Enabling CCS via low-temperature geothermal energy integration for fossil-fired power generation

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Abstract

Among the key barriers to commercial scale deployment is the cost associated with CO\textsubscript{2} capture. This is particularly true for existing large, fossil-fired assets that account for a large fraction of the electricity generation fleet in developed nations, including the U.S. Fitting conventional combustion technologies with CO\textsubscript{2} capture systems can carry an energy penalty of thirty percent or more, resulting in an increased price of power to the grid, as well as an overall decrease in net plant output. Taken together with the positive growth in demand for electricity, this implies a need for accelerated capital build-out in the power generation markets to accommodate both demand growth and decreased output at retrofitted plants. In this paper, the authors present the results of a study to assess the potential to use geothermal energy to provide boiler feedwater preheating, capturing efficiency improvements designed to offset the losses associated with CO\textsubscript{2} capture. Based on NETL benchmark cases and subsequent analysis of the application using site-specific data from the North Valmy power plant, several cases for CO\textsubscript{2} capture were evaluated. These included geothermally assisted MEA capture, CO\textsubscript{2}BOLs capture, and stand-alone hybrid power generation, compared with a baseline, no-geothermal case. Based on Case 10, and assuming 2.7 MMlb/h of geothermally sourced 150 °C water, the parasitic power load associated with MEA capture could be offset by roughly seven percent, resulting in a small (~1 percent) overall loss to net power generation, but at levelized costs of electricity similar to the no-geothermal CCS case. For the CO\textsubscript{2}BOLs case, the availability of 150 °C geothermal fluid could allow the facility to not only offset the net power decrease associated with CO\textsubscript{2}BOLs capture alone, but could increase nameplate capacity by two percent. The geothermally coupled CO\textsubscript{2}BOLs case also decreases LCOE by 0.75 ¢/kWh relative to the non-hybrid CO\textsubscript{2}BOLs case, with the improved performance over the MEA case driven by the lower regeneration temperature and associated duty for CO\textsubscript{2}BOLs relative to MEA.

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1. Introduction

Among growing concerns about the impact of fossil-fired electricity generation on global greenhouse gas concentrations and local air quality, there has been a significant amount of research and development on non-emitting, renewable technologies for baseload power generation. The body of literature on geothermal resources and their potential role in this baseload power market is enormous (e.g., [1-4]), yet in many cases, the degree to which geothermal has deployed to serve baseload needs is still quite small relative to the potential suggested by resource assessments [5]. While this mismatch traces its origins in a complex set of drivers, including market, policy and technical factors that have limited the development of geothermal resources, one of the most crucial is the quality of the geothermal resource required to provide a sufficiently attractive return on investment to incentivize development under market conditions to date. In particular, the development of geothermal resources has largely been shaped by the market pricing structure for baseload power and the availability of subsidies used to accelerate adoption, increase technology transfer and institutional learning, and decrease the cost penalty associated with deploying relatively novel technologies. Even with these subsidies, uncertainties around resource quality and productive lifetime, coupled with market uncertainties regarding future power pricing expectations, have resulted in development that has largely been limited to projects able to access the highest quality resources in areas with the market and policy conditions that best reduce the underlying uncertainties.

While development to date, fostered by funding from private and public sectors, has led to an invaluable amount of new learning on how best to develop these projects, only 3,450 MWe of baseload geothermal capacity exist in the U.S. [5]. These projects comprise a set of geothermal resources that tend to reflect hydrothermal systems with superlative temperatures and flow rates. For example, California’s Geysers field (1,584 MWe) produced about 2.6 MW per well as of 2014 [6]. Geothermal resources of this quality represent the lowest-hanging fruit for baseload power generation, akin to the very shallowest oil fields first produced over a century ago. As market and policy conditions evolve, it is likely that additional, slightly lower quality resources (i.e., those that can be produced at marginally higher cost) will be tapped for future baseload power. In the meantime, however, marginal geothermal resources could prove immensely valuable for direct use, including those at temperatures where baseload generation using today’s technologies tend to result in low efficiencies [2]. Direct use of geothermal resources for district heating and to provide work for systems like adsorption-based cooling or other processes has been explored in a number of ways, including via cascaded applications [7-10].

Still, lower-quality geothermal resources are available across much of the western United States [cite], and may offer an opportunity to support decreased emissions intensity in conventional fossil-fired processes by increasing process efficiency and/or offsetting efficiency penalties associated with emissions reduction techniques such as CO$_2$ capture. This would serve several purposes. In addition to developing additional operational experience and field data on geothermal systems integration, adding a hybrid geothermal component to existing processes will also increase the magnitude and geographical footprint of geothermal deployment. Such an approach might also offer a meaningful technology to span the gap called out by the Intergovernmental Panel on Climate Change (IPCC). The climate mitigation community continues to highlight the need for a portfolio of these bridging technologies – to include CO$_2$ capture and geologic storage, process efficiency improvements, and demand reduction efforts, among others – to allow for an economically efficient, societally acceptable transition toward a global economy powered by lower- or non-emitting energy technologies [11].

