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(71) Applicant(s)
ExxonMobil Upstream Research Company

(72) Inventor(s)
Barnum, Robert; Kaminsky, Robert D.; Higdon, Thomas H.

(74) Agent / Attorney
**Watermark Patent and Trade Marks Attorneys, Level 2 302 Burwood Road,
HAWTHORN, VIC, 3122**

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(71) Applicant (for all designated States except US):
EXXONMOBIL UPSTREAM RESEARCH COMPANY [US/US]; CORP-URC-SW-359, P.O. Box 2189, Houston, TX 77252-2189 (US).

(72) Inventors; and

(75) Inventors/Applicants (for US only): **BARNUM, Robert** [US/US]; 29726 Misty Crossing Lane, Spring, TX 77379

(US). **KAMINSKY, Robert, D.** [US/US]; 3749 Wakeforest Street, Houston, TX 77098 (US). **HIGDON, Thomas, H.** [US/US]; 5419 Broad Oaks Park, Houston, TX 77056 (US).

(74) Agents: **McARTHUR, Douglas W.** et al.; Exxonmobil Upstream Research Company, CORP-URC-SW-359, P.O. Box 2189, Houston, TX 77252-2189 (US).

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(54) Title: TEMPORARY FIELD STORAGE OF GAS TO OPTIMIZE FIELD DEVELOPMENT

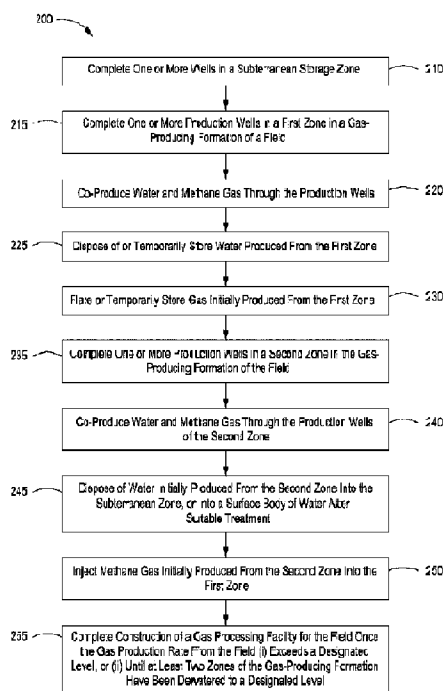


FIG. 2A

(57) Abstract: Methods for managing the production of fluids from a low-permeability subsurface formation in a field may include producing fluids from a coalbed formation. The method involves producing formation fluids from a first zone in the subsurface formation for a period of time so as to at least partially dewater the first zone. The formation fluids are separated into a liquid stream that primarily comprises water, and a gas stream that primarily comprises methane gas. The water is sent for disposal, such as into a subsurface formation, while the gas is temporarily stored or flared. A gas processing facility is constructed for the field. Construction of the gas processing facility is spread out or delayed until the field is ready to produce enough gas to allow the gas processing facility to operate at a substantially greater capacity than would be provided at the beginning of field development.



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TEMPORARY FIELD STORAGE OF GAS TO OPTIMIZE FIELD DEVELOPMENT

BACKGROUND

5 **Cross-Reference to Related Application**

[0001] The present application claims priority to and the benefit of U.S. Provisional Patent Application Serial Number 61/299,692, which was filed on 29 January 2010, which was entitled, "Temporary Field Storage of Gas to Optimize Field Development," and which is incorporated herein by reference in its entirety for all purposes.

10 **Field**

[0002] The present invention pertains to the field of recovery of hydrocarbon gas from a coal-bearing formation or gas reservoir. More specifically, the present invention relates to the economically efficient development of a field having coalbed methane.

Discussion of Technology

15 [0003] Coal-bearing formations naturally produce methane gas. Historically, the presence of methane was considered a safety issue for mining operations. A coal mine would need to be at least partially degassed before mining operations could commence. This typically involved drilling a well into the coal-bearing formation, and then venting the produced gas into the atmosphere.

20 [0004] Recently, oil and gas companies have increased the drilling of gas wells into coal formations for the purpose of capturing methane gas in commercially viable quantities. The gas is then processed and sold. Recovery of such methane, referred to as coalbed methane, has now become a significant source of natural gas for the natural gas production industry. According to some estimates, coalbed methane (CBM) now accounts for about 10% of
25 natural gas production in the United States. Significant CBM production occurs domestically in Wyoming, Colorado, Alabama, New Mexico, and other states.

[0005] Coal beds can be attractive targets for gas development because of their ability to retain large amounts of gas. While coal beds are typically considered low-permeability formations, a coal seam is nevertheless able to store, in some cases, multiple times more gas
30 (at standard conditions) than an equivalent volume of rock. This is because the methane compounds are able to adsorb onto the coal.

[0006] Many coal seams also contain water within the coal-bearing formation. In order to unlock the gas from the coal, the producer or field operator will typically "dewater" the

formation. This involves drilling a plurality of water production wells. Production of water will cause pressure in the coal-bearing formation to reduce and allow gas to desorb.

[0007] **Figure 1** presents a Cartesian coordinate graph **100** plotting fluid volume versus time. The graph **100** demonstrates phases **110**, **120**, **130** of field development for a coalbed methane field. Phase **110** is a dewatering stage; Phase **120** is a stable gas production stage; and Phase **130** is a decline stage.

[0008] The graph **100** also demonstrates production decline curves **140**, **150**. Decline curve **140** represents the production of water in units of volume over time. Decline curve **150** represents the production of methane, also in units of volume over time.

[0009] It can be seen from **Figure 1** that during the dewatering stage (Phase **110**), the coal-bearing formation produces relatively high volumes of water. However, as seen in decline curve **140**, the water production rate falls off rapidly as the formation is dewatered. At the same time, as seen in decline curve **150**, production of methane rapidly increases.

[0010] During the stable production stage (Phase **120**), the coal-bearing formation produces increasingly smaller volumes of water. Decline curve **140** shows that the water production rate continues to drop off as the formation is dewatered. At the same time, as seen in decline curve **150**, production of methane stabilizes.

[0011] Finally, during the decline stage (Phase **130**), the coal-bearing formation produces only relatively small volumes of water, which in some cases may be almost none. As seen in decline curve **140**, the water production rate trails off somewhat asymptotically. At the same time, as seen in decline curve **150**, production of methane also slowly decreases.

[0012] The graph **100** of **Figure 1** represents a fairly typically decline curve for a coalbed methane field. Many CBM zones require dewatering of the coal prior to exhibiting substantial gas production. This is discussed more fully in V.A. Kuuskraa and C.F. Brandenburg, "Coalbed Methane Sparks a New Energy Industry", Oil and Gas Journal, 87(41), 49-56 (1989); L. Bassett, Guidelines to Successful Dewatering of CBM Wells, SPE Paper No. 104,290, Society of Petroleum Engineers Eastern Regional Meeting, Canton, Ohio (October 11-13, 2006); J.P. Seidle, A Numerical Study of Coalbed Dewatering, SPE Paper No. 24,358, Society of Petroleum Engineers Rocky Mountain Regional Meeting, Casper, Wyoming (May 18-21, 1992).

[0013] Many coalbed formations have significant amounts of mobile water within natural fracture networks. Such networks are sometimes referred to as "cleats." Removing water from the cleats can take several months or even several years. Thus, Phase **110** shown in **Figure 1** may represent a period of time that is, for example, three to 36 months.

[0014] During the dewatering process of Phase 110, a low, but not insignificant, amount of natural gas may be produced. This gas needs to be dealt with. In some cases, flaring may be an option for dealing with this early gas. However, flaring is becoming less environmentally acceptable and, hence, alternatives are desirable.

5 [0015] In addition, when coalbed methane is produced, it may contain non-negligible amounts of acid gases, such as carbon dioxide or hydrogen sulfide, and/or other noncombustible or poisonous gases. Such other gases may include, for example, nitrogen or mercaptans. Undesirable gas components need to be separated from the methane gas in order to meet pipeline specifications. For example, some pipeline specifications may require that
10 methane gas contain less than 2 mol. percent of CO₂, and less than 4 ppm H₂S and mercaptans.

[0016] In order to remove acid gases from a methane gas stream, a gas processing plant must be constructed at the surface. Various processes have been devised to remove contaminants from a hydrocarbon gas stream. One commonly-used approach for treating raw
15 natural gas involves the use of physical solvents. An example of a physical solvent is Selexol[®].

[0017] Another approach for treating raw natural gas involves the use of chemical solvents. Examples of chemical solvents include methyl diethanol amine (MDEA), and the Flexsorb[®] family of amines. Amine-based solvents rely on a chemical reaction with acid gas
20 components in the hydrocarbon gas stream. Such chemical reactions are generally more effective than physical-based solvents, particularly at feed gas pressures below about 300 psia (2.07 MPa).

[0018] Hybrid solvents have also been used for the removal of acidic components. Hybrid solvents employ a mixture of physical and chemical solvents. An example of a
25 hybrid solvent is Sulfinol[®].

[0019] Cryogenic gas processing techniques are also known. Cryogenic gas processing is a distillation process that generates a cooled overhead gas stream at moderate pressures (e.g., 350-550 pounds per square inch gauge (psig)). In addition, liquefied acid gas is generated as a "bottoms" product.

30 [0020] In any of these processing techniques, the removal of acid gases creates a "sweetened" hydrocarbon gas stream. The sweetened stream may be used as an environmentally-acceptable fuel or as feedstock to a chemicals or gas-to-liquids facility. The sweetened gas stream may be chilled to form liquefied natural gas, or LNG.

[0021] The construction of a gas processing facility represents a significant capital outlay before the development of a field. Managing the expenditure of capital before and during the early development of a gas field can be critical to obtaining favorable economics. A key aspect of optimizing capital outlay is to minimize excess capacity in processing and export facilities. However, coalbed methane and other gas fields, such as shale gas fields and tight gas fields, can have long ramp-up times prior to reaching a high, relatively constant production rate.

[0022] One way to match facility size to production rate is to use modular facilities. However, this may not be an efficient approach since economies-of-scale may be lost. Leveraging economies-of-scale is often particularly critical if the gas is to be converted to liquefied natural gas and exported by ship or if the gas is to be transported by a long distance pipeline.

[0023] In addition to processing facilities, transport and export facilities may also be constructed to deal with gas produced during the dewatering stage of Phase 110. However, economic considerations typically favor exploiting economies of scale and constructing facilities suitable for the gas output rate expected when a field is fully operational and dewatering has been completed for many wells. Thus, facilities suitable for such gas rates will be significantly oversized during the initial dewatering stage of Phase 110. This mismatch between facility size and immediate needs represents inefficient use of capital.

[0024] In addition, certain facilities have minimal ability to adjust their throughput rates while retaining desirable efficiencies. This may be particularly true of liquefied natural gas (LNG) facilities and of gas processing for large export pipelines systems. Gas processing may include dehydration, heavier hydrocarbon removal, and CO₂ and H₂S removal.

[0025] Therefore, a method is needed for developing a gas field wherein the construction of gas processing facilities and/or export facilities is delayed until gas production rates have increased. Further, a need exists for a method for handling early gas production from a coalbed methane formation before or while substantially full-capacity facilities are being constructed.

SUMMARY

[0026] Methods for managing the production of fluids from a low-permeability subsurface formation are provided herein. The subsurface formation may be a coalbed zone, a shale gas zone, or a tight gas zone. The subsurface formation is in a field, such as a coalbed methane field or other field wherein natural gas is to be produced.

[0027] In one aspect, the method includes completing one or more wells in a first zone within the subsurface formation, and then producing formation fluids from the first zone so as to at least partially dewater the first zone. The method also includes completing one or more wells in a second zone within the subsurface formation, and then producing formation fluids
5 from the second zone so as to at least partially dewater the second zone.

[0028] The method further includes injecting gas from the formation fluids from the second zone into the first zone. The purpose is to temporarily store the gas for later production. The method also includes completing one or more wells in one or more subsequent zones within the subsurface formation.

10 [0029] A gas processing facility is required for the field. Accordingly, the method also includes substantially completing a gas processing facility. The gas processing facility is not substantially completed until (i) the gas production rate from the field is able to exceed a designated level, or (ii) at least the first and second zones of the subsurface formation have been dewatered to a designated level. After substantially completing the gas processing
15 facility, the method includes co-producing formation fluids from the first zone, the second zone, and the one or more subsequent zones.

[0030] It is desirable to separate the produced formation fluids into liquid and gas components. The liquid primarily comprises water, while the gas comprises at least 50 percent methane. Accordingly, the method also includes substantially separating water in the
20 co-produced formation fluids from the gas in a separator. The gas is delivered to the gas processing facility for processing.

[0031] In one aspect, the method also includes completing one or more water injection wells in a subterranean storage zone. The subterranean zone may be an aquifer, a salt cavern, a depleted hydrocarbon reservoir zone, or a coalbed zone that has been previously
25 substantially dewatered. The method then includes separating water from the gas in the formation fluids from the first zone during dewatering, and injecting water from the formation fluids from the first zone into the subterranean storage zone. The method may also include flaring a majority of the gas from the formation fluids from the first zone during dewatering of the first zone. As an alternative to flaring, the gas may be injected into a
30 subsurface permeable zone for essentially permanent disposal.

