represents the third pressure increment **13C.** In **Figure 13C,** fluid pressure in the treated volume **3510** is further reduced to 1,058 psi. In the pressure increment **13C,** it can be seen that negative displacement of about ½ of one foot just above the treated volume **3510** is taking place. Displacement at the surface may be occurring, but only in terms of a few inches.

[0341] Finally, **Figure 13D** represents the pressure increment **13D** at a fourth state. In **Figure 13D,** fluid pressure in the treated volume **3510** is further reduced to 658 psi. This amount is very close to hydrostatic pressure.

[0342] In the pressure increment **13D,** it can be seen that negative displacement of just under one foot is taking place immediately above the treated volume **3510.** Displacement at the surface is also occurring, but only in terms of about six inches. The displacement in **Figure 13D** indicates that in the absence of any faulting, the level of subsidence should be relatively minor. The largest vertical displacement in the pressure increment **13D** is directly over the treated volume **3510.** At the surface there is potentially about ½ of one foot of movement.

[0343] It is anticipated that in a typical production operation, a six inch subsidence experience would be well within a range of tolerance for the land owner or the production operator. However, to further control subsidence, an operator could choose to reduce the area of the treated interval to provide further support.

[0344] It is demonstrated from **Figures 12A-12D** and **13A-13D** that "pillars" of untreated oil shale would control subsidence. Based on the confirmatory results of the modeling, a method for developing hydrocarbons from a subsurface formation is substantiated. The unheated zone (or pillar) may be circular, may be a four-sided polygon, may be star-shaped, or may have another shape. The optimum size of the area of the subsurface formation to be heated is preferably at least as large as a size of the area to be left unheated. More preferably, the optimum size of the area to be heated is a size that is at least 20 percent greater than the size of the area to be left unheated. More preferably still, the optimum size of the area to be heated is a size that is at least 40 percent greater than the size of the area to be left unheated. Alternatively, the optimum size of the area to be heated defines a percentage of about 60 percent to 90 percent of the development area. Moreover, the optimum size of a single contiguous unheated area may be less than 25 percent of the development area or even less than 10 percent of the development area.

[0345] It is desirable to compare the results of a number of model pressure increments at different levels of softening, or conversion, within an oil shale formation. **Figure 14** provides a graph wherein different plots are made of the fluid pressure in a treated volume (shown on the horizontal or "x" axis) against the maximum principal stress in a model formation (shown on the vertical or "y" axis).

[0346] **Figure 14** shows four model runs made within the 840-foot by 840-foot section defining the treated volume **3410** or **3510.** Each run is represented by a line, indicated at **1410, 1420, 1430** and **1440,** respectively. Each run **1410, 1420, 1430, 1440** reflects a change or variation in the amount of softening of the rock in the treated volume. In the model runs **1410, 1420, 1430,1440,** softening represents the change in elastic modulus.

[0347] In the four runs, the Young's modulus for the treated interval in an unheated state was increased by various factors, as follows:

- line **1410** represents a run at a modulus of elasticity of 10 times less than the untreated estimate;
- line **1420** represents a run at a modulus of elasticity of 30 times less than the untreated state;
- line **1430** represents a run at a modulus of elasticity of 100 times less than the untreated state; and
- line **1440** represents a run at a modulus of elasticity of 300 times less than the untreated state.

Thus, each line represents a progressively softer condition for the treated interval.

[0348] For each run **1410, 1420, 1430, 1440** the maximum stress at element integration points was extracted and plotted. It can be seen from **Figure 14** that the stresses move toward becoming tensile as fluid pressure decreases. However, the stresses do not go below 150 psi of compression in any of the runs **1410, 1420, 1430, 1440.** Since the stress never becomes tensile, the likelihood of faulting and excessive subsidence is minimized.

[0349] It is also interesting to note that results of decreasing the elastic modulus by factors of 100 and 300 (represented by lines **1430** and **1440,** respectively) are quite similar. This indicates that the amount of softening at a modulus of elasticity of 100 times lower than an unheated state (represented by line **1430**) is actually the point where the treated volume provides no effective support for its overburden.

[0350] **Figure 14** also shows two vertical lines. Hydrostatic pressure in the model formation is shown by vertical line **1450,** while lithostatic pressure in the model formation is shown by vertical line **1460.** The lithostatic pressure represents the likely starting point when overburden load begins to be supported by the rock rather than the fluid pressure in the treated volume. The hydrostatic pressure represents the likely end point, at which fluid pressure will fall no further.

