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GIGAWATT-YEAR GEOTHERMAL ENERGY STORAGE COUPLED TO NUCLEAR REACTORS AND LARGE CONCENTRATED SOLAR THERMAL SYSTEMS

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ABSTRACT

Capital-intensive, low-operating-cost nuclear and solar thermal power plants are most economical when operated under base-load conditions. However, electricity demand varies on a daily, weekly, and seasonal basis. In deregulated utility markets this implies high prices for electricity at times of high electricity demand and low prices for electricity at times of low electricity demand. We examined coupling nuclear heat sources to geothermal heat storage systems to enable these power sources to meet hourly to seasonal variable electricity demand. Because the heat storage system is independent of the source of heat, the results are applicable to other large heat sources such as large-scale centralized thermal solar systems.

At times of low electricity demand the reactor or solar plant heats a fluid that is then injected a kilometer or more underground to heat rock to high temperatures. The fluid travels through the permeable-rock heat-storage zone, transfers heat to the rock, is returned to the surface to be reheated, and re-injected underground. At times of high electricity demand the cycle is reversed, heat is extracted, and the heat is used to power a geothermal power plant to produce intermediate or peak power. Below 300°C pressurized water is the preferred heat transfer fluid. These temperatures couple to existing light-water reactors. At higher temperatures supercritical carbon dioxide is the preferred heat transfer fluid.

Underground rock can not be insulated, thus small heat storage systems with high surface to volume ratios are not feasible because of excessive heat losses. The minimum heat storage capacity for seasonal storage is ~0.1 Gigawatt-year. Three technologies can create the required permeable rock: (1) hydrofracture, (2) cave-block mining, and (3) selective rock dissolution. The economic assessments indicated a potentially competitive system for production of intermediate load electricity. The basis for heat storage at temperatures <300°C exists with some development work; but, there are significantly greater challenges for storing heat at higher temperatures that require supercritical carbon dioxide as the geofluid. Such systems are strongly dependent upon the local geology.

INTRODUCTION

Electricity demand varies on an hourly, daily, and weekly basis. Low-capital-cost high-operating-cost fossil plants are used to meet variable electricity demand. However, restrictions on greenhouse gas releases and ultimately higher fossil costs may limit the use of fossil fuels for variable electricity production. Nuclear and renewable systems have high capital costs and low operating costs—conditions that economically favor operating these facilities at their maximum capacity. However, their output does not match electricity demand. Energy storage would enable nuclear and renewable energy sources to operate at full capacity while meeting variable energy demand. We have been examining large-scale geothermal heat storage to enable electricity storage (Lee and Forsberg, 2011; Kulhanek, 2011). The technology and requirements are described followed by the results of our analysis.

CONCEPT DESCRIPTION

A GWy geothermal heat storage system (Fig. 1) would use heat from a nuclear reactor or large solar thermal system at times of low electricity demand to heat a cube of rock ~400 meters on a side a kilometer or more underground to create an artificial geothermal heat source. The heat source would be used for the production of intermediate and peak electricity production using a typical geothermal power system. Most of our analysis assumed the heat source was a large light-water reactor (LWR); however, the heat source could be a thermal solar system or a high-temperature reactor.

For the LWR, the heat transfer fluid is pressurized hot or cold water. Cold water is heated going through a heat exchanger with hot primary reactor circuit water on the opposite side. The resulting hot water is injected underground at the top of a permeable zone of rock, travels through the rock, and transfers its heat to the rock. The resultant cold water is recovered from the bottom of the permeable rock zone, pumped back to the surface, and reheated to complete the cycle. At times of high electricity demand, the flow is reversed: cold water is injected at the bottom of the permeable rock zone, the cold water is heated going through the rock, and the resultant hot water from the top of the permeable rock zone flows to a geothermal power plant to produce electricity. The cold water from the geothermal power plant is re-injected at the bottom of the permeable rock zone.