[0032] In another aspect, the method further comprises completing one or more wells in a third zone within the subsurface formation, and producing formation fluids from the third zone so as to at least partially dewater the third zone. The method also includes shutting in the one or more wells completed in the second zone, and injecting gas from the formation

fluids from the third zone into the first zone for temporary storage. This injecting step is done before the gas processing facility is substantially completed. The method may then also include separating water from gas in the formation fluids from the second zone during dewatering of the second zone, injecting water from the formation fluids from the second zone into the subterranean storage zone, and also injecting water from the formation fluids from the third zone into the subterranean storage zone.

[0033] Another method for managing the production of fluids from a low-permeability subsurface formation is provided herein. The subsurface formation may be a coalbed zone, a shale gas zone, or a tight gas zone. The subsurface formation is in a field, such as a coalbed methane field or other field wherein natural gas is to be produced.

[0034] In one aspect, the method includes completing one or more wells in a first zone within the subsurface formation, and producing formation fluids from the first zone so as to at least partially dewater the first zone. The method also includes completing one or more injection wells in a zone in a second subsurface formation with higher permeability than the first zone. The zone in the second subsurface formation may be an aquifer, a salt cavern, or a depleted hydrocarbon reservoir zone. Preferably, the zone in the second subsurface formation is located in subsurface strata that is deeper than the subsurface formation that is undergoing dewatering.

[0035] The method further includes injecting gas produced from the first zone into the second subsurface formation. The gas from the first zone is held in the second subsurface formation for temporary storage.

[0036] The method also includes completing one or more wells in a second zone within the subsurface formation, and producing formation fluids from the second zone.

[0037] The method may also include substantially completing a gas processing facility. The gas processing facility is not substantially completed until (i) the gas production rate from the field is able to exceed a designated level, or (ii) at least two zones of the subsurface formation have been dewatered to a designated level. After substantially completing the gas processing facility, the method includes co-producing formation fluids from the first zone and the second zone.

[0038] It is desirable to separate the produced formation fluids into liquid and gas components. The liquid primarily comprises water, while the gas comprises at least 50 mole percent methane. Accordingly, the method also includes substantially separating water in the co-produced formation fluids from the gas in a separator. The gas is delivered to the gas processing facility for processing.

[0039] In one aspect, the method also includes completing one or more wells in one or more subsequent zones within the subsurface formation, producing formation fluids from the one or more subsequent zones so as to at least partially dewater the one or more subsequent zones, and injecting gas from the formation fluids from the one or more subsequent zones
5 into the zone in the second subsurface formation for temporary storage before substantially completing the gas processing facility.

[0040] In another aspect, the method may include separating water from gas in the formation fluids from the first zone during dewatering, and delivering water from the formation fluids from the first zone to a water disposal location. After the gas processing
10 facility is completed, gas is produced from the zone in the second subsurface formation, and delivered to the separator along with the co-produced formation fluids from the first zone and the second zone.

[0041] In yet another aspect, the method further includes: producing formation fluids from the second zone so as to at least partially dewater the second zone; separating water
15 from gas in the formation fluids from the second zone during dewatering of the second zone; injecting gas from the formation fluids from the second zone into a zone in a second subsurface formation with higher permeability than the first zone for temporary storage; delivering separated water from the formation fluids to the water disposal location; and after the gas processing facility is completed, producing gas from the zone in the second
20 subsurface formation and delivering the gas to the separator along with the co-produced formation fluids from the first zone and the second zone.

[0042] Yet another method for managing the production of fluids is provided herein. The method is for managing the production of fluids from a coalbed formation in a field. The fluids comprise water and gas. In one aspect, the method includes: completing one or more
25 wells in a first production section within the coalbed formation; producing formation fluids from the first production section so as to at least partially dewater the first section; completing one or more injection wells in a first subterranean storage zone; completing one or more injection wells in a second subterranean storage zone; separating the formation fluids into a liquid stream comprised substantially of water, and a gas stream comprising at least 50
30 mole percent methane gas; injecting the gas from the gas stream into a first subsurface formation for temporary storage; injecting water from the liquid stream into the second subterranean storage zone; completing one or more wells in a subsequent production section within the coalbed formation; substantially completing a gas processing facility for the field; after the first section has been at least partially dewatered and after the gas processing facility

is substantially completed, co-producing formation fluids from the first production section, the subsequent production section, and the first subterranean storage zone; substantially separating water in the co-produced formation fluids from the gas in a separator; and delivering the gas to the substantially completed gas processing facility for processing.

- 5 [0043] The first subterranean storage zone may be a zone in the coalbed formation. Alternatively, the first subterranean storage zone may be an aquifer that is deeper than the coalbed formation.

BRIEF DESCRIPTION OF THE DRAWINGS

- 10 [0044] So that the present inventions can be better understood, certain illustrations 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.

[0045] Figure 1 is graph showing various phases of development for a coalbed methane field. Production rates for water and methane gas are shown on separate decline curves.

- 15 [0046] Figures 2A and 2B present a single flowchart showing steps for managing the production of fluids from a low-permeability formation, in one embodiment.

[0047] Figures 3A through 3D provide illustrative cross-sectional views of a field under hydrocarbon gas development in accordance with the methods herein, in one embodiment.

- 20 [0048] In Figure 3A, formation fluids are being produced from a first zone in a gas-producing formation. Produced water is sent for disposal, while the gas is flared.

[0049] In Figure 3B, formation fluids are being produced from a second zone in the gas-producing formation. Produced water is sent for disposal, while methane gas is injected into the first zone.

- 25 [0050] In Figure 3C, formation fluids are being produced from a third zone in the gas-producing formation. Produced water is sent for disposal, while methane gas is injected into the first zone. Production wells from the second zone are shut in.

[0051] In Figure 3D, formation fluids are being produced from a fourth zone in the gas-producing formation, and all previous zones. Produced water is sent for disposal, while methane gas is processed in a gas processing facility and exported.

- 30 [0052] Figures 4A and 4B present a single flowchart showing steps for managing the production of fluids from a low-permeability formation, in an alternate embodiment.

[0053] Figures 5A through 5C provide illustrative cross-sectional views of a field under hydrocarbon gas development in accordance with the methods herein, in an alternate embodiment.

[0054] In Figure 5A, formation fluids are being produced from first and second zones of a gas-producing formation. Produced water is sent for disposal, while methane gas is injected into a zone in a second subsurface formation for temporary storage.

5 [0055] In Figure 5B, formation fluids are being produced from a plurality of zones in a gas-producing formation. Produced water is sent for disposal, while methane gas is processed in a gas processing facility and exported.

[0056] In Figure 5C, formation fluids are being produced from a plurality of zones in a gas-producing formation, along with water and previously-injected methane gas from the zone in the second subsurface formation. Produced water is sent for disposal, while methane
10 gas is processed in a gas processing facility and exported.

DETAILED DESCRIPTION OF CERTAIN EMBODIMENTS

Definitions

[0057] As used herein, the term “coal” refers to any combustible rock containing more than about 50% by weight carbonaceous material, and formed by compaction and induration
15 of plant matter.

[0058] As used herein, the terms “coal bed” or “coal seam” refer to any stratum or bed of coal. The terms may be used interchangeably herein.

[0059] As used herein, the term “coal bed formation” refers to a body of strata containing at least one coal bed, and typically one or more other strata including, without limitation,
20 clay, shale, carbonaceous shale, sandstone and other inorganic rock types. While a coal bed formation generally contains organic matter, at any one location the content of organic matter present can vary from almost none to nearly 100% of the total matter present.

[0060] As used herein, the term “coalbed methane” (CBM), refers to a natural gas consisting of primarily of methane, and also one or more acid gases such as carbon dioxide,
25 nitrogen, or hydrogen sulfide. Coalbed methane may also include lesser amounts of ethane, propane and other heavy hydrocarbons. Coalbed methane may be referred to by some as “coal gas.” CBM may be present in a free state, in an adsorbed state, and/or in solution with water or liquid hydrocarbons.

[0061] As used herein, the term “injectivity” means an indicator of the relative ease with
30 which a fluid is injected into a rock formation. Factors affecting injectivity into a coal bed formation include permeability, fracture conductivity, and secondary porosity. Injectivity may be measured in $\text{m}^3/\text{day}\cdot\text{kPa}$ or $\text{Mscf}/\text{day}\cdot\text{psi}$.

[0062] As used herein, the term “gas” refers to a fluid that is substantially in its vapor phase at ambient conditions (1 atm and 15° C).

[0063] As used herein, the term “fluid” refers to gases, liquids, and combinations of gases and liquids, as well as to combinations of gases and solids, and combinations of liquids and solids.

5 [0064] As used herein, the term “condensable hydrocarbons” means those hydrocarbons that condense at about 15° C and one atmosphere absolute pressure. Condensable hydrocarbons may include, for example, a mixture of hydrocarbons having carbon numbers greater than 4.

10 [0065] As used herein, the term “hydrocarbon” refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Hydrocarbons generally fall into two classes: aliphatic, or straight chain hydrocarbons, and cyclic, or closed ring hydrocarbons, including cyclic terpenes. Examples of hydrocarbon-containing materials include any form of natural gas, oil, coal, and bitumen that can be used as a fuel or upgraded into a fuel.

15 [0066] 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 15° C and 1 atm pressure. Hydrocarbon fluids may include, for example, oil, natural gas, coal bed methane, shale oil, pyrolysis oil, pyrolysis gas, a pyrolysis product of coal, and other hydrocarbons that are in a gaseous or liquid state.

20 [0067] As used herein, the term “natural gas” refers to a multi-component gas obtained from a crude oil well (associated gas) or from a subterranean gas-bearing formation (non-associated gas). The composition and pressure of natural gas can vary significantly. A typical natural gas stream contains methane (C₁) as a significant component. The natural gas stream may also contain ethane (C₂), higher molecular weight hydrocarbons, and one or more acid gases.

[0068] As used herein, an “acid gas” means any gas that dissolves in water producing an acidic solution. Non-limiting examples of acid gases include hydrogen sulfide (H₂S), carbon dioxide (CO₂), carbon disulfide (CS₂), carbonyl sulfide (COS), mercaptans, or mixtures thereof.

30 [0069] As used herein, the term “tight gas zone” refers to subsurface strata wherein gas is held within rock having very low permeability, such as less than about 0.1 md. Such a formation is may be highly compacted and may have undergone cementation and recrystallization. Such strata may be, for example, a sandstone, in which case the formation may be referred to as a “tight sand.” In a tight gas formation, it is important to expose as

much of the reservoir as possible, making horizontal and directional drilling desirable. This enables the wellbore to run along the formation, opening up more opportunities for the natural gas to enter the wellbore.

[0070] As used herein, the term “subsurface” refers to geologic strata occurring below the earth's surface.

Description of Selected Specific Embodiments

[0071] Methods for managing the production of fluids from a low-permeability subsurface formation are provided herein. The subsurface formation is in a field, such as a coalbed methane field or other field wherein natural gas is to be produced. The methods have utility during initial field development. More specifically, the methods may be used during an initial production phase when dewatering of the subsurface formation takes place.

[0072] **Figures 2A and 2B** present a unified flowchart showing steps for a method **200** of managing the production of fluids from a low-permeability subsurface formation, in one embodiment. As seen in **Figure 2A**, the method **200** first comprises completing one or more water production wells in a subterranean storage zone. This is shown at **Box 210**. The “completing” step may be performed by drilling one or more wellbores into the subterranean zone, and then completing the wellbores as water injection wells. Alternatively, the “completing” step may mean re-connecting previously-plugged wells with the subterranean storage zone.

[0073] The subterranean storage zone may be an existing aquifer. Alternatively, the subterranean zone may be a salt cavern or a substantially depleted hydrocarbon reservoir that is available to the operator of the field. Alternatively still, the subterranean storage zone may be a coalbed zone which has been previously dewatered. Alternatively still, the subterranean storage zone may be a section of a coalbed methane field or other field wherein natural gas is to be produced. These are all merely examples, as other available reservoirs may be utilized.

[0074] The method **200** also includes completing one or more production wells in a first zone. This is provided at **Box 215**. The first zone is in a gas-producing formation in the field. The gas-producing formation may be a shale gas formation. Alternatively, the gas-producing formation may be a so-called tight gas formation. Preferably, however, the formation is a coal-bearing formation. In this instance, the gas produced from the formation is coal bed methane.

[0075] The subterranean storage zone may be a lateral extension of the first zone which has been previously dewatered.

[0076] The method **200** also includes the step of co-producing water and methane gas through the production wells. This is shown at Box **220**. Production takes place from the first zone. During the initial stage of production, production fluids will predominantly include water. As production from the first zone continues, the water content of the produced fluids will decline, and the gas content will increase. The gas itself will comprise at least 50 mole percent methane.

