

Geothermal Power Capacity from Petroleum Wells – Some Case Histories of Assessment

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ABSTRACT

There are three types of petroleum wells potentially capable of supplying geothermal energy for electric power generation: (a) a producing oil or gas well with a water cut, (b) an oil or gas well abandoned because of a high water cut, and (c) a geopressured brine well with dissolved gas. This paper considers the basic technical and economic aspects of power generations from each of the three types of wells and presents case histories of estimating the available power capacity of a typical well (or a group of wells) in each of the above categories. We have conducted these assessments for commercial developers and operators.

The power capacity of wells in the first category is determined primarily by the production rate and temperature of the produced water, ambient temperature, and conversion efficiency of the geothermal power plant. The factors that control the wellhead temperature of the produced fluid are: formation temperature, well depth, well diameter and production rate. Our assessment of some producing oil wells in the Middle East showed that in spite of an attractive formation temperature, the wellhead temperature of the produced water was too low compared to the ambient temperature to allow commercial generation of geothermal power. However, solar energy or the gas being flared in such a field could be used to boost the temperature of the produced water and increase the power capacity.

The power capacity of an abandoned gas well depends on: (a) production rate and temperature of the produced water, (b) ambient temperature, (c) conversion efficiency of the geothermal power plant, (d) water salinity, (e) gas content in the produced fluid, (f) heating value of the gas, and (g) the characteristics of the equipment used to generate power from the produced gas. The production rates of water and gas from such a well depend on the hydraulic properties of the formation, gas content (dissolved as well as free) in the formation water, formation temperature and pressure, and well design. It is shown that the well's productivity could be substantially improved by working it over; both pumping and self-flowing the well are considered. A conceptual design of a hybrid system to produce power from both the produced gas and water is proposed. A case history of assessment of such a gas well from the U.S. Gulf Coast is presented in the paper; it is concluded that power generation from the well is technically feasible, and can be commercially acceptable. The possible approaches to improving the project economics are discussed.

The power capacity of a geopressured well is determined by all of the factors considered above for an abandoned oil or gas well plus the amount of overpressure in the formation. A geopressured production well that supplied the U.S. Department of Energy's demonstration power project in Pleasant Bayou, Texas, in the late 1980's was re-assessed. The well is estimated to be capable of generating 3.9 MW

of which 1.5 MW is from geothermal energy, 1.9 MW from the produced methane and 0.5 MW from kinetic energy of the produced fluid. Injection of the power plant waste fluid is an important issue in developing a geopressured project. For the example above, the net power available after deducting the parasitic power for injection is 3.1 MW. The economics of such a project is dependent on the market price of natural gas; if the gas price is high enough it would be more profitable to sell the produced gas rather than generating power from it.

1. GEOTHERMAL POWER FROM CO-PRODUCED OIL & GAS FIELD WATERS

Water produced along with the oil or gas from a petroleum well is separated and injected back. If this water has adequate temperature, it is possible to extract the geothermal energy in the produced water and generate electric power before injecting the water. No drilling cost would presumably be involved in such a power generation project from co-produced water from active oil or gas wells compared to a conventional geothermal project, where the drilling cost typically amounts to 30% to 40% of the total capital cost of a project. As such, the capital cost for a geothermal project from co-produced water can be significantly lower per kilowatt generation capacity than for a conventional geothermal project.

The potential power capacity of an oil or gas well, or a group of wells, producing with a water-cut would be determined primarily by the following variables:

- a) water production rate from the well or a group of wells;
- b) temperature of the produced water at the collection point or the outlet of the storage tank;
- c) water salinity;
- d) ambient temperature at the site vis a vis the temperature of the water; and
- e) conversion efficiency of the power plant to be used.

Figure 1 shows our correlation between the MW (net) power capacity per 1,000 gallons per minute (gpm) water rate as a function of the water temperature. This correlation is based on a thermodynamic model of binary power plants we have developed using data from 15 operating binary plants (13 in the U.S. and two overseas). Considering that these plants represent four different technologies (Ormat, United Technologies, Barber Nicholls and Ben Holt), and a wide range of the ambient temperatures involved, the match between our theoretical correlation and empirical data is good. We have used this correlation to assess the power capacity available from the production rate of water of a given temperature. However, the correlation assumes pure water; if the water has significant salinity the power capacity per gpm would be correspondingly lower.

