

MODULAR ENHANCED GEOTHERMAL POWER GENERATION AND METHOD

CROSS REFERENCE TO RELATED APPLICATIONS

[001] This application claims the benefit of the filing date of U.S. Provisional Application No. 60/077,456 titled MODULAR ENHANCED GEOTHERMAL POWER GENERATION AND METHOD, filed July 1, 2008.

TECHNICAL FIELD OF THE INVENTION

[002] Electricity is generated employing heat from hot dry rocks or other hot material in the earth's crust by modular components selected to produce electric power over at least several decades.

BACKGROUND OF THE INVENTION

[003] Geothermal energy has been used by man for tens of thousands of years. Hot springs were used by Indians in North America for cleansing and warmth. The hot spring waters, where the temperature was sufficient, were also used by Indians for cooking. In 1904 a geothermal power plant was operating in Lardarello, Italy. John D. Grant drilled wells in California during the 1920's, to extract steam, run an engine and generate electricity.

[004] A large-scale geothermal electricity generating plant began operation at the Geysers in California in the 1960's.

[005] The above examples of geothermal employment all involve ground water that is heated in the ground and comes to the surface as hot water or steam. Water is injected through wells, heated and comes to the surface in areas that are near the edges of tectonic plates. Such geothermal energy is not available in areas that are not close to the edges of tectonic plates or volcanic activity.

[006] Hot dry rocks are found by drilling in areas that are not near the edges of tectonic plates. Hot dry rocks geothermal energy storage is found in most of North America and other areas of the world.

[007] A U.S. Department of Energy hot dry rock geothermal facility was created and tested at Fenton Hill, New Mexico in 1978. In phase I, the facility included an energy extraction hole EE-1 that was drilled to 3,064m. Two water injection holes were drilled, but satisfactory connection with EE-1 was not established. A hole GT2-B was drilled and an acceptable connection with hole EE-1 was obtained at 2,673m. The two holes were separated by about 100 meters. Connection was established by injecting water and pressurizing the water to fracture the rock. A 60 KW binary fluid turbine generator was powered by steam from EE-1 for 417 days.

[008] Phase II wells EE-2 and EE-3 were drilled starting in April 1979. Well EE-2 reached a depth of 4,390 m. The wells were hydraulically fractured at multiple depths. An inadequate connection was established between the two wells. Well EE-3A was drilled off a mid portion of well EE-3, to a depth of 4,018m, to intersect fractures in well EE-2. During an initial 30 day test, 37,000 m³ (cubic meters) of water was pumped through the system. Initially 66% of the water was recovered at

192°C. A casing partially collapsed at 3200 feet. The casing was plugged above the collapse and a new bore was drilled from the plug. The loss of twelve thousand cubic meters of water is significant in an area where water is scarce. A flow test was conducted in 1989 and 1990 to obtain data for a long-term flow test. Down hole temperature did not change measurably during the testing. The first stage of long-term flow testing started on April 8, 1992. After 112 days of operation the injection pumps failed. New pumps driven by electric motors were installed. Testing continued for another 55 days with constant down hole temperature. Field test were then terminated due to very low funding. The Fenton Hill geothermal facility was eventually closed.

[009] A number of hot dry rock geothermal facilities have been opened in the United States and around the world since 1990. These facilities have encountered the problems at Fenton Hill and other problems. Establishing communication between a water injection well and an energy extraction well is difficult. The movement of water from injection wells is unpredictable. Water injected into some injection wells has disappeared. The communication between an injection well and an extraction well may become direct and develop a high capacity thereby limiting the expected temperature increase. In other situations good communication between an injection well and an extraction well is established and then flow to the extraction well decreases due to changes in the fractured rocks. The flow of water to the extraction well may even stop due to changes in the fractured hot dry rocks.

[0010] Well drilling into hot dry rock involves a number of potential problems. Direction control during drilling is very important. Global electronic positioning type

systems are available to indicate the position of a drill bit. Measurement of temperatures at various levels in the well bore is also necessary. The electronic sensors required for temperature measurement, location determination and other sensors must be able to withstand the temperatures encountered in the well bore.

[0011] Drilling fluids may boil as they approach the surface and pressure decreases. Removing drill stem from a bore can be very difficult if the drill stem is full of hot liquids. The liquids may need to be cooled before they reach the drilling rig level. It may also be necessary to employ special drilling fluids to prevent boiling.

[0012] The hot dry rocks and some materials above these rocks is abrasive and hard. Drill bits will have a relatively short life. Bits specifically designed for drilling into hot dry rocks are required. Oil is generally not found in formations that are as difficult to drill as hot dry rocks. Special drill bits are therefore required.

