US 20170145787A1

(19) United States

(12) Patent Application Publication

(10) Pub. No.: US 2017/0145787 A1

(43) Pub. Date: May 25, 2017

White et al.

(54) METHOD AND SYSTEM FOR REDUCING HEAT LOSS FROM SUBSEA STRUCTURES

(71) Applicant: **Cameron International Corporation**, Houston, TX (US)

(72) Inventors: **James Eden White**, Co Meath (IE); **Edmund Peter McHugh**, Co Longford (IE)

(73) Assignee: **Cameron International Corporation**, Houston, TX (US)

(21) Appl. No.: **15/424,323**

(22) Filed: **Feb. 3, 2017**

Related U.S. Application Data

(63) Continuation of application No. 12/673,005, filed on Feb. 10, 2010, now Pat. No. 9,593,556, filed as application No. PCT/IB2008/053625 on Sep. 8, 2008.

(60) Provisional application No. 60/977,073, filed on Oct. 2, 2007.

Publication Classification

(51) **Int. Cl.**

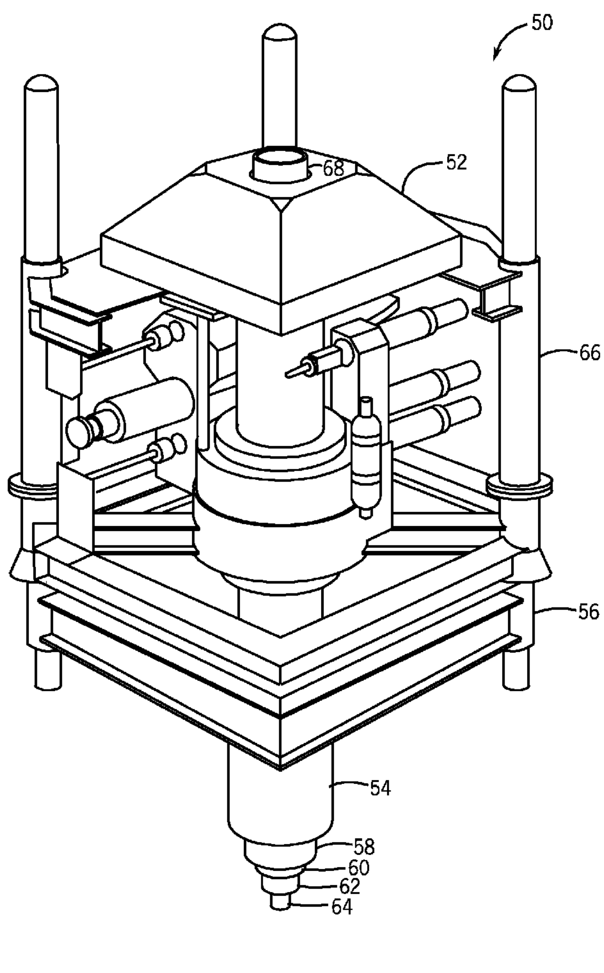
E21B 36/00	(2006.01)
E21B 41/02	(2006.01)
E21B 41/00	(2006.01)
E21B 33/037	(2006.01)

(52) **U.S. Cl.**

CPC ***E21B 36/003*** (2013.01); ***E21B 33/0375*** (2013.01); ***E21B 41/02*** (2013.01); ***E21B 41/0007*** (2013.01)

(57) **ABSTRACT**

There is provided a system and method for using a thermal insulating paint in a subsea environment. In accordance with one embodiment of the present technique, the thermal insulating paint may be applied to a casing for use in a subsea mineral extraction system. In another embodiment, a surface-rated thermal insulating paint may be applied to any component for use in a subsea mineral extraction system. The insulated component may be protected from the subsea environment to prevent damage to the surface-rated thermal insulating paint. For example, protecting the component may include burying it in cement or concrete, encasing it in another subsea structure or enclosure, or applying a protective sealant over the surface-rated thermal insulating paint.