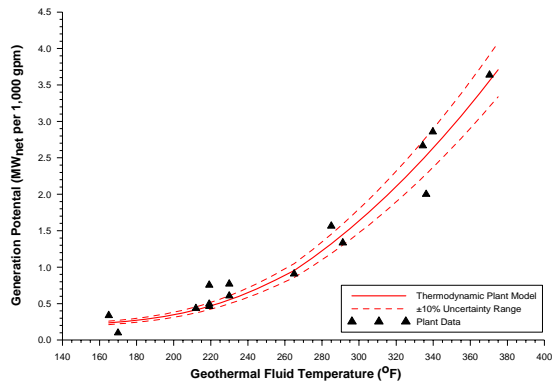


Figure 1. Theoretical and empirical correlation of net power per 1,000 gpm production versus temperature of geothermal water.

Oil and gas fields typically occur in low heat flow areas of the world (with a temperature gradient of 1.0 to 2.0°F per 100 ft); for example, Figure 2 shows the temperature versus depth correlation for some wells we are assessing in a sedimentary basin in the U.S. Gulf Coast area.

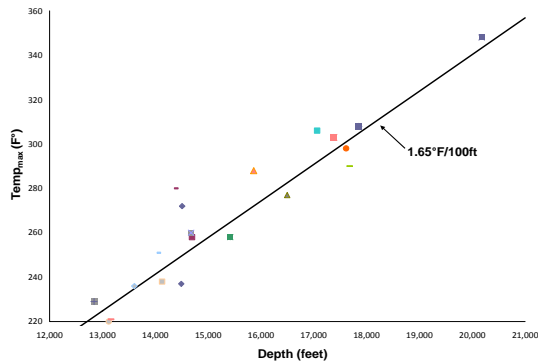


Figure 2: Temperature versus depth of abandoned wells in an area of the U.S. Gulf Coast.

Given the very deep wells in this area, bottomhole temperatures attractive enough for power generation can be found at many sites. However, the temperature of the produced water at the storage tank in an oil or gas field is significantly lower than the bottomhole temperature measured in the wells because of: (a) heat loss between the bottom and top of the well as water is produced, and (b) heat loss between the wellhead and the storage tank from the un-insulated surface piping.

The heat loss from the producing water between the bottom and top of an oil or gas well is considerably higher than in a geothermal well because of the smaller diameter and lower flow rates of petroleum wells compared to geothermal wells. Figure 3 shows the estimated wellhead temperature of water with a bottomhole temperature of 300°F at 20,000 ft. depth produced through 7-5/8-inch casing (6-inch ID) for a range of production rates and after various periods of operation; Table 1 shows the parameters used in preparing Figure 3.

Table 1. Parameters used in wellbore heat loss calculations.

Temperature gradient between the wellhead and well bottom:	0.0115°F/ft
Thermal conductivity of the formation:	1.4 BTU/hr-ft°F
Inner radius of well:	6 inch
Thermal diffusivity of the formation:	0.04 ft ² /hr
Overall heat transfer coefficient between well and formation, dependent on flow time:	1.006→0.541 BTU/hr-ft ² °F

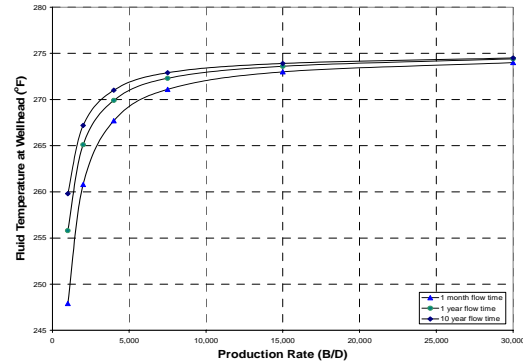


Figure 3. Reduction in Wellhead Temperature due to heat loss.

This figure shows that the heat loss from the wellbore is very high at the production rates typical of an oil well: a few hundred to a few thousand barrels per day (“B/D”). Geothermal wells typically produce at rates higher than 50,000 B/D, and as such, the producing water shows a negligible heat loss. Figure 3 also shows that the heat loss effect diminishes with time and essentially reaches equilibrium in a few months.