[0013] Circulation of drilling fluids is occasionally lost. Lost circulation of drilling fluids is more prevalent in hot dry rock drilling than in oil drilling. The loss of circulation may require substantial time and expense to eliminate the cause and restart circulation.

[0014] Casing and cementing procedures are difficult due to temperature and pressure considerations. The casing must have sufficient strength to withstand the higher pressures that may be encountered. To maintain a completed diameter of about 10 inches in may be necessary to bore a well with a bore diameter of 42 inches for the casing in a 10,000 meter deep well.

[0015] The future of Geothermal Energy published by Massachusetts Institute of Technology (MIT) in 2006 is a comprehensive assessment of enhanced, or

engineered geothermal systems. Section 4.11 of the MIT assessment states “there are still many areas of technology improvement needed that will help make the process more economical and less risky. Implementation of robust enhancement is needed to enable the exploitation of the heat in hot rock sources around the world.

SUMMARY OF THE INVENTION

[0016] The geothermal power generation system includes a well bore that extends downward from a well head into the earth’s crust to hot dry rock. A well bore portion also extends downward into hot dry rock to a well bottom.

[0017] Pluralities of casing strings are mounted in the well bore. Each casing string extends downward at least one thousand meters. Each casing string has an outside diameter that permits an upper end of each casing string to telescopically extend into an above casing string. A casing string bottom end with a smallest outside diameter is supported by hot dry rock. The well bore portion extending downward into the hot dry rock extends from the casing string bottom end to the well bottom.

[0018] A cold fluid supply pipe extends from the well head through the plurality of casing strings and into the well bore portion extending downward into hot dry rock. A plug closes a cold fluid supply pipe bottom end. The entire cold fluid supply is supported by the well head. The plug is above the well bottom when the cold fluid supply pipe is at a maximum well temperature.

[0019] A hot fluid return conduit is received in the cold fluid supply pipe. The hot fluid return conduit upper end is supported at the well head. A hot fluid return conduit bottom open end is positioned above the plug. The hot fluid return conduit has a uniform inside diameter from the hot fluid return conduit bottom open end to the well head. The wall thickness of the hot fluid return conduit decreases in steps from the well head to the hot fluid return conduit open end.

[0020] A heat exchanger is connected to the hot fluid return conduit upper end. The heat exchanger is also connected to the cold fluid supply pipe at the well head. A pump circulates an engineered heat convection fluid in a closed heat convection fluid chamber formed by the cold fluid supply pipe, the hot fluid return conduit, the heat exchanger and the pump.

[0021] An accumulator is connected to the closed heat convection fluid chamber. The accumulator receives and discharges the engineered heat convection fluid to accommodate temperature changes in the well bore.

[0022] A flash vessel is connected to the heat exchanger and receives an engineered turbine fluid from the heat exchanger at an elevated temperature and pressure.

[0023] A turbine and generator receive the engineered turbine fluid as a gas from the flash vessel. A condenser receives the engineered turbine fluid from the turbine, condenses the engineered turbine fluid into liquid form. A turbine fluid pump receives condensed engineered turbine fluid from the condenser and returns the engineered turbine fluid to the heat exchanger.

[0024] To employ the modular geothermal power generation system, a site for hot dry rock power generation is selected. An electricity generating module including a flash vessel, a turbine and an electricity generator driven by the turbine is selected. A condenser module and turbine fluid pump is selected which is compatible with the location is selected. A heat exchanger module is also selected. One or more heat extraction wells are drilled. The well or wells are drilled to provide substantial heat transfer area to provide the required heat to run the turbine.

BRIEF DESCRIPTION OF THE DRAWINGS

[0025] The presently preferred embodiments of the invention are disclosed in the following description and in the accompanying drawings, wherein:

[0026] Figure 1 is a sectional view of a hot dry rocks well and well casing with parts broken away;

[0027] Figure 2 is a sectional view of the upper portion of a hot dry rocks well including the well head, the casing, the cold fluid supply pipe and the hot fluid return conduit;

[0028] Figure 3 is a sectional view of the bottom portion of the bore, the bottom bore, the bottom casing string, the bottom casing concrete, the bottom of the cold fluid supply pipe and the bottom of the hot fluid return conduit with parts broken away;

[0029] Figure 4 is a schematic view of a hot dry rocks electricity generating facility that connects to the well head; and

[0030] Figure 5 is an enlarged vertical sectional view of the bottom portion of the well bore showing changes in the hot fluid return conduit outside diameter and the cold fluid supply pipe inside diameter.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

[0031] A bore 10 into hot dry rocks 12 is drilled by a large heavy duty drilling rig. The drilling rig has sufficient power to drill deep into the earth's crust and to lift casing strings 14 and up to several miles of drill stem pipe. The first bore portion 16 extends downward about 1,000 meters into the earth's crust employing current technology. Depending upon the total depth of a well 18, the first bore portion 16 has a diameter of about a meter. Each casing string 14 is about a thousand meters long. The first casing string 17 has relatively thin walls because the maximum horizontal pressure on the casing is relatively small.