[0351] **Figure 15** presents another flow chart showing steps that may be performed in connection with an alternate embodiment **1500** of the present inventions. In this method 1500, the modulus of elasticity of a treated interval is sequentially lowered in accordance with the graph of **Figure 14.** The method **1500** again relates to developing hydrocarbons from a subsurface formation containing organic-rich rock. Preferably, the organic-rich rock formation is comprised of solid or heavy hydrocarbons. Preferably, the solid hydrocarbons comprise kerogen.

[0352] The method **1500** employs the finite element computer model **3200** in order to analyze possible subsidence in the treated interval **3210** as a result of pyrolysis and production activities. Box **1510** shows the step of providing a finite element computer model. The purpose of the step **1510** is to simulate the production of hydrocarbon fluids from the subsurface formation.

[0353] In connection with method **1500,** areas are assigned to the computer model 3200. The areas represent a heated area and an unheated area within a development area. This step is shown at Box **1520.** The heated and unheated areas are adjacent to one another. In the illustrative model **3200,** the heated area represents one-quarter of a treated volume, and is represented by treated interval **3210.** The unheated area is understood to be adjacent the treated interval **3210,** but is not shown. In one aspect, the initial unheated area represents approximately 50% of the development area. The heated area **3210** versus an adjacent unheated area defines a size ratio.

[0354] A geomechanical property is assigned for the heated area **3210.** The geomechanical property is an initial post-treatment modulus of elasticity. This step is represented by Box **1530.** The initial post-treatment modulus of elasticity may be empirically determined through field tests. Alternatively, the initial post-treatment modulus of elasticity may be empirically determined through laboratory tests on one or more core samples. Alternatively still, the initial post-treatment modulus of elasticity may be estimated from previous field tests.

[0355] Next, it is determined whether a subsidence failure point has been reached in the overburden **3220** above the heated area **3210.** This is indicated at Box **1540.** In one aspect, the subsidence failure point is determined by analyzing the maximum principal stress in a portion of the area left unheated adjacent the heated area **3210.** In this instance, one determines whether the principal stress in the rock above the heated area **3210** becomes tensile. In any event, the subsidence failure point is determined at a first fluid pressure assigned within the heated area **3210.** The fluid pressure is representative of an early pore pressure.

[0356] The method **1500** also includes determining whether a subsidence failure point has been reached in the overburden **3220** above the heated area **3210** at a second fluid pressure. This is indicated at Box **1550.** The second fluid pressure represents a pore pressure that is lower than the first fluid pressure assigned within the heated area **3210.** The subsidence failure point is preferably determined by analyzing the maximum principal stress in a portion of the area left unheated adjacent the heated area **3210.** This again would involve a determination as to whether the principal stress in the rock above the heated area **3210** goes into a state of tension. In addition, changes in stress in the rock immediately adjacent to the heated area may be considered.

[0357] It is preferred that the step **1550** be repeated at sequentially lower fluid pressures until a subsidence failure point is reached or until the pore pressure approximates hydrostatic pressure. In one aspect, the fluid pressure is sequentially dropped in 50 psi increments to a hydrostatic pressure level. By stepping down or reducing the fluid pressure within the formation, one is able to simulate the production of fluid hydrocarbons from the heated area 3210 after pyrolysis, or treatment.

[0358] In accordance with **Figure 14** wherein runs were made at multiple moduli of elasticity, a second post-treatment modulus of elasticity is selected for the heated area **3210.** This step is shown in Box **1560.** The second post-treatment modulus of elasticity is lower than the first post-treatment modulus of elasticity. This means that the rock in the heated area **3210** is assigned a softer value. In one instance, the second lesser post-treatment modulus of elasticity is 30 times lower than the modulus of elasticity of rock in the unheated area.

[0359] Next, it is determined whether a subsidence failure point has been reached in the overburden **3220** above the heated area **3210** at the second lesser modulus of elasticity. This is indicated at Box **1570.** In this instance, one determines whether the principal stress in the rock above the heated area **3210** becomes tensile. In any event, the subsidence failure point is determined at a first fluid pressure assigned within the heated area **3210.** The fluid pressure is again representative of an early pore pressure.

