Deep Direct-Use for Industrial Applications: Producing Chilled Water for Gas-Turbine Inlet Cooling

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Keywords

Deep Direct-Use, DDU, industrial, absorption cooling, turbine inlet cooling

ABSTRACT

Direct use of deep, low-temperature geothermal resources is underutilized due to challenging project economics associated with developing a deep geothermal resource for what are historically small-scale, variable-demand projects. This project assesses the feasibility of geothermal energy integration in natural-gas combined cycle power stations in the Sabine Uplift and Gulf Coast regions of Texas. The low-grade geothermal resource is tapped to drive absorption chillers for production of chilled water at 5-10°C (41-50°F). This chilled water is stockpiled and dispatched to provide turbine inlet cooling (TIC) at the inlet to the compressor of a natural-gas combined cycle power plant, thereby boosting power production during periods of high temperature and high-power demand. This presentation focuses on the system design related to geothermal well-site selection (proximity vs. resource quality), absorption chiller size and location, chilled-water storage capacity, and dispatch logic to realize the maximum financial benefit.

1. Introduction

Geothermal energy use in the United States includes power generation occurring in western states such as California and Nevada that have conventional hydrothermal assets, as well as geothermal heat pumps applications throughout the county. Deployment beyond these applications will require use of engineered geothermal systems (EGS) for power generation or tapping low-temperature resources, which are more suited for direct use. The latter have found use in scattered, small-capacity systems for space heating, greenhouse heating, aquaculture, pools and spas, and district heating (see Figure 1). While such beneficial direct-use can be cost effective, the applications tend to be small and subject to "one-off" project development and design characteristics that are not conducive to regional or national deployment.

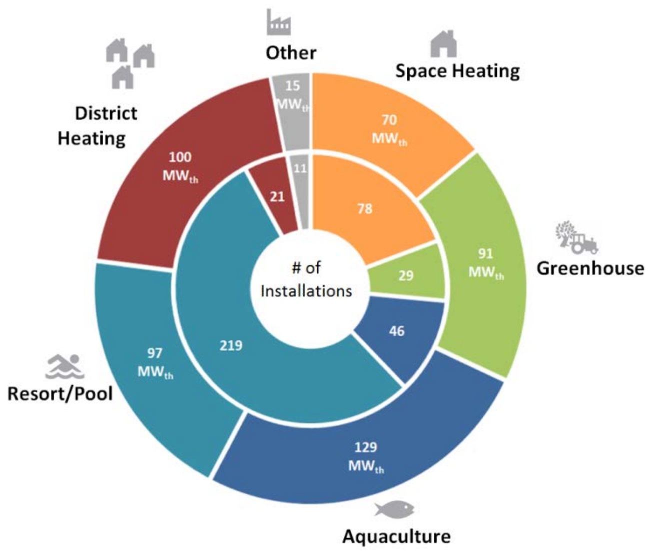


Figure 1. Current geothermal direct-use applications in the United States [Snyder et al., 2017].

When compared to these traditional direct-use applications, the possible integration of geothermal heat into thermo-electric power plants represents a large-scale opportunity with nationwide potential. For comparison, one of the largest current direct-use applications is district heating, with 21 systems and an average capacity of about 5 MW_{th} (Figure 1). A single turbine inlet cooling application for an average-size 500 MW_e combined cycle power station could be as large as 54 MW_{th}, 11-fold larger than the average district-heating system and of a scale comparable to the combined installed capacity of all geothermal district heating facilities in the United States [EPRI 2002]. With approximately 2200 thermo-electric power plants in the United States, the possibilities for significant geothermal augmentation are good, should suitable subsurface resources be nearby. The Deep Direct-Use (DDU) program with the U.S. Department of Energy's Geothermal Technologies Office seeks to identify and assess the feasibility of such DDU applications.

1.1 Low-Temperature Geothermal Resource in Texas

The study region chosen for the work aligns with known areas of low-temperature resource in Texas and western Louisiana. Southern Methodist University's Geothermal Laboratory (SMU) is a team member of the current project and has leveraged the extensive well database for the region to examine the resource potential in the region. This work is documented in prior studies as well as a complementary paper at this conference. SMU's "I-35 Corridor East" geothermal assessment completed in 2010 for the Texas State Energy Conservation Office [Blackwell et al., 2010] highlights an area of high heat flow along the Sabine Uplift in East Texas. The I-35 Corridor East project focused on temperature mapping of thousands of wells with depths of at least 7,000 feet in the eastern half of the Texas between interstate I-35 and the Texas-Louisiana border and encompassed North, East, and South Texas, including the large population centers along the Texas Gulf Coast. Temperature-at-depth maps at multiple depth intervals were created which will provide the basis for this DDU project analysis. The large region exhibits good potential for low-temperature direct-use applications with the power plants in the region (see Figure 2). A complementary paper in this conference describes the local resource in more detail [Batir et al., 2018].

