Problem 1: *Data below indicates how temperature varies with depth in a hypothetical geothermal electricity site.*

Temperature (^oC)	25	40	63	100	155	245
Depth (m)	0	200	400	600	800	1000

(a) *Plot the diagram depth $\times$ temperature.*

(b) *The power plant you are designing is operated with groundwater at 225^{o}C. Assuming there is no heat loss from the geothermal source to the environment, determine the depth that it is necessary to drill to produce hot stream for the plant facility.*

(c) *Part of the water used to generate electricity is also used in a district heating system with flow and return temperatures of 80^{o}C and 60^{o}C respectively. 10% of the energy supplied is lost in distribution. A total heat demand on a typical winters day from all building connected to the system is 20 MW. The current heating is supplied by a coal fired boiler operating at an efficiency of 80%. How much coal is consumed each day if the calorific value of the coal is 24 GJ.tonne^{-1}.*

(d) *It is proposed to supplement the boiler with a single geothermal well which will extract hot water at 80^{o}C and discharge the effluent into the sea. If the maximum flow rate is 71.65 litres.s^{-1}, how much coal will be saved each day.*

(e) *Briefly explain how a heat pump may be used to increase the potential output from the geothermal resource.*

Problem 2: *Geothermal energy, although considered derived from a renewable source, still has a strong impact in the environment. Table 1[1] shows a few potential environmental impacts of geothermal energy with both high- and low-temperature stream source (Paper 1, page 5). Discuss these impacts and compare them with those arising from fossil, nuclear and biomass fuels.*

Problem 3: *Paper 2 – Mining Heat from Schlumberger (page 16) describes the production of heat and power from geothermal sources. Read the paper and get ready to discuss the main aspects and technologies summarised in the manuscript.*

Problem 4: *Figure 1 shows a schematic of a geothermal binary cycle operating with groundwater-steam (high temperature) and isopentane (low temperature) fluids in the dual cycle.*

(a) *'Cold groundwater' is injected in injection well whereas hot water/steam is recuperated in the production well. In other words, subcooled water displaces water/steam trapped in the porous media (or is heated up by hot geological formations), and this is driven to the production well. Discuss the set of physical phenomena in this process:*

[1] T. Hunt (2000) 'Five Lectures on Environmental Effects of Geothermal Utilization', *The United Nations University*. ISBN: 9979-68-070-9. In attahcment.

- *multiphase flow in porous media (Darcy law),*
- *phase change (thermodynamic dome, temperature $\times$ entropy and pressure $\times$ enthalpy diagrams) and,*
- *heat transfer (conduction and convection) mechanisms.*

(b) *Analyse the isopentane thermodynamic cycle. Assume it works in an ideal Rankine Cycle.*

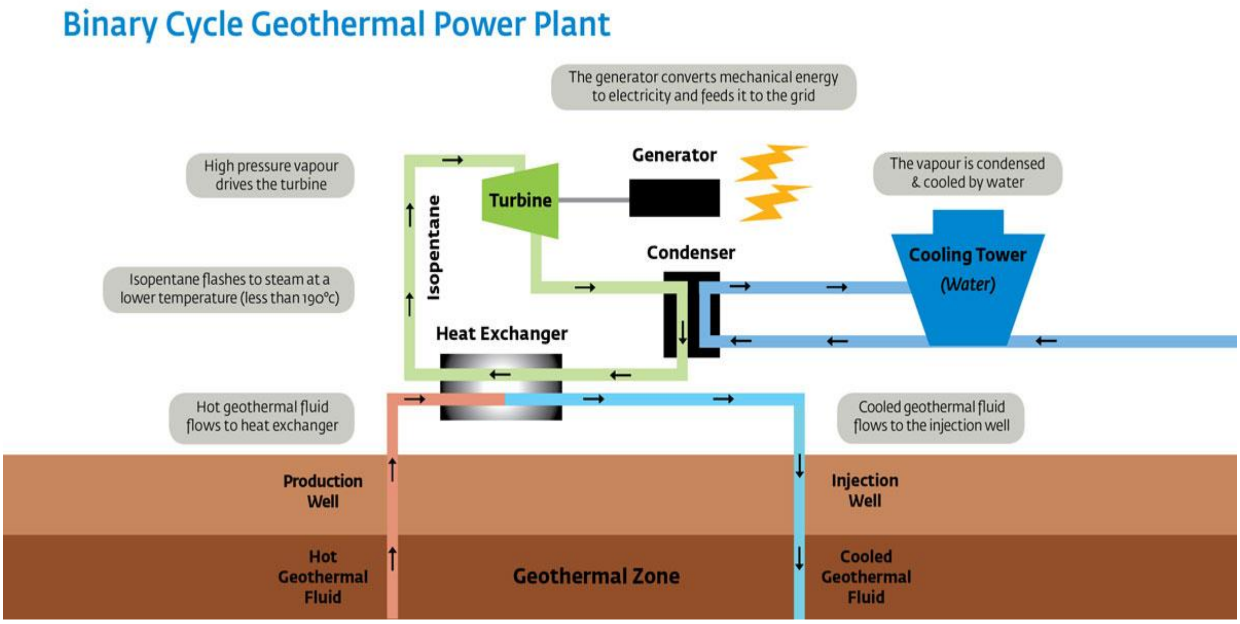


Figure 1: Binary cycle: Problem **Problem 4:**.

Problem 5: *A geothermal power plant uses groundwater extracted at 150^{o}C at a rate of 210 kg.s^{-1}. The plant produces 8000 kW of net power. The groundwater leaves the plant at 90^{o}C. If the environment temperature is 25^{o}C, calculate:*

(a) *Actual thermal efficiency;*

(b) *Maximum possible thermal efficiency;*

(c) *Actual rate of heat rejection from the power plant.*

Problem 6: *R-22 is the refrigerant fluid in a geothermal heat pump system for a house (Fig. 2). The heat pump uses underground water from a well* $\left(T_w^{in} = 13^o\text{C}; T_w^{out} = 7^o\text{C}\right)$ *to produce a heating capacity of 4.2 tons. Determine:*

(a) *Volumetric flow rate of heated air to the house* $\left(m^3/s\right)$;

(b) *Isentropic efficiency* (η_c) *and power* $\left(\dot{W}_c\right)$ *of the compressor;*

(c) *Coefficient of Performance;*

(d) *Volumetric flow rate of water from the geothermal well* (l/h)*;*

(e) *Sketch the* TS *diagram.*

Given the heat capacity $\left(C_p^{air} = 1.004\frac{kJ}{kg.K}\right)$ *and molecular weight* $\left(MW^{air} = 28.97\frac{kg}{kgmol}\right)$ *of air and heat capacity of water* $\left(C_p^{water} = 4.1813\frac{kJ}{kg.K}\right)$.

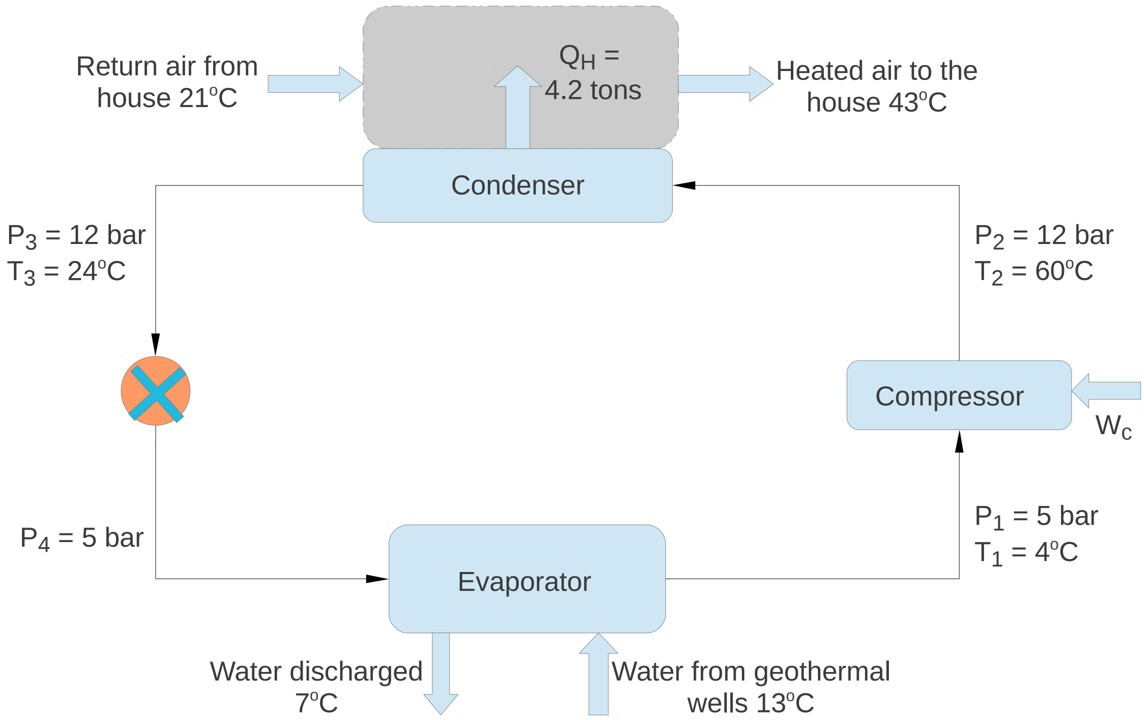


Figure 2: Heat pump cycle: Problem **Problem 6:**.

	Low-temperature systems	High-temperature systems	
		Vapour-dominated	Liquid-dominated
Driling operations			
Destruction of forests and erosion	•	••	••
Noise	••	••	••
Bright lights	•	•	•
Contamination of groundwater by drilling fluid	•	••	••
Mass withdrawal			
Degradation of thermal features	•	••	• • •
Ground subsidence	•	••	• • •
Depletion of groundwater	○	•	••
Hydrothermal eruptions	○	•	••
Ground temperature changes	○	•	••
Waste liquid disposal			
Effects on living organisms			
surface disposal	•	•	• • •
re-injection	○	○	○
Effects on waterways			
surface disposal	•	•	••
re-injection	○	○	○
Contamination of groundwater	•	•	•
Induced seismicity	○	••	••
Waste gas disposal			
Effects on living organisms	○	•	••
Micro-climatic effects	○	•	•

Table 1: Possibilities of environmental effects of geothermal development. Symbols: ○ : No effect; • : Little effect; •• : Moderate effect; • • • : High effect.

Paper for Discussion:

Environmental Impacts

The United Nations University

GEOTHERMAL TRAINING PROGRAMME
Orkustofnun, Grensásvegur 9,
IS-108 Reykjavík, Iceland

Reports 2000
Number 1

FIVE LECTURES ON ENVIRONMENTAL EFFECTS OF GEOTHERMAL UTILIZATION

Trevor M. Hunt
Institute of Geological and Nuclear Sciences,
Taupo,
NEW ZEALAND

Lectures on environmental studies given in September 2000
United Nations University, Geothermal Training Programme
Reykjavík, Iceland
Published in June 2001

ISBN - 9979-68-070-9

gas and coal are 9.5 and 46.9 Mt for electricity, and 9.9 and 49.0 for direct-use (at 35% plant efficiency). Similar numbers for natural gas, oil and coal can be determined for sulfur oxides (SO_x) and nitrogen oxides (NO_x) at 0, 0.25 and 0.26 Mt and 2.2, 7.6 and 7.6 kt (thousand tonnes) respectively for electricity, and 0, 0.26 and 0.28 Mt and 2.3, 7.9 and 7.9 kt respectively for direct-use. For direct-use, the values would be approximately half if the heat energy was used directly.