[0077] The water produced from the production wells will need to be managed. Accordingly, the method **200** next includes disposing of the water produced from the production wells. This is provided at Box **225**. Disposal may mean injecting the water into the subterranean storage zone or releasing the water, preferably after treating, into a surface body of water, such as a river, lake, or ocean.

[0078] The gas produced from the production wells will also need to be managed. Accordingly, the method **200** further includes the step of flaring the gas initially produced from the first zone. This is seen at Box **230**. Flaring may be utilized during the initial development of the field as the gas volumes are very low. As an alternative, however, the gas may be stored or essentially permanently disposed. Storage or disposal may be, for example, in a separate permeable formation within the subsurface. Storage may alternatively be in a depleted hydrocarbon reservoir. Storage may be desirable as the gas content of the formation fluids becomes higher.

[0079] The method also includes completing one or more wells in a second zone. This is shown at Box **235** of **Figure 2A**. The second zone is a second zone in the gas-producing formation of the field. The wells include production wells for producing formation fluids, that is, water and gaseous hydrocarbons. The method **200** then further includes co-producing water and methane gas from the second zone. This is seen at Box **240**.

[0080] The water produced from the production wells completed in the second zone will need to be managed. Accordingly, the method **200** next includes disposing of the produced water, such as by injecting the water produced from the production wells of the second zone into a subterranean zone or by releasing it to a surface body of water, such as a river, lake or ocean. This is provided at Box **245**. It is understood that some environmental treatment or purification of the water may be required before injection or other disposal. If the water can be treated to sufficient quality, in certain embodiments the produced water may be used for irrigation or drinking.

[0081] The gas produced from the production wells completed in the second zone will also need to be managed. In accordance with the present method **200**, the gas produced from

the second zone will be temporarily stored in the first zone. This is shown at Box **250**. Injecting produced gas into the first zone has the benefit of causing the first zone to have an increased gas content. Where the gas-bearing formation is a coal bed, the coal will adsorb much of the gas.

- 5 **[0082]** In order to inject produced gas into the first zone, gas injection wells will need to be provided. Preferably, production wells for the first zone are converted into gas injection wells. Because the gas is temporarily stored, it is not immediately processed through a gas processing facility. However, the method **200** may include constructing a gas processing facility. This is shown at Box **255**.
- 10 **[0083]** To enhance the economics of the field, and in accordance with certain aspects of the present inventions, the gas processing facility is not completed before the export of methane gas commences; instead, completion of the gas processing facility is delayed. In one embodiment, substantially final construction of the gas processing facility does not take place until the gas production rate from the field is able to exceed a designated level. For example,
- 15 the designated level might be 25 percent or, more preferably, 50 percent, or even 75 percent of the anticipated maximum weekly production rate from the field.

- [0084]** In another embodiment, construction of the gas processing facility may not be finalized until at least two zones of the gas-producing formation have been dewatered to a designated level. The designated level may be, for example, a reduction in average weekly
- 20 water production rate of 25 percent, or 50 percent, or even 75 percent, from the initial water production rate from the second zone.

- [0085]** The above approaches involve calculating production rate averages. Average production rates, such as daily, weekly, or monthly averages may be used. In making such calculations, shut-in times for field or facility maintenance or upsets may be excluded from
- 25 the averages. In addition, for purposes of the construction step of Box **255**, the gas processing facility may include an export facility.

- [0086]** The method **200** also includes completing one or more production wells in a third zone within the gas-producing formation of the field, which is representative of one or more subsequent zones. This is shown in Box **260** of **Figure 2B**. At the same time, the one or
- 30 more production wells completed in the second zone may be temporarily shut in. This step is seen at Box **265**. The shutting-in step is optional as the operator may choose to at least partially overlap production from the second zone and the third zone.

[0087] It is noted that the operator could shut in the first zone and commence injecting gas from the third zone into the second zone. This is not preferred as (a) the formation in the

first zone is most likely capable of receiving significant quantities of gas without exceeding formation fracture pressures, and (b) such would require the duplicative expense of converting the production wells in the second zone into injection wells. However, this is a matter of designer's choice.

- 5 [0088] In any instance, the method 200 next includes completing one or more production wells in a subsequent zone. This is provided at Box 270. The subsequent zone may be a fourth zone, a fifth zone, or more. Thereafter, the operator produces formation fluids from the subsequent zone and all previous zones. This means that water and hydrocarbon gas is produced from through the production wells of the first, second, third, and subsequent zones.
- 10 This is seen at Box 275. In the case of at least the first and second zones, the zones will contain primarily *in situ* gas.

- [0089] Once the gas processing facility is completed, gas processing may begin. Therefore, the method 200 also includes processing gas produced from the subsequent zone(s) and all previous zones in the gas processing facility. This is shown at Box 280. It is
- 15 noted here that the gas produced with the formation fluids may contain not only methane, but also ethane or heavier hydrocarbons. Further, it is possible that the gas will contain at least some percentage of acid gases such as carbon dioxide or hydrogen sulfide. Thus, in order to bring the hydrocarbon gas into a pipeline specification, the gas processing facility may need to remove at least a portion of acid gas components, remove heavy hydrocarbon components,
- 20 remove inert components, and/or remove water through dehydration.

- [0090] It may be that the gas processing facility is completed while gas is being produced in the third zone. Therefore, Box 255 may optionally include processing gas produced from the third zone before production occurs in the subsequent zone. However, it is preferred that a significant volume of produced gas be available from previous zones before gas processing
- 25 commences. Therefore, the operator may produce formation fluids from a fourth, fifth, or even sixth zone before processing begins in the gas processing facility. Construction of the gas processing facility is in all embodiments delayed in accordance with Box 255.

- [0091] The water produced from the production wells related to the third and subsequent zones will also need to be managed. Accordingly, the method 200 further includes disposing
- 30 of the water produced from the production wells of the third and subsequent zones. This is seen at Box 285. Disposal may comprise injecting the water into the subterranean storage zone through the connected wells of Box 210. The subterranean zone is a separate, preferably deeper, zone from the production zones. Alternatively, disposal may involve

releasing the produced water into a surface body of water, such as a river, a lake, or an ocean. This may be after suitable treatment.

[0092] It is noted here that the steps presented in Boxes 210 through 280 may be completed in an order different from the order shown in Figure 2. Further, some steps may be completed simultaneously or in an overlapping manner. Certain aspects of the steps in Figures 2A and 2B are demonstrated in Figures 3A through 3D.

[0093] Figures 3A through 3D provide illustrative cross-sectional views of a field 300 undergoing hydrocarbon gas development, in one embodiment. In each view, the field 300 contains a surface 302, and a subsurface 304. Further, the field 300 contains a gas-producing formation 350.

[0094] The gas-producing formation 350 may be a shale gas formation. Alternatively, the gas-producing formation may be a so-called tight gas formation. Preferably, however, the formation 350 is a coal-bearing formation. In this instance, the gas produced from the formation 350 is coal bed methane.

[0095] In Figure 3A, the gas-producing formation 350 has been sectioned to provide a first zone 310. A section may reflect a pattern such as a 5-spot pattern, or several adjacent patterns of wells. Production wells 312 have been completed in the gas-producing formation 350. Formation fluids are being produced from the first zone 310 of the gas-producing formation 350.

[0096] In each of Figures 3A through 3D, the field 300 also contains a water storage reservoir 360. The water storage reservoir 360 may be an existing aquifer. Alternatively, the water storage reservoir 360 may be a salt cavern or a substantially depleted hydrocarbon reservoir that is available to the operator of the field 300. Alternatively still, the water storage reservoir 360 may be a coalbed zone which has been previously dewatered. For example, the water storage reservoir 360 may be an extension of the gas-producing formation 350. In each of these instances, the water storage reservoir 360 serves as a subterranean storage zone. Although the water storage reservoir 360 is shown as being shallower than the gas-producing formation 350, it may be deeper.

[0097] Injection wells 362 are completed in the water storage reservoir 360. The injection wells 362 may have been drilled into the water storage reservoir 360 especially for injection of water. Alternatively, the injection wells 362 may be converted production wells, such as dewatering or gas production wells that had been previously-plugged. In either instance, one or more stages of fluid pumping may be utilized to obtain injection pressures resulting in sufficient and desired injection rates.

[0098] In **Figure 3A**, the formation fluids are being transported by the production wells **312** through the subsurface **304** and to the surface **302**. At the surface **302**, the formation fluids are transported through production lines **314** to a separator **305**. The separator **305** separates the formation fluids into liquids and gases. The separator **305** may be a gravity separator, a centrifugal separator, a flash vessel, or other separation unit for separating liquids from gases.

[0099] The liquids comprise primarily water, while the gases comprise primarily methane. Because methane boils at such a low temperature, it is preferred that the separator **305** be a low-temperature flash vessel to minimize water vapor. The formation fluids may be taken through a cooling unit (not shown) before entry into the separator **305**. The separator **305** may operate, for example, near ambient temperature and 50 psig.

[0100] After separation, the produced water exits the separator **305** and is transported for disposal. A water transport line **365** is provided in the field **300**. The water transport line **365** transports water from the separator **305** to the injection wells **362**. From there, water is injected through the injection wells **362** and into the water storage reservoir **360**.

[0101] A gas transport line **315** is also provided. The gas transport line **315** transports methane and other gases from the separator **305** to a flare **312**. From there, the gases are combusted and vented to the atmosphere. However, the operator may choose to temporarily or permanently store the gases in a separate underground reservoir. Alternatively, an above-ground storage tank or even a transport truck may be used for temporary storage. It is noted here that at the beginning of production from the first zone **310**, the produced fluids comprise predominantly water. Therefore, relatively little gas is flared or is otherwise captured.

[0102] **Figure 3B** presents a second view of the field **300**. This represents a next stage in development of the field **300**. In **Figure 3B**, the gas-producing formation **350** has been sectioned into a second zone **320**. Production wells **322** have been completed in the second zone **320**. Formation fluids are now being produced from the second zone **320** and to the surface **302**.

[0103] The formation fluids are transported through production lines **324** at the surface **302**. From there, the production fluids from the second zone **320** are taken to the separator **305**. The production fluids from the second zone **320** are then separated into water and gas. The water exits the separator **305**, and is transported through the water transport line **365** to the injection wells **362**. The water from the second zone **320** is then injected into the water storage reservoir **360**.

[0104] Concerning formation fluids in the gas phase, the gases produced from the second zone 320 are not flared or disposed; instead, the gas is transported through the gas transport line 315, and then diverted back through production lines 314 and into the production wells 312. The wells 312 have been temporarily converted to injection wells to facilitate the injection of gases from the second zone 320 of the gas-producing formation 350 into the first zone 310. In some embodiments, dedicated injector wells into the first zone 310 may be used alternatively or in addition to the wells 312.

[0105] Injection of gas from the second zone 320 of the gas-producing formation 350 into the first zone 310 provides temporary storage. The gas will be re-produced to the surface 302 in a later stage of field development. However, temporary storage in the first zone 310 allows the developer of the field 300 to delay the construction of an expensive, full-capacity gas processing facility.

[0106] It is also noted that the injection of gases from the second zone 320 of the gas-producing formation 350 into the first zone 310 need not wait until the first zone 310 has been fully dewatered. In one aspect, the operator may convert the production wells 312 into injection wells when water production from the first zone 310 has dropped from, for example, an initial production rate to a lower designated water production rate. For example, the designated reduction might be a decrease in average weekly production rate of about 50 percent, or 80 percent, or 90 percent.

[0107] Figure 3C presents a third view of the field 300. This represents yet a next stage in the development of the field 300. In Figure 3C, the gas-producing formation 350 has been sectioned into a third zone 330. Production wells 332 have been completed in the third zone 330. Formation fluids are now being produced from the third zone 330 and to the surface 302.

[0108] The formation fluids are directed into production lines 334. The formation fluids are delivered through the production lines 334 to the separator 305. There, the formation fluids from the third zone 330 are separated into water and gases. The water from the third zone 330 exits the separator 305 and is transported through the water transport line 365 to the injection wells 362. The water is then injected into the water storage reservoir 360.

[0109] Concerning formation fluids in the gas phase, the gases produced from the third zone 330 are not flared or disposed. Instead, the gas is released from the separator 305 through the gas transport line 315, directed into one or more of the production lines 314, and injected into the now-injection wells 312. The wells 312, again, have been temporarily converted to injection wells to facilitate the injection of gases from the third zone 330 of the

gas-producing formation **350** into the first zone **310**. At the same time, the production wells **322** from the second zone **320** may have been temporarily shut-in, or may continue to produce.

[0110] Injection of gas from the third zone **330** of the gas-producing formation **350** provides temporary storage. The gas from the third zone **330** will later be re-produced to the surface **302** along with gas from the first **310** and second **320** zones in a later stage of field development. Temporary storage of gas in the first zone **310** again allows the developer of the field **300** to delay the construction of an expensive, full-capacity gas processing facility.