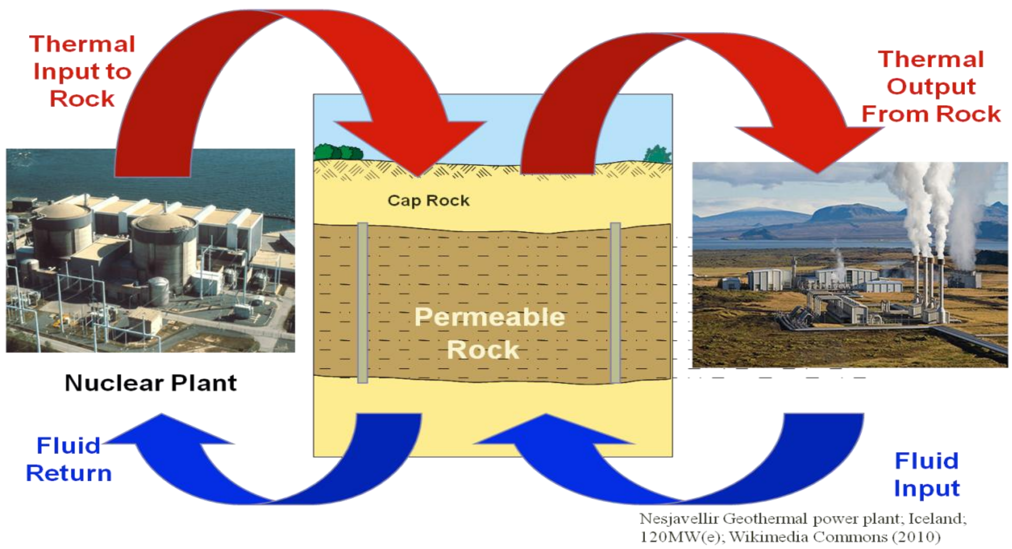

Figure 1: Conceptual Diagram of Nuclear-Geothermal Energy Storage System

This energy storage system allows separate sizing of the rate of heat addition, the heat storage capacity of the rock reservoir, and the rate of heat extraction for electricity production. The sizing of these three components depends upon local electrical grid needs. The capital costs of the storage media are very low relative to other energy storage technologies because rock is the storage media. The cost of inefficiencies is low relative to most other systems because heat (not high-quality electricity) is stored. The value of heat is less than electricity. The surface facility size is small relative to other systems because energy is stored a kilometer or more underground with approximately a 500-m cube capable of storing a gigawatt-year of heat.

The technology for storage temperatures up to 300°C is based on two commercial technologies: (1) heating of underground heavy oil deposits to lower the viscosity of the oil and thus enable it to be pumped and (2) traditional geothermal electricity production. There are some important differences. In this system the same piece of rock is repeatedly heated and cooled.

Our baseline studies (Table 1) examined a nuclear geothermal system coupled to a pressurized water reactor (PWR). The peak temperatures of a PWR are just under 300°C—about the same limit for using pressurized water to transfer heat from the reactor to the underground rock and about the peak temperature found in geothermal power stations. Above 300°C pressurized hot water is not useable because it dissolves silica—a nearly universal component of most geologies. An intermediate heat exchanger separates the water flowing through the reactor core from the water to transfer heat underground. These are the first such studies on higher-temperature geo-thermal storage systems. There have been numerous studies and multiple small commercial geothermal heat storage systems operating at lower temperatures to provide heat for buildings.

Table 1: Baseline Assumptions (Lee and Forsberg, 2011)

Technology	Chosen Option	Constraint
Power plant	Pressurized Water Reactor	T_{max}: 273°C
Geofluid	Pressurized water	P_{min}: 5.7MPa
Nuclear coupling	Bypass primary side	Intermediate HX(s)
Underground reservoir type	Enhanced geothermal (EGS)	Need for underground stimulation to boost rock permeability
Geothermal power cycle	Binary power cycle	Efficiency
Geology	Sandstone	Rock properties
Depth	1 to 1.5 km	Need for pressurized liquid water
Method to create permeability	Hydraulic fracturing	Max. permeability of reservoir = 2 Darcy

We assumed the geothermal power plant uses existing designs of geothermal power plants with the efficiencies of those plants as a function of temperature. This is a conservative assumption because a geothermal heat storage system would have power outputs measured in hundreds of megawatts versus ten or twenty megawatts. A much larger plant opens up choices for more efficient power cycles as well as improved economics. In most of our analysis we assumed the geology was sandstone with the permeability created by hydrofracture. There are other candidate geologies and other technologies to create permeable rock underground.

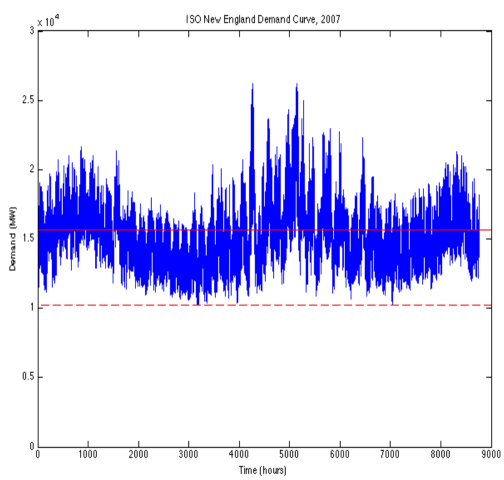

Figure 2: New England Electrical Demand Over One Year

STORAGE REQUIREMENTS

About 40% of the U.S. energy demand is in the form of electricity. The electricity demand varies with time (Fig. 2). Two thirds of the electricity is base-load electricity that is the traditional market for high-capital-cost low-operating-cost nuclear power plants that operate most economically under base load conditions. One third of the electricity demand is variable and is primarily met by fossil power plants that have lower capital costs but higher fuel operating costs.

To provide an understanding of future energy storage requirements, we (Oloyede 2011; Forsberg, 2011) estimated the electricity storage requirements for California under three idealized futures where all electricity was generated by nuclear or wind or solar. In each case (1) the electricity source over one year generated the kilowatt hours consumed by California over one year, (2) the electricity source operated at its full capacity to minimize electricity production costs, (3) electricity was stored when production exceeded demand to be provided to customers when demand exceeded production, and (4) there were no losses or inefficiencies in the electricity storage systems. In all cases the electricity demand was the real hourly California electricity demand for 8760 hours per year.

- *Nuclear*. All electricity is from nuclear plants with steady-state output for 8760 hr/y.
- *Solar*. All electricity is from solar thermal trough systems in the California desert using the National Renewables Energy Laboratory (NREL) model of performance and California solar data.
- *Wind*. All electricity is from wind systems using California wind data and NREL model of wind farm performance. It is unclear if

California has sufficient wind to meet its total needs.

The results are shown in Table 2 where storage requirements are defined as the fraction of total electricity that is produced that must go into storage when production exceeds demand to provide the electricity to meet demand when production is less than demand.