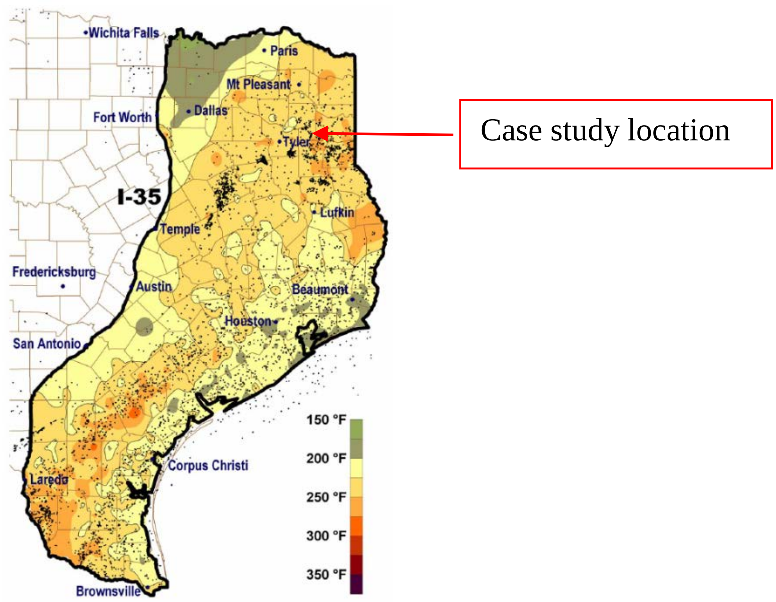


Figure 2. Texas geothermal resources at 9,000 ft depth taken from the SMU "I-35 Corridor East" Study.

1.2 Turbine Inlet Cooling (TIC)

Natural-gas combustion turbines and combined-cycle plants (combustion turbine(s) followed by a steam-cycle turbine) are becoming dominant power generators in the U.S. generation fleet. An attribute of all combustion turbines is that hot weather degrades their power capacities. The impact ranges from about 10 percent to 35 percent of the rated/nameplate output capacity, which is always rated at 59°F (15°C) as specified by the International Standards Organization. To compound matters, as ambient temperature increases, power demand and electricity prices typically increase too. Thus, turbine output decreases when it is most needed. In combined-cycle, cogeneration and combined-heat-and-power (CHP) systems, a rise in ambient temperature not only reduces the turbine power output, it also reduces the total thermal energy available in the turbine exhaust gases for the desired downstream use [Punwani & Hurlbert, 2006]. Inlet air cooling increases the gas density, allowing turbine performance to recover.

TIC can be provided by evaporative cooling of the turbine inlet air or through sensible chilling via mechanical vapor-compression or thermal absorption chillers, Figure 3. Evaporative coolers are simpler and less expensive, but these systems are limited by the local wet-bulb temperature and do not work as well in high-humidity regions. Prior studies have shown that active chilling can yield much greater benefits in terms of increased power output, especially in humid environments such as East Texas and the Gulf Coast [Punwani, 2008].