[0111] It is also noted that the injection of gas from the third zone **330** of the gas-producing formation **350** into the first zone **310** need not wait until the second zone **320** has been completely dewatered. Some overlap in production between the second zone **320** and the third zone **330** may take place. In addition, the operator may choose to inject and temporarily store the gas from the third zone **330** of the gas-producing formation **350** into the second zone **320**, or another previously dewatered zone, rather than the first zone **310**. In this instance, the production wells **312** from the first zone **310** are shut-in. These are matters of design choice.

[0112] **Figure 3D** presents a fourth view of the field **300**. This represents yet a next stage in the development of the field **300**. In **Figure 3D**, the gas-producing formation **350** has been sectioned into yet a fourth zone **340**. Production wells **342** have been completed in the fourth zone **340**. Formation fluids are now being produced from the fourth zone **340** and to the surface **302**.

[0113] The formation fluids enter production lines **344** at the surface **302**. The formation fluids are transported to the separator **305** for fluid separation. The separator **305** again separates production fluids from the fourth zone **340** into water and gas. Water from the fourth zone **340** is transported through the water transport line **365** and to the injection wells **362**. The water is then injected into the water storage reservoir **360**. At the same time, gas is released from the separator **305** into gas transport line **315**. Gas transport line **315** is preferably an overhead flash line.

[0114] The gases produced from the fourth zone **340** are not flared or disposed; instead, the gases are moved to a new gas processing facility **370**. To this end, a gas processing facility **370** has now been completed and is ready for gas processing and exporting.

[0115] In accordance with the present inventions, the gas processing facility **370** is not completed before the export of methane gas from the field **300** commences; instead, completion of the gas processing facility **370** is delayed. In one embodiment, substantially

final construction of the gas processing facility does not take place until the gas production rate from the field **300** is able to exceed a designated level. For example, the designated level might be 50 percent or, more preferably, 75 percent, or even 100 percent of the anticipated maximum weekly production rate from the field **300**. The designated level may be, for
5 example, 100 mscf/week, or 250 mscf/week.

[0116] In another embodiment, construction of the gas processing facility **370** may not be finalized until at least two zones of the gas-producing formation have been dewatered to a designated level. The designated level may be, for example, a reduction in average weekly water production rate of 50 percent, or 80 percent for the second zone. Alternatively,
10 construction of the gas processing facility **370** may not be finalized until at least three zones of the gas-producing formation have been substantially dewatered and gas produced from the second **320** and third **330** zones has been injected into the first zone **310**.

[0117] Because the gas processing facility **370** is now completed, it is ready to receive gas production from the gas-producing field **300**. In **Figure 3D**, gases from the fourth zone
15 **340** are being transported through a gas line **372** to the new gas processing facility **370**. At the same time, the wells **312**, **322**, **332** completed in the first **310**, second **320**, and third **330** zones, respectively, have been placed back on line.

[0118] Formation fluids produced from the first **310**, second **320**, third **330**, and fourth **340** zones are produced to the surface **302**. The formation fluids are transported through
20 production lines **314**, **324**, and **334**, respectively, to the separator **305**. The separator **305** separates all of these formation fluids into water and gas. Water exits the separator **305**, and is directed through water transport line **365**. The water transport line **365** carries water to the water injection wells **362**, where water continues to be injected into the water storage reservoir **360**.

25 [0119] Methane and other gases are released from the separator **305** through the gas transport line **315**. The gases then travel through gas line **372** and into the gas processing facility **370**. Because gas is produced from three or four (or even more) zones simultaneously, the gas processing facility **370** is able to operate immediately at high or even substantially full capacity.

30 [0120] Another method for managing the production of fluids from a low-permeability formation is disclosed herein. **Figures 4A** and **4B** present a unified flowchart showing steps for a method **400** for managing the production of formation fluids, in an alternate embodiment.

[0121] The method 400 first comprises completing one or more production wells in a low-permeability, gas-producing formation. This is shown at Box 410 of Figure 4A. The wells are completed in a first zone and in a second zone in a gas producing formation of a field. The gas-producing formation in the field may be a shale gas formation. Alternatively, the gas-producing formation may be a so-called tight gas formation. Preferably, however, the formation is a coal-bearing formation. In this instance, gas produced from the formation is coal bed methane. In any instance, the produced gas comprises greater than 50 mol. percent methane.

[0122] The method 400 also includes the step of co-producing water and methane gas through the production wells. This is shown at Box 415. The water and methane gas together comprise the majority of production fluids produced through the production wells from the first and second zones. During the initial stage of production, production fluids will predominantly be water. As production from the first and second zones continues, the water content of the produced fluids declines, and the gas content increases.

[0123] The water produced from the production wells will need to be managed. Accordingly, the method 400 also includes disposing of the water produced from the production wells. This is provided at Box 420. Disposal may mean injecting the water through injection wells into a subterranean storage zone. Alternatively, disposal may mean transporting the water to a tank or other place of temporary storage. Alternatively still, disposal may mean delivering the water for agricultural purposes, or releasing the water into the local water shed. Some environmental treatment or purification of the water may be required before this option is taken.

[0124] The method 400 further includes completing one or more gas injection wells in a zone in a second subsurface formation, preferably of higher permeability than that of the first zone. This is provided at Box 425. The “completing” step may be performed by drilling one or more wellbores into the zone in the second subsurface formation, and then completing the wellbores as water injection wells. Alternatively, the “completing” step may mean re-connecting previously-plugged wells with the zone in the second subsurface formation.

[0125] The method 400 also includes temporarily storing the gas produced from the first zone and the second zone in the zone in the second subsurface formation. This is seen at Box 430. The zone in the second subsurface formation may be an existing aquifer. Alternatively, the zone in the second subsurface formation may be a salt cavern or a substantially depleted hydrocarbon reservoir that is available to the operator of the field. Alternatively still, the zone in the second subsurface formation may be a coalbed formation which may or may not

have been partially dewatered. In any instance, methane gas produced from the first and second zones is injected into the zone in the second subsurface formation through the one or more gas injection wells.

[0126] The method also includes completing one or more wells in a third zone. This is shown at Box 435 of Figure 4A. The third zone is in the gas-producing formation of the field. The wells include production wells for producing formation fluids, that is, water and gaseous hydrocarbons. The method 400 then further includes co-producing the water and methane gas from the third zone. This is seen at Box 440.

[0127] As part of the producing step of Box 440, formation fluids are co-produced from the one or more wells in each of the first and second zones along with the one or more wells from the third zone. The produced fluids from the first and second zones will contain water. However, because these wells have been at least partially dewatered, they will also contain a higher percentage of methane gas than the third zone. Preferably, the first and second zones have been dewatered by at least 50 percent or, more preferably, by at least 80 percent, before they are placed in line for co-production with the third zone. Alternatively, the first and second zones have been dewatered sufficiently that the weekly average water production rate has fallen by at least 20 percent, or by at least 50 percent from the peak rate. Thus, a high volume of gas is now available for distribution to a gas processing facility.

[0128] The method 400 also includes constructing a gas processing facility. This is shown at Box 445 of Figure 4A. To enhance the economics of the field, and in accordance with the present inventions, the gas processing facility is not completed before the export of methane gas from the zones commences; instead, completion of the gas processing facility is delayed. In one embodiment, substantially final construction of the gas processing facility does not take place until the gas production rate from the field is able to exceed a designated level. For example, the designated level might be 50 percent or, more preferably, 80 percent, or even 100 percent of the anticipated maximum weekly production rate from the field.

[0129] In another embodiment, construction of the gas processing facility may not be finalized until at least two zones of the gas-producing formation have been dewatered to a designated level. The designated level may be, for example, a reduction in average weekly water production rate of 25 percent, or 50 percent, or more preferably, 75 percent, from initial water production rate for the combined first and second zones.

[0130] The above methods 200, 400 involve calculating production rate averages. Average production rates, such as daily, weekly, or monthly averages may be used. In making such calculations, shut-in times for field or facility maintenance or upsets may be

excluded from the averages. In addition, for purposes of the construction steps of Box 255 and Box 445, the gas processing facility may include an export facility.

[0131] The method 400 also includes optionally co-producing water and methane gas from the zone in the second subsurface formation. This is shown in Box 450 in Figure 4B.

5 Because of previous injections, these formation fluids will contain at least some methane gas, depending on how long the previous injection took place.

[0132] The water produced from the first, second, and third zones, and optionally from the zone in the second subsurface formation, will need to be managed. Accordingly, the method 400 next includes disposing of the water produced from these zones. This is
10 provided at Box 455. Disposal may again mean injecting the water through injection wells into a subterranean storage zone. Alternatively, disposal may mean transporting the water to a tank or other place of temporary storage. Alternatively still, disposal may mean delivering the water for agricultural purposes, or releasing the water into the local water shed.

[0133] In addition, the gas produced from the first, second, and third zones, and
15 optionally from the zone in the second subsurface formation, will need to be managed. Accordingly, the method 400 includes processing the gas produced from these zones. This is provided at Box 455. Processing is conducted in the newly completed gas processing facility.

[0134] Figures 5A through 5C provide illustrative cross-sectional views of a field 500 under hydrocarbon gas development in accordance with the methods herein, in an alternate
20 embodiment. These figures depict three of the stages for implementing the method 400, described above.

[0135] In each view, the field 500 contains a surface 502, and a subsurface 504. Further, the field 500 contains a low-permeability gas-producing formation 550. The gas-producing formation 550 may be a shale gas formation. Alternatively, the gas-producing formation 550
25 may be a so-called tight gas formation. Preferably, however, the formation 550 is a coal-bearing formation. In this instance, the gas produced from the formation 550 is coal bed methane.

[0136] The field 500 also contains a zone in a second subsurface formation 540. The zone in the second subsurface formation 540 serves as a place of temporary storage for
30 produced gas from the gas-producing formation 550. The zone in the second subsurface formation 540 may or may not have a classic geological trap structure. Although injecting into a trap structure is preferred, such structures may not be available. If the geostructure of the zone in the second subsurface formation 540 is relatively flat, the injected gas may slowly migrate laterally. However since the gas may be reproduced in a relatively short amount of

time, such as one to three years, a significant amount of the gas may be recaptured as described below in connection with **Figure 5C**.

[0137] In **Figure 5A**, the gas-producing formation **550** has been sectioned to provide a first zone **510** and a second zone **520**. Production wells **512** and **522** have been completed in the gas-producing formation **550** for the two respective zones **510**, **520**. Formation fluids are being produced from the first zone **510** and the second zone **520** through the gas-producing formation **550**.

[0138] In **Figures 5A** through **5C**, only one well **512** is shown completed in the first zone **510**, and only one well **522** is shown completed in the second zone **520**. Further, only two zones **510**, **520** are shown. However, it is understood that for purposes of the methods associated with **Figures 5A** through **5C**, each zone **510**, **520** may, and preferably does, have more than one production well completed therein. Further, there may be only one zone or more than two zones completed in the gas-bearing formation **550** during early production.

[0139] In each of **Figures 5A** through **5C**, the field **500** also contains a water disposal location **560**. The water disposal location **560** may be an existing aquifer, such as aquifer **360** shown in **Figure 3A**. Alternatively, the water disposal location **560** may be a substantially depleted hydrocarbon reservoir that is available to the operator of the field **500**. Alternatively still, the water disposal location **560** may be a coalbed zone which has been previously dewatered. For example, the water disposal location **560** may be an extension of the gas-producing formation **550**. In any instance, the water disposal location **560** is shown schematically in each of **Figures 5A**, **5B**, and **5C**.

[0140] In **Figure 5A**, formation fluids are being produced from the first **510** and second **520** zones of the gas-producing formation **550**. The formation fluids are being transported by the production wells **512**, **522** through the subsurface **504** and up to the surface **502**. At the surface **502**, the formation fluids are transported through production lines to a separator **505**. In the arrangement of **Figure 5A**, separate lines are shown for the production wells **512**, **522**, with production line **514** transporting fluids produced through production well **512**, and production line **524** transporting fluids produced through production well **522**. Fluids from the two transport lines **514**, **524** merge into line **516** before entering the separator **505**.

[0141] The separator **505** separates the formation fluids into liquids and gases. The separator **505** may be a gravity separator, a centrifugal separator, a flash vessel, or other separation unit for separating liquids from gases.

[0142] The liquids comprise primarily water, while the gases comprise primarily methane. Because methane boils at such a low temperature, it is preferred that the separator

505 be a low-temperature flash vessel. The formation fluids may be taken through a cooling unit (not shown) before entry into the separator **505**. The separator **505** may operate, for example, at 10° C and 50 psig to minimize water vapor.

[0143] After separation, the produced water exits the separator **505** and is transported for disposal. A water transport line **565** is provided in the field **500**. The water transport line **565** transports water from the separator **505** to the water disposal location **560**.

[0144] A gas transport line **515** is also provided. In the field development stage shown in **Figure 5A**, the gas transport line **515** transports methane and other gases to a return line **546**. From there, the gases enter a transport line **544** associated with injection well **542**. The injection well **542** is completed in the zone in the second subsurface formation **540**. The methane and other gases are then injected into the second subsurface zone **540** for temporary storage.