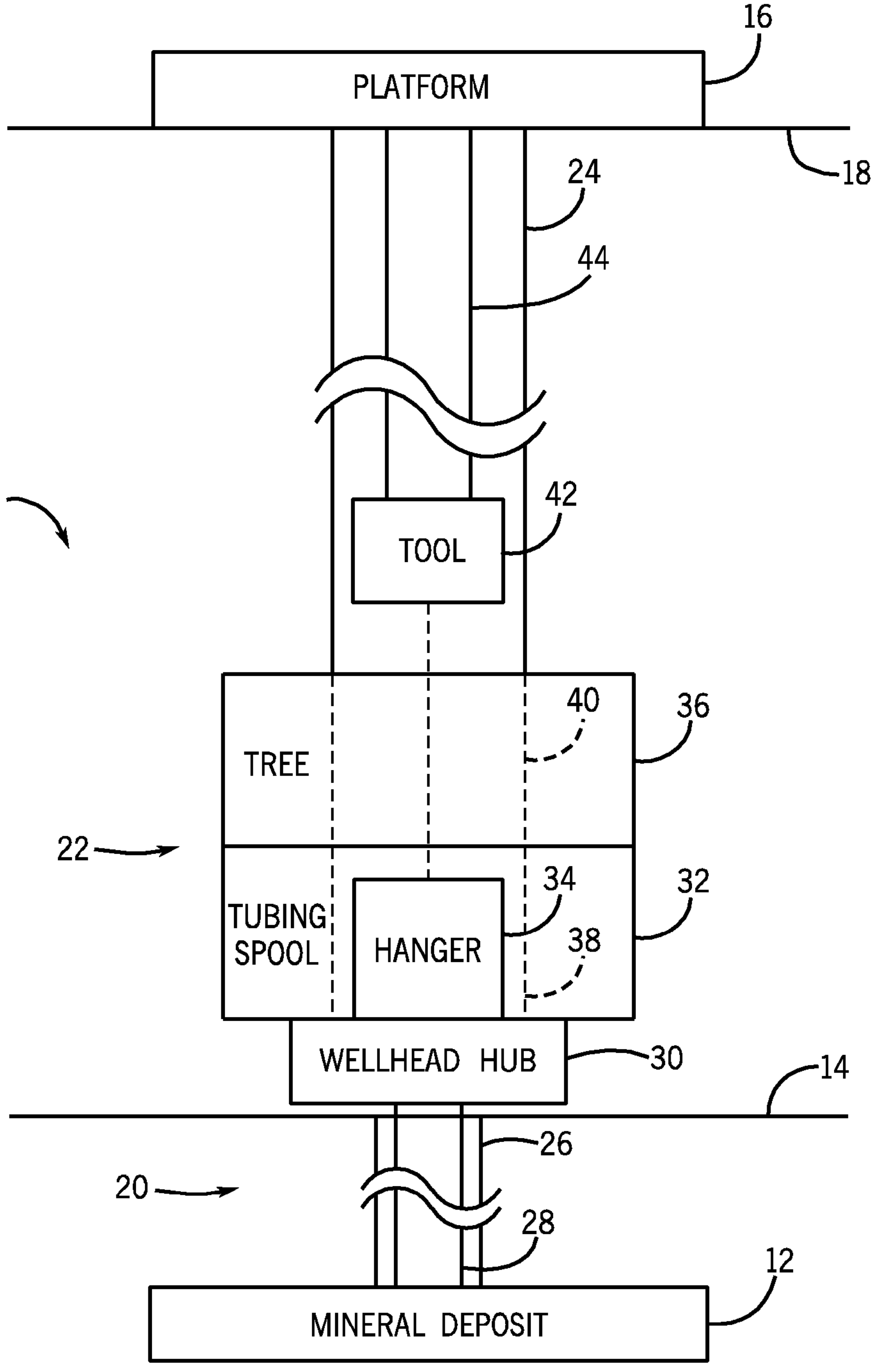

16
PLATFORM
18
24
44
10
TOOL
42
TREE
40
36
22
TUBING SPOOL
HANGER
34
32
38
WELLHEAD HUB
30
14
26
20
28
12
MINERAL DEPOSIT