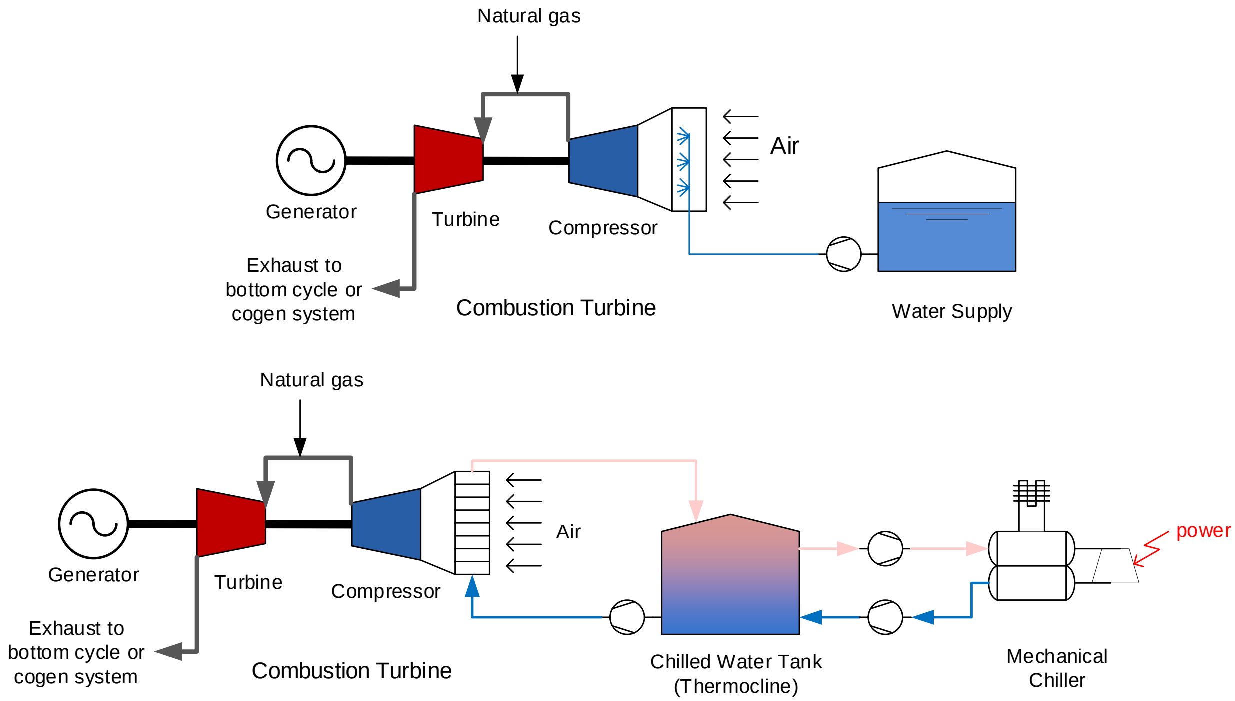


Figure 3. Typical TIC systems - evaporative cooling via spray injection (top) and chilled-water cooling with mechanical chiller (bottom).

1.3 Absorption Chillers with Thermal Storage

Although not as intuitive as direct heating, geothermal energy can be used to provide cooling through the use of commercial absorption chillers. At low pressure, water evaporates at low temperature while absorbing heat and this phenomenon can be used to produce refrigeration. A low-pressure condition is maintained in an evaporator/absorber with a salt solution that has a strong affinity for water. This salt, typically lithium bromide, absorbs water vapor that evolves from the evaporator to maintain the low-pressure condition in the chamber. The diluted salt solution is re-generated by (geothermal) heat and recycled to the absorber. A separate chilled water loop can include storage to decouple the rates of production and use of the chilled water. For example, absorption chillers can be sized to operate 24/7 on the steady geothermal heat source and supply chilled water to a holding tank. This chilled water can be dispatched to coincide with the periods of greatest power demand and/or hottest ambient temperatures to ensure the greatest economic benefit for the plant.

Prior studies that explored the use of absorption chillers for TIC identified as a limitation the need to couple heat availability from the operating power plant to the demand for chilling. Integrating geothermal energy removes this constraint, while inclusion of thermal energy storage allows for design of a small-capacity chiller that runs 24/7 off the geothermal resource to fill the storage system, which can be dispatched at a different rate as needed.