The electric power available from a given rate of water production at a given temperature at the storage tank will be influenced by the ambient temperature also. Figure 4 shows the electric power in Watts (gross) available per B/D of water versus water temperature for the ambient temperature conditions representative of Texas (70°F) and Alaska (40°F), assuming an utilization efficiency in power conversion of 0.45. This figure shows that the gross power available from a given production rate of water at a given temperature, in the most likely temperature range for co-produced water (less than 200°F), can be up to double in Alaska than in Texas.

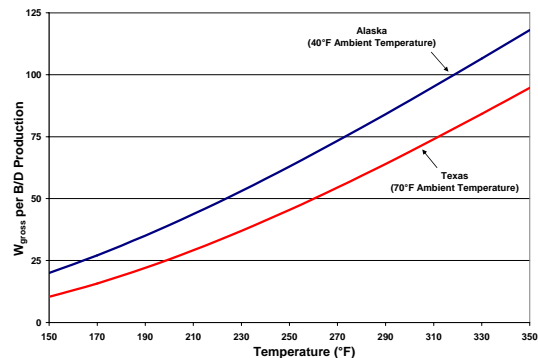


Figure 4. Impact of ambient temperature on gross power capacity of oilfield waters.

Let us consider a case history of assessment of the possibility of power generation from the water produced from an oil field in the Middle East. The daily average

ambient temperature at this oilfield is in the range of 68°F to 101°F. Assuming that cooling water at the lowest ambient temperature at the site (68°F) can be available, the maximum net power capacity per (B/D) of water with a bottomhole temperature of 160°F, is estimated at 6.8 W for a given power plant technology that was under consideration. From the 1.975 million B/D of water produced from the field, the net power available is 13.4 MW. The above estimate assumes that the water produced at the surface will have suffered only negligible heat loss from the bottomhole to the wellhead. This assumption is true only if the flow rate is high (tens of thousand B/D per well). In reality, water temperature at the various field processing sites in this field lies between 122°F and 129°F, with an average power potential of approximately 2.8W per B/D rather than 6.8W per B/D if there were no heat loss. If the plant is air-cooled, the net power would be lower than estimated and would fluctuate widely with the ambient temperature. For example, over the local minimum and maximum ambient temperatures of 68°F to 101°F, the power available from 1.975 million B/D of 160°F water (assuming no heat loss in the wells) will vary from 13.4 MW in the winter to 5.5 MW in the summer. This level of generation vis á vis the capital and operating costs involved could not justify the development of a commercial project.

Given that there is heat loss between the wellheads and field processing centers, insulating the pipelines can increase the net power capacity available from the surface facilities. If the gas production from the field is being flared, which is common in this region, the gas could be used instead to pre-heat the geothermal water, thus allowing the generation of more electric power.

If geothermal water is used to offset power generation from fossil fuels (diesel or gas) needed to run pumps and other electrical equipment in the field, there would be substantial reduction in the emission of carbon dioxide. One MW-hour of electricity generated from geothermal water rather than diesel will reduce carbon dioxide emission by about 760 kg. On an annual basis, a 1 MW plant amounts to a reduction in carbon dioxide emission of about 6 thousand metric tons, assuming a plant capacity factor of 90%. It should also be noted that a geothermal power plant has a much higher availability factor (typically 95%) compared to a fossil fuel plant (60% to 70% typical) and needs much less maintenance.

In the U.S. power generation from oil field waters is underway or being planned at several sites in Texas, Mississippi, Louisiana, Florida and Arkansas. The first such plant (of 250 kW capacity) has been operating since September 2008 at the Rocky Mountain Oilfield Testing Center in Wyoming (Johnson and Simon, 2009).

2. PRODUCTION OF GEOTHERMAL WATER FROM AN ABANDONED GAS WELL

The power capacity of an abandoned gas well depend on: (a) production rate and temperature of the produced water, (b) ambient temperature, (c) conversion efficiency of the geothermal power plant, (d) water salinity, (e) gas content in the produced fluid, (f) heating value of the gas, and (g) the characteristics of the equipment used to generate power from the produced gas. The production rates of water and gas from such a well depends on the hydraulic properties, temperature and pressure of the formation, gas content (dissolved as well as free) in formation water, and well design.