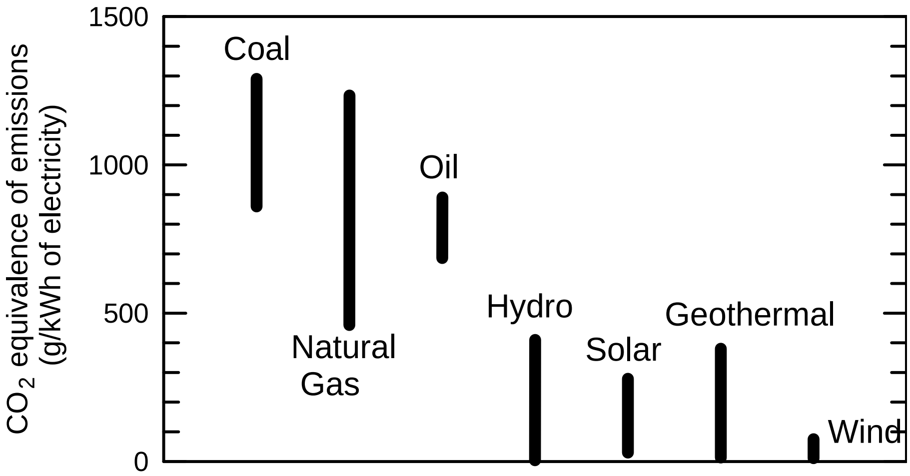


FIGURE 1: Relative amounts of greenhouse gas emissions from various types of electricity generation methods, data expressed as CO_2 equivalents; taken from Geothermal Energy News (May 1998), and geothermal data adjusted on basis of data from ETSU (1998)

In total, the savings from present worldwide geothermal energy production, both electric and direct-use, are summarised in Tables 1 and 2.

TABLE 2: CO_2, SO_x and NO_x savings (annual) from geothermal energy production; taken from Lund (2000)

CO_2 (10^6 t)			**SO_x (10^6 t)**			**NO_x (10^6 t)**		
Natural gas	Oil	Coal	Natural gas	Oil	Coal	Natural gas	Oil	Coal
19.4	82.2	95.9	0	0.51	0.54	4.5	15.5	15.5

2.3 Reduced sulphur gas emissions

The amount of sulphur gases (mainly H_2S) emitted from a geothermal power station (average 0.03 g/kWh) is less than 2% of that emitted from equivalent size coal- and oil-fired power stations (9.23 and 4.95 g/kWh, respectively).

3. ENVIRONMENTAL IMPACTS

Geothermal energy does have some environmental impacts, most of which are associated with the exploitation of high-temperature geothermal systems. In Table 3 the possibilities of environmental effects of geothermal development both for low-temperature areas and high-temperature areas are summarised.

3.1 Drilling operations

Exploitation of both low-temperature and high-temperature systems involves drilling wells to depths of 500-2500 m; this requires large drilling rigs and may take several weeks or months. For high-temperature systems the location of the drilling site is important, although directional drilling techniques have reduced this in recent times. The main environmental effects of drilling are shown here below.

TABLE 3: Possibilities of environmental effects of geothermal development

	Low-temperature systems	High-temperature systems	
		Vapour-dominated	Liquid-dominated
Drilling operations:			
Destruction of forests and erosion	●	● ●	● ●
Noise	● ●	● ●	● ●
Bright Lights	●	●	●
Contamination of ground-water by drilling fluid	●	● ●	● ●
Mass withdrawal:			
Degradation of thermal features	●	● ●	● ● ●
Ground subsidence	●	● ●	● ● ●
Depletion of groundwater	○	●	● ●
Hydrothermal eruptions	○	●	● ●
Ground temperature changes	○	●	● ●
Waste liquid disposal:			
Effects on living organisms			
surface disposal	●	●	● ● ●
reinjection	○	○	○
Effects on waterways			
surface disposal	●	●	● ●
reinjection	○	○	○
Contamination of groundwater	●	●	●
Induced seismicity	○	● ●	● ●
Waste gas disposal:			
Effects on living organisms	○	●	● ●
Microclimatic effects	○	●	●

○ No effect ● ● Moderate effect
● Little effect ● ● ● High effect

Impact of access and field development
The construction of road access to drilling sites can involve destruction of forests and vegetation which, particularly in tropical areas with high rainfall (Indonesia, Philippines), can result in erosion. Such erosion can result in large amounts of silt being carried by the streams and rivers draining the development area, This silt can affect fish in the river and may even affect fish in coastal waters near the mouth of the river. The silt may also deposit on the river bed where the gradient (flow rate) is less, causing the bed of the river to be raised and make the adjacent land more likely to be flooded during periods of high rainfall.

Effects of drilling operations
Drilling creates noise, fumes and dust which can disturb animals and humans living nearby. Typical noise levels (in approximate order of intensity) are:

- Air drilling – 120 dBa (85 dBa with suitable muffling);
- Discharging wells after drilling (to remove drilling debris) – up to 120 dBa;
- Well testing – 70-110 dBa (if silencers used);
- Heavy machinery (earth moving during construction) – up to 90 dBa;
- Well bleeding – 85 dBa (65 dBa if a rock muffler is used);
- Mud drilling – 80 dBa;

- Diesel engines (to operate compressors and provide electricity) – 45-55 dBa if suitable muffling is used.

The characteristics of the site (e.g. its topography) and meteorological conditions will also have an influence. To put the above noise levels into context, 120 dBa is the pain threshold (at 2-4000 Hz), noise levels in a noisy urban environment are 80-90 dBa, in a quiet suburban residence about 50 dBa and in a wilderness area 20-30 dBa (DiPippo, 1991; Armannsson and Kristmannsdottir, 1993). Noise is attenuated by distance travelled in air; there is approximately 6 dB attenuation every time the distance is doubled, but lower frequencies are attenuated less than higher frequencies. Thus, low rumbling noises from drill rigs and silencers carry much further than high frequency steam discharge noises.

Continuous drilling involves the use of powerful lamps to light the work site at night which can disturb local residents, domestic and wild animals.

Disposal of waste drilling fluid
In the past it was common practice to discharge waste fluids into nearby waterways.

3.2 Mass withdrawal

Large-scale exploitation of liquid-dominated high-temperature geothermal systems involves the withdrawal of large volumes of geothermal fluid. For example, between 1958 and 1991 more than 1700 Mt of fluid were withdrawn from the Wairakei geothermal field (New Zealand); assuming an average temperature of 200°C this represents nearly 2 km^3 of fluid (Hunt, 1995). In geothermal power schemes where the fluid withdrawn is reinjected, the reinjection wells are generally located away from the production wells to reduce the chances of the cooler reinjected water returning to the production wells and reducing the temperature of production fluids. Even if all the waste liquid is reinjected, there may be a large mass loss (up to 30% of that withdrawn) associated with discharge of water vapour into the atmosphere from the power station. A major consequence of the mass loss from parts of the field is the formation of a 2-phase (steam + water) zone in the upper part of the reservoir, and as production continues this zone increases in size and the pressures (both in and below this zone) decrease. At Wairakei, the deep (liquid phase) pressures declined by about 0.5 MPa (5 bar) during exploratory drilling, and a further 1.7 MPa (17 bar) during the first ten years of production, although subsequent pressure declines have been less than 0.5 MPa (Figure 2). Pressure declines in the reservoir, as a result of mass withdrawal and net mass loss, are an important cause of environmental changes at or near the surface.

Degradation of thermal features
In their natural, unexploited state many high-temperature geothermal systems are manifested at the surface by thermal features such as geysers, fumaroles, hot springs, hot pools, mud pools, sinter terraces and thermal ground with special plant species. Often these features are of great cultural significance, as well as being important tourist attractions. The thermal features result from the (upward) leakage of

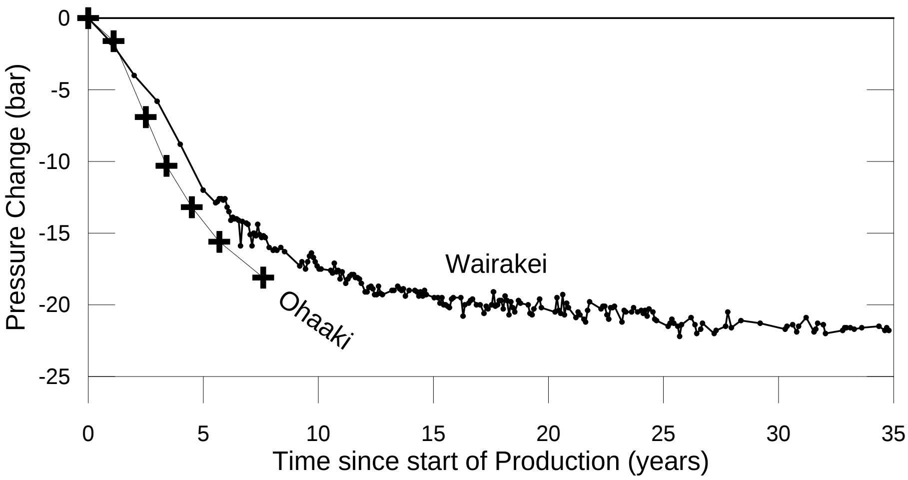


FIGURE 2: Deep reservoir pressure changes since start of production at the liquid-dominated, high-temperature geothermal fields of Wairakei (1958) and Ohaaki (1988), in New Zealand; note the rapid decline in pressure during the first 10 years of production

boiling geothermal fluid from the upper part of the reservoir, through overlying cold groundwater, to the surface.

Historical evidence shows that natural thermal features have been affected, often severely, during the development and initial production stages of most high-temperature geothermal systems. At Wairakei (New Zealand), nearly all the thermal features in the Waiora and Geyser Valleys (including more than 20 geysers) have died. At Ohaaki (New Zealand), the level and temperature of water in the Ohaaki Pool have declined since exploration drilling and reservoir testing began. Such effects are not confined to liquid-dominated systems. At Larderello (Italy) where the original natural activity consisted of numerous steam and gas jets, activity has now largely ceased, and at The Geysers (USA) there has been a decrease in the flow from hot springs since exploitation began.

Scientific evidence shows that the decline in thermal features is associated with the decline in reservoir pressure. As the pressure declines, so also does the amount of geothermal fluid reaching the surface and hence the thermal features decline in size and vigour. If pressures fall further then the features may die and the flow may reverse with cold groundwater flowing down into the reservoir; once this situation has occurred there may be little hope of resurrecting the features, at least within a human lifetime.

Depletion of groundwater
Most high-temperature geothermal systems are overlain by a cold groundwater zone. If exploitation of the system results in a large pressure drop in the reservoir, this groundwater may be drawn down into the upper part of the reservoir in places where there are suitable high-permeability paths (such as faults); such a situation is called a *cold downflow* (Bixley, 1990). If the lateral permeability of the rocks in the groundwater zone is low then a downflow may result in a drop in the groundwater level. For example, at Wairakei, a localised drop of more than 30 m in groundwater level has occurred associated with a cold downflow.

Downflows, and groundwater level changes, may also occur as a result of breaks in the casing of disused wells (Bixley & Hattersley, 1983).

Ground deformation
Withdrawal of fluid from an underground reservoir can result in a reduction of formation pore pressure which may lead to compaction in rock formations having high compressibility and result in subsidence at the surface. Subsidence has also been observed in groundwater and petroleum reservoirs. Horizontal movements also occur. Such ground movements can have serious consequences for the stability of pipelines, drains and well casings in a geothermal field. If the field is close to a populated area, then subsidence could lead to instability in dwellings and other buildings; in other areas, the local surface watershed systems may be affected.