[0145] In **Figures 5A** through **5C**, only one well **542** is shown as a gas injection well. However, it is likely that two or more injection wells will be completed for gas injection. One or more stages of gas compression may be utilized to obtain injection pressures resulting in sufficient and desired injection rates through the gas injection well **542**.

[0146] In the subsurface **504** shown in the illustrative field **500**, the zone in the second subsurface formation **540** is below the gas-producing formation **550**. A deeper zone is preferred for temporary storage so not to interfere with drilling into the target gas producing zones. The zone in the second subsurface formation **540** may be any subsurface stratum having an acceptable porosity and permeability for receiving and holding water. Such a formation may be a sandstone anticline, a deeper coalbed, an aquifer, or other such formation.

[0147] It is noted here that at the beginning of production from the first **510** and second **520** zones, the produced fluids comprise predominantly water. Therefore, little gas is stored in the zone in the second subsurface formation **540**. As dewatering takes place in the first **510** and second **520** zones, the gas content of the formation fluids will increase.

[0148] Injection of production fluids from the first **510** and second **520** zones of the gas-producing formation **550** into the zone in the second subsurface formation **540** provides temporary storage of gas. The gas will be re-produced to the surface **502** in a later stage of field development. However, temporary storage in the zone in the second subsurface formation **540** allows the developer of the field **500** to delay the construction of an expensive, full-capacity gas processing facility.

[0149] **Figure 5B** presents a second view of the field **500**. This represents a next stage in development of the field **500**. In **Figure 5B**, the gas-producing formation **550** has been

sectioned into a third zone **530**. Production wells **532** have been completed in the third zone **530**. Formation fluids are now being produced from the third zone **530** and to the surface **502**.

[0150] The formation fluids are transported through production lines **534** at the surface **502**. From there, the production fluids from the third zone **530** are taken to the separator **505**. En route, the production fluids from the third zone **530** may be merged with production fluids in lines **514** and **524** from the first **510** and second **520** zones, which continue to be produced. The merged production fluids travel together through line **516**.

[0151] The production fluids from the three zones **510**, **520**, **530** are separated in the separator **505** into water and gases. The water exits the separator **505** and is transported through the water transport line **565**. The water is then carried to the water disposal location **560**, which may be away from the field **500**.

[0152] The gases produced from the various zones **510**, **520**, **530** are released from the separator **505** into the gas line **515**. Gas line **515** is preferably an overhead flash line. In the stage of **Figure 5B**, the gases are then transported through gas transport line **572** into a newly completed gas processing facility **570**. At the same time, the one or more injection wells **542** are shut in.

[0153] In accordance with the present inventions, the gas processing facility **570** is not completed before the export of methane gas from the field **500** commences; instead, completion of the gas processing facility **570** is delayed. In one embodiment, substantially final construction of the gas processing facility does not take place until the gas production rate from the field **500** is able to exceed a designated level. For example, the designated level might be 50 percent or, more preferably, 75 percent, or even 100 percent of the anticipated maximum weekly production rate from the field **500**. The designated level may be, for example, 100,000,000 scf/week, or 250,000,000 scf/week.

[0154] In another embodiment, construction of the gas processing facility **570** may not be finalized until at least two zones of the gas-producing formation **550** have been dewatered to a designated level. The designated level may be, for example, a reduction in average weekly water production rate from the combined first and second zones of 50 percent, or 75 percent. Alternatively, construction of the gas processing facility **570** may not be finalized until at least three zones of the gas-producing formation **550** have been substantially dewatered.

[0155] Because the gas processing facility **570** is now completed, it is ready to receive gas production from the gas-producing field **500**. As noted, gases from the first **510**, second **520** and third **530** zones are being transported through a gas transport line **572** to the gas

processing facility **570**. Processed gas is then exported from the field **500** through export line **574**. The processed gas may ultimately be exported via pipeline or liquefied natural gas (LNG) ships.

[0156] **Figure 5C** presents a third view of the field **500**. This represents yet a next stage in development of the field **500**. In **Figure 5C**, the well **542** completed in the zone in the second subsurface formation **540** has been converted from an injection well to a production well. Formation fluids are now being produced from the zone in the second subsurface formation **540**, through the subsurface **504**, and to the surface **502**. At the same time, formation fluids continue to be produced from the gas-producing formation **540** through production wells **512**, **522**, **532**.

[0157] The formation fluids from the zone in the second subsurface formation **540** enter the fluid line **544** at the surface **502**. The formation fluids are then transported to the separator **505** through transport line **548**. En route, the formation fluids from the zone in the second subsurface formation **540** may be merged with formation fluids being transported through lines **514**, **524**, and **534**. The merged fluids then travel to the separator **505** through production line **516**.

[0158] At the separator **505**, the formation fluids from the various zones **510**, **520**, **530**, **540** are separated just as they were in the stage shown in **Figure 5B**. Separated water from the zones **510**, **520**, **530**, **540** is transported through the water transport line **565** to the water disposal location, shown schematically at **560**. At the same time, gases are released from the separator **505** into the gas transport line **515**. The gases are routed through the gas line **572** to the gas processing facility **570**. Because gas is being produced from three or even four zones simultaneously, the gas processing facility **570** is able to operate immediately at high or even substantially full capacity.

[0159] The gas processing facility **570** is being shown in **Figures 5B** and **5C** schematically. It is understood that the gas processing facility will be equipped with various valves, compressors, flow lines, and separator vessels for substantially removing any water vapor and acid gases from the gas introduced from line **572**. For example, the gas processing facility **570** may include a cryogenic distillation tower that substantially “freezes” out carbon dioxide and hydrogen sulfide. Alternatively, the gas processing facility **570** may include a contactor that utilizes a physical solvent or a chemical solvent to remove acid gases through counter-current or co-current contacting, along with a regenerator vessel. Where the gas is particularly sulfurous, the gas processing facility may further include a Klaus sulfur recovery unit, a tail gas treating unit, and a combustion furnace. The gas processing facility may

further have a refrigeration system for chilling the processed methane into liquefied natural gas (LNG). The current methods are not limited by the mechanics of gas processing.

[0160] As can be seen from the illustrative stages provided in **Figures 3A** through **3D**, and **Figures 5A** through **5C**, methods for managing the production of formation fluids from a low-permeability subsurface formation are provided herein. The subsurface formation is in a field wherein natural gas is to be produced. The methods have utility during initial field development. More specifically, the methods may be used during an initial production phase when dewatering of the subsurface formation takes place. The methods allow the developer of a field to use capital for the field more efficiently by delaying or spreading out the erection of main gas processing equipment until the field is ready for substantial gas production and sale. Stated another way, completion of the gas processing facility more or less coincides with a gas field being able to provide gas at near the facilities' rated capacities.

[0161] The methods herein may also reduce flaring needs. The methods herein permit gas handling early in the development of coalbed methane fields while not requiring excessive facility construction and capital outlay to deal with the modest amounts of gas produced during initial dewatering stages.

[0162] In some embodiments herein, the subsurface formation is a coalbed methane field. The field is divided into two or more coalbed zones. In some aspects, more than one coalbed zone is simultaneously dewatered to a designated level. The co-produced gas from the produced zones is sent to a single, previously dewatered coalbed zone for temporary storage. Injecting gas into a dewatered coalbed zone to repressurize or even increase the pressure above an initial pressure may cause adsorption and storage of significant amounts of gas. This gas may be stored for perhaps about 1 to about 5 years until gas processing and export facilities are available. The increased pressure in the dewatered zone may help keep water from flowing back into this zone. In some embodiments, wells used for dewatering a coalbed zone are also used for injecting gas for storage in the zone.

[0163] In some embodiments, gas produced from a coalbed zone may be temporarily stored in two or more types of subterranean formations. For example, the produced gas may be injected into and temporarily stored in a salt cavern, an aquifer zone, or a depleted hydrocarbon reservoir, in addition to storage in an earlier dewatered coalbed zone.

[0164] While it will be apparent that the inventions herein described are well calculated to achieve the benefits and advantages set forth above, it will be appreciated that the inventions are susceptible to modification, variation and change without departing from the spirit thereof.

THE CLAIMS DEFINING THE INVENTION ARE AS FOLLOWS:

1. A method for managing the production of fluids from a low-permeability subsurface formation in a field, the fluids comprising water and gas, and the method comprising:

completing one or more wells in a first zone within the subsurface formation;

producing formation fluids from the first zone so as to at least partially dewater the first zone;

completing one or more wells in a second zone within the subsurface formation;

producing formation fluids from the second zone so as to at least partially dewater the second zone;

injecting gas from the formation fluids from the second zone into the first zone for temporary storage;

completing one or more wells in one or more subsequent zones within the subsurface formation;

completing a gas processing facility when (i) the gas production rate from the field is able to exceed a designated level, or (ii) at least the first and second zones of the subsurface formation have been dewatered to a designated level;

after completing the gas processing facility, co-producing simultaneously the first zone, the second zone, and the one or more subsequent zones to generate co-produced formation fluids;

separating water from gas in the co-produced formation fluids in a separator; and

delivering the separated gas to the completed gas processing facility for processing, the gas comprising greater than about 50 mole percent methane before processing.

2. The method of claim 1, wherein the subsurface formation comprises a coalbed zone, a shale gas zone, or a tight gas zone.

3. The method of claim 2, further comprising:

completing one or more water injection wells in a subterranean storage zone;

separating water from gas in the formation fluids from the first zone during dewatering; and

injecting water from the formation fluids from the first zone into the subterranean storage zone.

4. The method of claim 3, further comprising:
flaring a majority of the gas from the formation fluids from the first zone during dewatering of the first zone.
5. The method of claim 3, wherein the subterranean storage zone is an aquifer, a salt cavern, a depleted hydrocarbon reservoir zone, or a coalbed zone that has been previously dewatered to the designated level.
6. The method of claim 3, wherein the subterranean storage zone is a coalbed zone that is a lateral extension of the subsurface formation that is undergoing dewatering.
7. The method of claim 3, wherein:
the subsurface formation is a coalbed zone; and
the subterranean storage zone is an extension of the coalbed zone wherein substantial dewatering has previously taken place.
8. The method of claim 2, further comprising:
separating water from gas in the formation fluids from the first zone during dewatering; and
disposing of the water by releasing it into a surface body of water.
9. The method of claim 2, wherein the designated level for dewatering the first and second zones of the subsurface formation is a reduction in the average weekly production rate of water in the first and second zones to less than 50 percent relative to the beginning water production for the second zone.

10. The method of claim 2, wherein the designated level for dewatering the first and second zones of the subsurface formation is calculated by:

establishing a time period;

calculating a weekly average water production rate for the at least one production well in the second zone over the time period;

determining a peak weekly average water production rate for the at least one well from the second zone; and

reducing the weekly average water production rate by at least 20 percent from the peak weekly average water production rate.

11. The method of claim 3, further comprising:

completing one or more wells in a third zone within the subsurface formation;

producing formation fluids from the third zone so as to at least partially dewater the third zone;

shutting in the one or more wells completed in the second zone;

injecting gas from the formation fluids from the third zone into the first zone for temporary storage before the gas processing facility is substantially completed.

12. The method of claim 11, further comprising:

separating water from gas in the formation fluids from the second zone during dewatering of the second zone;

injecting water from the formation fluids from the second zone into the subterranean storage zone;

separating water from gas in the formation fluids from the third zone during dewatering; and

injecting water from the formation fluids from the third zone into the subterranean storage zone.

13. The method of claim 12, wherein co-producing formation fluids further comprises coproducing formation fluids from the third zone with the formation fluids from the first zone, the second zone, and the one or more subsequent zones.

14. A method for managing the production of fluids from a low-permeability subsurface formation in a field, the fluids comprising water and gas, and the method comprising:

- completing one or more wells in a first zone within the subsurface formation;
- producing formation fluids from the first zone so as to at least partially dewater the first zone;

- completing one or more injection wells in a zone in a second subsurface formation having a permeability that is higher than the first zone;

- injecting gas produced from the first zone into the zone in the second subsurface formation for temporary storage;

- completing one or more wells in a second zone within the low-permeability subsurface formation;

- producing formation fluids from the second zone;

- completing a gas processing facility when (i) the gas production rate from the field is able to exceed a designated level, or (ii) at least one zone of the subsurface formation has been dewatered to a designated level;

- after completing the gas processing facility, co-producing simultaneously from the first zone and the second zone to generate co-produced formation fluids;

- separating water from gas in the co-produced formation fluids in a separator;
- and

- delivering the separated gas to the completed gas processing facility for processing, the gas comprising greater than about 50 mole percent methane before processing.

15. The method of claim 14, wherein the low-permeability subsurface formation is a coalbed zone, a shale gas zone, or a tight gas zone.

16. The method of claim 15, wherein the zone in the second subsurface formation comprises an aquifer, a salt cavern, or a depleted hydrocarbon reservoir zone.

17. The method of claim 16, wherein the zone in the second subsurface formation is located in subsurface strata that is deeper than the subsurface formation that is undergoing dewatering.