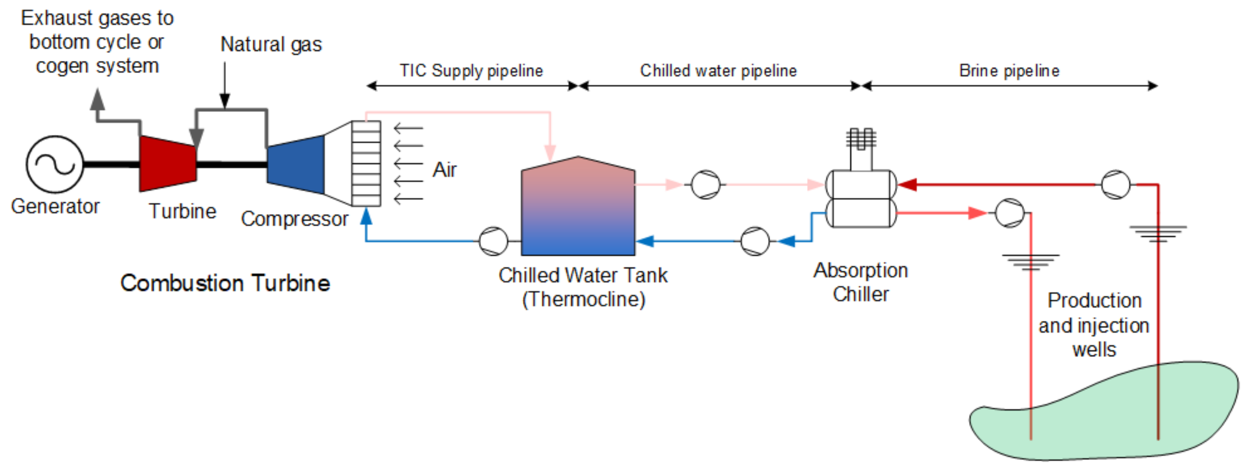


Figure 4. Turbine inlet cooling provided by geothermal-driven absorption chillers. The use of chilled-water storage allows one to decouple the geothermal use from the TIC dispatch.

2.0 Preliminary Findings

An initial assessment of project potential is made by comparing the estimated cost for accessing the geothermal resource to the estimated revenue potential from turbine inlet cooling. Geothermal energy cost is provided by examining the range of resource conditions identified by SMU Geothermal Laboratory [Batir, et al., 2018] and applying a techno-economic model for geothermal development. Application revenue is estimated as the maximum increase in revenue possible if turbine inlet cooling is applied to generate additional electric power. Power value is assessed using historic hourly wholesale price data for location in question. These initial estimates will be refined in later project work.

2.1 Geothermal Resource Costs

The development cost for the geothermal resource is estimated using a new version (v2.0) of the geothermal techno-economic simulation tool GEOPHIRES (GEOthermal energy for Production of Heat and electricity (“IR”) Economically Simulated). GEOPHIRES combines reservoir, wellbore, surface plant, and economic models to estimate the capital and operation and maintenance costs, instantaneous and lifetime energy production, and overall levelized cost of energy of a geothermal plant. In addition to electricity generation, direct-use heat applications and combined heat and power or cogeneration can be modeled. GEOPHIRES v2.0 includes updated cost correlations, coupling to the external reservoir simulator TOUGH2, enhanced wellbore simulator, and has been converted the programming language to Python and made open-source. An overview of the capabilities and updates to GEOPHIRES is provided in Beckers & McCabe 2018.

For this preliminary work, GEOPHIRES' thermal drawdown model is used to estimate reservoir production over time. The key input parameters for GEOPHIRES are listed in Table 1. All other variables within GEOPHIRES are left at their default values, with the notable exception of the drilling costs. The default drilling costs within GEOPHIRES are based on hard-rock EGS wells as reported in Lowry et al. 2017 and are likely not representative for a sedimentary region such as East Texas. Furthermore, the large number of wells in the region suggest that drilling criteria are known, and cost uncertainty would be low. Accordingly, the "Intermediate 1" drilling costs from Lowry et al.—representing reduced costs due to technical advancements—are applied for this feasibility study. Future work is planned to examine the applicability of this assumption. The switch from the GEOPHIRES' default to the "Intermediate 1" case reduces the estimated drilling cost from approximately $4.3 million down to $2.5 million per well for the 2,590-ft well depth of the case study.

The tornado plot shown as Figure 5 highlights the parameters of greatest influence on capital cost: pipeline distance, gradient, and drilling depth. The results are not surprising but require context for interpretation. Figure 6 shows a similar plot for levelized cost of heat (LCOH), which considers not only the capital cost, but the geothermal energy that is produced. Gradient and drilling depth are significant parameters in both figures, which highlights the importance of drilling costs and the temperature gradient available. The injection temperature becomes a significant parameter because it represents the amount of energy that can be extracted from the geothermal brine. A typical design-point for a single-stage absorption chiller heat source is about 88 °C (190 °F) [U.S. DOE, 2017]. This becomes the limiting temperature at which heat can be extracted from the geothermal brine. Based on the SMU data, the best guess brine surface temperature is about 111 °C, thus the ΔT for enthalpy extraction is only 23 °C. Widening this range would have a significant impact on LCOH.

Table 1. Input values for GEOPHIRES showing the best guess values for the region around the Eastman Chemical plant as well as a sensitivity range of ±25%.