This paper presents an analysis examining the applicability of using geothermal energy for process efficiency improvement at a coal-fired power generation facility. This study was undertaken specifically in an effort to understand the degree to which geothermal energy can be used for boiler feed water reheating to offset the efficiency losses associated with the addition of a CO$_2$ capture process to an existing coal plant. The next generation of technologies being built in the U.S. and elsewhere—particularly integrated gasification combined cycle (IGCC) and ultra-supercritical (USC) technologies—typically result in effluent streams of relatively high CO$_2$ purity. However, these new technologies carry with them a higher capital cost, and thus a higher levelized cost of electricity than traditional emitting coal-fired power generation [11]. While regulations and market dynamics have results in a decreased interest in investment in coal-fired power, coal remains the dominant fuel used for electric power generation in the U.S. with projected capacity decreasing by only 2 percent over the period 2015-2040 under the AEO Clean Power Plan case [12]. Beyond the U.S., where subcritical coal-fired generation still dominates the field
of current power systems development, this horizon may be even longer.

Depending on the evolution of national and international policies and mechanisms to address atmospheric concentrations of greenhouse gases, including CO₂, it is likely that there will be some overlap between the current fleet of conventional coal plants and the implementation of policies that incentivize the reduction of emissions. CO₂ capture and geologic storage (CCS) technologies are widely regarded as a cornerstone of this approach [11, 13-15], with per-ton costs varying significantly based in part upon the purity of the CO₂ in the emissions stream. However, for coal-fired power plants, capture and separation costs are relatively high, and are associated with energy penalties of 20-25 percent (average, OECD) [16]. The parasitic energy load incurred during the process of CO₂ capture for these coal-fired generating stations is of particular concern for both industrial and policy stakeholders. Because a 30 percent increase in load within the plant gate results in a commensurate decrease in power supplied to the grid, the potential impacts of CCS on the overall cost and availability of electricity in a carbon-constrained power market could be significant. All else equal, the energy required within the plant to capture a significant fraction of CO₂ would result in the need to use additional fossil or renewable fuels to make up the difference. The market impacts of decreasing the net power derived from the conventional coal fleet, coupled with an increase in costs associated with the higher fuel costs per MWh served to the grid—above and beyond the amortized capital and consumables costs incurred to build and operate the capture system itself—have far reaching implications for policymakers, industrial stakeholders and ratepayers.

Thus, the coal-fired power sector reflects an opportunity to apply technological options that might bridge the gap between the current, largely fossil-fired paradigm and a future low-carbon generation portfolio. A hybrid system that could harness geothermal power to help offset the energy requirements of a CO₂ capture retrofit would enable a conventional power plant to deploy a CO₂ capture system while still providing the same net generation capacity to the grid. This could also help develop markets for geothermal energy beyond baseload generation, allowing nearer-term deployment of geothermal systems to facilitate greater learning and integration, both of which will help drive overall costs down more quickly by moving applicable geothermal technologies more rapidly through their learning curve.

Figure 1. ASPEN PLUS model for the DOE Case 9 subcritical steam cycle with geothermal feed water preheating
2. Methodology

This work develops an analysis of the energetics and economics of an approach that pairs geothermal energy with an existing coal-fired power generation process, including an effort to understand the degree to which a hybrid system such as this might be able to produce additional power at incremental costs near the $0.06/kWh goal set by the U.S. Department of Energy’s Geothermal Technologies Office. The cases presented in the following analysis are focused on the use of geothermal energy to offset energy needs for CO₂ capture systems, but additional power associated with efficiency improvements could also be sold directly to the grid, resulting in a net generation gain, delaying investment in new capital. Thus, in addition to specifically examining this hybrid approach to enable CCS, the more general goal of this study is to estimate the marginal cost at which geothermal energy be used meaningfully—via addition of a geothermal production and heat exchange system—within existing power generation facilities to improve efficiency.

2.1. Site selection

The applicability and economics associated with the approach discussed here are likely to be a function of both the specific process heat needs of the facility being considered and the cost of geothermal heat supplied to the system. Given the highly site-specific nature of both of the geothermal and plant system components, a multi-scenario case study was undertaken using specific process and resource data for an existing coal plant. Selection of a site for analysis was focused on coal-fired electric power generation facilities that were located in promising geothermal provinces. The U.S. coal-fired electric generation fleet was screened to identify subcritical pulverized coal plants with nameplate capacities between 500 and 750 MW in regions where geothermal gradients suggested temperatures between 125 and 150 °C at or above depths of 3.5 km. Of the plants selected, The North Valmy power plant, located outside the town of Valmy in Nevada, USA, was chosen to provide the baseline data for this analysis because it satisfied the plant selection criteria and was located proximal to a known hydrothermal resource of recent interest by a resource development company.