In typical gas field operations in the U.S. Gulf Coast, wells are completed with a string of production tubing inside the cemented casing. The casing is perforated over an interval of typically a few tens of feet at the top of the gas-producing formation. Water often underlies the gas; and provides “water drive” to gas production. Both water and gas may be produced through the tubing, with the relative fraction of water in the total fluid (referred to as “water cut”) typically increasing with time. As the water cut increases, the operator often installs a smaller-diameter production tubing to increase fluid velocities, thus improving the ability to lift the water and gas out of the wellbore. The change in water production rate for different tubing diameters is illustrated in Figure 5, which is a plot of wellhead pressure versus flow rate of water for wells completed with 2-7/8-inch and 4-inch tubing arrived at by numerical simulation of wellbore flow. The well considered here produces from a reservoir with a gas-oil ratio of 1,000 SCF/bbl (indicating the presence of free gas saturation in the reservoir) and a permeability-thickness product (“kh”) of 200 md-feet. At low flow rates, higher flowing wellhead pressures are obtained with the smaller tubing diameter.

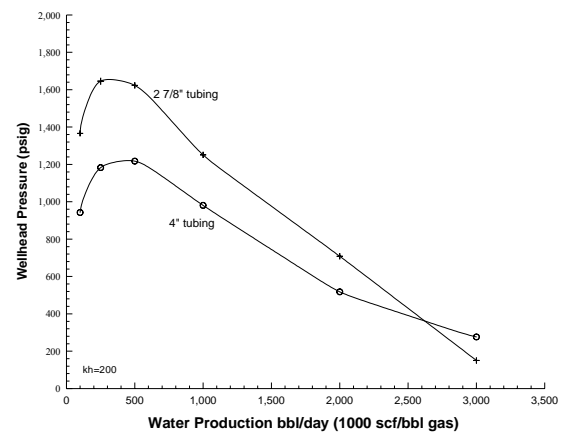


Figure 5: Flow characteristics of a gas well with water cut at abandonment condition.

To minimize water production, only the upper few feet of the productive zone are perforated in water drive systems. As a result of this “incomplete penetration” of the reservoir, the wells tend to have a large positive “skin factor.” This is one of two main parameters that control the “productivity index” (or PI) of a well, which is a measure of the flow into the well from the formation per unit pressure drawdown at the well bottom, the other parameter being reservoir flow capacity (“kh”). Wells that are perforated over a small interval typically have a high skin factor, which can reduce the PI of a well sharply. They can also have a low kh because of the small open interval. Because the goal here is to maximize water production (rather than minimize it as is the intention in gas production), one could perforate the entire interval of interest (including water-bearing sand layers) to increase the effective flow capacity of the formation, lower the skin factor and enable water production at higher rates. One could also pull the tubing and allow flow through the casing (7-inch ID) to reduce frictional pressure loss.

Figure 6 contrasts the water flow rate versus wellhead pressure behavior of an abandoned gas well (with 2-7/8-inch tubing and a flow capacity of 200 md-ft) with that of the same well if reworked with a larger-diameter completion (7 inch ID) and perforated to achieve a ten-fold

higher flow capacity (2,000 md-ft). As Figure 6 shows, in a gas reservoir with free gas saturation, major increases in flow rates can be obtained with a longer perforated interval and an increased well diameter, which reduces both frictional pressure loss and heat loss. However, this ten-fold increase in reservoir flow capacity (kh) would require perforating more than 1,000 ft. of casing. Pulling the tubing and perforating a long section of casing would be a major workover.

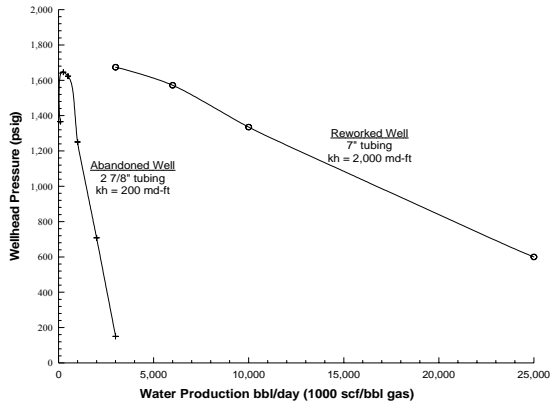


Figure 6: Wellhead flow conditions of the original well and the reworked well.

