Low-Temperature Projects of the Department of Energy’s Geothermal Technologies Program: Evaluation and Lessons Learned

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Low-Temperature Projects of the Department of Energy's Geothermal Technologies Program: Evaluation and Lessons Learned

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Abstract

This paper discusses opportunities and challenges related to the technical and economic feasibility of developing power generation from geothermal resources at temperatures of 150 °C and lower. Insights from projects funded by the U.S. Department of Energy (DOE), Geothermal Technologies Office inform these discussions and provide the basis for some lessons learned to help guide decisions by DOE and the industry in further developing this resource. The technical basis for low-temperature geothermal energy is well established and the systems can be economic today in certain situations. However, these applications are far from a "plug and play" product; successful development today requires a good knowledge of geothermal system design and operation.

Introduction

Beginning with the American Recovery and Investment Act (ARRA) projects in 2009, the Geothermal Technologies Office has funded 18 projects that focus on producing electrical power from low-temperature and/or co-produced fluids from oil and gas production. Of the six of those projects that have moved to Phase II, four are currently in or have completed Phase III. In addition to these projects, the National Renewable Energy Laboratory (NREL) has had numerous discussions with private-sector companies to develop a cooperative research and development agreement to demonstrate geothermal operations in commercial oil and gas fields. This paper draws from the experiences of these projects to provide a perspective on the technical and economic feasibility of low-temperature geothermal electricity in the U.S. today. Specific projects are not reviewed here, and, in particular, information obtained from private-sector discussions is left somewhat vague to protect the proprietary interests of the companies.

Although there are many ways of categorizing low-temperature geothermal power generation, the following applications are used for discussion in this paper:

- Low-Temperature Power Production: a geothermal system that produces only electricity and uses a geothermal resource as the sole thermal input.
- Low-Temperature Bottoming Cycle: a low-temperature turbine that is added to capture what would otherwise be waste heat from a higher-temperature geothermal system.
- Hybrid Geothermal System: a geothermal system that produces electricity with the low-temperature geothermal heat supplemented by an additional thermal input.
- Geothermal Co-Production: a geothermal system that uses thermal energy that is co-produced during the extraction of oil or natural gas.

Low-Temperature Power Production

Low-temperature geothermal resources are defined by the Department of Energy (DOE) as having an inlet water temperature of less than 150 °C. These systems represent a significant energy resource for the U.S. but are economically challenging for electric power generation. In addition to the challenges for all geothermal development (exploration, permitting, financing, and operation), low-temperature resources have low exergy and corresponding efficiencies for converting the heat to electricity.

DOE has embarked on a number of demonstration projects to gain experience with state-of-the-art equipment and to ultimately extend the economic feasibility of lower-temperature geothermal resources. These projects have demonstrated successful commercial operations at temperatures as low as 74 °C, but it is important to note that with low-temperature geothermal power the temperature of the heat rejection is nearly as important as the resource temperature. The 74 °C demonstration occurred at Chena Hot Springs in Alaska, using 4 °C cooling water from a nearby shallow well (Holdmann and List, 2007). Replicating this success with a similar resource in a hot region such as Nevada requires a significantly greater resource temperature so that there is a sufficient change in temperature within the power production unit. Two of DOE's successful projects will be briefly discussed here.

<u>Surprise Valley Electrification Corporation Project</u>
A demonstration project funded under ARRA was developed by the Surprise Valley Electrification Corporation (SVEC) just outside the town of Paisley, OR. SVEC provides power to the Bonneville Power Administration (BPA), and the motivation behind this project was to develop a new power source that would be financially beneficial to SVEC, a small rural electric cooperative. The project had ten specific objectives (adapted from Culp et al., 2016):

1. To demonstrate the production of sustainable and reliable competitively priced base-load power.
2. To demonstrate that local labor resources (e.g., irrigation well drillers, local trades) can develop geothermal resources economically.
3. To demonstrate that the Cooperative Business Development Model (non-profit) can develop the small geothermal resources within its service territory.
4. To demonstrate the advantage of fully utilizing the rural cooperative electric transmission system.
5. To demonstrate to other cooperatives that developing geothermal is an advantage to their members.
6. To demonstrate that geothermal development improves when geothermal uses are cascaded, e.g., when both electrical and direct-heat uses are considered.
7. To demonstrate that geothermal development can be integrated with an operating ranch to make both operations better.
8. To demonstrate the potential benefit to BPA when direct customers develop their own sources of power.
9. To demonstrate the uses of the 2-meter-depth temperature survey to facilitate the location of injection wells.