Variable	-25%	Best Guess	25%	Source
Drilling Depth [m]	1,943	2,590	3,238	SMU data
Gradient [deg.C/km]	28	37	46	SMU data
Drawdown Parameter [%/year]	0.38	0.50	0.63	Snyder et al., 2017
Flow Rate [kg/s]	56	75	94	Estimated from Productivity Index
Pipeline Distance [km]	4	5	6	SMU data
Productivity Index [kg/bar.s]	4.1	5.5	6.9	SMU data
Injection Temperature [deg.C]	66	88	110	Absorption Chiller Model

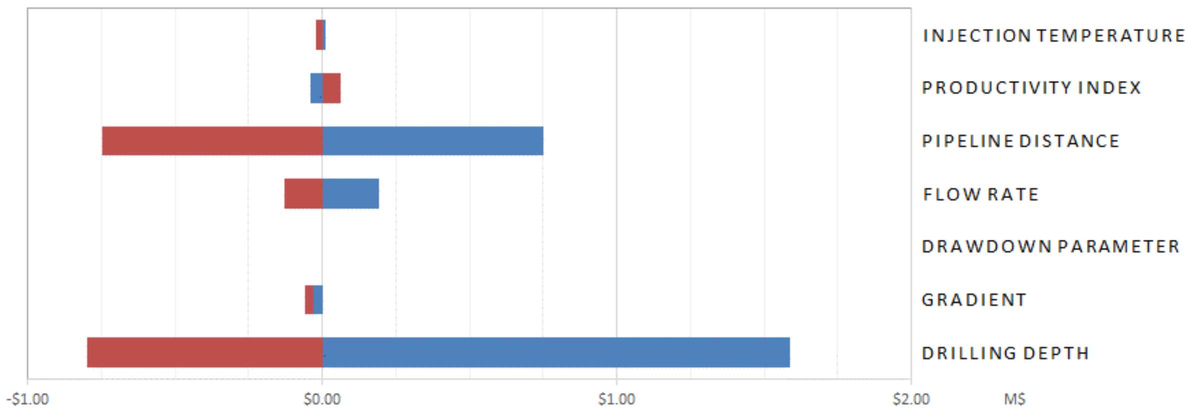


Figure 5. Sensitivity of capital cost ($ millions) to GEOPHIRES input variables listed in Table 1. The baseline-case cost is $12.7 million with a single producer/injector well pair.

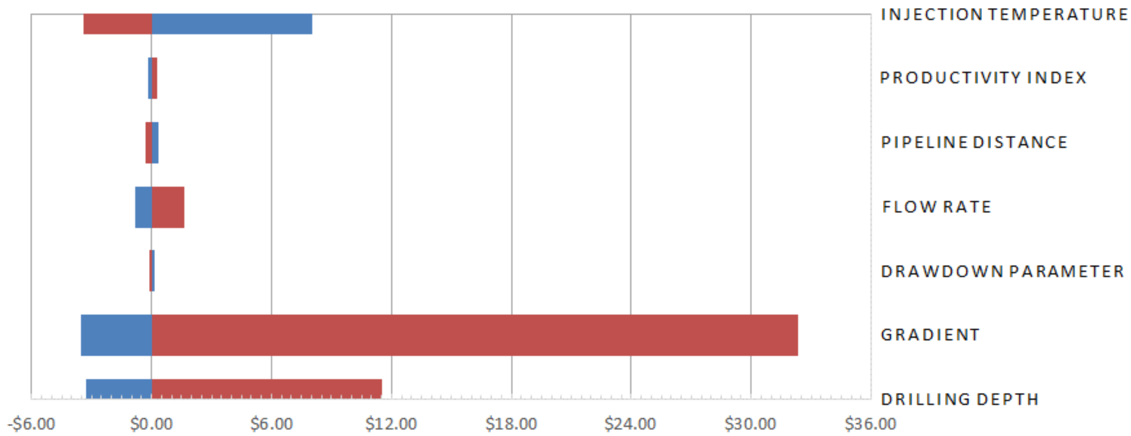


Figure 6. Sensitivity of levelized cost of heat (LCOH) to GEOPHIRES input variables listed in Table 1. The baseline-case LCOH is $7/MMBTU with an initial reservoir temperature of 116 °C.