In this case history, we considered pulling out the 2-7/8-inch production tubing and perforating the well over a longer section to achieve a productivity index of 200 lb/hour/psi. We have conservatively assumed that the reservoir has no free gas saturation; all gas entering the well is dissolved gas. We assumed that the static water level in the well is at the ground level; if the level were inside the wellbore, the well will not flow when opened. Self-flow of the well can be initiated by lowering a string of coiled tubing deep into the well and injecting a low-density fluid at depth to lighten the column of water in the upper part of the well. The injected fluid may be steam produced in a boiler at the surface, or nitrogen delivered to the site. The former method is sometimes used to initiate flow in deep geothermal wells. Once flow is initiated, as the brine travels up the wellbore, the pressure gradually declines and the dissolved gas will start to come out of solution, further lowering the density of the liquid column in the wellbore and thus enabling the well to maintain flow. As shown before, at high flow rates, there is very little cooling of the hot water as it travels from the bottom of the well to the surface.

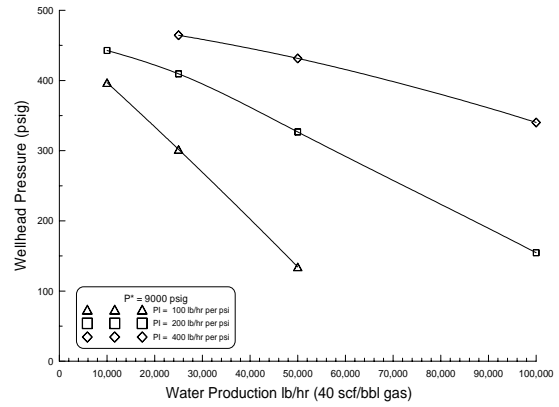


Figure 7: Wellhead flow conditions of the reworked well for various productivity index values.

The base case parameters used in computations are:

- 10-3/4-inch casing (9.794 inch inside diameter) from the surface to 13,400 feet;
- 7-5/8-inch liner (6 inch inside diameter) to 19,200 feet;
- PI of 200 lb/hour/psi;
- static reservoir pressure (P*) of 9,000 psig;
- bottomhole temperature of 280°F;
- flowing wellhead temperature of 270°F;
- dissolved gas content (methane) of 40 SCF/bbl, which is the saturation concentration at the bottomhole temperature; and
- gas gravity of 0.583 API.

In the base case scenario, the maximum available production from the well is estimated at 315 MCF/D of gas and 7,875 B/D (125,000 lbs/hour) of water at a bottomhole temperature of 280°F with a salinity of 115,000 ppm and a dissolved gas content of 40 scf/bbl, with a flowing wellhead pressure of 68 psia (assuming negligible heat loss). This water rate is about twice, and the gas rate is about one-tenth, of the rates prevalent when the well was abandoned at a gas-oil ratio of 1,000 scf/bbl. The water component can generate about 0.35MW (net) from a binary-cycle plant, as described above. Assuming an engine efficiency of 33% (net), the gas engine can generate 1.25 MW (net). Therefore, the combined power capacity from gas and water is 1.6 MW (net), that is, 22% of the power comes from geothermal energy and 78% from the produced gas.

This wellbore modeling work indicates that three variables significantly affect the productivity of such a reworked well: PI of the well, gas content in water and static reservoir pressure. Wellbore simulation results for several assumed PI values that bracket the estimated range of pressure drop in this well between the reservoir and the wellbore, are shown in Figure 7, which shows the flowing wellhead pressure versus water production rate (with 40 scf/bbl dissolved gas, and no free gas in the reservoir).

These calculations were repeated for a fixed PI of 200 lbs/hr/psi but with varying reservoir pressures (Figure 8) and for a fixed PI of 200 lbs/hr/psi and varying dissolved gas concentrations (Figure 9). Figures 7 through 9 show that the available water production rate from the reworked well would be strongly dependent on the PI of the well, static reservoir pressure and gas content in water. For any given wellhead flowing pressure, a higher water rate is

obtained for a higher value of PI, or reservoir pressure or dissolved gas content.