[0360] The method **1500** also includes determining whether a subsidence failure point has been reached in the overburden **3220** above the heated area **3210** at a second fluid pressure. This is indicated at Box **1580.** The second fluid pressure represents a pore pressure that is lower than the first fluid pressure assigned within the heated area **3210.** This again would involve a determination as to whether the principal stress in the rock above the heated area 3210 goes into a state of tension. In addition, changes in stress in the rock immediately adjacent to the heated area may be considered.

[0361] It is preferred that the step **1580** be repeated at sequentially lower fluid pressures until a subsidence failure point is reached or until the pore pressure approximates hydrostatic pressure. In one aspect, the fluid pressure is sequentially dropped in 50 psi increments to a hydrostatic pressure level. By stepping down or reducing the fluid pressure within the formation, one is again able to simulate the production of fluid hydrocarbons from the heated area 3210, but at a second lesser modulus of elasticity.

[0362] It is noted that the flow charts in **Figures 8, 9, 11** and **15** are merely illustrative. Other embodiments of the methods are within the scope of the claims, below. In one aspect, the method includes the steps of assigning an area of the subsurface formation to be heated, and also assigning an area of the subsurface formation to be left unheated. An initial value for a geomechanical property of the heated area is assigned. The geomechanical property represents a softened condition of the heated area. An assigned pore pressure in the heated area is incrementally decreased. From there, at least one of (1) the displacement of rock above the heated area, or (2) the maximum principal stress in the unheated area adjacent to the heated area at the second value for the geomechanical property, is evaluated. In this way, a likelihood of subsidence within the heated area may be considered.

[0363] Various geomechanical properties or criteria may be used. For example, the geomechanical property may be Young's modulus, shear modulus, V_p/V_s, Poisson ratio, or a Lame' constant.

[0364] In one aspect, the method further includes providing a second value of the geomechanical property in order to simulate a further softening of the organic rich rock relative to the initial value of the geomechanical property. From there, at least one of (1) the displacement of rock above the heated area, or (2) the maximum principal stress in the unheated area adjacent the first heated area at the initial value for the geomechanical property, may again be evaluated. In this way, a likelihood of subsidence within the heated area may be considered.

[0365] As part of the method, the step of increasing a size of the area of the subsurface formation to be heated relative to a size of the area to be left unheated may be performed. As part of the method, the shape of the area to be left unheated may be simultaneously or independently varied. The above steps may then be repeated at the new size ratio. Ideally, subsequent size ratios are provided and the steps repeated again so that an optimum size of the area of the subsurface formation to be heated relative to a size of the area to be left unheated may be determined.

[0366] In one aspect, the area of the subsurface formation to be left unheated defines a first configuration. After determining that subsidence above the heated area is predicted, the configuration of the subsurface formation to be left unheated may be changed to a second configuration. The above steps may then be repeated at the new configuration or the new size ratio.

[0367] It is preferred that the geomechanical property is the post-treatment modulus of elasticity. In one aspect, the initial value for the post-treatment modulus of elasticity is at least 5 times lower than the modulus of elasticity for the untreated area. Alternatively, the initial value for the post-treatment modulus of elasticity is at least 10 times lower than the modulus of elasticity for the untreated area. Subsequent values for the post-treatment modulus of elasticity may be 30 times lower than the modulus of elasticity for the untreated area, or even 300 times lower than the modulus of elasticity for the untreated area. A value of 300 times lower than the virgin modulus of elasticity is very likely to simulate a formation having virtually no independent ability to support an overburden.

[0368] The optimum size of the area of the subsurface formation to be heated relative to a size of the area to be left unheated will vary depending on the rock properties in the subsurface formation. Other factors such as depth of the subsurface formation may also affect the optimum size. In one aspect, the optimum size defines a percentage of about 40 percent to 90 percent. Alternatively, the optimum size defines a percentage of about 60 percent to 90 percent. Alternatively still, the optimum size defines a percentage of about 65 percent to 80 percent.