2.2 Modeling the Power Plant

A simulation model of the combined cycle or co-generation power plant was required to assess the potential benefit of turbine inlet cooling as a function of weather and operating conditions. The model was developed using IPSEpro (SimTech 2017), which is a flow-sheeting simulation tool that calculates heat balances and predicts design and off-design performance of power-plant components and systems. The Eastman Chemical cogeneration plant consists of two General Electric PG7241(FA) gas turbines (GTs) each with a rated capacity of 171.7 MW_e. The exhaust from each turbine is used to heat steam in a Heat Recovery Steam Generator (HRSG) and combined to power a two-stage steam turbine with a rated capacity of 126.5 MW_e. A fraction of the steam is used in the chemical plant as process steam. This process steam/condensate is ultimately returned to the power block, and its remaining enthalpy is used to heat the GT fuel, and then to pre-heat the inlet water to the HRSGs. Low- and high-pressure (HP) steam is extracted for use in the chemical plant.

Design models were developed in IPSEpro using process flow diagrams and data sheets provided by Eastman Chemical. Operational data for the cogeneration plant was also provided and included cycle-property data at 15-minute intervals. Data were provided for six representative days throughout the course of 2017 and gave an overview of the operational points of the cogeneration plant and indicate the effect of ambient temperatures on the system. Off-design models of the system were developed in IPSEpro, and the operational data were used to tune the correction curves and to validate the model output.

The response of the system to variations in key parameters (such as ambient temperature and load) were investigated. Modeling the full system (GTs, steam turbines, and HRSGs) led to problems with the model convergence when the system was far from the design point. Therefore, it was decided to model the GT separately from the steam turbine. This allowed a wider range of off-design operational points to be investigated. This approach is justified because the GT cycle and steam turbine cycle are not strongly coupled to one another—that is, the exhaust gas from the GT does not directly correlate with the steam inlet flow to the steam turbine. This is a result of the variable steam demand of the chemical plant. The operational data indicated that the steam entered the steam turbine at a constant temperature and pressure. The steam flow rate did not depend directly on the steam generated in the HRSG because the quantity of steam sent to the chemical plant varied significantly. A diagram illustrating the GT model is shown in Figure 7.

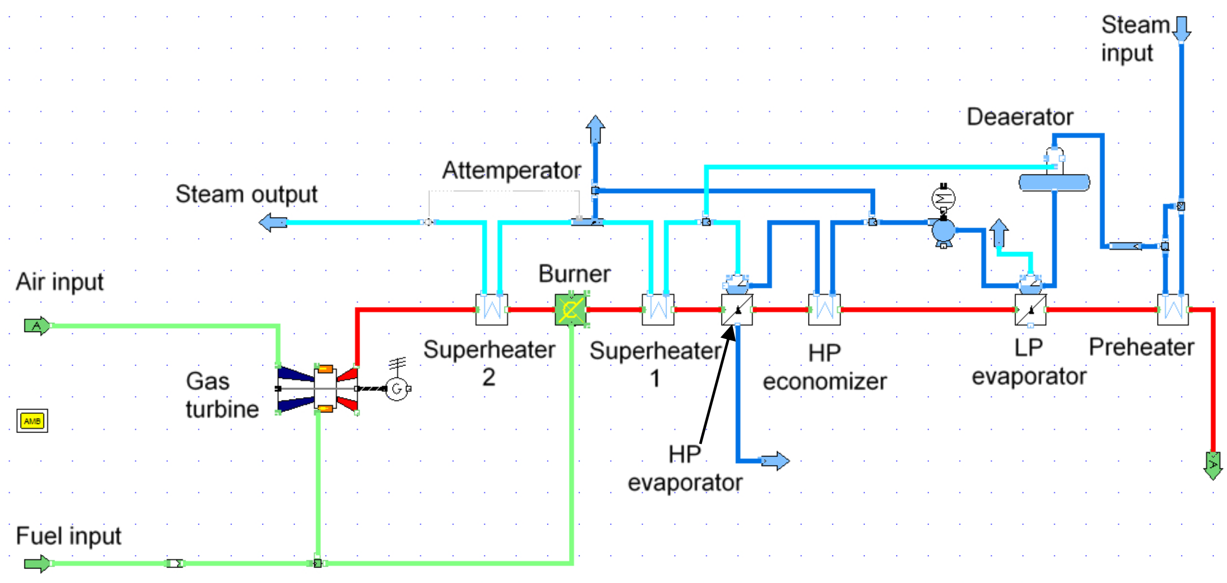


Figure 7: Screenshot of the gas turbine and heat recovery steam generator model from IPSEpro