10. To demonstrate that the development of distributed small resources contributes to building a sustainable region.

The project uses two production wells and one injection well, with an overall production level of 3,000 gallons per minute (gpm) and a temperature of 112 °C. The power production unit, developed by TAS Energy, is generating 3.1 megawatts (MW) of power for use by SVEC or sale to others.

A major issue for this project has been marketing the power produced. SVEC initially planned to sell power to BPA at a very favorable rate, but a significant drop in wholesale power prices in 2012 made sales to BPA unprofitable. One of the key lessons learned from the project was the importance of having a firm power purchase agreement (PPA) established prior to initiating construction (Culp et al., 2016). Subsequent efforts to sell power to PacifiCorp are still in negotiation.

This project provides a good example of the value of small-scale geothermal power production to a rural electric cooperative. It has also provided an economic benefit to the host community (Mink et al., 2015). In addition to these positive features, it also illustrates important challenges for a small geothermal developer. The project costs ultimately came in much higher than initially estimated, in part, because there were more needs for consulting advice than originally envisioned. Also, because there were deadlines associated with applying for grants, some of the project decision-making had to be based on assumptions of compensation in the PPA rather than securing the PPA first. The plant has also incurred unexpected operations and maintenance (O&M) costs associated with needing an onsite operator, which was not envisioned in the planning phases. In a small power plant, even modest unexpected O&M costs can have a significant impact on the project economics. It is anticipate that the plant will eventually be operated in a remote-operations approach, but transitioning to this approach will still require time and additional investment.

University of North Dakota Project

A demonstration project now entering the operational phase was led by the University of North Dakota (UND) under ARRA funding. The UND project had the following objectives:

1. Demonstrate the technical and economic feasibility of generating electricity from non-conventional low-temperature (150 °C to 300 °C) geothermal resources.
2. Demonstrate that the technology can be replicated within a wider range of physical parameters including geothermal fluid temperatures, flow rates, and the price of electricity sales.
3. Widely disseminate the results of this study and develop a skilled work force in geothermics.

After investigating a number of potential sites, the UND team found a good opportunity at a Continental Resources (CLR) water flood site in Bowman County, ND. The project uses water from two CLR water supply wells—Davis 44-29 (API No: 33-011-90121-00-00) and Homestead 43-33 (API No: 33-011-90127-00-00). The Davis well was drilled vertically to a depth of 2,163 m and horizontally 1,494 m in a high-porosity zone of the Lodgepole Formation (Mississippian) for a total drill length of 3,658 m. The Homestead well, also into the Lodgepole Formation, was drilled vertically to a depth of 2,306 m and horizontally 810 m, for a total drill length of 3,197 m.

The two water wells supply a combined flow of 875 gpm at a temperature of 98 °C, which is used to pressurize the Red River 'B' Zone (Ordovician) in the Cedar Hills oil field. Prior to installation of the organic Rankine cycle (ORC) systems, CLR was cooling the water in two forced-air cooling towers. For safety reasons, the water is still being cooled by CLR after passing through the ORC systems prior to injection.

The demonstration project features two 125-kW ORC engines that were provided as cost share by Access Energy. The Access Energy ORC is designed to sit on a gravel pad with easy connection to the water and electrical lines, but CLR required considerable construction, including a concrete pad located 10 m from the water supply and burial of all water and electrical lines. The economics of the system are highly favorable because it is a "piggyback" operation on existing infrastructure. The price for the 125-kW systems used for this demonstration is expected to be $260,000 per unit for similar applications. Installation costs will vary depending on existing site conditions. For comparing a potential greenfield project (with no existing infrastructure on which to piggyback), CLR indicated that the cost of drilling and completing the two horizontal wells was more than $2,000,000 each. It also should be noted that drilling costs are highly sensitive to industry demand and that the CLR wells were completed during a high-demand period.