[0032] The first bore portion 16 is drilled down about a thousand meters. The first casing string 17 of the casing 14 is lowered into the first bore portion 16, one section at a time. The first bore portion 16 is lined by concrete 20 as the first casing string 17 is lowered and casing sections are secured to each other. When the first casing string 17 is supported by the bottom of the first bore portion 16, a smaller drill bit is lowered through the first casing string 16 and a second bore portion 22 of the well 18 is drilled downward another thousand meters.

[0033] A second casing string 24 is lowered into the first casing string 17 one section at a time. The second casing string 24 has substantially thicker walls than

the first casing string 17 due to the increased horizontal pressures that may be exerted on the casing at the lower elevation. The casing sections of the second casing string 24 are secured to each other as the second casing string 24 is lowered into the second bore portion 22. The second bore portion 22 is lined by concrete 26 as the second casing string 24 is lowered to the bottom of the second bore portion 22. When the second casing string 24 is supported on the bottom of the second bore portion 22, the upper end of the second casing string 24 extends upward telescopically into the bottom of the first casing string 17 a substantial distance to accommodate thermal expansion and maintain a connection between the two casing strings 17 and 24. After the first casing string 14 and the second casing string 24 are in place in the first bore portion 16 and the second bore portion 22 respectively, a third bore portion is drilled.

[0034] The second casing string 24 has an outside diameter that is slightly less than the inside diameter of the first casing string 17. The second casing string 24 also has an increased wall thickness to withstand the pressure as stated above. The third casing string (not shown) and lower casing strings have stepped decreases in outside diameter and increases in wall thickness. Six casing strings are possible. A seventh casing string may have an inside diameter that is too small to support a heat extraction system.

[0035] Increasing the size and depth of the well bore are prime enhancement techniques to establish and maintain a sustainable minimum heat flow from hot rocks to a heat convection fluid 203.

[0036] The casing strings 14 and 24 are discontinued upon reaching solid rock. However drilling is continued upon reaching hot dry rock 12 to increase the bore surface area from which heat can be extracted. An engineered heat transfer fluid 201 maybe inserted into the lower portion of the well 18. Such an engineered fluid is required to operate at the temperature of the hot rock in which it is inserted and transfer heat from the rock to a heat conveyor.

[0037] A cold fluid supply pipe 30 is lowered into the well 18. The supply pipe 30 is a high strength pipe with joints 32 that can be attached together as each joint is lowered into the well 18. The wall thickness should be sufficient to withstand the maximum potential pressure to which the supply pipe 30 may be subjected. The bottom end 34 of the supply pipe 30 is closed by a supply pipe plug 36.

[0038] A hot fluid return conduit 38 with conduit joints 40 is received in the inside of the cold fluid supply pipe 30. The inside cross-section area of fluid return conduit 38 is the same as or smaller than the effective inside cross-section are of the cold fluid supply pipe 30. The hot fluid return conduit 38 inside cross-section area may be somewhat smaller than the cold fluid supply pipe 30 fluid passage cross-section area so that the fluid velocity in the hot fluid return conduit 38 exceeds the fluid velocity in the cold fluid supply pipe 30. The conduit bottom 42 of the hot fluid return conduit 38 is above the supply pipe plug 36 some distance. Joints 40 are provided in the hot fluid return conduit 38 to limit the length of each conduit section to the pipe length capacity of the drilling derrick.

[0039] The top end 44 of the first casing string 17 is anchored to the well head 46 near the ground surface S. The entire weight of the cold fluid supply pipe 30

together with the weight of fluid contained in the fluid supply pipe is supported at the well head 46. The hot fluid return conduit 38 is also supported at the well head 46. The inside diameters of the casing strings 17 and 24 in the upper portions of the well 18 are quite large. The casings provide space for the support of the cold fluid supply pipe 30 at one or more locations below the well head 46. The hot fluid return conduit 38 could also be supported at one or more locations below the well head 46. A support or supports below the well head 46 will reduce the tension load on the cold fluid supply pipe 30. The tension load on the hot fluid return conduit 38. The tension load on the hot fluid return conduit 38 can also be reduced by a support or supports below the well head 46. Reducing the tension loads on the cold fluid supply pipe 30 and on the hot fluid conduit 38 reduces the wall thickness in both the pipe and the conduit between the support or supports and the well head 46.