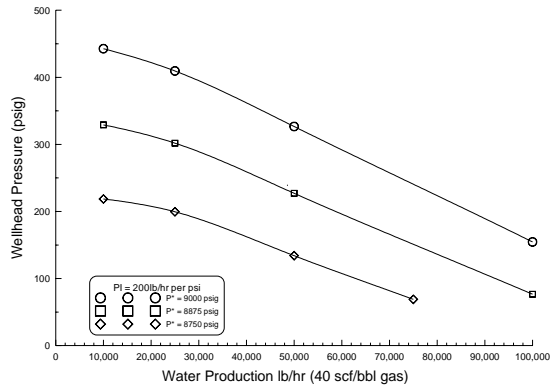


Figure 8: Wellhead flow conditions of the reworked well for various static reservoir pressures.

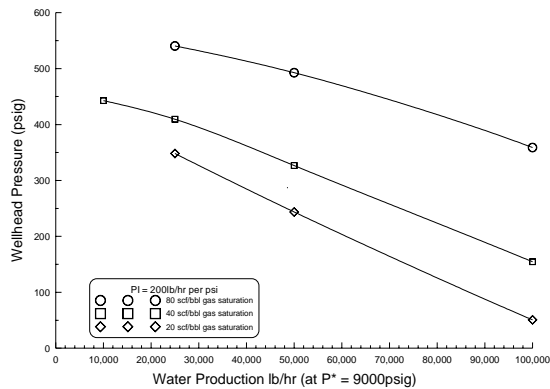


Figure 9: Wellhead flow conditions of the reworked well for various values of dissolved gas content in water.

The wellbore simulation work demonstrates that commercial flow rates of geothermal water and gas can be achieved from such a well if properly reworked to pull the tubing and to lengthen the perforated section of the cemented casing adequately.

It is possible that the gas content in the water will be low enough to allow pumping the water. Assuming a negligible gas concentration in the water, we have estimated the available power capacity of the reworked well, if pumped, as a function of the pump-setting depth as shown in Figure 10. The figure shows both the gross power capacity and the net power capacity (after deducting the parasitic power needed for pumping). Table 2 lists the parameters used for the pump calculation.

Table 2: Parameters used for pump calculations.

Productivity index - (gpm/psi):	0.48
Static pressure at production level - (psia):	9000
Depth to production level - (ft):	19200
Density of produced water - (lb/ft ³):	57.9
Vapor pressure at temperature of produced water - (psia):	49.2
Gas partial pressure - (psia):	0
Pump suction pressure - (psi):	55
Pressure safety margin - (psi):	10
Relative roughness - (ft):	0.0006
Casing ID - (inches):	7.92
Viscosity of produced water - (cp):	0.198
Pump discharge pressure - (psia):	50
Pump efficiency - (fraction):	0.64
Motor efficiency - (fraction):	0.95
Horsepower loss per foot of pump shaft - (hp/ft):	0.02
Parasitic load factor - (fraction):	0.1
Temperature of produced water - (°F):	280.0
Temperature of injected water - (°F):	150.0
Rejection temperature - (°F):	70.0
Average specific heat of water between T and T ₀ - (BTU/lb/°F):	1.01
Utilization factor - (fraction):	0.468
Number of wells:	1
Surface pipeline length - (ft):	0
Surface pipeline ID - (inches):	0
Increase in net elevation in pipeline run - (ft):	0

Figure 10 shows that the maximum net power capacity available from the reworked well is 0.96 MW at a pump-setting depth of about 1,000 ft. The pump for this pump-setting depth and rate can be either a line-shaft or electric submersible pump.

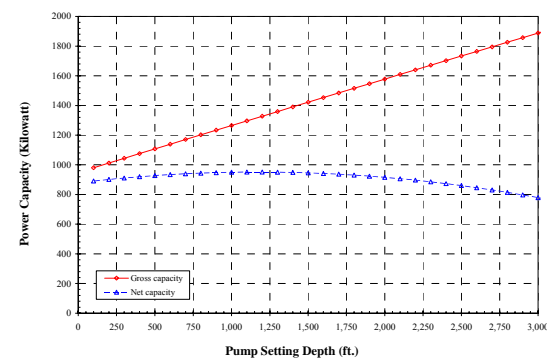


Figure 10: Power capacity of the reworked well if pumped.