Table 2: California Electricity Storage Requirements as Fraction Total Electricity Produced

	Hourly	Daily	Weekly
Nuclear	0.07	0.04	0.04
Wind	0.45	0.36	0.25
Solar	0.50	0.21	0.17

The hourly storage requirement refers to storage requirements based on production and demand analyzing hour by hour for the 8760 hours in a year. The daily storage requirements assumes some other technology (smart grids, etc.) which results in a constant electricity demand each day (total electricity consumed in one day divided by 24 hours) and the storage system must address variations in electricity demand between different days of the year. The weekly storage requirements assume the electricity demand is constant each week and the storage system must address variations in electricity demand between different weeks of the year.

While there are many technologies (batteries, pumped storage, etc.) to address short-term storage needs, there are no existing technologies (Electric Power Research Institute, 2010) to address weekly and seasonal energy storage needs because the storage media such chemical energy and elevated water are too expensive for a system that might be charged or discharged a couple of times per year. Weekly and seasonal storage is potentially half the long-term total storage need for a low-carbon world. Geothermal heat storage would be used to meet daily, weekly (weekday/weekend), and seasonal variations in electricity demand by either absorbing excess heat at a variable rate from reactor or solar thermal systems when available or delivering electricity at a variable rate when required. However, the response rate would be slow because it is a large (kilometers of piping) thermal system. Variations under an hour would require other storage and smart-grid systems. In this context, it is complementary to existing electricity storage technologies and is in a category by itself.

The U.S. electrical annual electrical consumption is about 500 gigawatt-years requiring the production of a 1000 to 2000 gigawatt-years of heat. In a world with restricted use of fossil fuels the thermal heat storage market in the United States to support electricity production would be measured in hundreds of gigawatt-years.

GEOTHERMAL SYSTEM SIZE

It is not possible to insulate rock a kilometer underground. Heat will conduct from hot rock to cold rock. However, as the system size is increased the fractional heat losses decrease because the surface to volume ratio decreases. Thus large systems have smaller losses than small systems. Conduction heat losses decrease with cycling and local heating of neighboring rock.

Fig. 3 shows the fractional heat loss for different cycles as a function of the system size. To keep heat losses to a couple of percent of the total heat storage for seasonal storage, the system size should be ~0.1 GWy or larger. If used for shorter-term storage, smaller systems would be viable because heat losses per cycle are less because heat is stored for a shorter period of time.

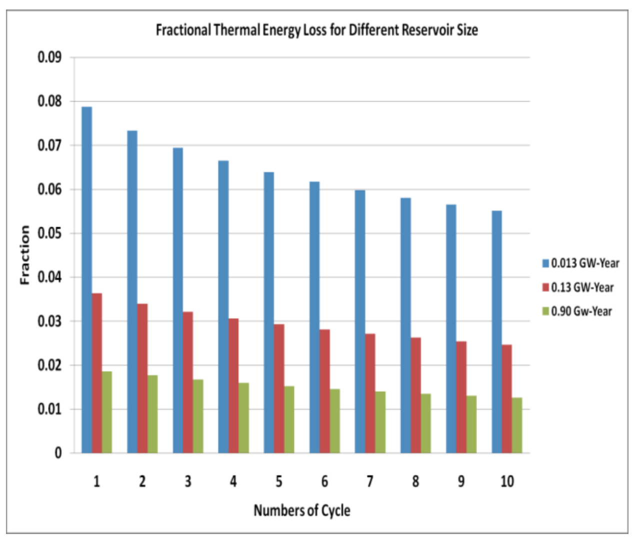

Figure 3: Fractional Heat Losses versus Number of Cycles for Different Size Systems (Lee, Forsberg, 2011): Inlet Temp: 250°C; Outlet Temp: 30°C; Porosity: 0.2; Diameter/Length 0.331, Cycle length: 6 months

There is a second heat loss mechanism, loss of the geothermal heat transfer fluid and its heat. To avoid this heat loss requires low permeability of rock around the high-permeability heat storage zone. The oil, mining, and hydroelectric industries have developed a variety of techniques such as cement grouting to reduce unwanted permeability.

CHOICE OF HEAT TRANSFER FLUID

There are several considerations in the choice of geothermal heat transfer fluid: compatibility with the local geology, cost, and efficiency. Three fluids were identified

- **Water**. Water is found in all rocks and is the fluid associated with existing geothermal power plants. Its peak temperature is limited to about 300°C because at higher temperatures it dissolves many components within rock.

- **Air.** Air has a low cost and is used in Compressed Air Energy Storage (CAES). In CAES (Electric Power Research Institute, 2010), air is compressed at times of low energy demand and stored like natural gas in underground caverns. At times of high energy demand, the compressed air is fed to gas turbines to produce electricity. There has been limited work with CAES-type systems to store the compressed air in the rock structure of sandstone and similar rocks with high porosity. Hot air as associated with geothermal heat storage is only compatible with some types of geology because oxygen in air will react with some types of rock over time. In most cases the reaction products have greater volumes and thus would reduce the fluid permeability of the rock.

- **Carbon dioxide**. All volcanoes emit carbon dioxide—a demonstration of its chemical compatibly with some types of high-temperature rock. It is being investigated as a heat transfer fluid for use in enhanced geothermal power systems. Lawrence Berkeley National Laboratory is constructing a first pilot geothermal power plant to extract heat at relatively low temperatures with supercritical carbon dioxide using a supercritical carbon dioxide power cycle. Beyond its chemical compatibility and low cost, it is a very non-ideal fluid whose properties can boost efficiency relative to other heat transfer fluids in geothermal systems.