[0369] In addition to the above methods, a method of minimizing environmental impact in a hydrocarbon development area is also provided. The hydrocarbon development area includes a subsurface oil shale formation. The method includes reviewing the topography of the hydrocarbon development area, and determining portions of the topography that are amenable to subsidence without significant environmental impact. For example, topological areas that are substantially flat or that have only modest profile changes may tolerate subsidence more than topological areas that have greater surface relief. Alternatively, areas with little vegetation may suffer less environmental impact due to changes in runoff than areas with much vegetation. Alternatively still, areas that have no buildings are preferred for subsidence pyrolysis over areas that have permanent surface structures. The method also comprises heating the oil shale formation below those portions of the topography that are amenable to subsidence without significant environmental impact in order to pyrolyze the oil shale and produce hydrocarbons.

[0370] In one aspect, the method further includes determining a portion of the topography that is more environmentally sensitive to subsidence than the portions of the topography that are amenable to subsidence without significant environmental impact. From there, the method includes inhibiting the heating of a portion of the oil shale formation below that portion of the topography that is more environmentally sensitive, thereby forming a pillar.

[0371] The step of inhibiting the heating may include drilling at least one cooling well through the oil shale formation below the portion of the topography that is more environmentally sensitive to subsidence. It may also include injecting a cooling fluid into the cooling well in order to inhibit pyrolysis within the portion of the oil shale formation below that portion of the topography that is more environmentally sensitive to subsidence. The cooling fluid may be any fluid that is not artificially heated at the surface.

[0372] Yet an additional method for developing hydrocarbons from an oil shale formation is provided herein. The method comprises mechanically characterizing geological forces acting upon the oil shale formation, and also mechanically characterizing the oil shale formation after at least partial pyrolysis of the oil shale formation has taken place. The method also comprises selecting a first prototype pillar geometry, and selecting a dimension for the first prototype pillar geometry representing a first selected percentage area of the oil shale formation. Preferably, the first prototype pillar geometry is one quarter of a square. A subsidence model for the first prototype pillar geometry at the first selected percentage area is then run.

[0373] An evaluation takes place in connection with the method. In this respect, the method also includes evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the first selected percentage area.

[0374] The method may further comprise selecting a dimension for the first prototype pillar geometry representing a second selected percentage area of the oil shale formation, and then running a subsidence model for the first prototype pillar geometry at the second selected percentage area. An evaluation again takes place. In this respect, the method also includes evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the second selected percentage area.

[0375] The method may further include selecting a second prototype pillar geometry, and selecting a dimension for the second prototype pillar geometry representing a first selected percentage area of the oil shale formation. A subsidence model for the second prototype pillar geometry at the first selected percentage area may then be run, and an evaluation made as to whether failure of the oil shale formation may occur at the selected second prototype pillar geometry and the first selected percentage area.

[0376] In one aspect, the step of mechanically characterizing geological forces acting upon the oil shale formation comprises assigning overburden and underburden forces acting upon the oil shale formation. In another aspect, the step of mechanically characterizing the oil shale formation after at least partial pyrolysis of the oil shale formation comprises assigning a post-treatment modulus of elasticity that is lower than an initial modulus of elasticity for the oil shale formation prior to pyrolysis.

[0377] In one aspect, the step of evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the first selected percentage area comprises determining whether rock in the overburden immediately above the oil shale formation goes into a state of tension. In another aspect, the step of evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the first selected percentage area comprises determining whether unacceptable displacement of rock in the overburden occurs.

[0378] It is preferred that the first selected percentage area represents no more than 50 percent of the oil shale formation within a development area. More preferably, the first selected percentage area represents no more than 25 percent of the oil shale formation, or no more than 10 percent of the oil shale formation within a development area. Preferably, the first prototype pillar geometry defines at least two separate pillars within the oil shale formation.

[0379] In some embodiments, compositions and properties of the hydrocarbon fluids produced by an *in situ* conversion process may vary depending on, for example, conditions within an organic-rich rock formation. Controlling heat and/or heating rates of a selected section in an organic-rich rock formation may increase or decrease production of selected produced fluids.

[0380] In one embodiment, operating conditions may be determined by measuring at least one property of the organic-rich rock formation. The measured properties may be input into a computer-executable program. At least one property of the produced fluids selected to be produced from the formation may also be input into the computer-executable program. The program may be operable to determine a set of operating conditions from at least the one or more measured properties. The program may also be configured to determine the set of operating conditions from at least one property of the selected produced fluids. In this manner, the determined set of operating conditions may be configured to increase production of selected produced fluids from the formation.