3. CONCEPTUAL DESIGN OF A HYBRID POWER PLANT

Once the mixture of natural gas and geothermal water is delivered to the wellhead of the production well, the utilization of the two energy resources to generate electric power can be accomplished readily. The natural gas may be separated from the geothermal water and fed as fuel to an internal combustion engine that is coupled to an electric generator. Several companies manufacture complete,

transportable, skid mounted gas engine-generator units. Such systems are commonly used in oil and gas field operations.

Figure 11 shows the schematic of our conceptual hybrid geothermal/natural gas power plant. The turbine exhaust gas flows through a condenser which cools and converts the low pressure exhaust gas to a liquid. The low-pressure liquid is pumped and returned to the vaporizer to complete the thermodynamic Rankine cycle. While either air or water may be used as the condensing medium, air-cooled condensers are used generally for binary cycle power plant application because a source of cooling water typically is lacking at geothermal plant sites.

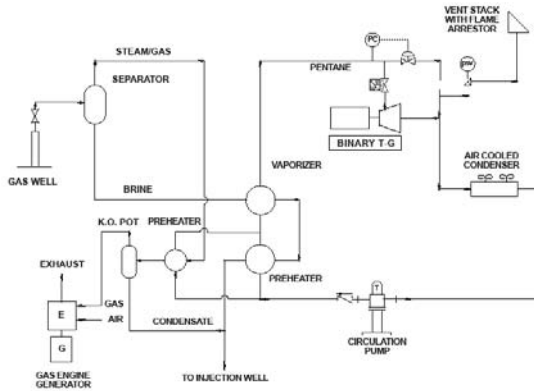


Figure 11: Schematic of a possible hybrid power plant.

The two-phase mixture of gas and geothermal water, which flows from the production well, is separated into a vapor phase and a liquid phase in the separator, located near the wellhead. The vapor phase consists of a mixture of the natural gas and water vapor. The heat in the vapor phase is transferred to a slip-stream of the binary cycle working fluid in a shell-and-tube heat exchanger (labeled “pre-heater” in Figure 11).

The effluent from the pre-heater flows into the K.O. Pot, where the cooled natural gas is separated from the steam condensate, and the gas is fed as fuel to the gas engine-generator unit. The condensate from the K.O. Pot is piped to the injection well, together with the spent geothermal water, for subsurface disposal. The hot water from the wellhead separator flows in series through the vaporizer, then through the pre-heater and on to the injection well for disposal. The pressurized working fluid from the discharge of the circulating pump is heated in the pre-heater, then fully vaporized in the vaporizer before it enters the gas expander turbine which drives the electric generator. The exhaust vapor from the turbine flows to the Air Cooled Condenser where the vapor is condensed to liquid. The liquid is returned to the suction of the Circulating Pump to complete the binary fluid power generating cycle.

4. ECONOMICS OF POWER GENERATION FROM AN ABANDONED GAS WELL

As estimated before, if the reservoir has no free gas, the reworked well can supply 0.35 MW (net) of geothermal power and 1.25 (net) of gas-generated power. Assuming a 10.0¢/kWh price (including subsidies) for the 0.35 MW (net) geothermal power (qualified as renewable) and 6.0¢/kWh for 1.25 MW (net) gas-generated power, the annual per-well revenue is \$843,000. Of this, \$285,000 (that is, 34%) is from geothermal water and \$558,000 (that is, 66%) is from gas, assuming a 95% capacity factor for

the binary-cycle plant supplied with the geothermal water and an 85% capacity factor for the gas engine. The annual per-well operating cost of the project is assumed to be 2.0¢ per kW-hour for the overall capacity of 1,593 kW at an average 90% capacity factor, that is, \$251,000. Therefore, the net cash flow per well is \$592,000 per year. Assuming unit capital costs of the binary plant and the gas engine to be \$2,000/kW and 1,400/kW, respectively, and the cost of removing the production tubing, repairing or replacing the casing, and perforating a larger section of the well to restore the well to production, etc., to be \$2,000,000 per well, the total capital cost per well is \$4,436,000. The capital cost, which does not include any injection well cost, is about \$2,785 per installed kilowatt. At the annual net cash flow rate of \$592,000, the project has a 7.5-year pay-out; any injection cost will lengthen the pay-out time.