[0040] The cold fluid supply pipe 30 with the supply pipe plug 36 forms a portion of a closed chamber for an engineered heat convection fluid 203. The cold fluid supply pipe 30 and the supply pipe plug 36 supports the weight of all the engineered heat convection fluid 203 in the cold fluid supply pipe 30 and in the hot fluid return conduit 38. The fluid pressure difference between the inside of the hot fluid return conduit 38 and the outside surface of the hot fluid return conduit at any location from the well head to the conduit bottom 42 is due to circulating pump pressure rather than to the fluid head. The hot fluid return conduit 38 needs to have sufficient strength to support its entire weight and the fluid head of a circulating pump 58.

[0041] The cold fluid supply pipe 30 has an outside surface that is subjected to the pressure of a static head of the static heat conducting engineered well fluid 201 in the lower portions of the well 18. However, the static heat conducting engineered well fluid 201 is only useful in the bottom portion of the well where the heat convection fluid is to be heated by hot dry rocks.

[0042] The pressure exerted on the outside of the cold fluid supply pipe 30 by the heat conducting engineered well fluid 201 counter acts a portion of the force exerted on the inside of the cold fluid supply pipe by the engineered heat convection fluid 203. If the well 18 is filled with heat conducting fluid 201 from the well head 46 downward, substantially all of the pressure on the inside walls of the cold fluid supply pipe 30 would be offset by the pressure of heat conducting well fluid 201 on the outside of the fluid supply pipe assuming both fluids have about the same density. However, there is a possibility that the hot dry rocks or other portions of the bore 10 will develop a crack or other fluid passage that will drain heat conducting engineered well fluid 201 from the well 18. As a result of this potential, the cold fluid supply pipe 30 should have sufficient wall thickness to withstand the internal pressure of the engineered heat convection fluid 203 when the bore 10 of the well 18 is otherwise free of liquid. The thickness of the walls of the cold fluid supply pipe 30 can decrease from the bottom end 34 to the well head 46 as the pressure of the heat convection fluid decreases.

[0043] Temperature changes cause the steel employed in the cold fluid supply pipe 30 and the hot fluid return conduit 38 to expand or contract. The cold fluid supply pipe 30 should hold the supply pipe plug 36 above the bottom of the well 18

when the cold fluid supply pipe 30 is at its maximum length. The conduit bottom 42 of the hot fluid return conduit 38 is to remain separated from and above the supply pipe plug 36 over an expected range of temperatures of the hot fluid return conduit and the cold fluid supply pipe 30.

[0044] The hot fluid return conduit 38 is coated with a heat transfer barrier 50 at a level where the engineered heat convection fluid 203 reaches its maximum temperature up to the well head 46. The heat transfer barrier 50 can be on the inside surface of the hot fluid return conduit 38 or on the outside surface of the hot fluid return conduit. The heat transfer barrier 50 can also be on the inside surface and the outside surface of the hot fluid return conduit 38. The heat transfer barrier 50 may be a thin ceramic material.

[0045] A control system for the well 18 includes a number of sensors. A sensor is employed to sense the volume of the heat conducting fluid 201 as indicated by the distance from the well head 46 to the conducting fluid head. The level of the heat conducting fluid will indicate possible changes in the bore 10. Pressure in the bottom of the bore 10 can also be monitored to determine if there is an unexpected change in the well 18. The temperatures of the rocks or other material in the heat extraction area of the bore 10 are sensed to determine if heat is being removed at a sustainable rate. Temperatures of the engineered heat convection fluid 203 are measured at the inlet to the well head 46 and the lower end of the fluid supply pipe 30. The temperature of the engineered heat convection fluid 203 is also measured in the hot fluid return conduit 38 at the upper end of the heat transfer area and at the well head 46. The fluid flow rate of the engineered heat convection fluid 203 is

measured at the inlet end of the cold fluid supply pipe 30 and at the outlet from the hot fluid return conduit 38. Additional sensors and controls are required for the heat exchanger 54, the turbine 80 and the condenser 92.