Some lessons learned from this project include the following:

1. Determine target formations. Data from oil and gas operators, state oil and gas regulatory agencies, and state geological surveys help to identify producing formations and their properties.
2. Determine the quantity of energy available in the target formations.
    a. A complete thermal analysis of the basin or region yields the most useful information.
    b. Critical data include: bottom-hole temperature, heat flow, stratigraphy, lithology, lithological properties, thermal conductivity, and subsurface structure.
3. Determine the potential for fluid production.
    a. State oil and gas regulatory agencies and state geological surveys have data on oil, gas, and water production. State water commission/agencies have data on water quality, aquifers, and regulations.
    b. Consider single horizontal wells, multiple conventional wells, and unitized fields.
4. Calculate energy production capacity of each formation based on different well combinations and power-plant scenarios. This is a broad overview rather than a site-specific analysis.
5. Research and understand the local electrical power industry. Obtain the PPA before committing to the project.
6. Work with the high-level personnel in the oil company partner. Obtain a memorandum of understanding that addresses all issues in the project, including

what to expect if the company goes out of business, is bought out, or changes management.

7. Be prepared for project delays.

These projects illustrate the fact that there are numerous and diverse factors to be considered in developing a power production system: geology, power generation unit design and acquisition, construction contracting, power sales marketplace, partnerships, and economics.

Low-Temperature Bottoming Cycles

In a high-enthalpy geothermal resource, it is typical to produce energy in a flash-steam design, which can result in steam exiting the turbine at temperatures suitable for power generation with a binary-cycle turbine. Adding the binary cycle to utilize what is effectively waste heat from the flash plant creates a low-temperature bottoming cycle. Two demonstration DOE bottoming binary plants were installed as retrofits to operating flash-steam plants in Nevada. The binary unit installed at the Beowawe facility is a water-cooled plant, whereas the binary unit installed at Dixie Valley is an air-cooled plant.

Both the Dixie Valley and Beowawe plants completed their two-year test period, during which the operational data were provided to DOE. During the tests, both plants experienced curtailments—and in some instances, shutdowns—during the hotter portion of the day during the summer months. This is illustrative of a challenge in generating power from lower-temperature geothermal resources, where a moderate increase to the ambient temperature can have a significant impact on the total temperature difference (ΔT) available to the heat engine. Depending on the design ambient temperature, decreases in output by 50% should be expected, especially with air-cooled plants (Williams and Mines, 2015).

During the two-year operational period, both projects experienced startup issues that resulted in unexpectedly high O&M costs. Although such experiences are possible events in any power-plant startup, the impacts can be magnified for a small system that is typical in low-temperature geothermal applications. A prior economic evaluation of the Dixie Valley and Beowawe projects indicated that similar projects could go forward with a return on investment (ROI) in excess of 10% if the O&M costs of the first two years were not indicative of longer-term trends (Williams and Mines, 2015). Collection and analysis of O&M over much longer time periods would be a good addition to future projects.

Hybrid Geothermal System

We are defining a hybrid low-temperature geothermal system as one having energy inputs within the geothermal plant boundary that provide supplemental energy services. Hybridizing the output from a geothermal energy plant can be done with any energy source; as an example, photovoltaic solar power could provide augmented electric output during the daylight hours. However, there are synergistic advantages that can occur using a thermal energy source, such as concentrating solar power (CSP). Both CSP and geothermal power systems use Rankine cycle heat engines, which makes it possible to design systems with some sharing of plant equipment. Furthermore, the solar and geothermal resources are not coupled, which can help reduce a portion of the long-term risk for the geothermal plant.

One design concept for a geothermal/CSP hybrid is shown in Figure 2 (Wendt et al., 2015). In this case, the CSP field provides supplemental heat to the geothermal brine before it enters the evaporator. In this example, the CSP system is limited to providing heat during daylight hours, but plant operations could be extended by including thermal storage.