Water can exist as pressurized water or steam. If steam rather than pressurized hot water is the heat transfer fluid, there are a large set of constraints on the depth of the heat storage zone. The steam condensation temperature depends upon pressure; thus, reservoir pressure determines steam condensation temperature. The enthalpy change associated with the phase change from vapor to liquid increases as operating pressure decreases. This implies that the required mass flow rate to transfer the same amount of heat decreases as burial depth of the thermal reservoir decreases. Since pressure drop in the porous body is proportional to mass flow rate, it might seem that pressure drop decreases as burial depth decreases. However, the density of saturated steam decreases as burial depth decreases, leading to an increase in velocity for the same mass flow rate. This causes a rise in pressure drop. Hence, there are two competing phenomena that are associated in determining the burial depth, from the view point of pressure drop. These complexities and other considerations indicate that pressurized water rather than steam will be the preferred heat transfer fluid under most circumstances at temperatures less than 300°C

We examined the engineering implications (Kulhanek, 2012) of the three fluids under a standard set of conditions (Table 3) for three peak heat storage temperatures: 250, 500, and 730°C. These correspond to different types of nuclear or solar power systems providing the heat. Reservoir size, system pressure losses, pump/compressor power, and number of wells were computed for each case and results compared. Many parameters are involved and changing one may change results significantly. For example, increasing well diameter from 0.5 m, which is today the maximum drilling diameter, to 1 m reduces the high frictional pressure loss of wells and, especially for CO_2 and air, considerably lowers the number of wells. Another important parameter is reservoir permeability which determines its pressure loss. Hence, a number of calculations with various data sets was performed to study effects of these parameters, and to select the most feasible geofluid.

Pressurized liquid water was found to be preferred below 300°C, however its capability to dissolve rock disables it from use at higher temperatures. At temperatures of 500°C and 730°C, the CO_2 performs better than air in all examined aspects. Furthermore, CO_2 density differences between the injection and production well cause a significant increase of pressure at the outlet of the production well during heat recovery. If this pressure increase could be exploited, the system round trip efficiency will be enhanced.

Table 3: Standard Conditions Used to Compare Alternative Heat Transfer Fluids

PARAMETER	VALUE	UNIT
Stored energy	1.0	[GW-year]
Reservoir permeability	1.0	[Darcy=1E-12m^2]
Reservoir burial depth	1,000	[m]
Reservoir diameter	500	[m]
Well inner diameter	1.0	[m]
Well pipe relative roughness	0.000045	[m]
Heat exchangers pressure drop	500	[kPa]
Compressor(pump) thermodynamic efficiency	0.9	[-]
Rock porosity	0.35	[-]
Rock specific heat	0.85	[kJ/kgK]
Rock density	2,600	[kg/m^3]
Surrounding rock temperature at res. depth	50	[°C]
Injection well inlet pressure	20	[MPa]
Maximum temperature	250-730	[°C]
Compressor(pump) inlet temperature for discharging mode	32	[°C]

At the maximum temperature of 250°C water requires only one well while CO_2 requires two and air requires seven. At temperatures of 500°C and 730°C, CO_2 requires one well for both cases and air two. Equally important, there are large differences in the pumping power (Fig. 4). At 250°C, pressurized water has the lowest pumping power. At higher temperatures, CO_2 has the lowest pumping power. Only in systems with very high permeability would air be attractive as the geofluid.

GEOLOGICAL REQUIREMENTS

There are several requirements for heat storage.

- **Chemical compatibility**. The geology must be compatible with the heat transfer fluid as discussed above. Chemical reactions that increase the volume of the rock will lower the permeability and plug the heat transfer zone. Chemical reactions that reduce rock volume may be acceptable

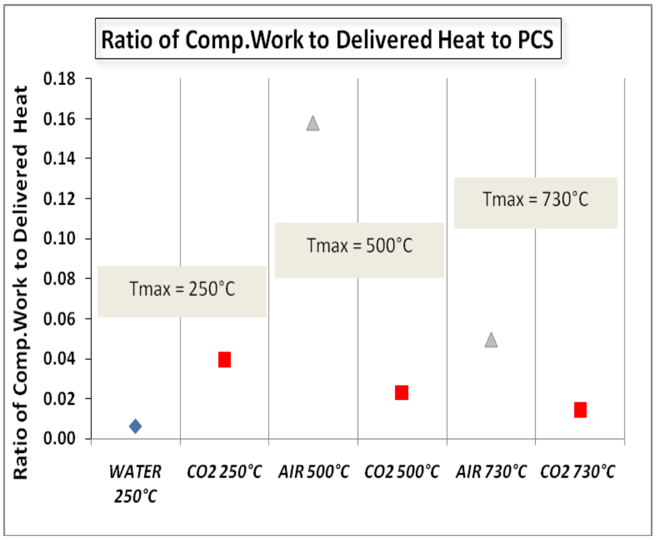

Figure 4: Ratio of Compressor (Pump) Work to Delivered Heat to the Power Conversion System

- **Permeability.** A minimum permeability of about a Darcy is required to avoid excessive pumping costs in the heat storage zone. Outside the heat storage zone, the permeability must be an order of magnitude lower to reduce fluid losses and hence heat losses to acceptable levels. The loss of 5% of the heat transfer fluid implies loss of 5% of the heat. High fluid losses would make the system uneconomic. The pressurized water or supercritical carbon dioxide will also be partly treated to reduce scale and other engineering problems in the heat exchangers, pumps, and power cycles—implying other economic incentives to avoid fluid losses. A wide variety of techniques have been developed in the oil industry to reduce rock permeability such as cement grout and silica injection to create low-permeability zones.