[0381] In accordance with one aspect of the production processes of the present inventions, a temperature distribution within the organic-rich rock formation may be computed using a numerical simulation model. The numerical simulation model may calculate a subsurface temperature distribution through interpolation of known data points and assumptions of formation conductivity. In addition, the numerical simulation model may be used to determine other properties of the formation under the assessed temperature distribution. For example, the various properties of the formation may include, but are not limited to, permeability of the formation.

[0382] The numerical simulation model may also include assessing various properties of a fluid formed within an organic-rich rock formation under the assessed temperature distribution. For example, the various properties of a formed fluid may include, but are not limited to, a cumulative volume of a fluid formed in the formation, fluid viscosity, fluid density, and a composition of the fluid formed in the formation. Such a simulation may be used to assess the performance of a commercial-scale operation or small-scale field experiment. For example, a performance of a commercial-scale development may be assessed based on, but not limited to, a total volume of product that may be produced from a research-scale operation.

[0383] Some embodiments include producing at least a portion of the hydrocarbon fluids from the organic-rich rock formation. The hydrocarbon fluids may be produced through production wells. Production wells may be cased or uncased wells and drilled and completed through methods known in the art.

[0384] The above-described processes may be of merit in connection with the recovery of hydrocarbons in the Piceance Basin of Colorado. Some have estimated that in some oil shale deposits of the Western United States, up to 1 million barrels of oil may be recoverable per surface acre. One study has estimated the oil shale resource within the nahcolite-bearing portions of the oil shale formations of the Piceance Basin to be 400 billion barrels of shale oil in place. Overall, up to 1 trillion barrels of shale oil may exist in the Piceance Basin alone.

[0385] Certain features of the present invention are described in terms of a set of numerical upper limits and a set of numerical lower limits. It should be appreciated that ranges formed by any combination of these limits are within the scope of the invention unless otherwise indicated. Although some of the dependent claims have single dependencies in accordance with U.S. practice, each of the features in any of such dependent claims can be combined with each of the features of one or more of the other dependent claims dependent upon the same independent claim or claims.

[0386] While it will be apparent that the invention herein described is well calculated to achieve the benefits and advantages set forth above, it will be appreciated that the invention is susceptible to modification, variation and change without departing from the spirit thereof.

Claims

1. A method for developing hydrocarbons from an organic-rich rock formation located in a development area while controlling subsidence, comprising:

> heating portions of the organic-rich rock formation through non-formation oxidative heat generation, the heating pyrolyzing a portion of formation hydrocarbons located in a heated zone in the organic-rich rock formation into hydrocarbon fluids;
> preserving at least one unheated zone within the organic-rich rock formation that is not heated, thereby leaving formation hydrocarbons located in the at least one unheated zone substantially unpyrolyzed, the at least one unheated zone also being located within the development area; and
> sizing an area of the at least one unheated zone in order to substantially optimize the heated zone while controlling subsidence above the organic-rich rock formation.

2. The method of claims 1, wherein the organic-rich rock formation is an oil shale formation.

3. The method of claim 2, wherein the at least one unheated zone represents no more than 50 percent of the development area.

4. The method of claim 2, wherein substantially optimizing the heated zone comprises identifying a maximum area of heating while still controlling subsidence above the organic-rich rock formation, and then reducing the size of the heated zone by about 1 to 10 percent of the maximum area of heating.

5. The method of claim 2, further comprising:

> selecting a geometry for the at least one unheated zone within the development area, wherein the selected geometry refers to a selected size, a selected shape, or a selected location within the development area.

6. The method of claim 2, wherein the step of sizing the area of the at least one unheated zone comprises considering a geomechanical property of the organic-rich rock formation selected from Poisson ratio, the modulus of elasticity, shear modulus, Lame' constant, V_p/V_s, and combinations thereof.

7. The method of claim 3, wherein the step of sizing the area of the at least one unheated zone is performed through input into a computer model, the method further comprising:

> (a) assigning for the computer model an initial post-treatment modulus of elasticity for the heated zone, wherein the initial post-treatment modulus of elasticity is lower than a modulus of elasticity for the organic-rich rock formation in an untreated state.