18. The method of claim 15, further comprising:
completing one or more wells in one or more subsequent zones within the low permeability subsurface formation;
producing formation fluids from the one or more subsequent zones so as to at least partially dewater the one or more subsequent zones; and
injecting gas from the formation fluids from the one or more subsequent zones into the zone in the second subsurface formation for temporary storage before completing the gas processing facility.
19. The method of claim 15, further comprising:
separating water from gas in the formation fluids from the first zone during dewatering;
delivering water from the formation fluids from the first zone to a water disposal location; and
after the gas processing facility is completed, producing gas from the zone in the second subsurface formation and delivering the gas to the separator along with the co-produced formation fluids from the first zone and the second zone.
20. The method of claim 19, wherein:
the water disposal location is an aquifer, a salt cavern, a depleted hydrocarbon reservoir zone, or a coalbed zone that has been previously dewatered to the designated level; and
delivering water to the water disposal location comprises injecting the water.
21. The method of claim 19, wherein:
the water disposal location is a surface watershed; and
delivering water to the water disposal location comprises releasing water to the watershed.
22. The method of claim 19, wherein:
the subsurface formation is a coalbed zone;
the water disposal location is an extension of the coalbed zone wherein substantial dewatering has previously taken place; and

delivering water to the water disposal location comprises injecting the water into the coalbed zone.

23. The method of claim 19, further comprising:

producing formation fluids from the second zone so as to at least partially dewater the second zone;

separating water from gas in the formation fluids from the second zone during dewatering of the second zone;

injecting gas from the formation fluids from the second zone into the zone in the second subsurface formation for temporary storage;

delivering separated water from the formation fluids to the water disposal location; and

after the gas processing facility is completed, producing gas from the zone in the second subsurface formation and delivering the gas to the separator along with the co-produced formation fluids from the first zone and the second zone.

24. The method of claim 2 or claim 15, wherein the designated level for the gas production rate from the field is at least 25 percent of the anticipated maximum weekly production rate from the field.

25. The method of claim 15, wherein the designated level for dewatering the at least one zone of the low-permeability subsurface formation is a reduction in the average weekly production rate of water in the first zone to less than 50 percent relative to the beginning water production for the first zone.

26. The method of claim 15, wherein the designated level for dewatering the at least one zone of the low-permeability subsurface formation is calculated by:

establishing a time period;

calculating a weekly average water production rate for the at least one production well in the at least one zone over the time period;

determining a peak weekly average water production rate for the at least one well from the at least one zone; and

reducing the weekly average water production rate by at least about 20 percent from the peak weekly average water production rate.

27. The method of claim 10 or claim 26 wherein the weekly average water production rate excludes any well shut-in periods.

28. The method of claim 2 or claim 15, wherein the designated level for dewatering means that the first and second zones have been dewatered to the designated level.

29. The method of claim 1 or claim 15, wherein the gas processing facility refrigerates the methane into liquefied natural gas, or introduces the methane into a pipeline.

30. A method for managing the production of fluids from a coalbed formation in a field, the fluids comprising water and gas, and the method comprising:

- completing one or more wells in a first production section within the coalbed formation;

- producing formation fluids from the first production section so as to at least partially dewater the first section;

- completing one or more injection wells in a subterranean storage zone;

- separating the formation fluids into a liquid stream comprised of water, and a gas stream comprising at least 50 mole percent methane gas;

- injecting the gas from the gas stream into a first subsurface formation for temporary storage;

- injecting water from the liquid stream into a second subsurface formation;

- completing one or more wells in a subsequent production section within the coalbed formation;

- completing a gas processing facility for the field;

- after the first production section has been at least partially dewatered and after the gas processing facility is completed, co-producing simultaneously from the first production section, the subsequent production section, and the first subsurface formation to generate co-produced formation fluids;

separating water in the co-produced formation fluids from the gas in a separator; and

delivering the gas to the completed gas processing facility for processing.

31. The method of claim 30, wherein the first subsurface formation is a zone in the coalbed formation; or an aquifer that is deeper than the coalbed formation.

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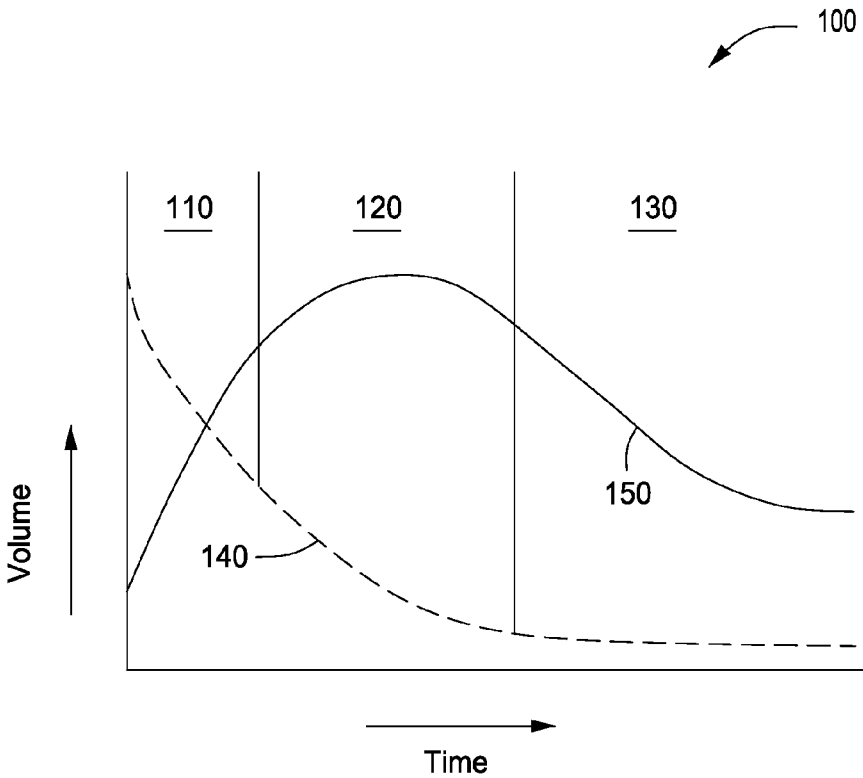


FIG. 1

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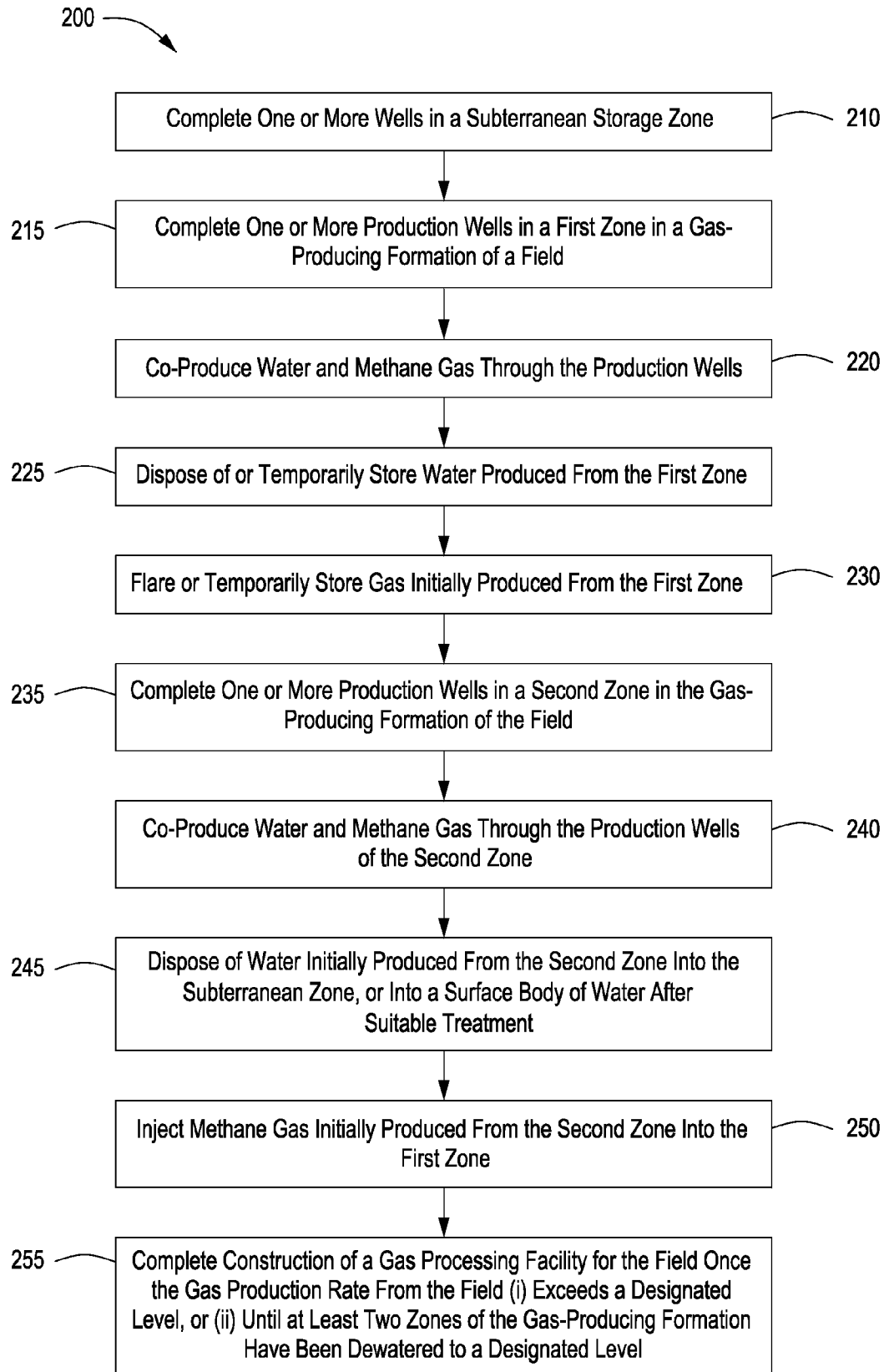


FIG. 2A

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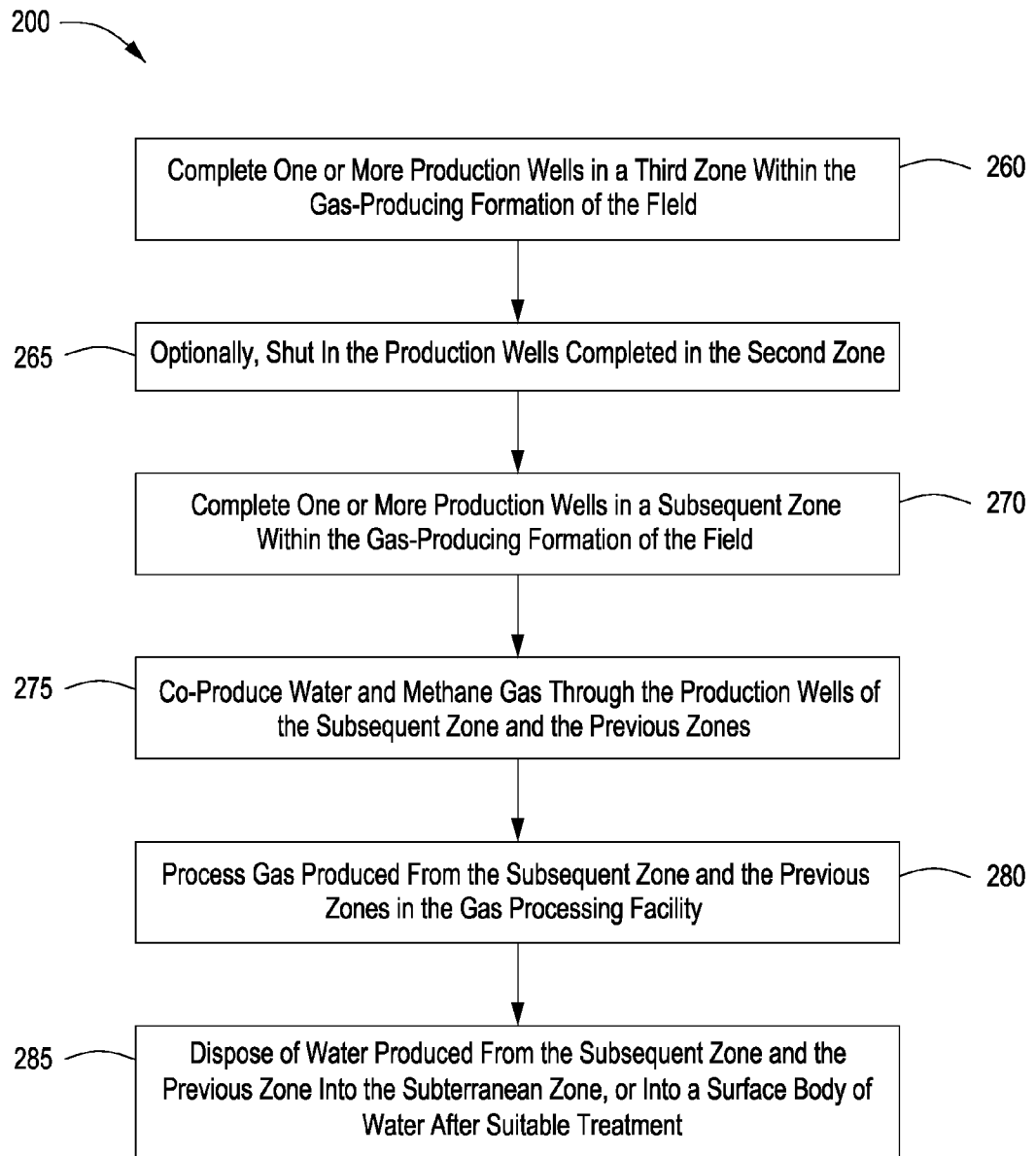