[0046] The hot fluid return conduit 38 is connected to an inlet 52 of a heat exchanger 54 by a pipe 56. The heat exchanger outlet 64 for the heat convection fluid 203 is connected to a pump 58 by a pipe 60. An accumulator 62 is connected to the pipe 60 to insure that there is sufficient heat convection fluid 203 to keep the closed circuit full of heat convection fluid during changes in the total volume of the closed circuit due to changes in the temperature of the cold fluid supply pipe 30 and other components of the closed system. A pipe 66 is connected to the pump outlet 68 and to an inlet 70 to the cold fluid supply pipe 30 at the well head 46. The engineered heat convection fluid 203 is to remain liquid at all operation temperatures and pressures. Insulated pipes 56, 60, 66 contain the heat convection fluid and retain heat.

[0047] The heat exchanger 54 has turbine fluid inlet 72 and a turbine fluid outlet 74. The turbine fluid inlet 72 receives engineered turbine fluid 205 that is to be heated in the heat exchanger 54 by hot heat convection fluid 203 received from the hot fluid return conduit 38 through pipe 56. Heat carried from the hot dry rocks 12 by the heat convection fluid 203 is transferred to engineered turbine fluid 205 in the heat exchanger 54. The engineered heat convection fluid 203 that has transferred heat to the engineered turbine fluid 205 is discharged from the heat exchanger 54 through a heat exchanger outlet 64. A pipe 60 carries the cooled engineered heat convection fluid to a pump 58. A pump outlet 68 discharges heat convection fluid 203 through

pipe 66 to an inlet 70 to the cold fluid supply pipe 30. The pipe 56 to the heat exchanger 54 is insulated. The pipes 60 and 66 that convey engineered convection fluid 203 from the heat exchanger 54 to the cold fluid supply pipe 30 may also be insulated. The engineered heat convection fluid 203 is to remain a fluid at all times as stated above. Temperature and pressure are to keep the heat convection fluid 203 in a saturated state. The engineered heat convection fluid 203 is in a closed system. However the volume of the closed system changes when the temperature of the steel cold fluid supply pipe 30 changes and causes the cold fluid supply pipe to expand or contract. An accumulator 62 supplies heat convection fluid 203 when the fluid supply pipe expands and receives convection fluid from the pipe 60 when the fluid supply pipe 30 contracts. The accumulator 62 is connected to pipe 60 between the heat exchanger outlet 64 and the pump 58 where a minimum pressure occurs.

[0048] The engineered turbine fluid 205 is heated in the heat exchanger 54. Hot turbine fluid 205 is conveyed from the turbine fluid outlet 74 to a flash vessel 76 by a pipe 78. The turbine fluid 205 changes from a liquid to a gas in the flash vessel 76. The turbine 80 receives the engineered turbine fluid 205 from a gas conduit 82 connected to the flash vessel 76 and the high pressure end 84 of the turbine. A turbine shaft 86 of the turbine 80 is connected to and drives a generator 88. A gas discharge 90 on the low pressure end of the turbine 80 is connected to a condenser 92 by a conduit 94. The turbine fluid is cooled and condensed to a liquid turbine fluid. Liquid turbine fluid 205 is conveyed from the condenser 92 to a turbine fluid pump 96 by a pipe 98. Turbine fluid 205 discharged from the turbine fluid pump 96 is conveyed to the turbine fluid inlet 72 of the heat exchanger 54 by a pipe 100. The

condenser 92 receives cooling liquid through a coolant inlet 102 and a coolant pipe 104. Hot coolant is discharged from the condenser 92 through a condenser coolant discharge 106 and a coolant discharge pipe 108. The condenser coolant is generally water. The water comes from the ground, from a stream, from a lake, or other source. The cooling water can also come from a cooling tower. One or more pumps are required to move the cooling water. A substantial quantity of water can be lost by evaporation in a cooling tower. In areas where water is scarce, the condenser 92 can employ air as a coolant. Air is an effective coolant for a condenser 92 when the turbine fluid 205 changes from a gas to a liquid at a temperature well above the ambient air temperature.

[0049] The engineered turbine fluid 205 is in a closed system as described above. An accumulator 110 is provided in the pipe 98 to accommodate expansion and contraction of the turbine fluid 205 due to temperature changes.

[0050] Heat is removed from the well at a rate which maintains a nearly constant temperature in the hot dry rocks 12. Due to the rate of heat removal from a well 18 and the size of the generator 88, a number of wells like well 18 may be required to run one turbine 80.