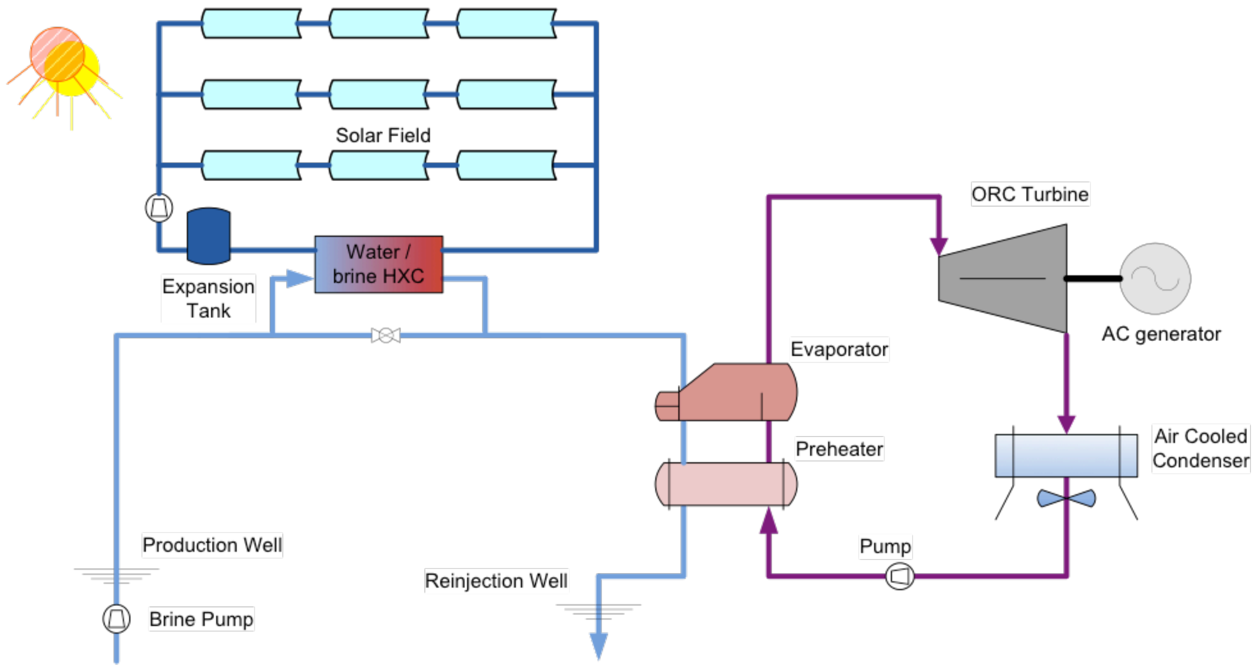

Figure 1. Example geothermal/CSP hybrid plant (from Wendt et al., 2015).

In certain situations, there are a number of compelling features for hybridizing a low-temperature geothermal plant:

- During the development of the geothermal plant, a lower resource temperature or flow rate than expected can present a significant financial risk. Adding CSP to the plant could allow a marginal plant to be developed economically rather than abandoned.
- Power output from air-cooled binary plants is lowest when ambient temperatures are high, due to reduced efficiency in the condenser and corresponding increases in the turbine exhaust pressure. Due to the correlation between ambient temperature and solar insolation, CSP systems will typically have their highest output during these periods, and they can mitigate plant output reductions. This can be particularly valuable in situations where peak pricing is available to the plant operator.
- Over time, the temperature of a geothermal resource can decline, and although this is incorporated into the initial plant design, the temperature may decline faster than originally predicted. In such situations, a CSP plant could be added to the system to restore brine temperatures to their design levels.
- Beyond the design illustrated in Figure 1, it is possible to increase thermal and exergy efficiency of a geothermal plant by incorporating a CSP system. One analysis showed a benefit of converting geothermal energy to electricity at an efficiency of 1.7 to 2.5 times

greater than would occur in a stand-alone, binary-cycle geothermal plant using the same geothermal resource (Turchi et al., 2014).

Recently, the world's first hybrid geothermal/CSP power plant was commissioned by Enel Green Power North America (PV Magazine, 2016). The Stillwater 2 geothermal plant, rated at 33 MW, was suffering from declining capacity due to reductions in brine temperature. Enel added a 2-MW CSP system to the plant, using a configuration similar to Figure 1, which is expected to extend the life of the geothermal reservoir. Early test results performed in collaboration with Enel, Idaho National Laboratory, and NREL have confirmed that the combination of a 2-MW solar thermal facility with a 33.1-MW geothermal plant increased overall output at Stillwater by 3.6% compared with production from geothermal only (Enel press release, 2016).