The North Valmy power plant, a subcritical pulverized coal-fired power plant has been operating since 1981, with a second unit added in 1985 for a combined nameplate capacity of a 521 MW. Located in the Humboldt River Valley, the North Valmy plant is located two miles (3 km) from the Hot Pot hot springs. The Hot Pot field has been the focus of geothermal resource exploration beginning in the 1970s [17] and through the current decade, including recent lease and exploration by Oski Energy, LLC. During their lease of the field, Oski drilled several new gradient wells to augment the 70s-vintage gradient wells, and acquired new seismic data to image the complex system at Hot Pot [18]. Based on interpretation of the new seismic lines, Oski had proposed to drill a series of intermediate test wells in an attempt to determine whether the field was economically suited to commercial development, but funding issues led to closure of the project prior to drilling the proposed Phase 2 wells.

2.2. Geothermal resource

The primary geothermal reservoir of interest at the North Valmy site, as modeled for this study, is the Valmy formation, an Ordovician sequence of siliceous marine sediments and volcanic rocks accreted to the western margin of North America during the Paleozoic and late Triassic. During the Neogene, the Humboldt River Valley region was subjected to extensional rifting and associated localized volcanism. As a result of this complex evolution, the tectonic, structural and stratigraphic setting of this area is also highly complex. While Neogene sediments, deposited in basins produced during extension, are often evaluated as geothermal reservoir rocks elsewhere in this region, estimates by [17] suggest that Neogene sediments near the Hot Pot geothermal site may only be present to depths of around 1000 feet, making them a less desirable target for geothermal production at this location.

The Hot Pot hot springs, where geothermal fluids flowed to the surface until aquifer drawdown for cooling water at the North Valmy plant depleted the surface expression of the springs, likely reflects a shallow convective system in the Neogene basin fill sediments. In their exploration of the Hot Pot field, Oski’s shallow gradient wells exclusively sample this reservoir. The purpose of the seismic surveys, conducted beginning in 2009, was to image
the shallower reservoir and to determine whether the hotter fluids present were being brought to the near-subsurface from a deeper reservoir via one of the many north-northwest trending faults that intersect the area.

Geochemistry data from wells producing from the Valmy formation suggests that the formation is separated from the basin fill sediments by low permeability aquitards in the Halvallah and Antler sequences [19]. Because the Valmy formation demonstrates good reservoir quality, flow rate and temperatures regionally, this reservoir may offer a more attractive target for geothermal development than the local, relatively shallow Neogene sediments. An existing geothermal project at Beowawe field produced from three wells the Valmy formation at rates of 150-250 kg/s (combined) with initial temperatures between 210 and 215 °C [20]. However, no wells into the Valmy are present in the vicinity of the Hot Pot site. Plans to drill deeper gradient wells – targeted for Phase II development using seismic data gathered during Oski Energy’s Hot Pot project – were shelved when Oski abandoned the project. Oski had hoped to identify and intersect a transmissive fault to optimize well productivity, but it remains unclear from the seismic data whether the faults are transmissive as posited, or whether the Hot Pot field is heated via a convective system fed primarily by meteoric and near-surface groundwater.

In the absence of specific characterization data on the possible reservoirs at the Hot Pot site, the authors used the published geothermometry data, Oski’s seismic data, and data on the Valmy formation taken from the Beowawe field to develop a set of cases that reflect possible resources available near the North Valmy plant. Characterization—including drilling, logging, core analysis and hydraulic testing in a well drilled into the reservoir—is necessary to validate reservoir quality and refine assumptions upon which this analysis is based. Still, this case study approach enables an understanding of the range of marginal development costs associated with integrated geothermal energy into the power generation cycle at a coal-fired power plant.

Establishing potential drilling depths were estimated based on gradients of 70 °C/km and 90 °C/k, taken from Lane [17]. Using these values for Cases 1 and 2 resulted in drill depths of approximately 5000 and 6600 feet respectively to reach temperatures of 150 °C. In the absence of flow rate testing at the Hot Pot site, flow rate data were taken from the Beowawe field, which produces from the Valmy formation. Initial production at Beowawe averaged roughly 600,000 lb/h [kg/h] between the three project wells [20]. A simple extrapolation of this rate to the North Valmy site suggests that the plant’s process water needs – 2,500,000 lb/h – could be met using four or five production wells. A review of geothermal project development in Nevada [21] was used to estimate well needs for reinjection of produced geothermal fluid; three reinjection wells have been costed in this analysis, which is both conservative and close to the 2:1 ratio used at Beowawe field.