- **Mechanical properties.** Rock plastic behavior must be avoided to prevent closure of cracks through which the heat transfer fluid flows. This is likely to be a major constraint at higher temperatures in the choice of geology and the method used to create a permeable rock heat storage zone.

Three methods to create permeable rock zones have been identified. The preferred choice will depend upon the local geology and economics. Analysis indicates that permeabilities above one Darcy are required to have acceptable fluid pumping costs.

Hydrofracture

The first option is drilling wells into a permeable rock. The rock permeability to flow can be increased by hydraulic fracturing. Hydraulic fracturing is injection of high pressure water with proppants into the geology of interest. The high pressure water opens fractures in the rock and the fracture width is maintained after the injection by introducing proppants into the fracture. The proppants prevent the fractures from closing when the injection is stopped. In the oil and gas mining industries, induced rock fracturing is a standard industrial practice.

Hydraulic fracture is dependent upon the initial permeability of the rock. The more permeable the initial geology is, the easier the hydraulic fracture process. Fig. 5 illustrates ranges and representative value of permeability for some common sedimentary and igneous rocks. Sandstone has superior permeability relative to other rocks. The thermal properties of different rocks are approximately the same. Hence, sandstone will be the preferred geology under most conditions.

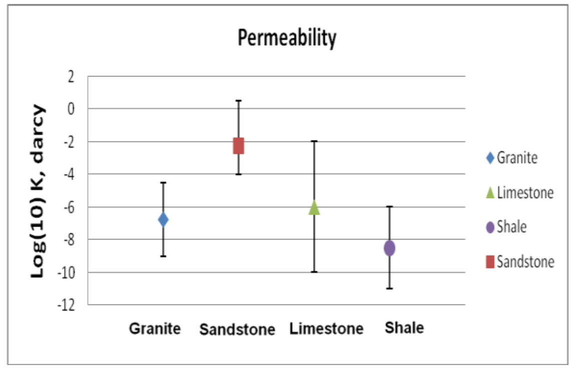

Fig.5: Permeability for different rocks

A two-step-in-one fracture stimulation and gravel-pack procedure has created reservoirs with target permeabilities of 2D or greater. In this context, hydrofracture has not been developed for geothermal heat storage systems where the reservoir will be used for many decades with large incentives for high permeability and low pumping loses. Hydrofracture has been used extensively for one-time recovery of oil and gas. Very high permeability is not required for this application. It is not currently known how much existing technology could increase permeability if there were large incentives for higher permeability rock.

Mine options

Unlike the well option, where micro-scale fractures provide the permeability, the mining options (Lee, Forsberg, Driscoll, Sapiie, 2010) involve the creation of underground rubble zones with macroscopic fractures. Conventional mining operations would create mine tunnels at two levels, with the levels separated by 50 to 500 meters. The top level must be below the depth where the hydrostatic pressure of the groundwater exceeds the pressure necessary to maintain the required pressure for the heat transfer fluid—for pressurize water sufficient pressure to prevent flashing. At the lower level, silos would be created (25 meters and larger in diameter) upward from the bottom level. The silos would be spaced to prevent rock collapse. Holes for explosives would be drilled between the upper level and the top of the silos. Controlled timed explosives would then create rubble chimneys between the upper and lower level. The mined volume of the original silos is the void space in the final chimneys of broken rock between the two levels. These chimneys would then be the primary heat storage volumes. The rock in the side walls would be secondary heat storage.

The tunnels at the top, the bottom, and connecting the two levels are the collector paths for hot and cold water in the heat storage reservoir and thus are sized to meet both mining requirements and geothermal heat storage operational requirements. Local geology and mining economics would determine the specific design of rubble bed.

The construction technology is a combination of traditional block caving mining and the underground civil engineering done for facilities such as the Swedish SFR waste disposal facility, non-salt strategic oil reserve storage facilities, and some hydro facilities. The distinction between traditional mining operations and underground civil engineering is that the underground civil engineering structures are designed for century lifetimes whereas mines are designed only to last as long as it takes to remove the ore. The access would include a shaft and likely an inclined tunnel to enable high volume rock removal.

We evaluated pressure drops and thermal time constants associated with different fractured rock diameters (Fig. 6). The pressure drops are so low that pressure drop is not expected to be a significant design constraint. However, the actual rubble bed will have a distribution of rock sizes and thus a smaller void fraction and somewhat higher pressure drops. Practically, when rock size becomes greater than 0.1 m, it is unreasonable to expect any marginal decrease in pressure drop.