If the well has negligible gas content it can be pumped. As shown before, such a well can yield 960kW (net). At 10.0¢/kWh price for geothermal power, the annual per-well revenue is \$799,000 assuming a 95% capacity factor. The annual per-well operating cost would probably still be on the order of 2.0¢/kWh. If so, the annual per well operating cost of the plant would be \$160,000. The net annual revenue per well would amount to \$639,000. Besides the \$2,000,000 capital cost of reworking the well, capital cost of the plant at \$2,000 per kilowatt and the \$500,000 cost of a line-shaft pump will be required, yielding a total capital cost of \$4,420,000 for 960 kW (net) capacity. This implies a unit capital cost of \$4,604 per kW installed, which is much higher than \$2,785 per kW installed for the case of the self-flowing well with 40 SCF/bbl gas content in water. However, the pumped well case shows a little shorter pay-out time of 6.9 years compared to 7.5 years for the self-flowing well case.

The above estimate of economics does not include the following upside possibilities:

- savings due to the economy of scale when several wells are considered together;
- cost savings from custom-designing an optimum hybrid brine-gas power plant;
- cost savings from buying used gas engines or binary turbines; and
- the likely presence of free gas saturation in the reservoir allowing significantly more gas production as well as more brine production (due to the “gas lift” effect) from each well.

The following costs have not been considered in the economics:

- cost of injection of the waste water and supplying cooling water;
- cost of mitigation of any environmental impact; and
- cost of connecting the plant to the local grid.

5. GEOTHERMAL POWER FROM A GEOPRESSURED BRINE WELL IN A GAS BASIN

The power capacity of a geopressured well in a gas basin is determined by all of the factors considered in the last case history plus the issue of overpressure in the reservoir. In 1989, the U.S. Department of Energy funded a technically successful demonstration project of power generation from a geopressured system (Chacko, 1998). In the process several abandoned “wells of opportunity” were selected and tested in Texas and Louisiana. Of the wells of opportunity

identified, well Pleasant Bayou #2 (PB-2) in Texas was reworked, thoroughly flow-tested for several years and used to supply a small demonstration plant. This well, which is shut in, has the relevant characteristics listed in Table 3.

Table 3: Characteristics of the geopressured well.

Depth:	16,465 ft.
Production tubing diameter:	5 ½ in.
Perforated interval:	14,644 to 16,704 ft.
Gross pay:	60 ft.
Porosity:	19%
Permeability:	200 md.
Bottomhole pressure:	9,800 psia
Bottomhole temperature:	302°F
Gas content in brine:	24 SCF/Bbl
Heating value of gas:	951 Btu/lb
Brine salinity:	127,000 mg/l
Maximum tested flow rate:	25,000 B/D
Flowing wellhead temperature:	292°F
Flowing wellhead pressure:	3,000 psia

Given the above parameters, on behalf of the well owner we have estimated the initial power capacity available from well PB-2 flowing at 20,000 B/D. At the flowing wellhead temperature of 292°F, 20,000 bbls/day will generate 1,460 kW of gross power from the thermal energy of the brine. In addition, this same 20,000 B/D production will yield 480 MCF of gas per day or 19 million BTU per hour. A gas engine typically consumes about 10,000 BTU per kW-hour. Therefore, 20,000 B/D of brine production will yield an additional 1,900 kW of gross power from the gas. For an initial flowing wellhead pressure of 3,000 psia, the

hydraulic horse power initially available will be 1,020; assuming a 70% efficiency in conversion to shaft horsepower, this power is equivalent to 530 kW. The total gross power initially available from well PB-2 is thus estimated at 3,890 kW, of which 37% would initially come from geothermal energy, 49% from gas and 14% from hydraulic energy. As production continues, the hydraulic power component would decline and the percentages of the geothermal and gas power components would increase.

During the long-term testing of well PB-2, the produced brine was injected into a shallower well (well PB-1), which was capable of accepting 20,000 B/D of injection for 2 years with a wellhead pressure between 400 to 600 psia. Assuming a temperature of 150°F for the injection water, injection of 20,000 B/D at a pressure of 600 psia would consume 760 kW. Therefore, the net power initially available from the well is 3,130 kW.

ACKNOWLEDGEMENT

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