FIG. 2B

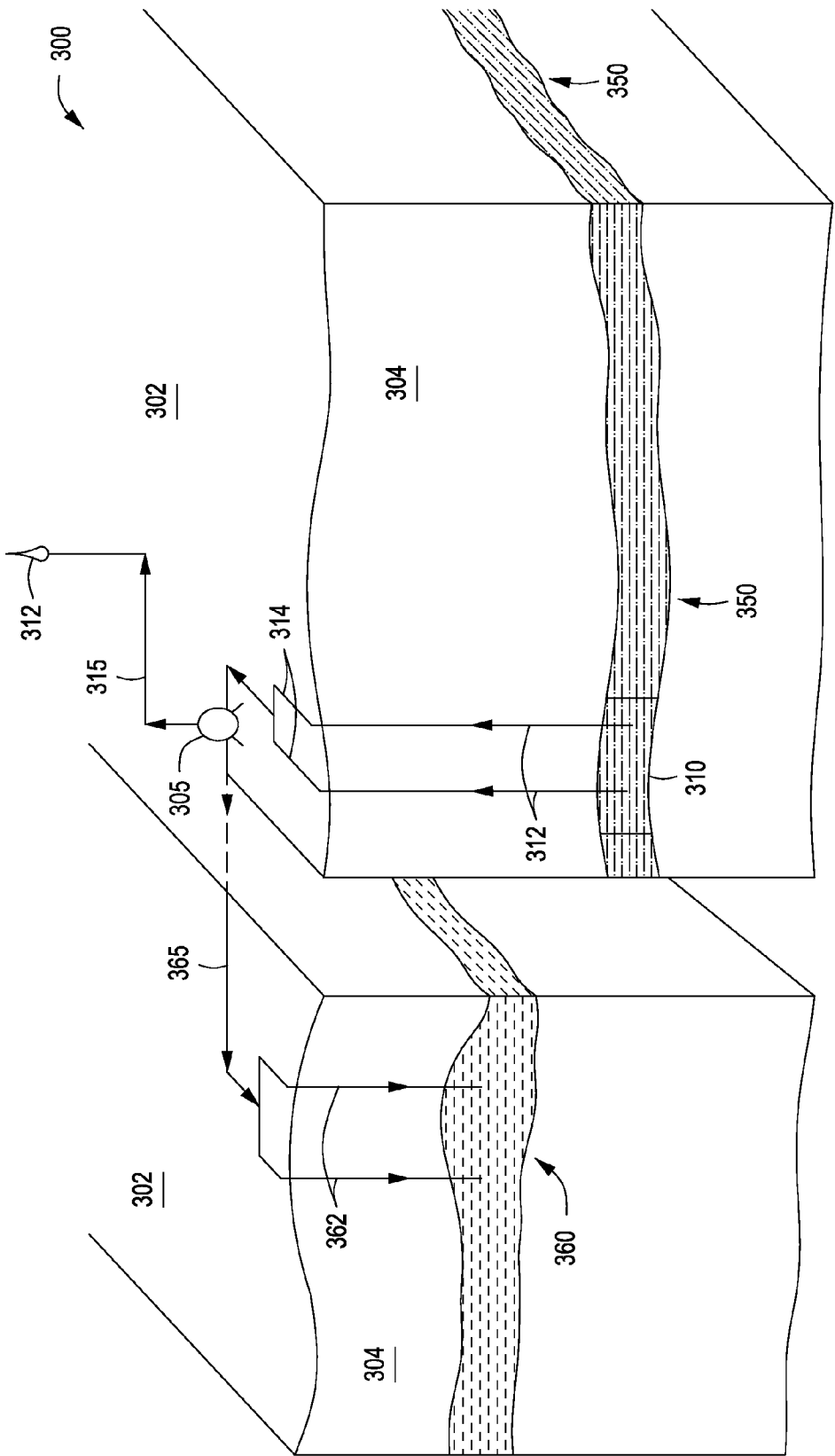


FIG. 3A

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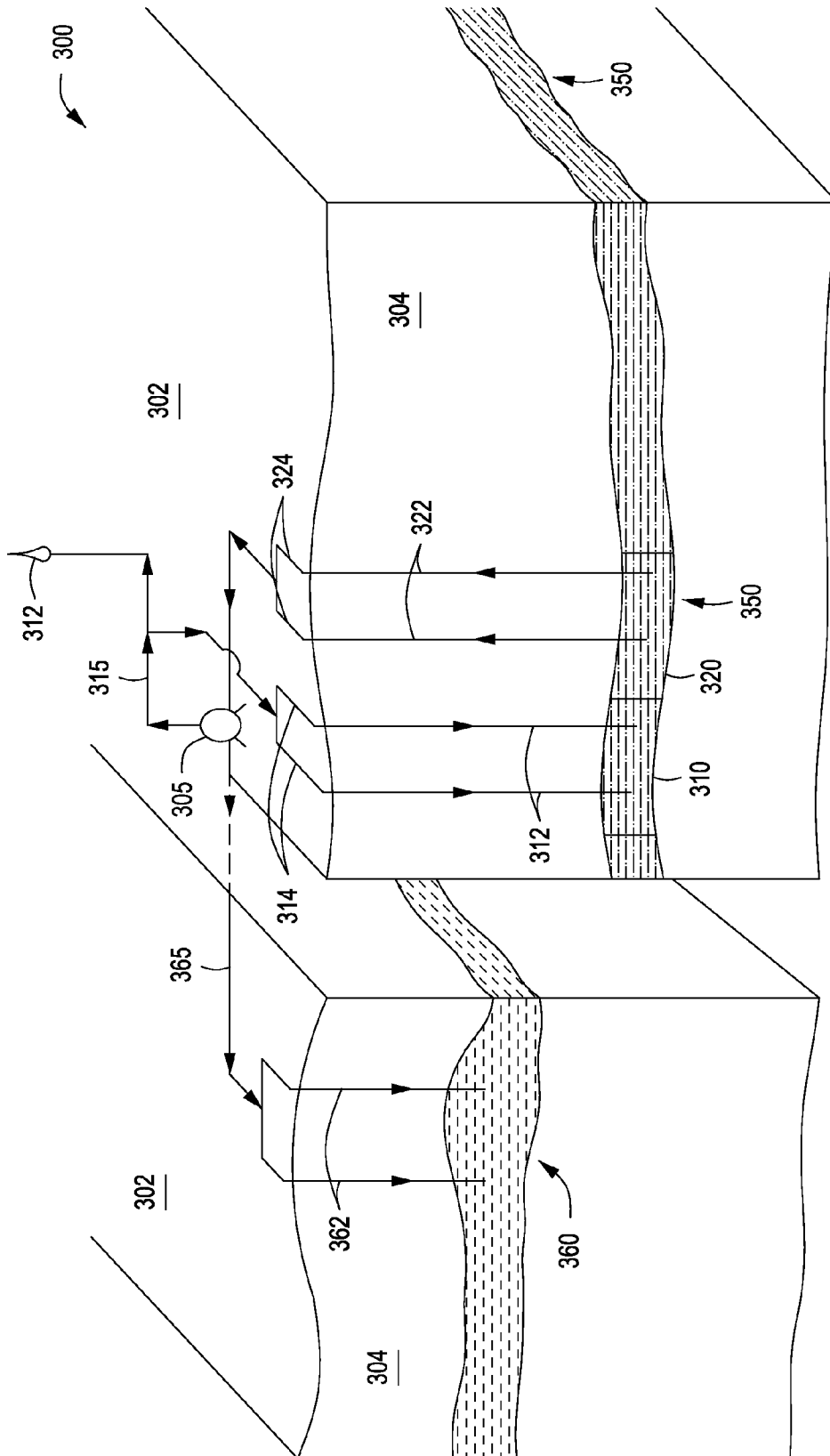