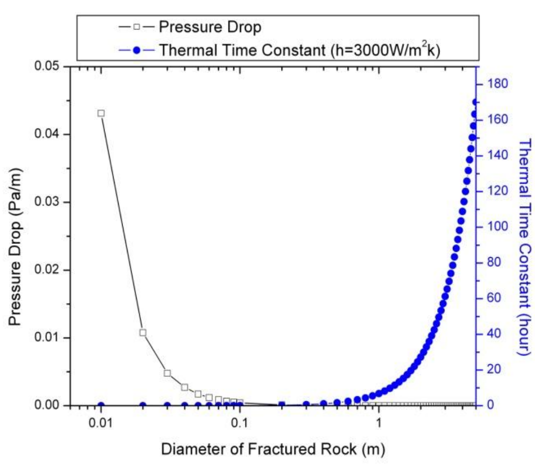

Figure 6: Pressure drop and thermal time constants for the mining option (Lee, Forsberg, Driscoll, Sapiie, 2010)

However the figure at the same time tells us that there should be a limit on the size of the fractured rock from the viewpoint of transferring heat from the rock to the fluid. When the rock size becomes greater than 0.4 m in diameter, it starts to take more than an hour to heat up the rock or cool down the rock, and beyond a rock diameter of 1 m, heat storage time increases significantly, possibly becoming a crucial design constraint. It appears that having a fractured rock size between 0.1m~0.6 m is optimum when it comes to satisfying both pressure drop, and achieving a reasonable thermal time constant.

Selective Dissolution

High permeability zones can be created by selective removal of materials. We examined the option of combining heavy oil recovery with nuclear geothermal heat storage system using California heavy oil fields (Forsberg, Krentz-Wee, Lee, Oloyede, 2010). Heavy oil has a very high viscosity. To recover heavy oil, steam is injected into the oil reservoir to increase the rock temperature, thus lowering the oil viscosity, and enabling the heavy oil to drain to oil recovery wells.

Heavy oil operations typically recover 20 to 40% of the heavy oil—but larger fractions can be recovered in some cases. The conversion to a geothermal heat storage system with cyclic heating and cooling of the reservoir with pressurized water over time will ultimately recover most of the remaining oil. Each cycle of heat storage and recovery implies a washing of the geology with hot water and extraction of some fraction of the remaining oil. The oil would be removed at the power plant. The permeability of the reservoir will increase with time. Because of the high value for oil, there would be incentives to move the reservoir over time to boost heavy oil recovery—limited only by reasonable distances to transport heat from reactor to the underground heat storage zone.

There are other options to dissolve selected rock components in different geologies to increase rock permeability. Both hot water and supercritical carbon dioxide will dissolve selected species. However, selected dissolution comes at the price of the necessity to remove what is dissolved in the heat transfer fluid at the power plant. In the case of heavy oil, the oil naturally separates from the hot water and has a high commercial value. For other species it may precipitate as the heat transfer fluid is cooled in the power plant. This type of option is geology specific.

POWER CYCLES

If water is the heat transfer fluid, a standard geothermal power plant is used to extract heat stored underground. If the source of heat is an LWR with a peak temperature near 300°C, the LWR thermal-to-electricity efficiency is between 33 and 36% whereas geothermal power plant efficiencies are ~27%. The lower efficiency of geothermal power systems is a consequence of the small size of existing geothermal power plants (typically ~10 MWe), design requirements to address impurities in the geofluid, and various engineering tradeoffs to reduce capital costs.

We did not design a geothermal power cycle specifically for this system with power levels of 100 MWe or larger. Instead we assumed the efficiencies of existing geothermal power plants. There are significant economics of scale and improvements in equipment efficiency with scale. A geothermal power system designed for a 100 MWe or larger will likely be different from the traditional double-flash power cycle assumed in our work. The most likely change would be adoption of a triple flash power cycle with somewhat higher efficiencies but greater complexity. In many respects, the design of multi-flash power cycles is similar to the design of multi-flash distillation plants to produce pure water from seawater. These plants have been built on the scale from megawatts to hundreds of megawatts where the economics strongly favor increasing the number of stages as the plant output increases.

Last and least understood is the water quality of a geothermal heat storage system. In a traditional geothermal power plant the geofluid is typically poor quality water with hydrogen sulfide, carbon dioxide, dissolved solids, and fine particles. The poor geofluid water quality lowers the efficiency of the geothermal power plant because of scaling on heat transfer and other surfaces within the power plant and non-condensable gases. It is a major factor in the high operating and maintenance costs associated with geothermal energy systems.

In an engineered geothermal heat storage system, the same rock and same fluid is repeatedly heated and cooled. The non-condensable gases in a geothermal heat storage system will decrease with time as removed from the system. If pressurized water is used, there is the option of treating this water and partly controlling its chemistry. Such actions may help avoid reductions in the permeability of the heat storage zone over time, reduce equipment corrosion and reduce scaling. There has been little work on how to control the geofluid chemistry in such a system although it is likely to have a significant impact on efficiency and operating costs.

There are also a variety of secondary energy losses such as the heat exchangers that transfer heat from the nuclear or solar thermal power plant to the geofluid. Our analysis for a nuclear geothermal system using pressurized water indicated that the efficiency of heat generation in the reactor to the variable electricity output with seasonal storage 34 to 46% of a thermal-to-electricity base-load power plant. Our assessment, based on very limited work, is that ultimately the efficiency of a geothermal heat storage system for variable electricity production will be about 70% of a system without storage. Several areas for improved efficiency were identified.

- *Geothermal power plant design*. Our analysis used the efficiency of existing geothermal power plants with outputs of a few megawatts. Significant improvements would be expected if the design is optimized for several hundred megawatts.
- *Coupling with nuclear or solar plant*. Initial evaluations assumed simple heat exchanger systems. Integration with the power plant feed-water system can reduce temperature drops and thus inefficiencies in the heat exchangers.
- *Geofluid chemistry*. Many of the inefficiencies in existing geothermal power plants are a consequence of the water chemistry and large quantities of inert gases. In a geothermal heat storage system, inert gases can be purged and some control of water chemistry may be possible to reduce fouling and inefficiencies in the power system.