The operational data were used to validate the off-design IPSEpro model. The normalized heat rate is plotted versus part load fraction in Figure 8. Heat rate (fuel thermal content divided by electric generation, MMBTU/kWh$_e$) is a common measure of cycle efficiency. The operational data did not exhibit any correlation between ambient temperature and power generation. This is because the Eastman plant typically runs at part-load operation with primary responsibility to the power and steam demands of the chemical plant. Since the required power is generally below the design value, the power-diminishing effect of high-ambient temperatures may be overcome by simply increasing the air and fuel flow rate through the GT. For this reason, most applications do not deploy turbine inlet cooling until the plant is operating at full load. Still, it is possible to quantify the effect of ambient temperatures on part load as well as full-load conditions, as illustrated in Figure 9. The IPSEpro simulation shown in Figure 9 shows that the relative effect of inlet temperature is the same regardless of whether the plant is at full load or 75% of full load. The curve and data points are each normalized by the respective operating power (100% or 75%) at design-point wet-bulb temperature. For a given load, higher temperatures lead to lower power outputs. The design point conditions by ISO definition are dry-bulb temperature of 15°C and relative humidity of 60% (corresponding to a wet-bulb temperature of 10.8°C).

Having validated a GT model with operational data, we consider two operational modes:

1. A cogeneration plant operating identically to the Eastman chemical plant. Hourly power data was provided for 2017 and is used to evaluate the benefit of turbine inlet cooling on the existing plant as it currently operates.
2. A merchant plant, running nominally at full load for the entire year.
3.

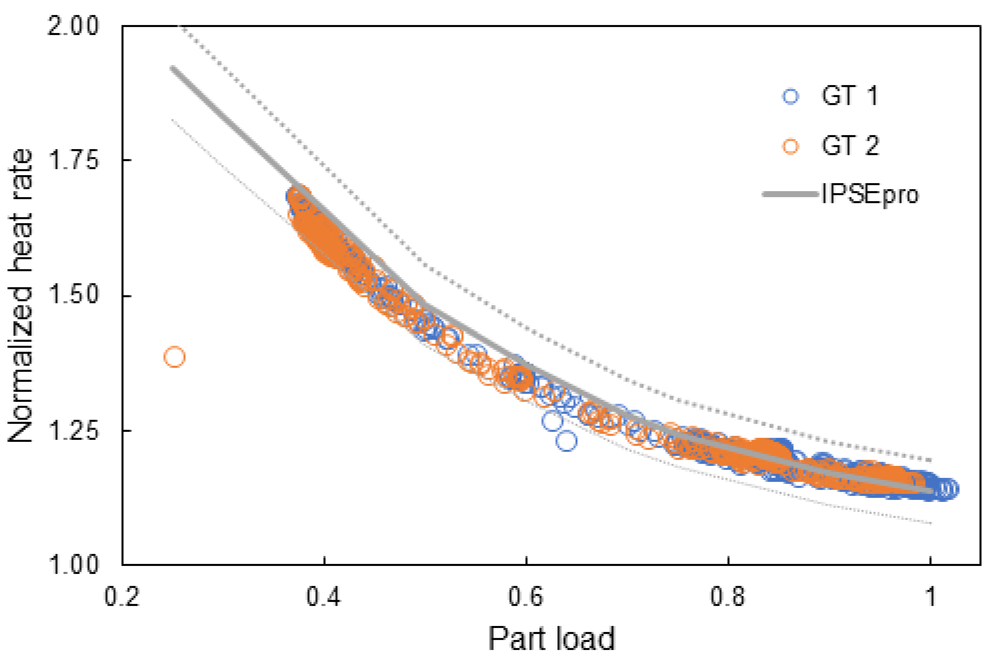


Figure 8: Variation of heat rate with part load operation for the gas turbines (GTs). This figure compares operational data and IPSEpro model output. The model heat rate ±5% is illustrated with dotted lines.