FIG. 1

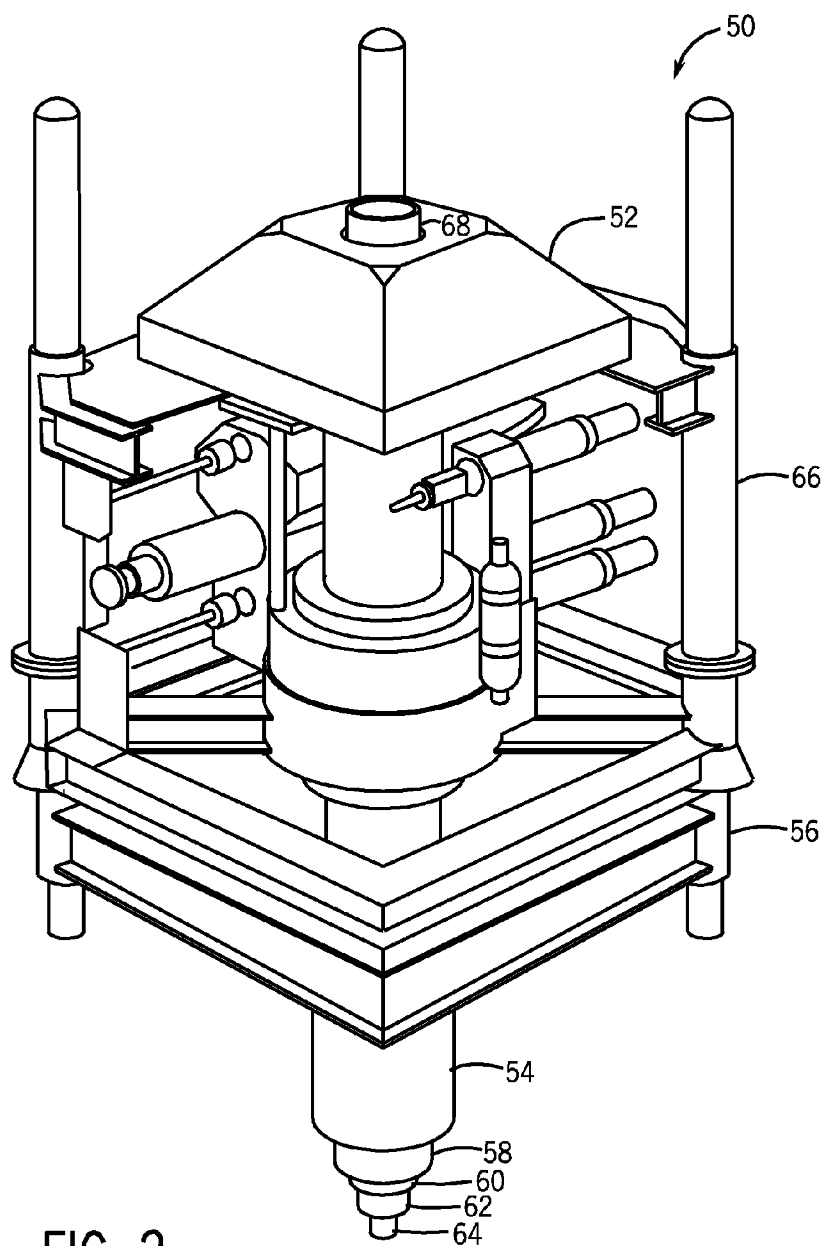


FIG. 2

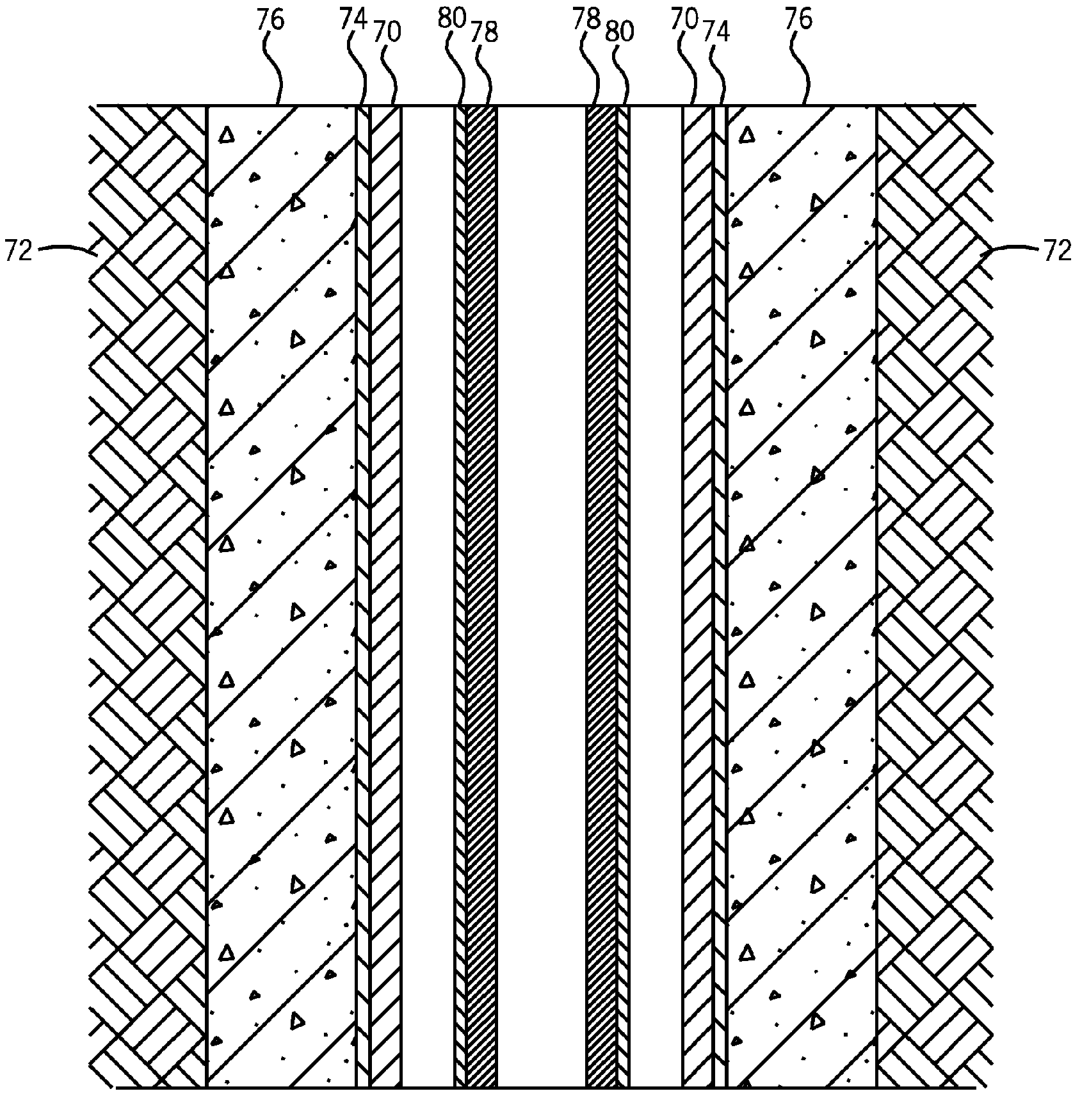


FIG. 3

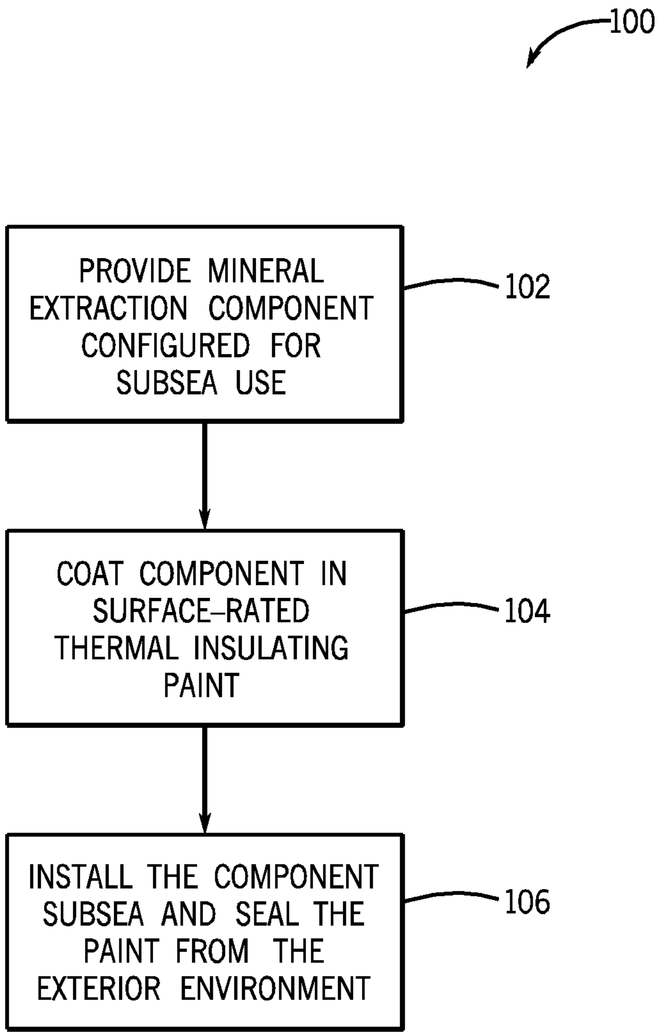

100
PROVIDE MINERAL EXTRACTION COMPONENT CONFIGURED FOR SUBSEA USE
102
COAT COMPONENT IN SURFACE-RATED THERMAL INSULATING PAINT
104
INSTALL THE COMPONENT SUBSEA AND SEAL THE PAINT FROM THE EXTERIOR ENVIRONMENT
106

FIG. 4

METHOD AND SYSTEM FOR REDUCING HEAT LOSS FROM SUBSEA STRUCTURES

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a continuation of U.S. Non-Provisional application Ser. No. 12/673,005, entitled "Method and System for Reducing Heat Loss from Subsea Structures," filed on Feb. 10, 2010, which is hereby incorporated by reference in its entirety, and which is a U.S. National Stage Application of PCT Application No. PCT/IB2008/053625, entitled "Method and System for Reducing Heat Loss from Subsea Structures," filed on Sep. 8, 2008, which is hereby incorporated by reference in its entirety, and which claims benefit of U.S. Provisional Application No. 60/977,073, entitled "Method and System for Reducing Heat Loss from Subsea Structures," filed on Oct. 2, 2007, which is hereby incorporated by reference in its entirety.