[0051] The heat exchanger 54, the turbine 80, and the condenser 92 are selected and sized to correspond to the capacity of the selected generator 88. When a number of wells 18 are provided to supply the required energy to drive the turbine 80 and generator 88, the heat exchanger 54 can be designed to receive heat convection fluid 203 from multiple wells 18. However, the heat convection fluid 203 from each well should remain separate and be returned to the well 18 that it came

from. The heat exchanger 54 can therefore be part of a separate module or it can be part of the power module. The power module includes the flash vessel 76, the turbine 80 and the generator 88. The condenser 92 is a separate module because the coolant source that is available will determine the condenser construction. Each well 18 is also a separate module. The pipe 56, from each well 18, can convey hot engineered heat convection fluid 203 a substantial distance from a well 18 and to a heat exchanger 54.

[0052] A pump 58, shown in Figure 4, receives cold heat convection fluid 203 from the heat exchanger 54 and forces the convection fluid into the cold fluid supply pipe 30. A second pump in line 66, that receives heat convection fluid 203 from the hot fluid return conduit 38 and supplies the hot convection fluid to the heat exchanger 54, may be added if desired. The second pump will insure that the heat convection fluid remains under pressure in the heat exchanger 54 and does not change from a liquid to a gas. The second pump also increases the pressure of the heat convection fluid 203 at the inlet to supply pump 58. An increase in the pressure of the heat convection fluid 203 in the heat exchanger 54, the pipe 56 at the inlet 52 to the heat exchanger and the pipe 60 at the inlet to the supply pump 58 reduces the possibility of cavitation and reduces the pressure increase in the heat convection fluid between the heat exchanger outlet 64 and pump outlet 68. A second pump for heat convection fluid 203 also permits the heat exchanger 54 and the turbine 80 to be located some distance from the well 18. In some power generation facilities it is expected that several wells 18 will supply heat convection fluid 203 to one heat exchanger 54 and turbine. However, it is also possible that one well 18 will supply

heat convection fluid 203 to multiple modules each of which includes a turbine 80 and a generator 88 through a suitable heat exchanger arrangement. There may be a separate heat exchanger 54 for each well 18. There also may be a separate heat exchanger inlet 52, a heat exchanger outlet 64, and internal heat exchanger passages for each well 18 in one heat exchanger 54. It is desirable that the engineered heat convection fluid 203 for each well 18 be in a closed system. A loss or increase in engineered heat convection fluid 203 indicates problems in a well 18 that may be serious. Such problems need to be discovered as earlier as possible to prevent excessive damage to a heat producing well 18.

[0053] The flow of engineered heat convection fluid 203 through the cold fluid supply pipe 30 and the hot fluid return conduit 38 should be as free as possible. Restrictions to flow are minimized. The inside diameter of the hot fluid return conduit 38 is therefore uniform from the conduit bottom 42 to the well head 46. The inside pressure and the outside pressure exerted on the hot fluid return conduit 38 by the convection fluid 203 will be substantially the same at any selected elevation below the well head 46 when the convection fluid is not flowing. The supply pump 58 will increase the pressure on the outside surface of the fluid return conduit 38 at the well head 46. The inside pressure and the outside pressure exerted by the convection fluid at the conduit bottom 42 will be the same even when fluid is flowing. As a result, the fluid return conduit 38 can have relatively thin walls at the conduit bottom 42. The wall thickness of the fluid return conduit 38 at the well head 46 must be substantial to support the entire weight of the fluid return conduit. The decrease in wall thickness of

the fluid return conduit 38 is obtained by decreasing the outside diameter of the fluid return conduit in steps from the well head 46 to the conduit bottom.

[0054] The cold fluid supply pipe 30 must support the weight of all the engineered heat convection fluid 203 contained in the supply pipe and in the hot fluid return conduit 38. The cold fluid supply pipe 30 is also supported at the well head 46 and must have sufficient strength to support the entire weight.

[0055] The pressure of the engineered heat convection fluid 203 on the inside walls of the cold fluid supply pipe 30 is substantial at bottom end 34 of the fluid supply pipe. The required wall thickness of the cold fluid supply pipe 30 at its bottom end 34 will depend on the depth of the bottom end 34 from the well head 46. A heat conducting well fluid 201 in the well bore 10 may be lost and therefore not available to reduce the strength required to hold the pressure exerted by the engineered heat convection fluid 203.