FIG. 3B

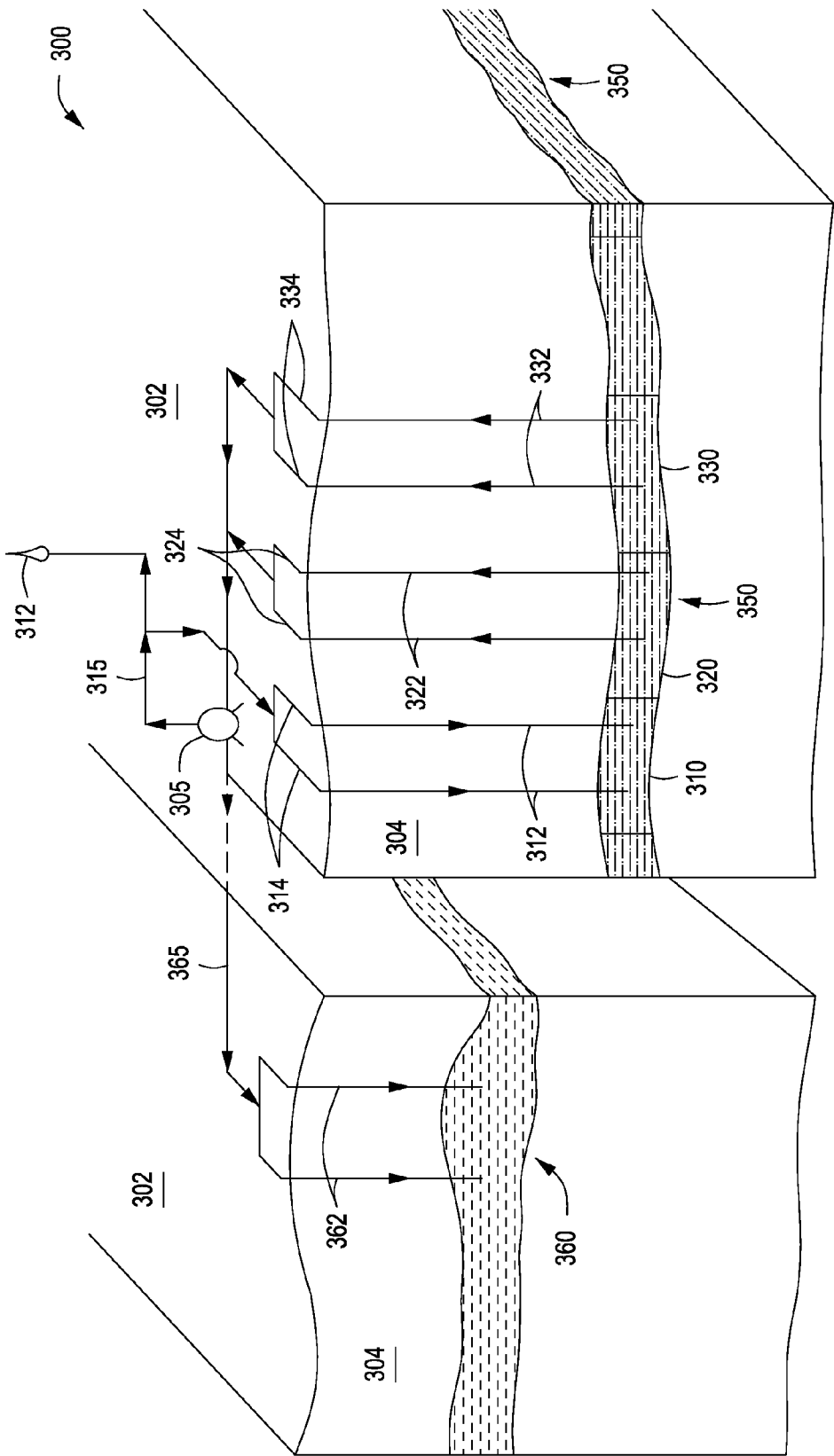


FIG. 3C

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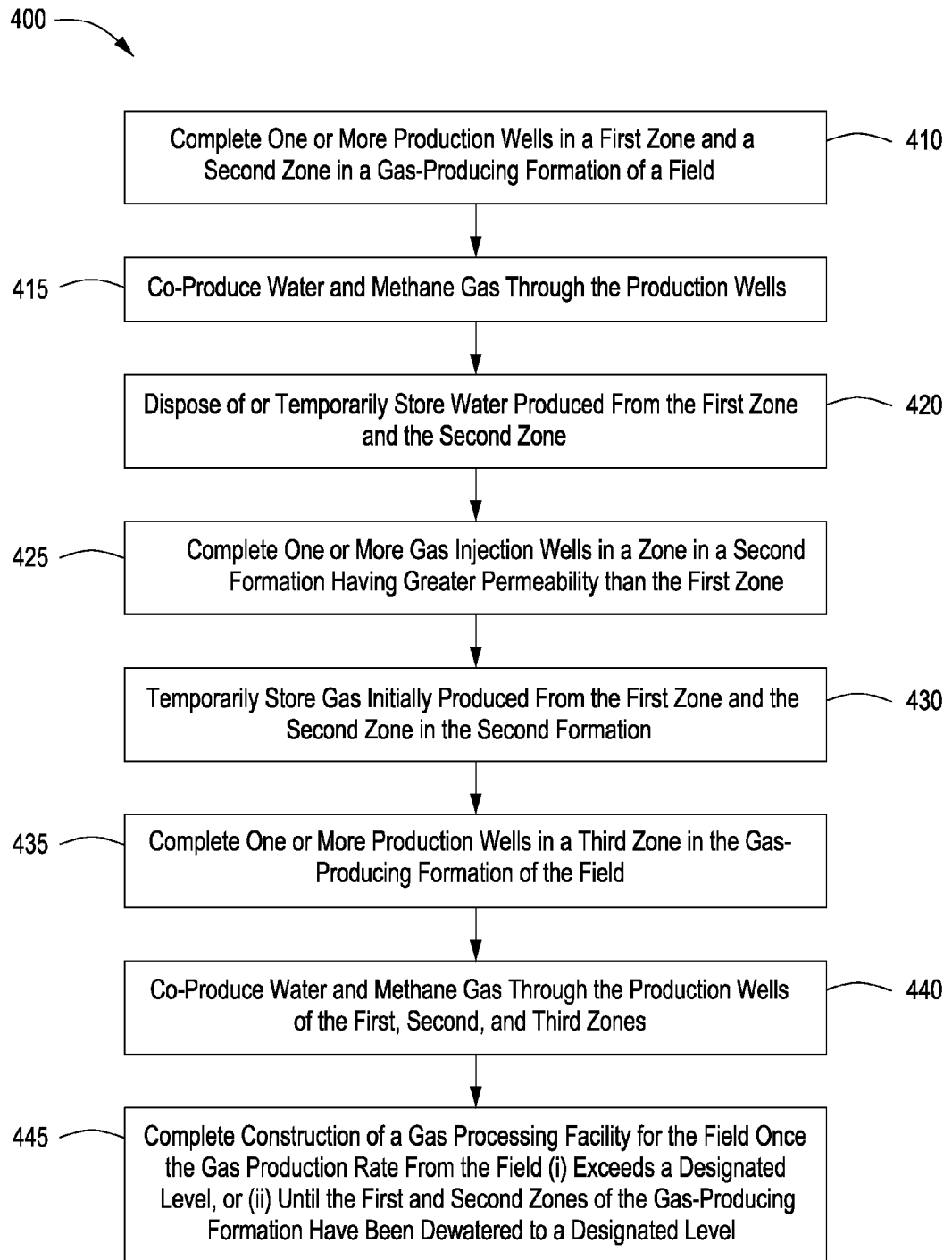


FIG. 4A

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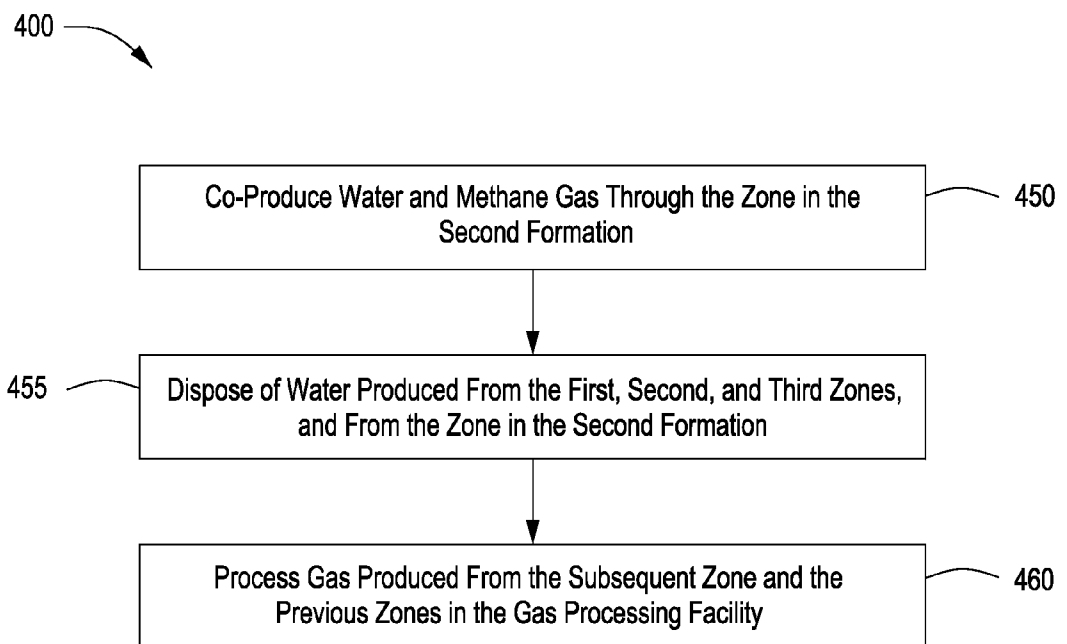


FIG. 4B

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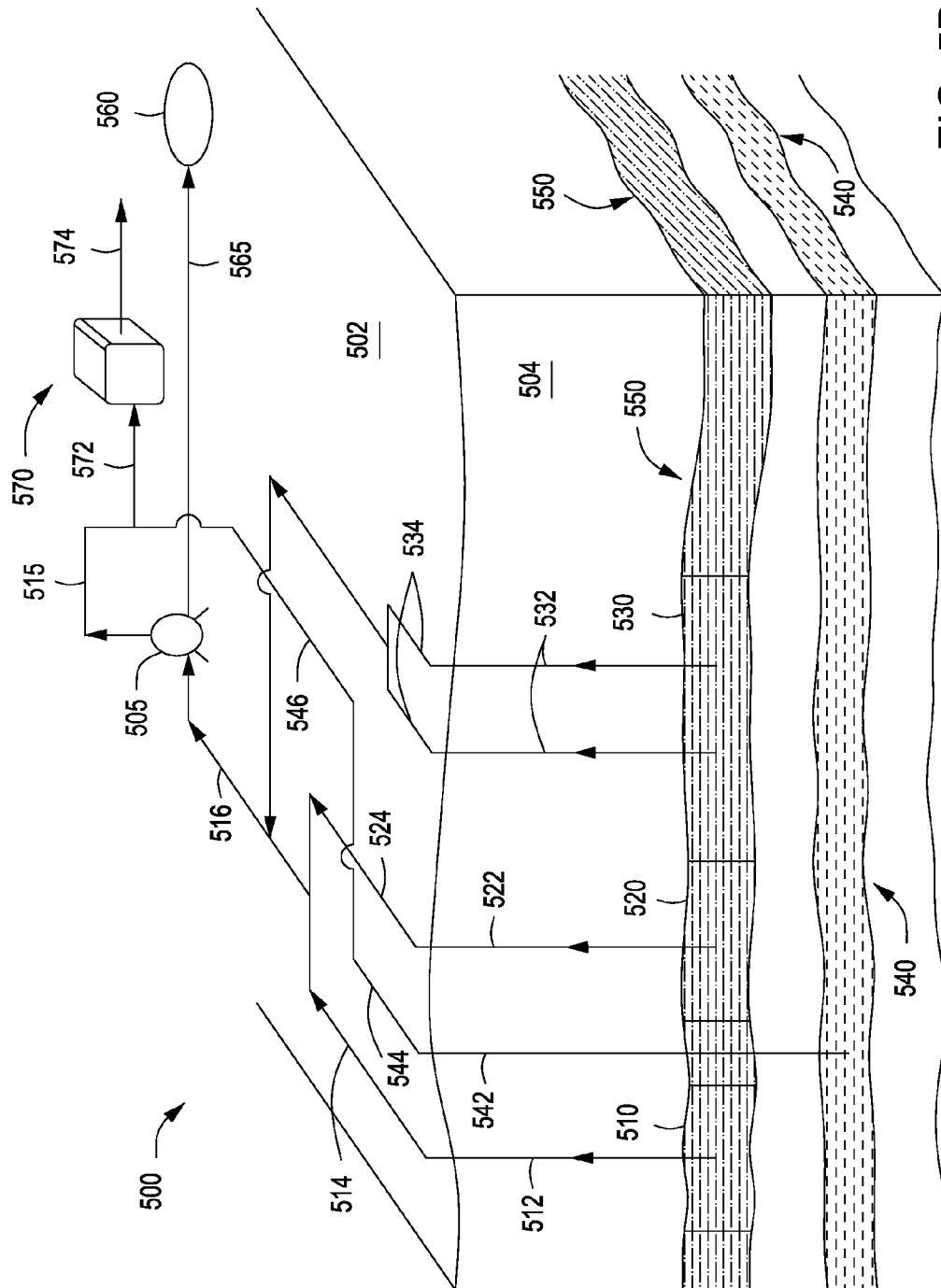


FIG. 5B

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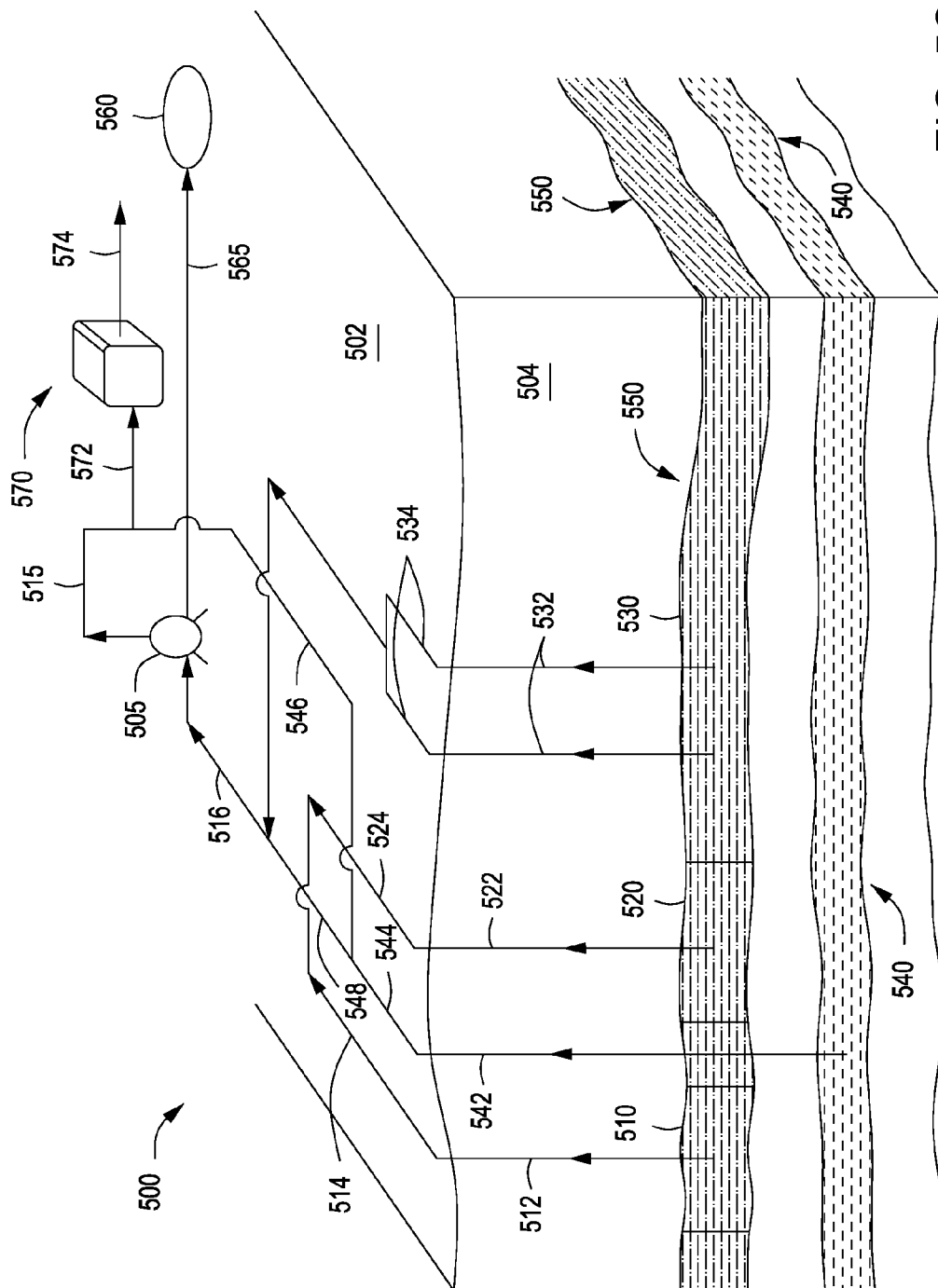


FIG. 5C