BACKGROUND

[0002] This section is intended to introduce the reader to various aspects of art that may be related to various aspects of the present invention, which are described and/or claimed below. This discussion is believed to be helpful in providing the reader with background information to facilitate a better understanding of the various aspects of the present invention. Accordingly, it should be understood that these statements are to be read in this light, and not as admissions of prior art.

[0003] Natural resources, such as oil and gas, are used as fuel to power vehicles, heat homes, and generate electricity, in addition to myriad other uses. Once a desired resource is discovered below the surface of the earth, drilling and production systems are often employed to access and extract the resource. These systems may be located onshore or offshore depending on the location of a desired resource.

[0004] Further, such systems generally include a wellhead assembly through which the resource is extracted. These wellhead assemblies may include a wide variety of components and/or conduits, such as casings, trees, manifolds, and the like, that facilitate drilling and/or extraction operations. For example, casings, such as a production casing, may be utilized to carry the resource from the reservoir to the surface wellhead for production.

[0005] In subsea environments, drilling and extraction components may be exposed to relatively low temperatures, for example, in the range of 0-10° C. Resources extracted from beneath the sea floor may be at a much higher temperature, such as, for example, 70° C. The difference in temperatures between the extracted resource and the surrounding seawater may result in rapid heat loss from the extraction component through which the resource is extracted.

[0006] For example, a metal casing used to carry oil from the sea floor may experience a temperature gradient of around 60-70° C. Metal may be the most cost-effective material to use in such a corrosive, high-pressure, high-temperature environment, however the metal casing provides little resistance to heat loss. Rapid heat loss through the metal casing may result in the formation of hydrates in the casing. Hydrates are waxy build-ups formed by the combination of water, such as from condensation, and the resource being carried up the casing. Hydrates may plug a pipeline, necessitating a costly and time-consuming unblocking procedure. In addition, extensive hydrate formation may result in the loss of a well, at a great cost.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] Various features, aspects, and advantages of the present invention will become better understood when the following detailed description is read with reference to the accompanying figure, wherein:

[0008] FIG. **1** is a block diagram of a mineral extraction system in accordance with an embodiment of the present invention;

[0009] FIG. **2** is a perspective view of a subsea well assembly in accordance with an embodiment of the present invention;

[0010] FIG. **3** is a section view of a portion of a subsea well assembly in accordance with an embodiment of the present invention; and

[0011] FIG. **4** is a flow chart of a process for manufacturing and using a subsea well assembly in accordance with an embodiment of the present invention.

DETAILED DESCRIPTION OF SPECIFIC EMBODIMENTS

[0012] One or more specific embodiments of the present invention will be described below. These described embodiments are only exemplary of the present invention. Additionally, in an effort to provide a concise description of these exemplary embodiments, all features of an actual implementation may not be described in the specification. It should be appreciated that in the development of any such actual implementation, as in any engineering or design project, numerous implementation-specific decisions must be made to achieve the developers' specific goals, such as compliance with system-related and business-related constraints, which may vary from one implementation to another. Moreover, it should be appreciated that such a development effort might be complex and time consuming, but would nevertheless be a routine undertaking of design, fabrication, and manufacture for those of ordinary skill having the benefit of this disclosure.

[0013] When introducing elements of various embodiments of the present invention, the articles "a," "an," "the," and "said" are intended to mean that there are one or more of the elements. The terms "comprising," "including," and "having" are intended to be inclusive and mean that there may be additional elements other than the listed elements. Moreover, the use of "top," "bottom," "above," "below," and variations of these terms is made for convenience, but does not require any particular orientation of the components.

[0014] FIG. **1** illustrates an exemplary mineral extraction system **10** having surface-rated insulation (e.g., paint) disposed on various subsurface components (e.g., in the sea or subsea). In one embodiment, the insulation may be a paint not intended, designed, or capable of enduring the harsh environment in seawater, below the sea, and/or exposure to mineral deposits. However, the components may be insulated with the surface-rated insulating paint and then subsequently sealed off from the surrounding environment (e.g., seawater) as discussed below. The system **10** may be configured to extract minerals, such as oil and gas, from a mineral deposit **12** beneath a sea floor **14**, and to carry the minerals to a platform or other production vessel **16** at sea level **18**. The illustrated mineral extraction system **10** generally includes a well **20**, a wellhead **22**, and a casing **24**.