[0056] The inside cross section area of the hot fluid return conduit 38 is the inside radius squared times π . The minimum cross section area available for cold fluid supply is substantially the same as the inside cross section area of the hot fluid return conduit 38. As the outside diameter of the hot fluid return conduit 38 decreases in steps from the well head 46 to the conduit bottom, the inside diameter of the cold fluid supply pipe 20 is decreased in steps. Decreases in the inside diameter of the cold fluid supply pipe 30 permits a decrease in the outside diameter of the cold fluid supply pipe. The horizontal thickness of the cold fluid supply pipe 30 is increased in steps in the lower portion of the bore 10 to withstand the pressure exerted by the engineered heat convection fluid 203. The wall thickness of the fluid

supply pipe 30 at the well head 42 is based on the strength required to support the weight of the fluid supply pipe 30 and the engineered heated convection fluid 203. The maximum outside diameter of the cold fluid supply pipe 30 is dependent upon the maximum fluid pressure at the supply pipe plug 36. Reducing the maximum outside diameter of the cold fluid supply pipe 30 reduces the required diameter of the bore 10 at the well head and thereby reduces drilling cost. Reducing the maximum outside diameter of the cold fluid supply pipe 30 also reduces the total weight of the fluid supply pipe 30. Alternatively, the decreasing diameter of the hot fluid return conduit 38 from the well head 46 toward the conduit bottom 42 makes it possible to increase the depth of the well without increasing the diameter of the bore 10 at the well head 46.

[0057] The thickness of a heat transfer barrier 50, if employed, should be included in the calculations described above. The weight of a heat transfer barrier 50 should also be considered. However, since the bore 10 of the well 18 with the well head 46 and the casing strings 14 and 24 form a nearly closed system, a heat transfer barrier 50 may not be needed.

[0058] Oil wells are drilled using a drill bit that mechanically grinds material and flushes the material to the surface with water. The drill bits employ three or more conical rollers with radially projecting teeth. The drilling rate in hot dry rocks with these drill bits is relatively slow due to the hardness of the hot dry rocks. Some inventors are working on systems that will increase the drilling rate in hard rocks. One system employs flame jets with high temperature flame. Another system employs hot water at high temperature and pressure. Both systems appear to work

well on granite slabs on the surface. Further development may be required to develop these systems to work in deep bore holes. The geothermal power generation system described above can employ any workable drilling system. A drilling system that reduces drilling expense in deep wells 10 will be an assistance in a hot dry rock heat recovery system as described above.

CLAIMS

I claim:

1. A modular geothermal power generation method comprising:
 - selecting a site suitable for a geothermal power generation;
 - selecting an electricity generating module including a flash vessel, a turbine with a fluid flow rate that corresponds to a flash vessel capacity and an electricity generator driven by the turbine with a generator capacity that corresponds to a power output of the turbine and the flash vessel capacity;
 - selecting a condenser module with a condenser and a turbine fluid pump, a turbine fluid condensing capacity to condense a turbine fluid discharged from the turbine as a gas into a turbine fluid liquid, and a condenser coolant system that employs resources available in an area of the site;
 - selecting a heat exchanger module with a capacity to heat all the turbine fluid received from the condenser;
 - drilling one or more heat extraction wells each of which includes a well bore that extends from a well head into material with an elevated temperature a distance to provide a substantial heat transfer area, mounting a casing in at least a portion of the well bore, inserting a cold fluid supply pipe with a supply pipe upper end supported by the well head, a closed supply pipe lower end positioned in the hot dry rock above a bore bottom end, a static heat conducting fluid in the bore bottom end and a hot dry rock elevated temperature portion of the well bore, inserting a hot fluid return conduit into the supply pipe upper end with a conduit upper end supported by the well head and a conduit lower end inside the supply pipe and spaced from the closed supply pipe lower end, connecting the conduit upper end to a heat

exchanger inlet of the heat exchanger module and connecting a heat exchanger outlet to the supply pipe upper end; and

circulating a heat convection fluid at a controlled rate into the supply pipe upper end of the cold fluid supply pipe, into the conduit lower end, out the conduit upper end, through the heat exchanger and back to the supply pipe upper end.