The largest recorded subsidence in a geothermal field (15 m) is in part of the Wairakei field (New Zealand) This subsidence has caused:

- Compressional and tensional strain on pipelines and lined canals;
- Deformation of drill casing;
- Tilting of buildings and the equipment inside;
- Breaking of road surfaces;
- Alteration of the gradient of streams and rivers.

Ground movements have been recorded in other high-temperature geothermal fields in New Zealand, at Cerro Prieto (Mexico), Larderello (Italy), and The Geysers (USA). Subsidence in liquid-dominated fields has been greater than in vapour-dominated fields, because the former are often located in young, relatively-poorly compacted volcanic rocks and the latter are generally in older rocks having lower porosity.

Ground temperature changes
The formation and expansion of a 2-phase zone in the early stages of exploitation of a liquid-dominated geothermal system can also alter the heat flow. Steam is much more mobile than water; it can move through small fractures that are impervious to water and can move much more quickly through larger fractures. The generation and movement of steam can therefore result in increased heat flow and increased ground temperatures so that vegetation becomes stressed or killed.

At Wairakei, heat flow from natural thermal features was about 400 MW prior to the start of exploitation in 1958, increased to a peak of nearly 800 MW by the mid 1960s, and has since declined to about 600 MW (Allis, 1981). Most of this increase was associated with increased thermal activity in the Karapiti thermal area, which is situated 3 km south-west of the main production borefield. These changes have been attributed to steam rising to the surface through fissures that were previously impervious to water.

3.3 Waste liquid disposal

Most geothermal energy developments bring fluids to the surface in order to mine heat contained within them. In high-temperature liquid-dominated geothermal fields the volumes of resultant liquid waste involved may be large: at Wairakei, a medium-sized power station (156 MW), it is currently about 5800 m^3/hr. For vapour-dominated systems it is less, and for low-temperature systems it is very much less: at Chevilly-Larue (France) it is only about 3 m^3/hr. The waste fluid is disposed of by putting it into waterways or evaporation ponds, or reinjecting it deep into the ground. Surface disposal causes more environmental problems than reinjection.

Environmental problems are due not only to the volumes involved, but also to the relatively high temperatures and toxicity of the waste fluid. For example, at Wairakei the waste water has a temperature of about 140°C. The chemistry of the fluid discharge is largely dependent on the geochemistry of the reservoir, and the operating conditions used for power generation and will be different for different fields (Webster, 1995). For example, fluids from the Salton Sea field (USA), which is hosted by evaporite deposits, are acidic and highly saline (pH <5, [Cl] = 155 000 ppm). At the other extreme, those of the Hveragerdi field (Iceland) are alkaline and of very low salinity (pH >9, [Cl] <200 ppm). Most high-temperature geothermal bore waters include high concentrations of at least one of the following toxic chemicals: lithium (Li), boron (B), arsenic (As), hydrogen sulfide (H_2S), mercury (Hg), and sometimes ammonia (NH_3). Fluids from low-temperature reservoirs generally have a much lower concentrations of contaminants.

Most of the chemicals are present as solute and remain in solution from the point of discharge, but some are taken up in river or lake bottom sediments, where they may accumulate to high concentrations. The concentrations in such sediments can become greater than the soluble concentration of the species in the water, so that re-mobilisation of the species in the sediment, such as during an earthquake or flood, could result in a potentially toxic flush of the species into the environment. Chemicals which remain in solution may be taken up by aquatic vegetation and fish (Webster & Timperly, 1995), and some can also move further up the food chain into birds and animals residing near the river. For example, in New Zealand, annual geothermal discharges into the Waikato River contain 50 kg mercury, and this is regarded as partly responsible for the high concentrations of mercury (often greater than 0.5 mg/kg of wet flesh) in trout from the river and high (greater than 200 μg/kg) sediment mercury levels.

Effects on living organisms
If hot waste water from a standard steam-cycle power station is released directly into an existing natural waterway, the increase in temperature may kill fish and plants near the outlet. Release of untreated waste into a waterway can result in chemical poisoning of fish, and also birds and animals which reside near the water because some of the toxic substances move up the "food chain".

Effects on waterways
Release of large volumes of waste water into a waterway may increase erosion, and if uncooled and untreated there may be precipitation of minerals such as silica near the outlet surface disposal

Contamination of groundwater
Release of waste water into cooling ponds or waterways may result in shallow groundwater supplies becoming contaminated and unfit for human use

Induced seismicity
Most high-temperature geothermal systems lie in tectonically active regions where there are high levels of stress in the upper parts of the crust; this stress is manifested by active faulting and numerous earthquakes. Studies in many high-temperature geothermal fields have shown that exploitation can result in an increase (above the normal background) in the number of small magnitude earthquakes (microearthquakes) within the field. It is believed the increase is caused by reinjection because when reinjection is stopped the number of small earthquakes decreases, and when it is restarted the number increases (Sherburn et al., 1990). High wellhead reinjection pressures increase the pore pressure at depth particularly in existing fractures, which allows movement to suddenly release the stress and resulting in an earthquake. This phenomenon occurs in both liquid- and vapour-dominated fields, but has not been observed in low-temperature fields. Detailed studies show that the induced microearthquakes cluster (in space) around and below the bottom of reinjection wells and so the effects at the surface are generally confined to the field (Stark, 1990). To date no serious damage has been caused by such earthquakes, but they do frighten people.

3.4 Waste gas disposal

Gas discharges from low-temperature systems do not usually cause significant environmental impacts. In high-temperature geothermal fields, power generation using a standard steam-cycle plant may result in the release of non-condensable gases (NCG) and fine solid particles (particulates) into the atmosphere (Webster, 1995). In vapour-dominated fields in which all waste fluids are reinjected, non-condensable gases in steam will be the most important discharges from an environmental perspective.

The emissions are mainly from the gas exhausters of the power station, often discharged through a cooling tower. Gas and particulate discharges during well drilling, bleeding, cleanouts and testing, and from line valves and waste bore water degassing, are usually insignificant. The concentration of NCG varies not only between fields but can also from well to well within a field, thus changes to the proportion of steam from different wells may cause changes in the amounts of NCG discharged.

Gas concentrations and compositions cover a wide range, but the predominant gases are carbon dioxide (CO_2) and hydrogen sulphide (H_2S).

Carbon dioxide
Carbon dioxide occurs in all geothermal fluids but is most prevalent in fields in which the reservoir contains sedimentary rocks, and particularly those with limestones. Carbon dioxide is generally the most abundant NCG. It is colourless and odourless, and is heavier than air and can thus accumulate in topographic depressions where there is still air. It is not highly toxic (c.f. hydrogen sulfide) but at high concentrations it can be fatal due to alteration of pH in the blood. A 5% concentration in air can result in shortness of breath, dizziness, and mental confusion. At 10% a person will normally lose consciousness and quickly be asphyxiated. Exposure standards range from 5000 to 30,000 ppm (for 10 min.). There is some evidence that in high-temperature fields the amount of CO_2 discharged (per unit mass withdrawn) decreases with time as a result of de-gassing of the deep reservoir fluid and a decline in heat transfer from the formations occurs.

Hydrogen sulphide

H_2S is characterised by a "rotten egg odour" detectable by humans at very low concentrations of about 0.3 ppm. At such concentrations it is primarily a nuisance, but as the concentration increases, it may irritate and injure the eye (10 ppm), the membranes of the upper respiratory tracts (50-100 ppm), and lead to loss of smell (150 ppm). At a concentration of about 700 ppm it is fatal. Because H_2S is heavier than air it can accumulate in topographic depressions where there is still air, such as well cellars and the basements of buildings near the gas exhausters. The disappearance of the characteristic smell at concentrations greater than 150 ppm is especially dangerous because it leads to people failing to recognise potentially fatal concentrations. Exposure standards range from 10 to 50 ppm (10 min.). In sparsely populated areas, H_2S emissions may not prove a problem, and at many sites, there are already natural emissions from fumaroles, hot springs, mudpots etc. H_2S emissions can vary significantly from field to field, depending on the amount of H_2S in the geothermal fluid, and the type of plant used to exploit the reservoir (Table 4).

H_2S dissolved in water aerosols, such as fog, reacts with atmospheric oxygen to form more oxidised sulphur-bearing compounds; some of these compounds have been identified as components of "acid rain", but a direct link between H_2S emission and acid rain has not been established. U.S. Occupational Safety & Health ceiling level for H_2S is 14 mg/m^3, but an ambient air quality standard of 0.042 mg/m^3 is used in California.

TABLE 4: H_2S emissions from some geothermal plants; taken from ETSU (1998)

Field	H_2S emission (g/kWh)	Reference
Wairakei, NZ	0.5	Barbier, 1991
The Geysers, USA	1.9	Barbier, 1991
Lardarello, Italy	3.5	Barbier, 1991
Cerro Prieto, Mexico	4.2	Barbier, 1991
Krafla, Iceland	6.0	Armannsson and Kristmannsdottir, 1992
Ohaaki, NZ	6.4	Barbier, 1991

Other gases

Geothermal power stations do not emit oxides of nitrogen (NO_x), which combine photochemically with hydrocarbon vapours to form ground-level ozone which harms crops, animals and humans. However, geothermal gases may contain ammonia (NH_3), trace amounts of mercury (Hg) and boron (B) vapour, and hydrocarbons such as methane (CH_4). Ammonia can cause irritation of the eyes, nasal passages and respiratory tract, at concentrations of 5 to 32 ppm. Inhalation or ingestion of mercury can cause neurological disorders. Boron is an irritant to the skin and mucus membranes, and is also phytotoxic at relatively low concentrations. but these metals are generally emitted in such low quantities that they do not pose a human health hazard. The metals may also be deposited on soils and, if leached from there, they may contribute to groundwater contamination.

Binary plants use low-boiling point fluid, commonly iso-pentane, which may escape from the plant over a period of time. The gas phase may be recognised in the steam, and values of up to 4000 ppm have been recorded.

Effects on living organisms

The impacts of H_2S discharge will depend on local topography, wind patterns and land use. The gas can be highly toxic, causing eye irritation and respiratory damage in humans and animals, and has an unpleasant odour. Boron, NH_3, and (to a lesser extent) Hg, are leached from the atmosphere by rain, leading to soil and/or vegetation contamination (Webster, 1995). Boron, in particular, can have a serious impact on vegetation. Contaminants leached from the atmosphere can also affect surface waters and affect aquatic life. Details of biological impacts of these gases are given by Webster & Timperley (1995).

Microclimatic effects
Even in geothermal power schemes which have complete reinjection, a considerable amount of gas (mainly steam) may be lost to the atmosphere. For example, at Ohaaki, of 70 Mt of fluid withdrawn (1988 - 1993) about 20 Mt (nearly 30%) was discharged to the atmosphere. Such discharges of warm water vapour may have a significant effect on the climate in the vicinity of the power station, depending on the topography, rainfall, and wind patterns. Under certain conditions there may be increased fog, cloud or rainfall. Microclimatic effects are mainly confined to large power schemes on high-temperature fields; exploitation of low-temperature geothermal systems does not cause significant microclimatic effects.

3.5 Landscape impacts

Land use
Power plants must be built on the site of geothermal reservoirs because long fluid transmission lines are expensive, and they result in losses of pressure and temperature. At the site, land is required for well pads, fluid pipelines, power station, cooling towers and electrical switchyard. The actual area of land covered by the total development can be significantly higher than the area required for these components. For example at Cerro Prieto field (Mexico) the area covered by the well pads (12 ha) is only 2% of the total area (540 ha) encompassing all the wells and the 180 MWe power station.