[0015] The well **20** may include the mineral deposit **12** and a borehole **26**. A conductor **28** may be disposed within the borehole **26** to extract minerals from the mineral deposit **12** and to inject chemicals into the deposit **12**. For example, chemicals may be injected into the mineral deposit **12** to improve mineral recovery. The conductor **28** may encase various casings and tubings to facilitate transfer of different fluids in and out of the well **20**. For example, within the conductor **28** there may be disposed one or more concentric casings and a production tube. In addition, the conductor **28** may be buried in cement or concrete to secure it within the borehole **26**. Minerals from the mineral deposit **12** below the sea floor **14** may be very hot, while the temperature of the seawater above the sea floor **14** is relatively very cold. Minerals traveling up through the production tube in the conductor **28** may experience a large drop in temperature near the sea floor **14**, resulting in a waxy build-up known as hydrates. Hydrates may be reduced or prevented by insulating the conductor **28**, the casings, and/or the production tube, as described in more detail below.

[0016] The wellhead **22** may generally include a wellhead hub **30**, a tubing spool **32**, a hanger **34**, and what is colloquially referred to as a "Christmas tree" **36** (hereinafter a tree). The wellhead hub **30** may include a large diameter hub that is disposed near the termination of the borehole **26** at the sea floor **14**. Thus, the wellhead hub **30** may provide for the connection of the wellhead **22** to the well **20**. In one embodiment, the wellhead hub **30** includes a Deep Water High Capacity (DWHC) hub manufactured by Cameron of Houston, Tex. The wellhead hub **30** may couple the conductor **28** to the wellhead **22**.

[0017] The tubing spool **32** may provide an intermediate connection between the tree **36** and the wellhead hub **30** and may also support the hanger **34**. The tubing spool **32** may be secured to the wellhead hub **30** prior to installation of the tree **36**. A tubing spool bore **38** may enable fluid communication between a tree bore **40** and the well **20**. Further, the hanger **34** may be secured within the tubing spool bore **38**. The hanger **34** may secure the conductor **28**, tubing, and casing suspended in the borehole **26**. The hanger **34** generally provides a path for hydraulic control fluid, chemical injections, or the like to be passed through the wellhead **22** and into the borehole **26**.

[0018] The tree **36** may route the flow of extracted minerals from the well **20**, regulate pressure in the well **20**, and inject chemicals down hole into the borehole **26**, for example, via a variety of flow paths (e.g., bores), valves, fittings, and controls for operating the well **20**. Further, the tree **36** may provide fluid communication with the well **20**. For example, the tree bore **40** may enable completion and workover procedures, such as the insertion of tools (e.g., the hanger **34**) into the wellhead **22**, the injection of various chemicals into the well **20**, and the like. Further, minerals extracted from the well **20** (e.g., oil and natural gas) may be regulated and routed via the tree **36**. For instance, the tree **36** may be coupled to the casing **24**, a jumper, or a flowline, and tied back to other components, such as a manifold on the platform **16**. Accordingly, extracted minerals flow from the well **20** to the platform **16** via the wellhead **22** before being routed to shipping or storage facilities.

[0019] Other devices may also be coupled to the wellhead **22** or used to assemble and control various components of the wellhead **22**. For example, in the illustrated embodiment, the system **10** includes a tool **42** suspended from a drill string **44**. In some embodiments, the tool **42** may include a running tool that is lowered (e.g., run) from the platform **16** to the well **20** or to the wellhead **22** to assemble various components of the system **10**. The tool **42** may be run to the wellhead **22** within the casing **24**. The casing **24** may also include other casings and tubings to carry various fluids, such as hydraulic fluids, injection chemicals, and extracted minerals to and from the platform **16**. As with the tubing, casings, and conductor **28** in the well **20**, the casing **24** may be insulated using thermal insulation paint, as described in more detail below.

[0020] FIG. **2** illustrates an exemplary subsea mineral extraction system **50**. The system **50** includes a wellhead **52**, a conductor **54**, and a base **56**. Casings **58**, **60**, and **62** are disposed concentrically within the conductor **54**. A tubing **64** is disposed within the casing **62**. The tubing **64** may be used to transport the extracted minerals from the mineral reservoir **12** (FIG. **2**) to the wellhead **52**. The casings **58**, **60**, and **62** may contain various production equipment and fluids, such as, for example, a blowout preventer, drilling mud, injection chemicals, and the like. The base **56** may be situated on or near the sea floor **14** and may facilitate connection of the conductor **54** to the wellhead **52**. The wellhead **52** may be coupled to the base **56** via a frame **66**. A casing **68** may be utilized to transport the extracted minerals from the wellhead **52** to a platform or other production vessel at sea level. The casing **68** may contain additional casings for carrying various fluids to and from the surface.