A geothermal heat storage system differs from traditional geothermal systems in that one has some choice on the selection of the geology. Traditional geothermal systems are a form of heat mining—the power plant must be built where the hot rock exists. New nuclear and solar thermal plants can be sited where the geology is favorable for heat storage. For existing plants, hot pressurized water can be moved by pipeline many kilometers to locations with more favorable geology; thus, there is no requirement that the heat storage zone be directly below a nuclear or solar thermal power station if more suitable geology is within a few kilometers of the power plant site. The geothermal heat storage zone can be located under land or offshore water—just like the construction of conventional mines and oil fields under land or water. For a nuclear geothermal system, the geothermal power plant would likely be built outside the security zone to avoid unnecessary costs associated with security.

In the longer term there is the potential of geothermal heat storage with temperatures up to 700°C and using supercritical carbon dioxide as the heat transfer fluid. There are large economic incentives to develop such systems but equally large technical challenges—including a limited set of geologies where such operating temperatures might be possible and a much more limited set of technologies (perhaps only cave block mining) to create a permeable rock zone. No statements of technical feasibility can be made at this time.

There are two economic drivers. The first is higher efficiency associated with higher temperatures. The second is the potential for a direct-cycle supercritical carbon dioxide power cycle. Carbon dioxide is an extremely non-ideal fluid. This results in a high supercritical-carbon-dioxide hydrostatic pressure in the wells injecting the cold high-density fluid underground and a low hydrostatic pressure in the heat recovery wells with hot fluid to the geothermal power plant that translates into high-pressure high-temperature supercritical carbon dioxide to the power cycle. That, in turn, implies an efficient and low-cost power cycle relative to any other system. There are many technical uncertainties and thus engineering feasibility can't be assured at this time.

SPECIAL MARKETS

This paper describes utility applications—the electricity goes to the grid. However, there are also non-traditional markets with potentially larger near-term incentives to develop the technology and different economic constraints. Nuclear reactors and solar thermal systems have been proposed for military bases and isolated communities. The central problem for such applications is the need to assure heat and power under all conditions—including when the nuclear reactor is down for refueling or a solar thermal system can not operate because of extended cloud cover. The traditional response is the use of diesel generators—an expensive option. In these environments the geothermal heat storage system can assure electricity and heat for months independent of the availability of local power sources or outside power.

The separate sizing of the rate of heat addition and the rate of heat recovery (in contrast to pumped hydro storage and batteries) may open other markets. In the southwest United States and some other areas there are electrical markets with a 12 hour period of relatively low demand and a 4 to 6 hour period of high demand in late afternoon. For such systems, the rate of heat removal from storage may be several times greater than the maximum rate of heat addition.

ECONOMICS

The above analysis addressed the technical components of storage systems. The other factor is economics where the differences in the price of electricity over time are as important as the engineering to determine the economics. For example, California has a deregulated energy market where the price of electricity is determined by supply and demand. As a result, the price per megawatt-hour of electricity can fluctuate wildly, going from -$10 to $350 within a single day. As shown in Fig. 7, for the vast majority of the hours in a year electricity is sold for $0-$50, but there are a significant number of times when the price is much higher. There are also a non-negligible number of hours when the electricity price was negative, which seems odd because that implies there were times when electricity was a waste product and destroying it was worth more than creating it. This is largely tied to the daily cycle of electricity: power supply can be higher than demand at night. However, the cost of shutting down the power plants during those hours is sometimes much higher than selling at a negative price—this is particularly true for nuclear and some types of fossil plants where there are significant costs and time associated with startup and shutdown.

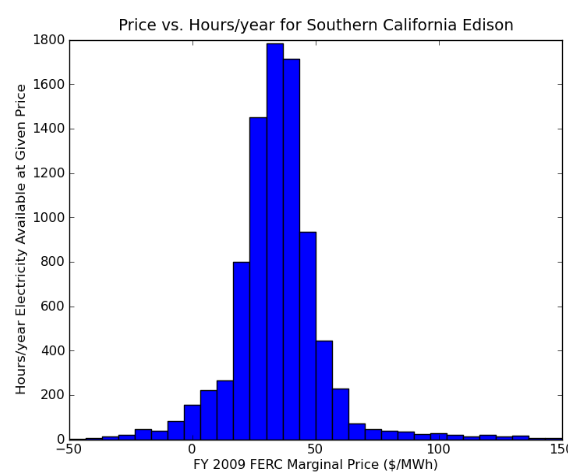

Figure 7: Southern California Edison Prices for FY 2009 (California Independent System Operator Daily Report Archive)

Usually negative prices (Sewalt and de Jong, 2007) happen for a short period of time at night, but there are a significant number of hours each year where the price of electricity is less than the cost to produce that electricity. This provides incentives to find alternative markets for heat at times of low electricity demand—such as geothermal heat storage systems.