In many cases, the land between the well pads and pipes may continue to be used for other purposes, although at some sites the nature of the development may make this impracticable. For example, at Wairakei, where the development is located in a relatively narrow valley, there are a lot of individual pipelines, separation plants, steam discharges and surface hot water drains which effectively divide the land up into very small parcels. This precludes the land being used for anything else, although it is unlikely the land would have had another productive use. In contrast, the development at nearby Ohaaki (Broadlands) field, the design of the development has resulted in much larger parcels of land between the pipelines and the road system so the land will continue to be used. Areas previously used for stock and arable farming are now used mainly for sheep farming, and land which was mainly self sown pine scrub is worked as a productive forest.

The impact on land use depends on the type of development, and the original use of the land.

Visual intrusion
A geothermal plant must be located close to the resource, so there is often little flexibility in the siting of the plant. Geothermal plants generally have a low profile, and need not have a tall stack like coal and oil fired power plants. However, their visual impact may still be significant, as geothermal fields are often situated in areas of outstanding natural beauty. Any associated natural thermal features (e.g. geysers and hot pools) may be a tourist attraction or of historical and cultural significance. Visual impact may be particularly high during drilling due to the presence of tall drill rigs.

3.6 Catastrophic events

Like any large engineering development, catastrophic events may occur during the construction and operation of a large-scale geothermal power scheme.

Landslides
For schemes in areas of high relief and steep terrain, landslides are a potential hazard. Landslides may be triggered either:

a) Naturally, by heavy rain or earthquake; or
b) As a result of construction work, which may have removed the "toe" of the slide.

Such events are relatively rare but the result may be severe, such as for the landslide on 5 January 1991 in Zunil field (Guatemala), when 23 people were killed (Goff & Goff, 1997).

Hydrothermal eruptions
Although rare, hydrothermal eruptions (also called "hydrothermal" or "phreatic explosions") constitute a potential environmental hazard in high-temperature liquid-dominated geothermal fields (Bixley and Browne, 1988; Bromley & Mongillo, 1994). Eruptions occur when the steam pressure in near-surface aquifers exceeds the overlying lithostatic pressure and the overburden is then ejected, generally forming a crater 5-500 m in diameter and up to 500 m in depth (although most are less than 10 m deep).

A hydrothermal eruption occurred on 13 October 1990 in the Agua Shuca fumarole area of Ahuachapan field (El Salvador) which killed or injured people living nearby (Goff & Goff, 1997). At Wairakei field, hydrothermal eruptions began (or significantly increased) in the Karapiti thermal area after development of the field began. At least 15 eruptions have occurred here but fortunately nobody has been killed or injured.

4. SUMMARY

- Use of geothermal energy has low environmental impact, particularly when compared with fossil fuels.
- Most environmental impacts are associated with the exploitation of high-temperature systems, particularly in liquid-dominated fields (Table 3).
- Exploitation of low-temperature systems rarely has any significant environmental effects.

Paper for Discussion:

Mining Heat

Mining Heat

Heat emanating from the Earth's core could replace a substantial percentage of the energy currently produced by burning gas, oil and coal for electricity generation. The Earth's heat is an inexhaustible resource whose use creates almost no greenhouse gas emissions. It is, in short, a nearly perfect solution to the world's energy needs. But before the world can take advantage of this abundant supply of heat, there are daunting economic and technological hurdles to clear.

Craig Beasley
Rio de Janeiro, Brazil

Bertrand du Castel
Tom Zimmerman
Sugar Land, Texas, USA

Robert Lestz
Keita Yoshioka
Chevron Energy Technology Company
Houston, Texas

Amy Long
Singapore

Susan Juch Lutz
Salt Lake City, Utah, USA

Kenneth Riedel
Chevron Geothermal Indonesia Ltd
Jakarta, Indonesia

Mike Sheppard
Cambridge, England

Sanjaya Sood
Houston, Texas

Oilfield Review Winter 2009/2010: 21, no. 4.

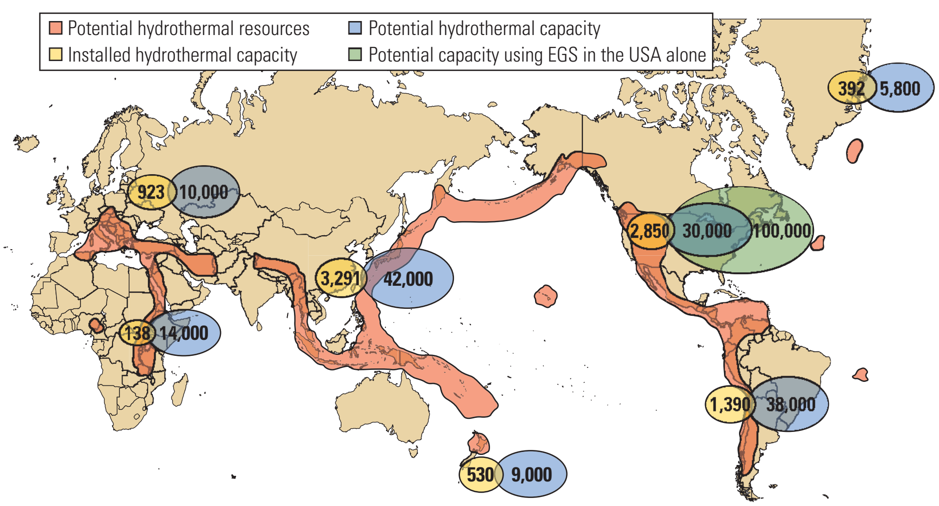
For help in preparation of this article, thanks to Mo Cordes, Houston; and Stephen Hallinan, Milan, Italy.
GeoFrame and TerraTek are marks of Schlumberger.

1. Blodgett L and Slack K (eds): *Geothermal 101: Basics of Geothermal Energy Production and Use*. Washington, DC: Geothermal Energy Association (2009), http://www.geo-energy.org/publications/reports/Geo101_Final_Feb_15.pdf (accessed August 1, 2009).

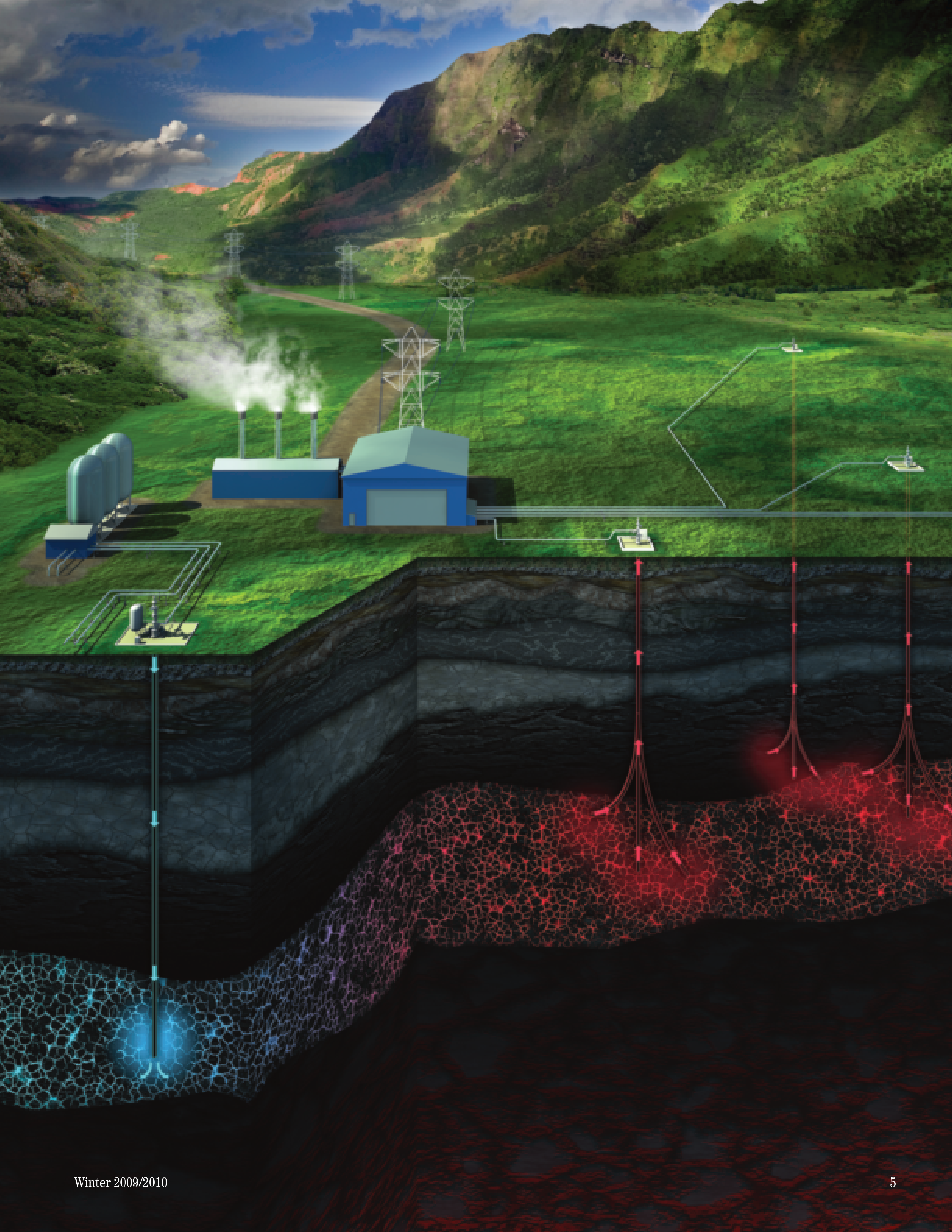
The mechanics of harvesting the Earth's natural subsurface heat seem to be familiar petroleum engineering tasks: drill and complete wells and produce fluids from wells landed in targeted formations beneath the surface. But the prize in geothermal energy production is not fluids. It is heat. So while there is considerable potential for technology transfer from the oil and gas upstream business—drilling rigs, bits, pressure control and other basic practices and technologies—the specifics of hydrocarbon and geothermal energy production diverge.