[0021] In accordance with an embodiment of the present invention, casings may be insulated with a thermal insulating paint. A thin layer of the thermal insulating paint may provide insulation equivalent to several inches of traditional insulation. For instance, less than a millimeter of thermal insulating paint may provide insulation comparable to six inches of foam insulation.

[0022] In another embodiment, components that are buried below the sea floor **14**, encased in cement, or otherwise sealed from the subsea environment may be insulated with a surface-rated thermal insulating paint. The surface-rated thermal insulating paint may be a resin containing highly porous particles obtained by drying a wet sol-gel, such as Nansulate®, available from Industrial Nanotech, Inc., of Naples, Fla. As described above in FIG. **1**, the conductor **54** may be at least partially buried under the sea floor **14**. That is, the conductor **54** may be disposed within the borehole **26**. To ensure that the conductor **54** remains in place, cement or concrete may be placed around the conductor **54** within the borehole **26**. In addition, other components may be partially or completely buried in cement or concrete. For example, the base **56** may be at least partially encased in cement. Other components may include casings, piles, and other equipment situated at or near the sea floor. In addition, some casings and tubings may be protected from the subsea environment by being encased in other casings.

[0023] The cement, concrete, or outer casing may constitute a protective structure within which a surface environment may be approximated. That is, the protective structure may seal the surface-rated thermal insulating paint from the subsea environment which would otherwise damage the paint. For example, the paint may be applied and then sealed off from the seawater, chemicals, oil and gas, and other harsh substances that may break down or reduce the effectiveness of the paint. The sealing may be provided by concrete, cement, casings, housings, or other subsurface sealants (e.g., paints). Other subsurface sealants may include, for example, a sealant or paint that is rated for a subsea or corrosive environment. The subsurface sealant may be insulative or merely resistant to the surrounding environment, such as, for example, seawater, chemicals, oil, gas, etc. In addition, different sealants may be utilized depending on the location of the surface-rated thermal insulating paint and the environment. That is, one sealant may be resistant to seawater and may be applied to an external component, while another may be resistant to chemicals or oil and gas and may be applied to a component disposed within the system. This technique may also be applied as a cost-reducing measure where a more expensive subsea-rated thermal insulating paint is available. That is, one or more layers of the surface-rated thermal insulating paint may be applied to a component, then the subsea-rated thermal insulating paint may be applied over the surface-rated paint to protect the system from the subsea environment. Accordingly, the surface-rated thermal insulating paint may be utilized in a location where its use would otherwise be precluded.

[0024] Traditional insulating techniques are not generally useful in this application as molded insulation, such as foam, polymer, and resin, cannot, for example, support the load of the surrounding casings **58**, **60**, and/or **62**. In addition, traditional insulation may permit moisture to accumulate between the insulation and the object being insulated. This accumulation of moisture may lead to corrosion of the insulated object. By applying one or more layers of thermal insulating paint to the object, moisture does not accumulate on the surface of the object. In addition, the thermal insulating paint may provide a very thin insulative coating as compared to other types of insulation. The thermal insulating paint may have a thickness of less than 50 mils, 40 mils, 30 mils, 20 mils, or even 10 mils. For example, in some embodiments, the thermal insulating paint may have a thickness of about 4.5-7.5 mils. This coating may provide as much insulation as several inches of traditional insulation, while still withstanding the pressures associated with subsea use.

[0025] FIG. **3** illustrates a section of buried subsea mineral extraction components in accordance with an embodiment of the present invention. A conductor **70** is buried in a sea floor **72**. The conductor **70** is coated with one or more layers **74** of surface-rated thermal insulating paint and surrounded by cement **76**. Within the conductor **70**, a casing **78** is also coated with one or more layers **80** of surface-rated thermal insulating paint. The paint layer **74** is protected from the subsea environment by the cement **76**, and the paint layer **80** is protected from the subsea environment by the conductor **70**. The surface-rated thermal insulating paint may therefore be used to insulate the casing **78** and the conductor **70** to reduce the possibility of hydrates forming in the system.

[0026] FIG. **4** illustrates a flow chart of an exemplary process **100** for insulating a subsea mineral extraction component. A mineral extraction component may be provided for use in a subsea environment (block **102**). The component may be at least partially or entirely coated in a surface-rated thermal insulating paint (block **104**). That is, a portion or all of the component may be covered in the paint. The portion may include, for example, an interior and/or an exterior of a casing. In addition, the portion may include a length of the casing which will be buried in the sea floor. Coating the component in the surface-rated thermal insulating paint may include applying multiple layers of the surface-rated thermal insulating paint. For example, three layers of paint may be applied to the component, with each layer drying for a time before the next layer is applied. Each layer may be applied at a thickness of approximately 3-5 mils, which results in a dry layer of 1.5-2.5 mils thickness.