The large-scale introduction of renewables is likely to increase the variation in the price of electricity with time. For example, if very low-cost solar power systems were developed, the price of electricity at midday in the summer would crash but the price of electricity at night in the winter with short days would dramatically increase. The same is true for large-scale use of wind where the highest production is in the spring—the time of lowest electricity demand

The large differences in the price of electricity provide the economic incentive for storage and finding uses for heat from nuclear reactors at times of low or negative electricity prices. An initial economic analysis (Lee, Forsberg, 2011) was done for the New England electricity grid for a nuclear geothermal system with pressurized water reactors. For the specific set of assumptions, the economic analysis (Fig. 8) that showed adding nuclear geothermal capacity to the system reduces the overall electricity generating costs. This is a proposed system containing (1) 10 GWe of base-load nuclear plants producing electricity, (2) ~6 GWe of base-load nuclear plants producing electricity and heat for the storage system with geothermal intermediate-load electricity production using the stored heat, and (3) natural gas peaking units. The higher capital cost of a nuclear geothermal system versus natural gas turbines makes natural gas turbines preferred for the peak power production—units that operate only a few hundred hours per year where fuel costs are low.

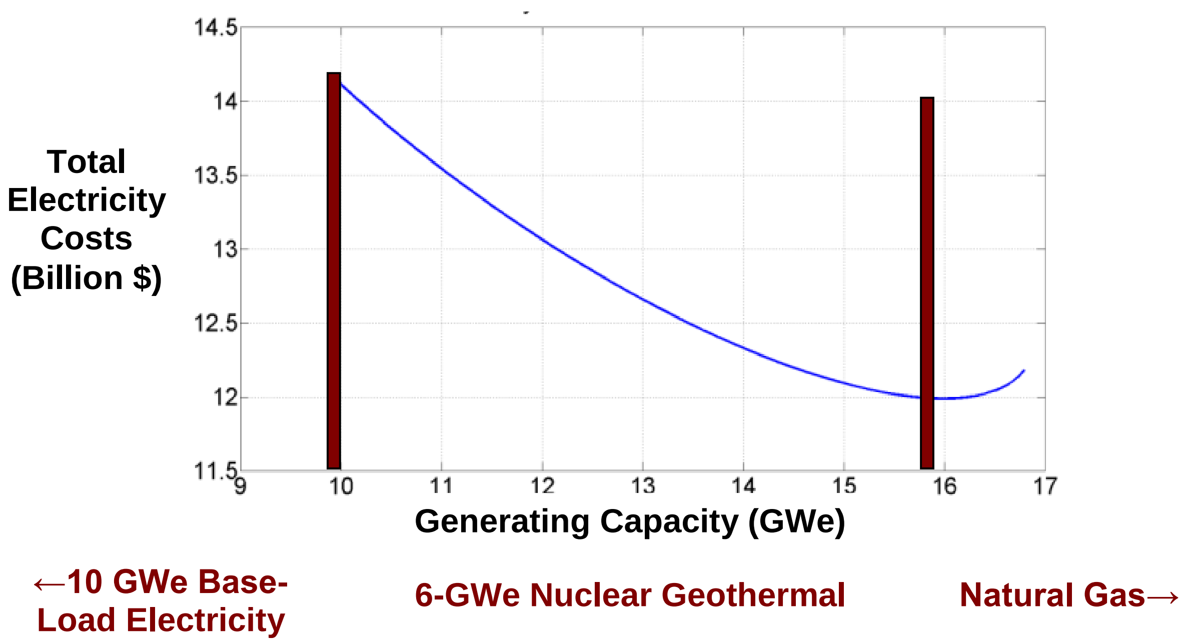

Figure 8: Total Cost of New England Electricity Vs Capacity of Nuclear Geothermal Capacity.

The results of economic evaluations are sensitive to the assumed capital costs, the different methods to generate electricity in a specific grid, and the variations in electricity demand.

CONCLUSIONS

We have completed initial studies on large-scale geothermal heat storage systems to allow daily, weekly, and seasonal storage of electricity in the form of thermal energy. The heat source could be a nuclear or thermal-solar power plant. The concept is technically feasible. It economic viability is dependent upon the local geology and incentives for storage. Those incentives will grow dramatically with any restrictions on greenhouse gas releases and/or large scale use of renewables.

The technology exists today for coupling with light-water reactors or solar thermal systems at temperatures less than 300°C to a geothermal heat storage system. However, there are significant geological uncertainties relative to traditional geothermal power systems. In a heat storage system the rock is repeatedly heated and cooled creating mechanical stresses and a changing geothermal environment. Significant work is required to develop the appropriate power cycles because (1) the power outputs will be an order of magnitude larger than existing geothermal power plants potentially enabling the use of more efficient power plant designs, (2) the plants will operate to meet intermediate and peak power demands rather than base-load power demands, and (3) the option to control underground water chemistry may simplify plant design and operations.

The concept is potentially applicable to storing heat at much higher temperatures such as would be produced by high-temperature reactors and some advanced solar thermal power systems. This will likely require the use of supercritical carbon dioxide as the geofluid. While there is research on using carbon dioxide as a geothermal heat transfer fluid, none of this research is at really high temperatures. There are major questions about the behavior of most rocks if repeatedly heated and cooled at high temperatures. The underground engineering technologies, from well development to creation of a permeable rock zone, only partly exist.

The long-term incentives to develop large-scale geothermal heat storage for electricity production are large. Only two technologies (Oloyede, 2011) have been identified that have the potential to economically store large quantities of energy on a seasonal basis if there are restrictions on the use of fossil fuels: heat and hydrogen. The fundamental advantage of geothermal heat storage is that rock is cheap—it may be the only storage media cheap enough for seasonal energy storage to enable full utilization of nuclear and renewable energy systems in a low carbon world.

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