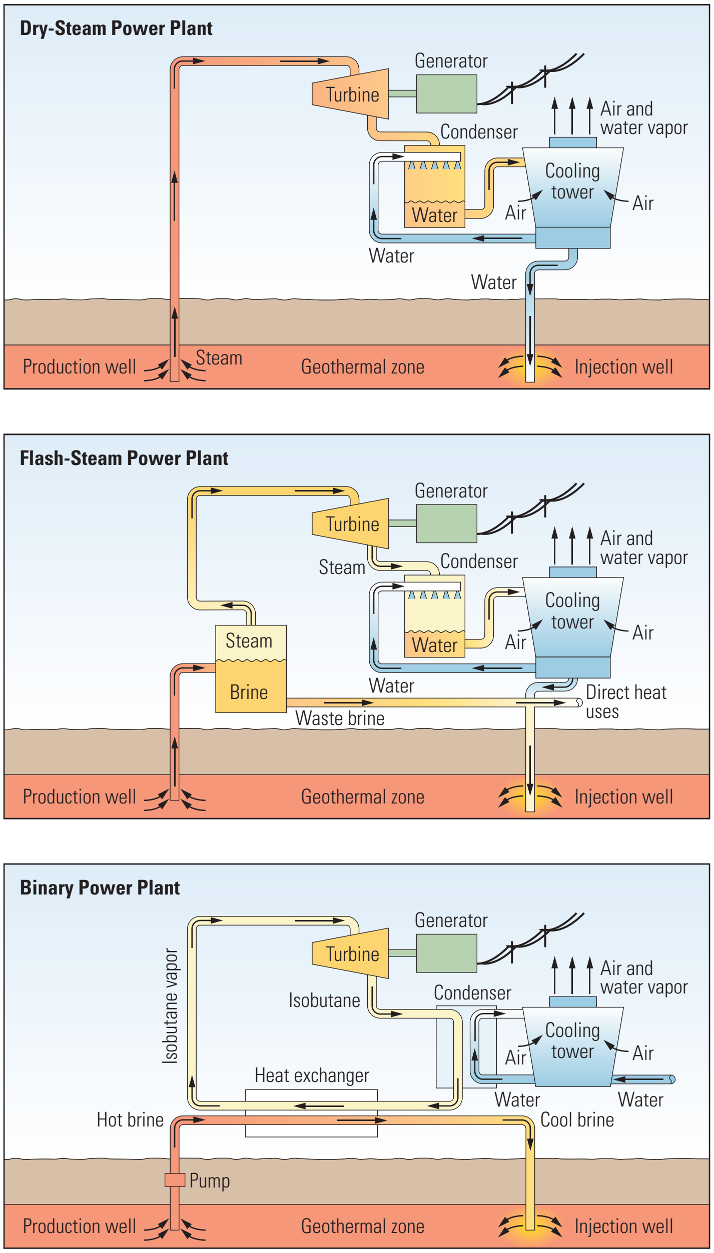
For example, ultrahigh temperature represents an obvious problem in bringing oil industry technology to bear on geothermal exploration and production: It renders useless the sophisticated tools and sensors that are dependent on pressure-tight seals and electronics. The industry, however, is continually overcoming temperature limitations. In reality, the accurate characterization of geothermal reservoirs is a more fundamental obstacle to realizing the full energy potential from the Earth's heat. Constructing geothermal reservoir models and simulations using seismic surveys and logging data will require more innovation than adaptation such as increases in hardware temperature tolerances.

Still, the comparison between heat and hydrocarbon exploitation remains compelling. Many of the geothermal wells currently feeding power plants have been constructed by oilfield workers using essentially traditional drilling and completion equipment and techniques. Today, those efforts have resulted in geothermal or, more accurately, hydrothermal fields that feed power plants producing about 10,000 megawatts (MW) of electricity in 24 countries (below).[1]



^ Potential hydrothermal resources. The first major hydrothermal developments were located in areas with high tectonic activity marked by volcanoes, geysers, hot springs and large hot-water reservoirs. These resources are relatively shallow and often flow to the surface naturally. A large portion of potential resources, given here in megawatts, is made up of enhanced geothermal systems (EGS) and is contingent on technological development.





^ Geothermal power plants. Dry-steam power plants are the most basic style of geothermal power plants (*top*). Steam piped from a hydrothermal reservoir directly enters turbines to generate electricity. As the steam cools and condenses, the water is gathered and injected back into the reservoir where it is reheated as it travels through the formation to the production well. Flash-steam plants (*middle*) use hot water that is below the boiling point while at reservoir pressure but that flashes to steam at lower surface pressures. Binary power plants (*bottom*) use a closed system to exploit even cooler reservoirs whose water temperatures are less than 150°C [302°F]. Water flows or is pumped to the surface and enters a heat exchanger where it brings a second fluid, in this case isobutane, to its boiling point, which must be below that of water. The second fluid expands into a gaseous vapor that then powers electricity-generating turbines. This fluid may be circulated through the heat exchanger for reuse rather than being disposed of and, because the water does not come into contact with the power generator, maintenance costs are usually lower than with dry-steam or flash-steam hydrothermal plants.

Hydrothermal energy is a specific form of geothermal resource. Characterized by high temperature, high permeability and rock that contains large volumes of water, it is often found at relatively shallow depths. Without stimulus, or aided only by high-temperature electrical submersible pumps, these formations can deliver superheated water or steam to the surface through large-diameter production wells. The steam, or hot water flashed into steam at the surface, is funneled to drive turbines that generate electricity. Such formations exist in relatively few places around the world. Hydrothermal reservoirs are found predominantly in areas of high tectonic activity where hot-water reservoirs are abundant and pressured, such as in the area of the Pacific Ocean known as the "Ring of Fire."

Most formations around the world that have the requisite water and permeability do not have sufficient heat to be considered geothermal energy sources. But there are others with deep, high-temperature zones that lack only sufficient water or permeability, and it is these that may hold the most promise as future sources of geothermal energy. The solution to tapping such widely available heat resources is through enhanced, or engineered, geothermal systems (EGS).

Put simply, EGS projects create or sustain geothermal reservoirs. In cases of low permeability, the formation may be hydraulically fractured. Formations with little or no liquid or without a sufficient recharge source may be supplied with water through injection wells. Today, engineers and geophysicists are bringing techniques for EGS to high-temperature dry reservoirs at depths of 3 to 10 km [10,000 to 33,000 ft] below the surface. At these depths, the rock is hot enough to convert water to superheated steam.

These hot dry rock (HDR) systems are a unique type of EGS, characterized by very hot basement formations with extremely low permeability. They require hydraulic fracturing to connect water-injection wells to water-production wells.

Other prospective formations contain permeability and water but are not hot enough for geothermal applications. To exploit these resources, less ambitious concepts are being advanced through binary power plants. These plants use water that is below the boiling point to heat a second fluid with a boiling point that is below that of water. The vaporized second fluid is funneled to turbines to generate electricity (left).[2]

This article focuses on hydrothermal and HDR technology. The state of EGS technology is discussed through preparations for an EGS-expansion project in Nevada, USA, a case history from

Indonesia and lessons learned from the original HDR project located in the southwest of the United States.

The High Cost of Deep Heat

The upside potential of geothermal energy may be enormous. In 2008, world electricity consumption was 2 terawatt years. The heat flux continuously flowing from the Earth's core is equivalent to about 44 terawatt years.[3] These numbers are astronomical of course, but if only a small percentage of this potential were to be tapped, it would easily supply most of the world's energy demands. Most geothermal resources are also truly renewable in that the same fluids can be reheated, produced, injected and recycled throughout the life of the reservoir.

Besides the technological questions are financial ones that persist in the face of otherwise positive investment factors (above right). Geothermal projects, with few exceptions, require a significantly higher initial capital outlay than do oil and gas, solar, wind and biomass projects. The risk is also higher, and the current experience with return on investment in geothermal installations is discouraging. For example, a 50-MW hydrothermal project is estimated to yield an initial rate of return of less than 11% and a profit-to-investment (P/I) ratio of 0.8. By comparison, a large oil and gas project typically yields an initial rate of return of nearly 16% and a P/I of 1.5.[4]

These poor financial results are partially a reflection of geography. Areas with favorable hydrothermal conditions tend to be sparsely populated and far from large electricity markets. Financial results are also hampered by the difficulty inherent in drilling and developing these formations. Geothermal resources are found in much harder and hotter rock than those for which petroleum and mining industry bits are designed, so drilling is slower and more costly. To be economic, geothermal wells must accommodate relatively large flow volumes, and therefore wellbore diameters must be greater than those of most oil and gas wells. This adds considerably to well construction costs. The extreme temperature of geothermal environments forces operators to choose high-priced premium products for such things as cements, drilling fluids and tubulars.

While in recent decades the oil industry has greatly refined drilling and reservoir management efficiencies—consequently reducing costs—it has often done so through such electronics-based innovations as logging while drilling and subsurface monitoring. These tools are currently restricted to temperatures below about 175°C [350°F] and are not available for use in high-temperature geothermal wells.

Renewable Energy Sources	Capacity Factor, %	Reliability of Supply	Environmental Impact	Main Application
Geothermal	86 to 95	Continuous and reliable	Minimal land usage	Electricity generation
Biomass	83	Reliable	Minimal (noncombustible material handling)	Transportation, heating
Hydroelectric	30 to 35	Intermittent, dependent on weather	Impacts due to dam construction	Electricity generation
Wind	25 to 40	Intermittent, dependent on weather	Unsightly for large-scale generation	Electricity generation (limited)
Solar	24 to 33	Intermittent, dependent on weather	Unsightly for large-scale generation	Electricity generation (limited)

^ Alternative energy comparative value. Among renewable energy sources, geothermal energy is one of the most attractive based on the capacity factor—the percentage of energy actually produced by a plant compared with its potential output when operated continually at full capacity. It also compares favorably with other alternative energy sources when different metrics are used. (Capacity factor data from Kagel A: *A Handbook on the Externalities, Employment, and Economics of Geothermal Energy*. Washington, DC: Geothermal Energy Association, 2006.)

Finding and Defining

With the exception of some "blind" deep, high-temperature systems, the search for hydrothermal formations is made relatively easy by hot springs and fumaroles that are visible at the surface.[5] Additionally, many hydrothermal fields are in deep sedimentary basins where oil and gas drilling and, more importantly, data collection have already occurred.

The geologic setting for hydrothermal reservoirs varies. The reservoirs in the largest fields contain a wide range of rocks, including quartzite, shale, volcanic rock and granite. Most of these reservoirs are identified not by lithology but by heat flow. They are convection systems in which hot water rises from depth and is trapped in reservoirs whose caprocks have been formed by the mixing of upwelling geothermal fluids with local groundwaters and by precipitation of carbonate and clay minerals.

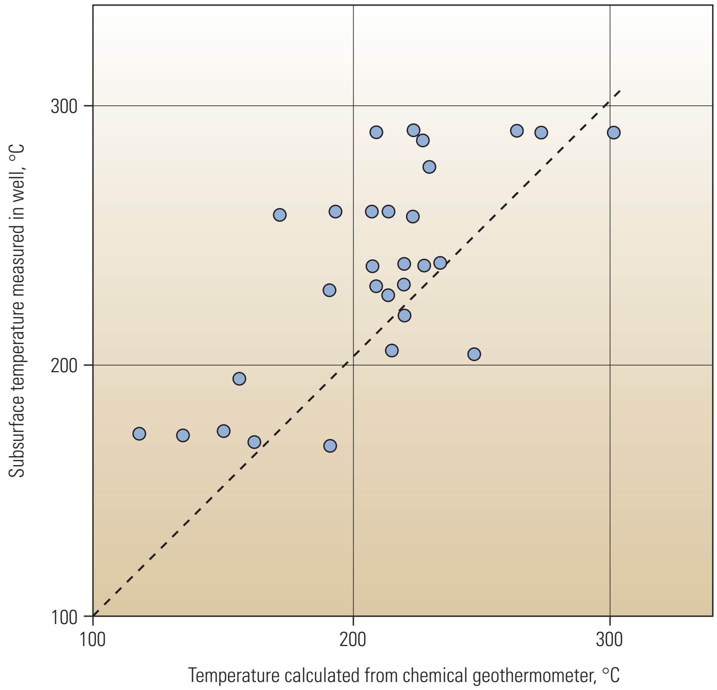
Therefore, the search for a commercial near-surface hydrothermal reservoir is based on identifying tectonic activity, heat source, heat flow, water recharge and outflow of deep fluids to the surface. Permeability is typically characterized by a network of fractures or active faults held open by local in situ stresses.

The hunt for a hydrothermal reservoir begins with an assessment of available regional data on heat flow, seismic activity, thermal springs and characteristic surficial elemental signatures from remote sensing and imaging. Geophysical, geologic and geochemical techniques that can provide information on the size, depth and shape of deep geological structures are then put into effect.

Subsurface temperature measurements are the most direct method for ascertaining the existence of a hydrothermal system. Thermal-gradient holes can be as shallow as a few meters, but to exclude surface-temperature effects the preference is for a depth of more than 100 m [330 ft]. Temperature surveys can delimit areas of enhanced thermal gradients—a basic requirement for geothermal systems. In volcanic terrains, high-temperature rocks may occur at relatively shallow depths, and it is likely that a heat source is present. In systems of deep circulation, high temperatures indicate thin continental crust, high rates of heat flow and deep permeable faults that transmit mantle heat close to the surface.