[0027] Once the surface-rated thermal insulating paint has been applied to the subsea mineral extraction component, the coated component may be installed subsea such that the surface-rated thermal insulating paint is sealed off from the subsea environment (block **106**). For example, the coated component may be buried in cement or concrete. The coated component may also be sealed within a casing or other subsea component. Further, the component may be internally coated such that the surface-rated thermal insulating paint is not exposed to the external environment. It may also be desirable to seal the insulating paint from other environments for which it is not rated. That is, production and extraction fluids such as oil, gas, injection chemicals, etc. may also damage the surface-rated thermal paint, therefore the insulative coating may be further sealed off from such environments. For example, the paint may be applied only to portions of components that will not be exposed to such environments.

[0028] While the invention may be susceptible to various modifications and alternative forms, specific embodiments have been shown by way of example in the drawings and have been described in detail herein. However, it should be understood that the invention is not intended to be limited to the particular forms disclosed. Rather, the invention is to cover all modifications, equivalents, and alternatives falling within the spirit and scope of the invention as defined by the following appended claims.

1. A system, comprising:

a surface-rated insulation not rated for a subsea environment or a corrosive environment; and

a protective structure configured to protect the surface-rated insulation from the subsea environment or the corrosive environment.

2. The system of claim **1**, wherein the surface-rated insulation is susceptible to break down or reduced effectiveness in the subsea environment or the corrosive environment.

3. The system of claim **2**, wherein the surface-rated insulation is susceptible to seawater in the subsea environment, and the protective structure blocks seawater from contacting the surface-rated insulation.

4. The system of claim **2**, wherein the surface- rated insulation is susceptible to oil, gas, or chemicals in the corrosive environment, and the protective structure blocks the oil, gas, or chemicals from contacting the surface-rated insulation.

5. The system of claim **1**, wherein the surface-rated insulation comprises a surface-rated insulative paint.

6. The system of claim **1**, wherein the surface rated insulation comprises highly porous particles obtained by drying a sol-gel.

7. The system of claim **1**, wherein a coating of the surface-rated insulation has a thickness of less than 50 mils.

8. The system of claim **1**, wherein a coating of the surface-rated insulation has a thickness of less than 30 mils.

9. The system of claim **1**, wherein a coating of the surface-rated insulation has a thickness of less than 10 mils.

10. The system of claim **1**, wherein the surface-rated insulation is configured to resist moisture accumulation along a surface covered by the surface-rated insulation.

11. The system of claim **1**, wherein the surface-rated insulation excludes foam insulation.

12. The system of claim **1**, wherein the surface-rated insulation excludes insulation not configured to support a load.

13. The system of claim **1**, wherein the protective structure comprises a subsea-rated sealant.

14. The system of claim **13**, wherein the subsea-rated sealant comprises a subsea-rated paint.

15. The system of claim **1**, wherein the protective structure comprises concrete or cement.

16. The system of claim **1**, wherein the protective structure comprises a tubing or an enclosure.

17. The system of claim **1**, comprising a component configured to be deployed in the subsea environment or the corrosive environment, wherein at least a portion of the component is configured to be covered by the surface-rated insulation that is protected by the protective structure.

18. The system of claim **17**, wherein the component is part of a subsea hydrocarbon system.

19. The system of claim **17**, comprising a wellhead, a Christmas tree, a valve, a tubing, a manifold, a hanger, a running tool, a production string, a base, a pile, or combination thereof, coupled to or including the component.

20. A system, comprising:

an insulative paint susceptible to break down or reduced effectiveness in a subsea environment or a corrosive environment; and

a protective structure configured to protect the insulative paint from the subsea environment or the corrosive environment.

21. The system of claim **20**, comprising a component configured to be deployed in the subsea environment or the corrosive environment, wherein at least a portion of the component is configured to be covered by the insulative paint that is protected by the protective structure.

22. A method, comprising:

insulating a component with an insulation not rated for a subsea environment or a corrosive environment; and

protecting the insulation from the subsea environment or the corrosive environment via a protective structure.

23. The method of claim **22**, wherein insulating the component with the insulation comprises coating a surface of the component with an insulative paint that is susceptible to break down or reduced effectiveness in the subsea environment or the corrosive environment.

24. The method of claim **22**, wherein protecting the insulation comprises blocking exposure of the insulation to the subsea environment or the corrosive environment with a subsea-rated sealant, concrete, cement, a tubing, an enclosure, a seafloor, or a combination thereof.

* * * * *