Geothermal Co-Production

In the production of oil and gas, it is typical for wells to produce hot water, and this fluid creates additional processing steps that add cost to operations. However, this detriment can be transformed into valuable energy by adding a geothermal plant and creating co-produced energy. Such a system was tested by DOE at the Rocky Mountain Oilfield Testing Center (RMOTC) at NPR-3 (Teapot Dome Oilfield) near Casper, Wyoming. The 250-kW ORC power unit was designed to use 40,000 barrels per day (bpd) of 170 °F (~77 °C) produced water from the field's Tensleep Formation. Because of the lack of sufficient cooling water for the condenser, the cooling system was design as an air-cooled unit (Johnston and Simon, 2009). By 2012, the plant had produced over 1,332 MWh of power from 7.8 million barrels of co-produced hot water, and operated with a 97% online availability (Williams et al., 2012). The system operated at RMOTC until 2013, when it was then mothballed for future deployment at a commercial oilfield.

The regional potential of geothermal co-production was recently assessed in a DOE-funded study by UND. Resource temperatures in the Williston Basin range from 90 °C to 150 °C in a number of oil and gas producing formations that lie at depths of 2,400 m to 4,500 m. The basin is largely circular with low-dipping (e.g., 3°) flanks, except where small anticlines, such as the Nesson anticline, and large fault-related features, such as the Cedar Creek anticline, disrupt the strata. Heat flow in the basin averages 53.4 mW m^{-2} ±16.2 mW m^{-2}, and favorable resource temperatures occur over a large area in deep formations. The regional climate is classified as extreme continental with mean annual temperatures of 7 °C to 10 °C. Thus, fluid volume is the most uncertain parameter for site and resource selection in the Williston Basin.

The North Dakota Industrial Commission, Oil & Gas Division, maintains a database of oil, water, and gas production by pool, unit, and well that is available on their subscription website (https://www.dmr.nd.gov/oilgas/). Thus, it is possible to easily identify sites and formations that yield the greatest fluid volumes and to correlate the results with resource temperatures. Analysis by Gosnold et al. (2015) indicated that the greatest co-produced fluid volumes are from the Bakken (Devonian-Mississippian), Madison (Mississippian), and Red River (Ordovician) Formations (Table 1). The Madison Formation has temperatures of 100 °C to 110 °C at depths of 2.5 km to 3 km. The Red River Formation has temperatures of about 130 °C to 140 °C at depths of 4 km. The Bakken Formation is a tight shale that produces more oil than water, but the total fluid volume is more than twice that of the Red River and Madison Formations. Bakken temperatures range from 120 °C to 130 °C. The total combined power production for the top ten producing wells in the Madison and Red River Formations based on an exit temperature of 70 °C and an ambient air temperature of 10 °C (mean annual for ND) for an ORC with 6% efficiency would be about 700 kW and 800 kW, respectively. Thus, the volumes of co-produced fluids from individual wells in the Williston Basin are insufficient for economic development.

Table 1. Produced Fluid Volumes from Bakken, Red River, and Madison Formations

Pool	Bbls Oil	Bbls Water	WOR Ratio	Bbl Oil/Well	Bbl Water/Well
Bakken	20,046,962	13,818,929	0.7	4,163	2,869
Red River	829,559	3,305,592	4.0	1,659	6,611
Madison	699,470	8,119,405	11.6	366	4,253

Ultimately, the UND co-production project was intended to demonstrate the technology in an operating oil and gas field. The co-production project was initiated with industry partner Encore, Inc., in the Eland-Lodgepole field near Dickinson, ND. The field consists of 12 oil and gas wells producing about 350 gpm of 100 °C saline water at a central location. However, soon after the project began, Encore was purchased by Denbury, who declined to partner in the demonstration project. Although other partners were sought at great length, the attempt was ultimately unsuccessful and the demonstration did not occur. Reasons for the lack of development are partly economic and partly related to infrastructure. The economic reasons can be summarized as follows:

1. The value proposition and business model of oilfield operators is to minimize development time and maximize production, resulting in high rates of return. In contrast, a geothermal co-production investment requires a long-term time horizon. The returns from the electricity revenue (or offsetting infield generation) are small compared to the revenue gained by producing oil as fast as possible while the price is high.
2. An independent operator providing power as a service to the oilfield could potentially solve the challenge above. Currently, the power industry is skeptical that it would result in significant revenue. Coupled with the uncertain lifetime of oilfield operations under a single management company (as demonstrated by losing Encore as a partner), this appears to the service industry as a risky, low-return investment.
3. Obtaining an attractive PPA is challenging. Where the utility grid powers field operations, the rates provided to the operator in the areas investigated are typically low, making it difficult for co-produced geothermal energy to compete.
4. Economies of scale work against most co-production applications. Large geothermal systems (tens of MW) are not feasible due to the high fluid flow rates required. The smaller systems that are technically feasible have higher $/kW unit costs that reduce the economic attractiveness.

Project Economics

The DOE project at Surprise Valley has well-documented cost data that can be used to calculate a levelized cost of energy (LCOE). A summary of the input data used in the calculation is shown in Table 2. Long-term expectations for plant O&M costs are not yet available for the Surprise Valley Plant, so an estimate was based on standard assumptions for geothermal in the 2015

NREL Annual Technology Baseline (ATB) (NREL, 2015). The ATB model was also used as a source for a number of the other assumptions required for the LCOE evaluation.

Table 2. Economic Assumptions used in Evaluation

Parameter	**Value**	**Source**
Net Power Output	2.374 MW	Culp et al. (2016)
Construction Cost, before grants	$22,000,000	Culp et al. (2016)
Construction Cost, after grants	$16,900,000	Culp et al. (2016)
Plant Capacity Factor	90%	NREL (2015)
Projected Annual O&M Cost	$273,000	NREL (2015)
PPA Price Escalation	1% annual	General assumption
Inflation	2.5% annual	NREL (2015)
Project Life	20 years	NREL (2015)
Financing	50% debt	NREL (2015)
Financing Term	15 years	General assumption
Debt Cost	8%	NREL (2015)
Equity Cost	13%	NREL (2015)
Production Tax Credit	2.6 cents/kWh	DSIRE
Investment Tax Credit	10%	DSIRE

Five different financial cases were evaluated using the NREL Cost of Renewable Energy Spreadsheet Tool (CREST) model https://financere.nrel.gov/finance/content/crest-cost-energy-models). The first case assumes municipal utility ownership with a cost of capital of 3.1%. This cost of capital was based on a recent review of AAA-rated municipal bonds with 10–20-year durations (GMS, 2015). The other cases assume the plant owner is an independent power producer (IPP), and investment costs with and without grants, and with and without the currently available production tax credit and investment tax credit for geothermal—both of which are available as of the date of this paper but are scheduled to expire at the end of 2016 (DSIRE). The results are shown in Table 3 and illustrate the challenging economics faced by this type of application. For the IPP cases, the LCOE would not be attractive today in the U.S. except possibly for remote power applications or other niche markets. The lower cost of capital for a municipal utility, such as Surprise Valley, when combined with the government grants that were available for this project are more attractive, but still not broadly competitive with grid power today.

Table 3. Results of LCOE Calculations

Scenario	LCOE, Nominal $/kWh
Municipal utility ownership, including grants	0.098
IPP ownership, including grants and tax credits	0.110
IPP ownership, including grants but no tax credits	0.141
IPP ownership, no grant, existing tax credits	0.145
IPP ownership, no grants, no tax credits	0.178

Conclusions

The technical basis for low-temperature geothermal energy is well established and the systems can be economic today in certain situations. However, a stand-alone geothermal power plant using low-temperature resources has two daunting challenges: thermodynamics and the lack of economies of scale. These systems may be one or even two orders of magnitude smaller in scale than most geothermal plants, and the economies of scale present in geothermal development make such projects challenging to develop at attractive costs today.

Alternative design approaches—such as geothermal co-production and hybridization—offer some attractive features for low-temperature geothermal power production. Development and capital costs can be shared across other system components, and the plant size can become larger, thus mitigating economies of scale discussed above. However, for the co-production market to truly develop, a better fit is needed between the business models of oilfield operators and geothermal power developers.

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