Hydrothermal reservoirs require high temperatures and effective permeability, which is offered by coherent rocks capable of supporting open fracture systems. These rocks have a relatively resistive signature. The associated clay-rich caprocks, however, have low resistivity. The resistivity contrast at the base of the caprock, which can be

2. "First Successful Coproduction of Geothermal Power at an Oil Well," *JPT Online* (October 21, 2008), http://www.spe.org/jpt/2008/10/first-successful-coproduction-geothermal-oil-well/ (accessed July 14, 2009).
3. Pollack HN, Hurter SJ and Johnson JR: "Heat Flow from the Earth's Interior: Analysis of the Global Data Set," *Reviews of Geophysics* 31, no. 3 (August 1993): 267–280.
4. Long A: "Improving the Economics of Geothermal Development Through an Oil and Gas Industry Approach," Schlumberger white paper, www.slb.com/media/services/consulting/business/thermal_dev.pdf (accessed September 15, 2009).
5. A fumarole is a vent or opening in the Earth's surface through which steam, hydrogen sulfide or other gases escape.



^ Subsurface temperature predictions. Temperatures measured in wells drilled into hydrothermal systems are compared with temperatures calculated from geothermometers before drilling. The dashed line indicates the location where points would plot if measured and calculated values agreed perfectly. Points above the line indicate calculated temperatures that were underestimated. (Adapted from Duffield and Sass, reference 9.)

determined through magnetotelluric (MT) measurements, can provide an indication of geothermal prospectivity.[6] MT has become a standard method for mapping the caprock geometry constraining geothermal reservoirs.

If wells have been drilled in an area, many of the parameters measured indirectly from the surface can be obtained directly from well log data. These logs can highlight regions of porosity, saline fluid saturation and temperature variations, which may indicate the presence of hydrothermal reservoirs.

Since these resources may be found in fractured, tectonically stressed areas, their presence is often marked by microseismic events that also serve as a guide to drilling into the fractured rocks once other favorable geothermal conditions are established. By recording a relatively large number of these events over weeks or months and calculating their epicenters, seismologists can determine the location and orientation of fractures.

Seismic reflection and seismic refraction surveys have been used only sparingly in geothermal exploration. Although obtaining refraction profiles requires a considerable effort at depths of 5 to 10 km [16,400 to 33,000 ft], standard seismic reflection surveys often yield useful results in these areas. During geothermal exploration, gravity surveys are used to define lateral density variations associated with a magmatic heat source in volcanic-hosted systems or with fault blocks buried beneath sedimentary cover in systems of deep circulation. But their main value is in defining changes in groundwater level and in monitoring of subsidence and injection, which are directly related to the resource's ability to recharge itself. By correlating the surveys and weather, it may be possible to define the relationship between data from a gravity survey and the precipitation that produces changes in shallow groundwater levels. When corrected for this effect, gravity changes show how much of the water mass discharged to the atmosphere is replaced by natural inflow.[7]

The Concept

The most common approaches to geothermal exploration include anomaly hunting, anomaly stacking and conceptual modeling. Mathematical velocity models are routinely used to predict the depth to a formation of interest, and physical models can be used to simulate rock layers. Conceptual models are hypothetical, bringing together observed and inferred information to identify geothermal targets and predict reservoir capacity. Such models are often combined with geostatistical and classical technologies such as those employed for reservoir characterization.

Hydrothermal conceptual models combine observed and inferred information to illustrate reservoir fluid and rock properties and often include data captured through cation and gas geochemistry. They also take into account MT resistivity interpreted in the context of basic geology and hydrology and through mapping of surficial hydrothermal alteration.[8]

The most important element of a hydrothermal conceptual model is a predicted natural-state isotherm pattern—solid lines drawn to indicate temperature and depth across a subsurface section. Though difficult to arrive at during the exploration stage, case histories indicate it can be done based on interpretation of the geothermometry—a technique that allows the determination of subsurface temperature using a combination of methods including the chemistry of hot-springs fluids and distribution of hydrothermal alteration minerals at the surface. Patterns of geophysical anomalies and resistivities and a general knowledge of the local geology, hydrology and faulting or structural history may also be used.

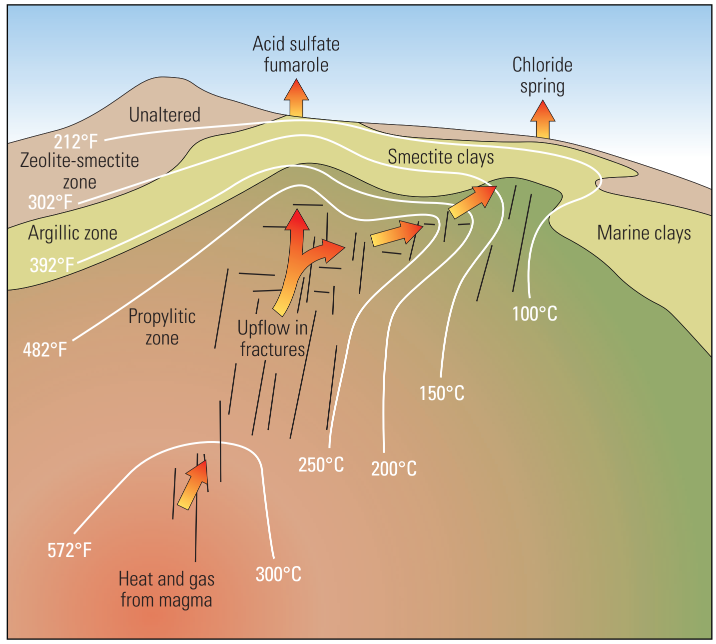
Hot water circulating in the Earth's crust may dissolve some of the rock through which it flows. The amounts and proportions of these solutes in the water are a direct function of temperature. If the water rises quickly from the geothermal reservoir to the surface, its chemical composition does not change significantly and it retains an imprint of the subsurface temperature. Subsurface temperatures calculated from hot-springs chemistry have been confirmed by direct measurements made at the base of holes drilled into hydrothermal systems.[9]

Geothermometry uses ionic and stable isotope ratios in the water to determine the maximum subsurface temperature (above left). Geochemical and isotopic geothermometers developed over the past two decades assume that two species or compounds coexist within the geothermal reservoir and that temperature is the main control on their ratio.[10] They also assume that no change in that ratio has occurred during the water's rise to the surface.

Gas ratio geothermometers can also be used to determine subsurface reservoir conditions. By integrating these geochemical data with information from temperature-gradient wells and structural mapping, engineers can build conceptual models that display fluid-flow patterns within a hydrothermal reservoir as geological cross sections and maps (right). An upward flow of water creates an upward isotherm pattern and indicates permeable rocks. When reservoir flow is vertical, temperatures increase significantly with depth. In an outflow zone the flow is horizontal and temperatures decrease with depth.[11]

Permeable zones have smaller temperature gradients with depth than do impermeable ones and generally display a convective isotherm pattern. In very low-permeability formations, the temperature gradient is steep and is easily seen in a cross section as closely spaced isotherms that reveal a conductive thermal regime. The gradient helps determine the location of permeable and impermeable zones.

Since low resistivity usually indicates low-permeability conductive clays, MT surveys may be used to locate the base of a geothermal caprock and, indirectly, its high thermal gradient. The dimensions of the reservoir can then be mapped and used to identify drilling targets and prospective locations of production and injection wells.



^ Isotherms from geothermometry. Cation geothermometry data from a fumarole and a chloride hot spring can be modeled using a geological interpretation to obtain a subsurface temperature profile. The hot spring is assumed to be close to the top of the water table. Propylitic alteration transforms iron- and magnesium-bearing minerals into chlorite, actinolite and epidote. (Adapted from Cumming, reference 8.)

Enhancing Nature

The hydrothermal fields that are now online and that were discovered through these techniques and models represent the geothermal industry's low-hanging fruit. The future of geothermal energy lies in more-complex systems that must be coaxed into production and in recovering more heat from those already in existence through EGS projects (right).

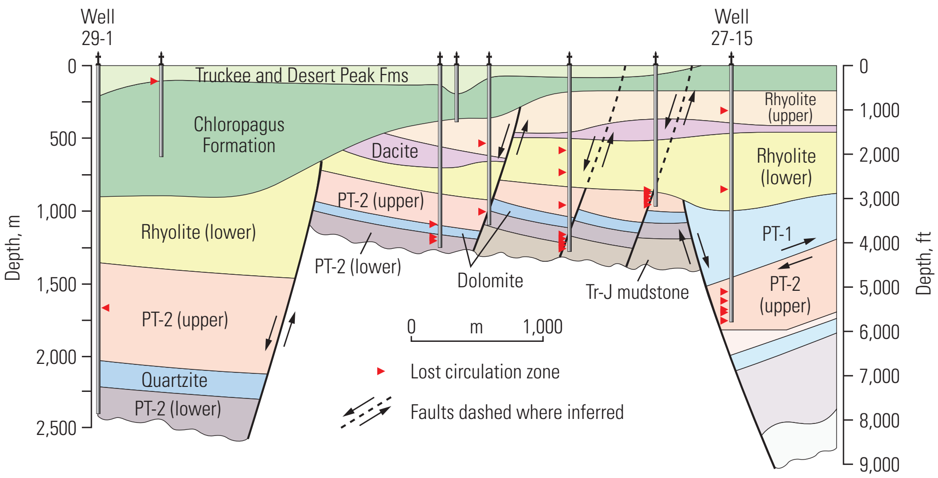
Similar to processes in oil and gas operations, conceptual modeling may be used to plan and execute EGS projects for hydrothermal reservoir development. Using data gained from years of production to construct better models, engineers can assess the potential response of these geothermal fields to infill drilling, water injection and other processes that help extend the field and improve reservoir efficiency.

At Desert Peak near Fernley, Nevada, a geothermal field was discovered and defined in the 1970s and 1980s. It has been delivering power to a double-flash power plant since 1986 and is typical of the deep-circulation, or fault-controlled, geothermal systems of the western USA.[12] An EGS project that would expand the operation through hydraulic and chemical stimulation is under study. The study will determine the distribution of rock types, faults, alteration minerals and mineralized fractures east of the existing hydrothermal field to create a new structural model of the field.[13]

Category of Resource	Thermal Energy, in Exajoules [1 EJ = 10^{18} J]
Conduction-dominated EGS Sedimentary rock formations Crystalline basement rock formations Supercritical volcanic EGS	 100,000 13,300,000 74,100
Hydrothermal	2,400 to 9,600
Coproduced fluids	0.0944 to 0.4510

^ Enhanced geothermal systems potential in the USA. Estimates for the potential energy payout from EGS resources at depths between 3 and 10 km are more than 13 million exajoules (EJ). Recovery of even a small percentage would be more than enough to supply all the electrical needs of the nation. [Adapted from "The Future of Geothermal Energy," http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf (accessed June 30, 2009).]