2. A geothermal power generation system comprising:

a well bore that extends downward from a well head into the earth's crust to hot dry rock and a well bore portion extending downwardly into hot dry rock to a well bottom;

a plurality of casing strings mounted in the well bore wherein each casing string has an outside diameter that permits an upper end of each casing string to telescopically extend into an above casing string, a casing string bottom end with a smallest outside diameter supported by hot dry rock, and wherein the well bore portion extending downward into the hot dry rock extends from the casing string bottom end to the well bottom;

a cold fluid supply pipe extending from the well head through the plurality of casing strings and into the well bore portion extending downward into hot dry rock, a plug closing a cold fluid supply pipe bottom end, wherein the entire cold fluid supply pipe is supported by the well head, and the plug is above the well bottom when the cold fluid supply pipe is at a maximum well temperature;

a hot fluid return conduit received in the cold fluid supply pipe with a hot fluid return conduit upper end supported at the well head, a hot fluid return conduit bottom open end positioned above the plug and wherein the hot fluid return conduit has a uniform inside diameter from the hot fluid return conduit bottom open end to the well head, and wherein the

wall thickness of the hot fluid return conduit decreases in steps from the well head to the hot fluid return conduit open end;

a heat exchanger connected to the hot fluid return conduit upper end and the cold fluid supply pipe at the well head; and

a pump circulating an engineered heat convection fluid in a closed heat convection fluid chamber formed by the cold fluid supply pipe, the hot fluid return conduit, the heat exchanger and the pump.

3. A geothermal power generation system comprising:

a well bore that extends downward from a well head into the earth's crust to hot dry rock and a well bore portion extending downwardly into hot dry rock to a well bottom;

a plurality of casing strings mounted in the well bore, each of which extends downward at least one thousand meters, wherein each casing string has an outside diameter that permits an upper end of each casing string to telescopically extend into an above casing string, a casing string bottom end with a smallest outside diameter supported by hot dry rock, and wherein the well bore portion extending downward into the hot dry rock extends from the casing string bottom end to the well bottom;

a cold fluid supply pipe extending from the well head through the plurality of casing strings and into the well bore portion extending downward into hot dry rock, a plug closing a cold fluid supply pipe bottom end, wherein the entire cold fluid supply pipe is supported by the well head, and the plug is above the well bottom when the cold fluid supply pipe is at a maximum well temperature;

a hot fluid return conduit received in the cold fluid supply pipe with a hot fluid return conduit upper end supported at the well head, a hot fluid return conduit bottom open end positioned above the plug and wherein the hot fluid return conduit has a uniform inside diameter from the hot fluid return conduit bottom open end to the well head, and wherein the wall thickness of the hot fluid return conduit decreases in steps from the well head to the hot fluid return conduit open end;

a heat exchanger connected to the hot fluid return conduit upper end and the cold fluid supply pipe at the well head; and

a pump circulating an engineered heat convection fluid in a closed heat convection fluid chamber formed by the cold fluid supply pipe, the hot fluid return conduit, the heat exchanger and the pump.

4. A geothermal power generating system, as set forth in claim 3, including an accumulator connected to the closed heat convection fluid chamber for receiving and discharging the engineered heat convection fluid as required due to temperature changes in the well bore.
5. A geothermal power generating system, as set forth in claim 3, including a flash vessel connected to the heat exchanger and receiving an engineered turbine fluid from the heat exchanger at an elevated temperature and pressure.
6. A geothermal power generating system, as set forth in claim 5, including a turbine and generator that receives the engineered turbine fluid as a gas from the flash vessel.

7. A geothermal power generating system, as set forth in claim 6, including a condenser that receives the engineered turbine fluid from the turbine, condenses the engineered turbine fluid into liquid form, and a turbine fluid pump that receives condensed engineered turbine fluid from the condenser and returns the engineered turbine fluid to the heat exchanger.
8. A geothermal power generating system, asset forth in claim 3, wherein the plurality of casing strings includes up to six casing strings.
9. A geothermal power generating system, as set forth in claim 3, wherein the bore is lined by concrete as a casing string is lowered into the bore.
10. A geothermal power generating system, as set forth in claim 3, wherein the inside diameter of the cold fluid supply pipe decreases in steps from the well head downward to correspond to decreases in the wall thickness of the hot fluid return conduit from the well head to the hot fluid return conduit bottom end to maintain a substantially constant flow area in the cold fluid supply pipe for engineered heat convection fluid.

ABSTRACT OF THE DISCLOSURE

The geothermal power generation system includes a heat module well bore that extends down into hot dry rock. A casing and concrete line the bore from the well head to hot dry rock. The well bore extends into the hot dry rock. A cold fluid supply pipe extends down into the hot dry rock and is closed by a supply pipe plug. A hot fluid return conduit extends into the supply pipe to a conduit bottom above the pipe plug. The supply pipe and the return conduit are connected to a heat exchanger. A circulating pump circulates heat convection fluid into the supply pipe, through the return conduit, and through the heat exchanger in a closed circuit. Turbine fluid carries heat from the heat exchanger to a turbine and generator module. A condenser module condenses turbine fluid and returns the turbine fluid to the heat exchanger for heating.