8. The method of claim 7, further comprising:

> (b) assigning a first fluid pressure in the heated zone;
> (c) confirming that a subsidence failure point has not been reached at the first fluid pressure;
> (d) assigning a second lower fluid pressure in the heated zone; and
> (e) determining whether a subsidence failure point has been reached at the second lower fluid pressure.

9. The method of claim 7, wherein the initial post-treatment modulus of elasticity is at least 5 times lower than the initial post-treatment modulus of elasticity for the organic-rich rock formation in an untreated state.

10. The method of claim 8, wherein the step of confirming that a subsidence failure point has not been reached comprises confirming that a Mohr-Coulomb failure criterion does not present a likelihood of faulting within the at least one unheated zone.

11. A method for developing hydrocarbons from an organic-rich rock formation while controlling subsidence, comprising:

> (a) providing a finite element computer model of a subsurface zone within the organic-rich rock formation;
> (b) providing for the computer model a designated heated area, and an unheated area located in the subsurface zone adjacent to the designated heated area, thereby providing a selected size ratio of the unheated area to the heated area within the subsurface zone;
> (c) assigning geomechanical properties for the heated area and the unheated area;
> (d) determining whether a subsidence failure point has been reached in rock above or adjacent the heated area at a first fluid pressure within the heated area;
> (e) determining whether a subsidence failure point has been reached in rock above or adjacent the designated heated area at a second

lower fluid pressure within the designated heated area, thus simulating a reduction of fluid pressure within the subsurface zone; and
(f) heating the subsurface formation in the designated heated area, thereby pyrolyzing at least a portion of formation hydrocarbons found in the organic-rich rock formation into hydrocarbon fluids.

12. The method of claim 11, wherein the geomechanical properties comprise the Poisson ratio, the modulus of elasticity, shear modulus, Lame' constant, V_p/V_s, or combinations thereof.

13. A method for developing hydrocarbons from an oil shale formation, comprising: mechanically characterizing geological forces acting upon the oil shale formation;

mechanically characterizing the oil shale formation after at least partial pyrolysis of the oil shale formation;
selecting a first prototype pillar geometry;
selecting a dimension for the first prototype pillar geometry representing a first selected percentage area of the oil shale formation;
running a subsidence model for the first prototype pillar geometry at the first selected percentage area; and
evaluating whether failure of the oil shale formation may occur at the selected first prototype pillar geometry and the first selected percentage area.

14. The method of claim 13, wherein mechanically characterizing the oil shale formation after at least partial pyrolysis of the oil shale formation comprises assigning a post-treatment modulus of elasticity that is lower than an initial modulus of elasticity for the oil shale formation prior to pyrolysis.

15. A method for importing hydrocarbons, comprising:

locating a subsurface formation outside of the territorial boundaries of a first country, the subsurface formation containing organic-rich rock;
arranging to have hydrocarbon fluids loaded into a marine vessel, the hydrocarbon fluids having been produced as a result of non-formation oxidatively heating the subsurface formation across a development area, thereby pyrolyzing at least a portion of formation hydrocarbons in the organic rich rock into the hydrocarbon fluids, and wherein heating the subsurface formation was conducted in a deliberate manner to control subsidence by preserving at least one unheated zone within the formation that is not heated, thereby leaving formation hydrocarbons in the organic rich rock in the at least one unheated zone unpyrolyzed, with the at least one unheated zone being located within the development area; and
arranging to have the marine vessel transport the hydrocarbon fluids to a terminal within the territorial boundaries of a second country.

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EUROPEAN SEARCH REPORT

Application Number
EP 08 00 3956

DOCUMENTS CONSIDERED TO BE RELEVANT

Category	Citation of document with indication, where appropriate, of relevant passages	Relevant to claim	CLASSIFICATION OF THE APPLICATION (IPC)
A	US 4 368 921 A (HUTCHINS) 18 January 1983 (1983-01-18) * column 2, line 27 - line 33 * * column 4, line 7 - line 55 * * column 5, line 35 - line 51 * -----	1-15	INV. E21B43/243
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			TECHNICAL FIELDS SEARCHED (IPC)
			E21B

The present search report has been drawn up for all claims

Place of search	Date of completion of the search	Examiner
The Hague	6 March 2009	Rampelmann, Klaus

CATEGORY OF CITED DOCUMENTS

X : particularly relevant if taken alone
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For more details about this annex : see Official Journal of the European Patent Office, No. 12/82

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