6. For more on MT: Brady J, Campbell T, Fenwick A, Ganz M, Sandberg SK, Buonora MPP, Rodrigues LF, Campbell C, Combee L, Ferster A, Umbach KE, Labruzzo T, Zerilli A, Nichols EA, Patmore S and Stilling J: "Electromagnetic Sounding for Hydrocarbons," *Oilfield Review* 21, no. 1 (Spring 2009): 4–19.
7. Manzella A: "Geophysical Methods in Geothermal Exploration," Lecture notes. Pisa, Italy: Italian National Research Council International Institute for Geothermal Research, http://www.cec.uchile.cl/~cabierta/revista/12/articulos/pdf/A_Manzella.pdf (accessed August 10, 2009).
8. Cumming W: "Geothermal Resource Conceptual Models Using Surface Exploration Data," *Proceedings of the Stanford University 34th Workshop on Geothermal Reservoir Engineering*, Stanford, California, USA (February 9–11, 2009).
9. Duffield WA and Sass JH: "Geothermal Energy—Clean Power from the Earth's Heat," US Geological Survey, Circular 1249, http://pubs.usgs.gov/circ/2004/c1249/ (accessed August 3, 2009).
10. A geothermometer is a mineral or group of minerals whose composition, structure or inclusions are fixed within known thermal limits under particular conditions of pressure and composition and whose presence thus denotes a limit or a range for the temperature of formation of the host rock.
11. Cumming, reference 8.
12. A double-flash system uses brine separated from geothermal water before it was flashed. The brine is flashed a second time at a lower pressure, and the resulting steam is used to drive a separate turbine or is sent to the high-pressure turbine through a separate inlet.
13. Lutz SJ, Moore JN, Jones CG, Suemnicht GA and Robertson-Tait A: "Geological and Structural Relationships in the Desert Peak Geothermal System, Nevada: Implications for EGS Development," *Proceedings of the Stanford University 34th Workshop on Geothermal Reservoir Engineering*, Stanford, California (February 9–11, 2009).



^ One of two Desert Peak cross sections. This conceptual cross section of the geothermal field shows the stratigraphy and interpreted structure from Well 29-1 in the south to Well 27-15 in the north. The key features of this section are the gently dipping top of the basement rocks in the north, the presence of a pre-Tertiary 1 (PT-1) interval in Well 27-15 and the thick Tertiary section (green) in the southern wells. Faults and structural interpretations are based on lithologies and stratigraphic sequences encountered in each well, and locations of lost circulation zones identified from well cuttings and well logs. Well 27-15 is the candidate for hydraulic stimulation. (Adapted from Lutz et al, reference 13.)

The model proposed is based on analysis of mud logs and cores and incorporates new data from three wells drilled in the production portion of the field. Two cross sections have been constructed based on correlations observed in these three wells (above).

Researchers logged a candidate stimulus well, 27-15, adjacent to the current production area to aid in evaluating lithologies and characterizing stress and fractures. Gamma ray and caliper data were recorded and borehole images were also acquired. Features identified from these resistivity-contrast–generated images include bedding planes, lithologic contacts, foliations, conductive mineral grains, drilling-induced fractures and natural fractures.[14]

In combination with other petrologic and petrographic studies incorporated into a GeoFrame model, this imaging provided a more complete understanding of the geological characteristics of the well as a candidate for EGS. Further rock mechanics testing conducted at the Schlumberger TerraTek Geomechanics Center of Excellence in Salt Lake City, Utah, USA, will characterize rock strengths and stress behavior of potential reservoir rocks within the proposed stimulation interval.

The researchers noted that the productive portion of the Desert Peak geothermal field lies within an older structural horst bounded by north-west-trending faults. The results of tracer tests indicate that fluids injected into the production area can cross into currently nonproductive areas along younger northeast-trending faults. The scientists were unable, however, to determine the depth of the fluid transmissivity and whether the basement fault served as a barrier or conduit to geothermal fluids. Upcoming hydraulic and chemical stimulation experiments are expected to increase permeability and fluid-fracture connectivity in this enhanced system.

Making the Good Better

The dominant tools of EGS—reservoir modeling, drilling, hydraulic fracturing and water injection—are familiar to petroleum engineers. Unfortunately, their use in geothermal applications is more than a matter of adapting them to increased temperatures.

For example, in oil and gas formations, both induced and natural fracturing are reasonably well-understood concepts. But because oil sands are fractured to increase flow in discrete stratigraphic intervals—and the goal in a geothermal resource is to maximize heat exchange in large volumes of fractured crystalline rock—the operations differ greatly in their application. Whereas traditional hydraulic fracturing operations are constrained predominantly by rock stresses and boundary considerations, complex rock and fluid interactions and heat transfer must be considered when determining injection rates, pumping times and injection temperatures for fracturing geothermal formations.

In recent years, stimulation of oil-bearing formations by fracturing has become increasingly sophisticated and efficient as the industry developed methods for modeling, plotting, tracking and even controlling fracture direction. But most of these techniques rely heavily on electronic sensors placed downhole near the sandface depth. Temperature limitations render these devices useless in geothermal zones.

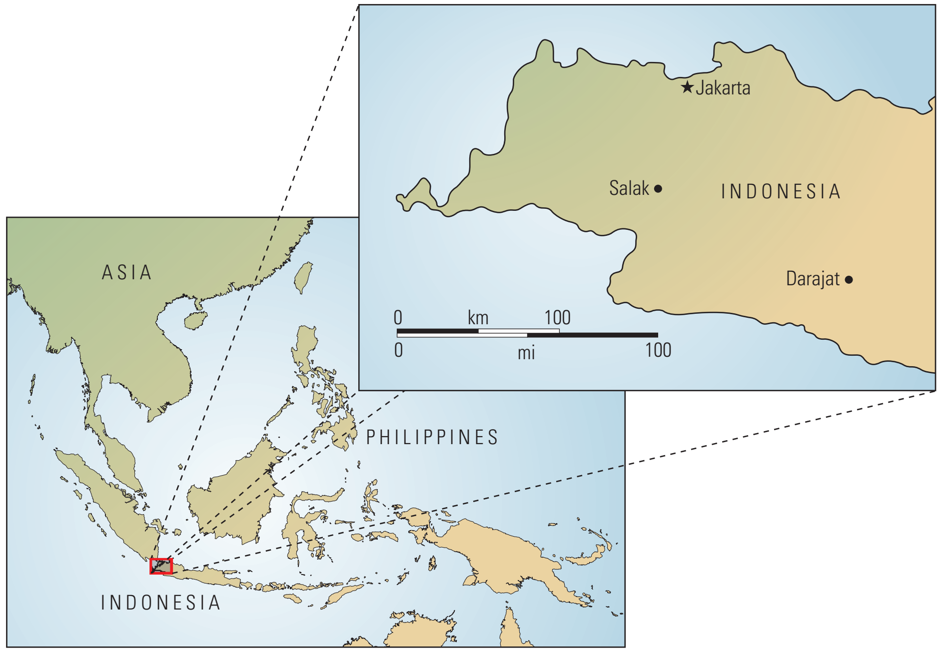
Still, oilfield-style interventions are being applied successfully in many of the world's largest geothermal fields, which are typically the highest temperature volcanic-hosted systems. These operations are essentially EGS and include such established projects as the Salak geothermal field, operated by Chevron. The largest of its kind in Indonesia, the Salak field is located within a protected forest about 60 km [37 mi] south of Jakarta (next page, top right).

Chevron has maintained steam production levels and optimized heat recovery at Salak through infill drilling and water injection into deep wells on the field's margins where permeability is low. Through the use of tracers, chemical and microseismic monitoring, and pressure-temperature surveys of individual wells, Chevron has been able to gauge the impact of its injection strategy and to move injection wells farther from the field's center and closer to its edges. This approach has simultaneously generated more area for infill drilling and expanded the field. It has also allowed the company to convert several injection wells into producers once the formation has thermally recovered.

More recently, geophysical data, including MT and time-domain electromagnetic surveys on the field's margins, have identified potential reservoir extensions to the west and north of the proven area. To the west, the Cianten Caldera exhibits a low-resistivity layer at depths similar to those in the Salak reservoir, and microseismic data show distinct depth distribution of the proven reservoir through the western area.

Drilling results in the caldera indicated noncommercial temperatures. Ring dike intrusions appeared to preclude fluid circulation from the proven reservoir. Geothermal reservoir boundaries tend to be vague, and new wells often encounter low-permeability but hot formations that must be stimulated to provide adequate injection rates. The operator therefore began a long-term, massive cold-water injection program. This operation takes advantage of the extreme temperature differences between the injectate and the formation—more than 149°C [268°F]—and the formation's relatively high coefficients of thermal contraction to create fractures.

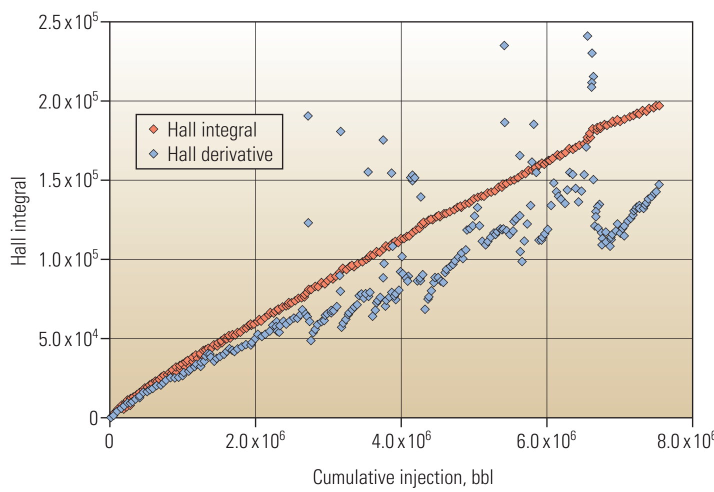
Three injection stimulations were conducted on one low-permeability well in the Cianten Caldera that lies within the boundaries of the Salak concession. These stimulations included injection of about 9.8 million bbl [1.6 million m^3] of water. To evaluate the impact of these treatments on injection performance, the operator used a modified Hall plot and analysis that indicated fracture development within the formation (below right). Injectivity improvements were also quantified through periodic pressure-falloff tests and the creation of a geomechanical reservoir simulation model calibrated against field history.[15] The final analysis concluded that injectivity had been increased significantly. Two additional wells drilled in the area will undergo the same type of stimulation to allow injection of water produced from the high-temperature core of the reservoir.



^ Salak field, Indonesia.

The Great Heat Exchange

Hot dry rock—HDR—reservoirs represent particularly high-potential geothermal systems. The total amount of heat that may be unlocked from these reservoirs worldwide through injection or fracturing has been estimated at 10 billion quads—about 800 times more than that estimated for all hydrothermal sources and 300 times that available from hydrocarbon reserves.[16]

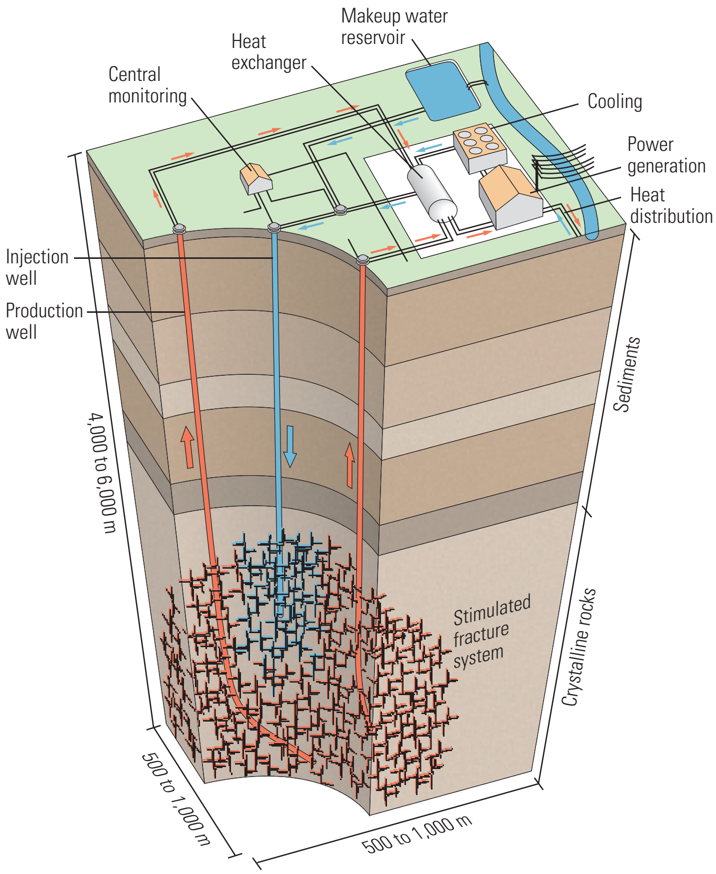


^ Evaluating injection performance. A modified Hall plot provides a qualitative indicator of injection performance. The Hall integral (orange) is a straight line if the well skin factor does not change over time. A steeper slope indicates some type of flow resistance, such as plugging or scaling, while a shallower slope indicates formation stimulation. In subtle cases, such as this one in Salak field, plotting the Hall derivative (blue) on the same scale improves the diagnosis. A derivative curve above the integral curve indicates increased resistance and below the integral curve—as shown here—ongoing stimulation. This analysis confirmed fracture development during cold-water injection in the field. (Adapted from Yoshioka et al, reference 15.)