2.3. Process Modeling

All cases were simulated using Aspen Plus and Exchanger Design and Rating tools, and costs were evaluated using the Aspentech Process Economic Analyzer. For each case, equipment sizing, heat and material balancing and net power were calculated, as well as associated costs. All analysis is based on the NETL Case 9 benchmark reflecting a 550 MW pulverized coal-fired power plant, and Case 10, which is the CO2 capture-enabled permutation of Case 9. The benchmark cases were applied for preliminary analysis and for comparison across configurations, prior to preparation of site-specific models. The North Valmy plant was parameterized for the Aspen Plus modeling using data taken from EIA filings 923 and 860, including nameplate capacity, actual generation, fuel consumption, stocks and receipts, and other associated facility information. Please see the final project report [22] for a much deeper treatment of the process modeling completed for this site, as well as for other elements of the methodology and finer granularity in the results.

3. Results

Based on the NETL benchmark Cases 9 and 10, and assuming 2.7 MMlb/h of geothermally sourced 150 °C water, the parasitic power load associated with MEA capture could be offset by roughly seven percent, resulting in a small (~1 percent) overall loss to net power generation, but at levelized costs of electricity similar to the no-geothermal CCS case. For the CO2BOLs case, the availability of 150 °C geothermal fluid could allow the facility to not only offset the net power decrease associated with CO2BOLs capture alone, but could increase nameplate capacity by two percent. The geothermally coupled CO2BOLs case also decreases LCOE by 0.75 €/kWh relative to
the non-hybrid CO₂BOLs case, with the improved performance over the MEA case driven by the lower regeneration temperature and associated duty for CO₂BOLs relative to MEA (Figure 2).

Figure 2. Comparison of net electric power and levelized cost of electricity estimates for each model case

For the North Valmy site-specific case, based on an estimated geothermal resource temperature of 125 °C—considered low-grade heat because it falls below the 150 °C temperatures typically needed to generate power via organic Rankine cycle technology—integration of geothermal fluids to provide boiler feedwater preheating duty at the North Valmy plant could enable a 10-MW increase to the 520 MW net power generation from the plant. Alternatively, the same geothermal energy could increase the cycle efficiency by 1% (26 to 27%) for a 550 MW monoethanolamine (MEA) based carbon capture or up to 6% for an advanced (CO₂BOLs) carbon capture plant and a four-fold increase in the geothermal flow rate (26 to 32%). Should the flow rate at the Valmy site be half of that modelled in this primary case, sensitivity analysis suggests a similar halving of power production under this configuration. This would reflect a 1 percent increase in the plant efficiency, with a 0.4 ¢/kWh decrease in levelized cost of electricity.

4. Discussion

Bridging from the current fossil fired paradigm to a future where energy production is largely accomplished via a low-emissions mix of generation technologies, including baseload geothermal, will require a flexible portfolio of integrated technologies to enable decreasing greenhouse gas intensity in the industrial sector. Marginal geothermal resources—those for which there is currently a lack of market or enabling technologies to produce as baseload power—may offer an opportunity to improve efficiency of conventional systems or buy down efficiency penalties associated with emissions capture within the electricity sector. The analysis presented here suggests that pairing even a relatively low temperature geothermal resource with a coal-fired power facility could result in efficiency improvements that increase capacity by 10 MW at an incremental cost of electricity of between $0.06 and $0.07/kWh, very close to the $0.06/kWh goal set forth by the U.S. Department of Energy Geothermal Technologies Office. By leveraging the existing capital already resident within the current fossil-fired generation fleet, the capital costs associated with these hybrid geothermal projects largely account for wellfield infrastructure and maintenance, and where opportunities to leverage extant wellfield infrastructure are present, capital costs may be even lower.

While its proximity to a known hydrothermal system (hot springs) makes the North Valmy power station relatively rare among U.S. coal-fired power plants, the potential geographical match between existing fossil- and/or biomass-fired generation assets and low-grade geothermal resources may offer opportunities to implement geothermal hybrid approaches to address process-specific heat needs including those associated with CO₂ capture, improve overall plant efficiency, and increase utilization of renewable, zero-emission geothermal resources. The marginal increases in the cost of power, under the conditions assumed in this study, are quite small, on the order of only a few percent in most cases. In the longer view, as greenhouse gas emissions become more heavily regulated in the United States and abroad, capacity increases to conventional fossil-fired power generation that can be effected via renewable hybridization, without a significant net increase to CO₂ emissions, could be increasingly attractive,
particularly in the presence of policies that incentivize CCS. As the U.S. replaces and upgrades its current generation fleet, the potential for co-application of geothermal energy for efficiency and new CCS-coupled fossil- or biomass-fired generation could allow for purpose-sited facilities designed to support emissions reduction and renewable deployment targets.

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References