14. Kovac KM, Lutz SJ, Drakos PS, Byersdorfer J and Robertson-Tait A: "Borehole Image Analysis and Geological Interpretation of Selected Features in Well DP 27-15 at Desert Peak Nevada: Pre-Stimulation Evaluation of an Enhanced Geothermal System," *Proceedings of the Stanford University 34th Workshop on Geothermal Reservoir Engineering*, Stanford, California (February 9–11, 2009).
15. Yoshioka K, Pasikki R, Suryata I and Riedel K: "Hydraulic Stimulation Techniques Applied to Injection Wells at the Salak Geothermal Field, Indonesia," paper SPE 121184, presented at the SPE Western Regional Meeting, San Jose, California, USA, March 24–26, 2009.
16. Duchane D and Brown D: "Hot Dry Rock (HDR) Geothermal Energy Research and Development at Fenton Hill, New Mexico," *GHC Bulletin* (December 2002), http://geoheat.oit.edu/bulletin/bull23-4/art4.pdf (accessed August 11, 2009).

    "Quad" is a short term for quadrillion and is a unit of energy equal to 10^{15} BTU [1.055×10^{18} J]. It is the equivalent of about 180 million bbl of oil [28.6 million m^3]. For reference, the total 2001 US energy consumption was about 90 quads. The total HDR resource numbers published by Duchane and Brown were calculated by summing the thermal energy content of rock beneath the Earth's land masses at temperatures above 25°C [77°F] from the surface to 10,000 m [33,000 ft]. While these numbers seem astronomical and do include resources that are impractical to recover because they are low temperature or are unreachable, they still represent an enormous amount of energy.

Unlike hydrothermal EGS, there are, as yet, no commercial HDR fields, so experience with these systems has been confined primarily to pilot projects. Of particular importance to the concept is an extended study at Fenton Hill—the first HDR project—that began in the early 1970s. The Fenton Hill HDR site is about 64 km [40 mi] west of Los Alamos, New Mexico, USA. It includes two confined reservoirs created in crystalline rock at 2,800 and 3,500 m [9,200 and 11,480 ft] with reservoir temperatures of 195°C and 235°C [383°F and 455°F], respectively. Flow tests were conducted in each of the reservoirs for almost a year. The project, conducted over a period of about 25 years, ended in 1995.



^ The EGS concept as applied to HDR. Fractures are generated from an injection well (blue) drilled into a low-permeability reservoir of deep crystalline rock. Production wells (red) are then drilled into the fractured zone. Injected water is heated as it flows from the injection well to the production wells.

HDR systems are essentially reservoir-creation projects. One of the most important lessons learned at Fenton Hill is that it is nearly impossible to connect two existing boreholes by creating a hydraulic fracture between them. Reservoirs should therefore be created by stimulating or creating fractures from the initial borehole and then accessing them by two production boreholes (left).[17]

Work at Fenton Hill also advanced the case for HDR fields by defining which critical factors in their construction are controllable. For example, the reservoir's size is a direct linear function of the amount of fluid injected into it (next page). Similarly, temperature, injection pressure and flow rate, production backpressure, and the number and placement of wells are all manageable variables within HDR field development.

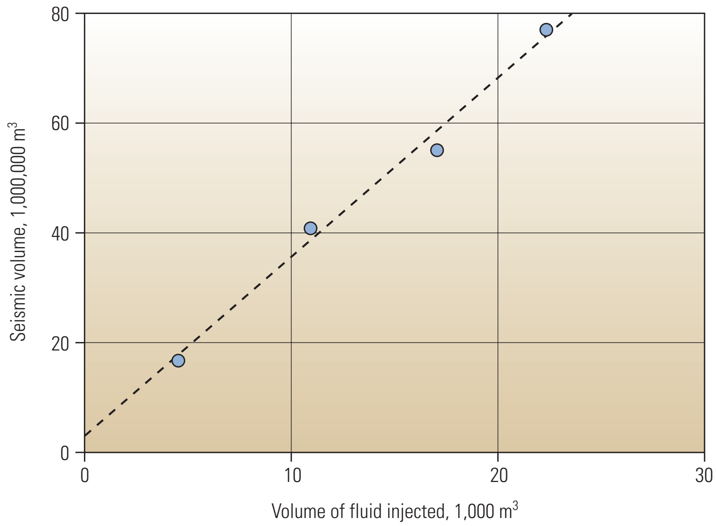
While many of the technological questions associated with HDR systems were answered through the work at Fenton Hill, uncertainties about reservoir creation remain. Although a relationship can be established between fluid volume injected and resulting volume made available for heat exchange, the fractured surface area within that volume of rock is more difficult to quantify.

One approach renders an order-of-magnitude estimate of the rock volume required. This is obtained by equating the heat flow rate from the reservoir with the change in stored thermal energy, assuming uniform extraction of heat throughout the volume. The heat flow rate is a function of rock density, volume and heat capacity, and the change in rock temperature over time.

A numerical simulation study by Sanyal and Butler suggests the electrical power generation rate achievable on a unit rock volume basis is 26 MW_e/km^3 [106 MW_e/mi^3].[18] This power-production correlation requires a volume of roughly 0.19 km^3 [0.05 mi^3] to generate 5 MW_e. Such a cube would measure 575 m [1,886 ft] on each side, and the simulation is based on an assumption of uniform properties, including permeability, within the stimulated region.

The study concluded that if constant production is maintained, generation capacity is primarily a function of the stimulated rock volume. Other considerations may include well configuration, number of wells within a reservoir volume, reservoir mechanical properties, reservoir stress state and natural fracture features. These characteristics collectively determine how the reservoir is best stimulated to create the requisite volume and the flow paths necessary for effective heat extraction.[19]

17. Brown DW: "Hot Dry Rock Geothermal Energy: Important Lessons from Fenton Hill," *Proceedings of the Stanford University 34th Workshop on Geothermal Reservoir Engineering*, Stanford, California (February 9–11, 2009).
18. Sanyal SK and Butler SJ: "An Analysis of Power Generation Prospects from Enhanced Geothermal Systems," *Proceedings of the Stanford University 34th Workshop on Geothermal Reservoir Engineering*, Stanford, California (February 9–11, 2009).
    MW_e stands for electrical megawatt.
19. Polsky Y, Capuano L Jr, Finger J, Huh M, Knudsen S, Mansure AJC, Raymond D and Swanson R: "Enhanced Geothermal Systems (EGS) Well Construction Technology Evaluation Report," Sandia Report SAND2008-7866: Sandia National Laboratories, December 2008.
20. Polsky et al, reference 19.
21. Kumano Y, Moriya H, Asanuma H, Wyborn D and Niitsuma H: "Spatial Distribution of Coherent Microseismic Events at Cooper Basin, Australia," *Expanded Abstracts*, 76th SEG Annual Meeting and Exhibition, New Orleans (October 1–6, 2006): 595–599.
    Microseismic multiplet analysis, based on a high-resolution relative hypocenter location technique, uses waveform similarity to identify events located on geometrically or geophysically related structures.
22. Petty S, Bour DL, Livesay BJ, Baria R and Adair R: "Synergies and Opportunities Between EGS Development and Oilfield Drilling Operations and Producers," paper SPE 121165, presented at the SPE Western Regional Meeting, San Jose, California, March 24–26, 2009.



^ Controlling reservoir size. During a massive hydraulic fracture test at Fenton Hill, a linear relationship was established between the seismically active reservoir volume and the volume of injected fluid, as determined from microseismic event location data. (Adapted from Duchane and Brown, reference 16.)

Despite the progress being made on the technological aspects of HDR exploitation, commercial viability of these prospects remains elusive as a consequence of their depth and temperature. For example, commercial hydrothermal well depths range from less than 1 km to a rare few that reach about 4 km [13,000 ft], such as the EGS project in Soultz-sous-Forêts, France. HDR wells, because they are in crystalline basement formations, are typically much deeper. As a consequence, HDR wells are likely to be characterized by varied lithology and the extensively documented problems associated with deep drilling and completion.[20]

The Gap

Owing to the obvious similarities between hydrocarbon and heat mining, it is tempting to assume that adapting the technology of the former to the latter is a matter of focus. Recent development of tools for use in some applications—HPHT oil and gas wells, hydrothermal fields and steamflooding—encourages such assumptions.

Geothermal energy resources, however, differ across the world, and the ease with which this technology transfer will take place is a function of those differences. The highest grade of resource—hydrothermal—is shallow, permeable and hot and has a natural water-recharge system. The techniques and methods used to tap that resource are and will continue to be familiar to oilfield personnel.

Lower-grade resources that require intervention in the form of injection or fracturing, or whose temperatures are below the boiling point of water, are also being produced at a profit through the use of technology adapted from the petroleum industry. Coproduction is a current technique that uses the hot water produced with oil and gas to run binary plants, which in some cases generate all the field's electricity needs.

But the real prize in geothermal energy production will come once the technology required for EGS and HDR reservoirs is widely available. Despite current barriers to commerciality, HDR projects do have an advantage over those for conventional hydrothermal systems in that they can be located near major electricity markets.

That they still require much technological innovation, however, has created a tendency among many of those best equipped to solve these problems—petroleum industry professionals—to abandon the notion of HDR developments in favor of more immediate and familiar pursuits.

With the prospects of large payoffs, there has been progress on making HDR projects economically attractive, including the vital area of reservoir-creation monitoring and control. In the Cooper basin of Australia, for example, geophysicists recently applied microseismic multiplet analysis to a dataset from an HDR hydraulic fracturing operation to help characterize the developing fracture system within the reservoir.[21]

The greatest potential for improving the economics for geothermal energy projects, as in any high-risk, high-cost venture, is by risk reduction through a better understanding of the subsurface. The unknowns that affect drilling and completion risk, environmental impact, stimulation and overall project success are all exacerbated by a lack of knowledge about lithology, stress regime, natural seismicity, preexisting faults and fractures, and temperature at depth.[22]

Correcting these shortcomings will be a matter of growth, but of a type with which the E&P industry is long familiar. It took the offshore industry more than 50 years of lessons learned between the first well drilled in shallow water just out of sight of land to routine placement of wells in water depths of more than 3,000 m [10,000 ft] and hundreds of kilometers from shore. Moving from shallow, high-grade hydrothermal formations to deep, hot dry rocks will require a similar evolution in technology, equipment and trained personnel. Given the prize in the offing, however, it is certainly just a matter of time. —RvF