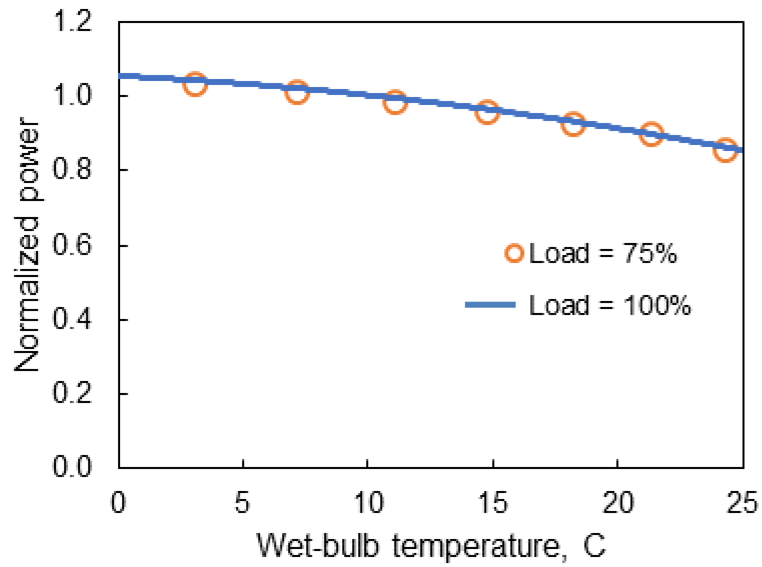


Figure 9: Effect of wet-bulb temperatures on GT power output. Power normalized by the power at ISO design point conditions (Tdb = 15 °C, RH = 60%) at that load condition.

2.3 Annual cooling opportunity and revenue calculation

Hourly data for 2017, including power production, wet-bulb and dry-bulb temperatures (T_{wb} and T_{db}) and pressure, were obtained for the Eastman plant. For each hour, the relative humidity (RH), specific humidity and enthalpy of the incoming air were calculated. The specific cooling opportunity is given by the difference in enthalpy of air at the observed value and at the design value, unless the ambient enthalpy is below the design enthalpy, in which case the cooling opportunity is zero. The specific cooling opportunity is then multiplied by the air mass flow rate to find the required cooling power for each hour.

The turbine inlet cooling system comprises an absorption chiller and storage vessel, and the capacity of these two components determines the cooling load that may be delivered at every hour. The chiller is assumed to run at full load for the entire year (via geothermal heat), and the cold water fills the storage tank. The available cooling load at each hour is the cooling that can be supplied by the chiller, plus the cooling available from the storage tank. In the initial analysis, a simple control algorithm for dispatch of cooling is applied:

- Whenever the required cooling is less than the cooling power of the chiller, the inlet air is cooled to the design value, and excess chiller capacity continues to fill the tank. If the tank is full, the chiller is shut off or bypassed.
- If the required cooling is more than the cooling power of the chiller, then the tank level falls as water is dispatched to provide the required cooling load. If the storage tank is emptied, the turbine inlet air is not cooled down to the design temperature.

Having evaluated the temperature of the cooled inlet air, the increase in power output may be calculated by using Figure 9. Hourly real-time electricity price data for 2017 were obtained from the Southwest Power Pool (https://www.spp.org/), the grid operator for the Longview region. The increase in annual revenue may be found by multiplying the additional power by the locational marginal price (LMP) at each timestep.

Cooling one GT inlet to its design temperature at every hour of the year would lead to additional electricity generation of 80.3 GWh_e at the Eastman plant, and 128.7 GWh_e for a merchant plant. This corresponds to an additional revenue of $2.6 million and $3.8 million for the Eastman plant and a merchant plant respectively. These values represent the maximum revenues that may be achieved, exclusive of other practicalities. Providing cooling to both gas turbines would roughly double these values.

2.4. Sizing the chiller and thermal storage tank

Storage provides a way for the geothermal system and chiller to run at full load all year, thereby meeting a flexible cooling demand while reducing the size of these components. The optimal sizing of the chiller and storage, and the storage dispatch strategy are closely related and require careful analysis.

For example, a 12-MW_{th} chiller at the Eastman plant could provide about 80% of the annual cooling opportunity with no storage Figure 10 (top). The chiller provides more than enough cooling throughout the winter. However, summer cooling loads frequently exceed 12 MW_{th} and the chiller rarely cools the air to the design value. However, it is notable that the chiller can generate an annual total of 105.1 GWh_{th} of cooling energy, while annual cooling opportunity is only 60.3 GWh_{th}. This indicates that the chiller is large enough (perhaps too large), but that it cannot always provide cooling at the required times. Storage can provide the flexibility to deliver cooling independent of the chiller status and provide greater cooling power than the chiller can on its own.

The influence of a 5000 m^3 (1.3 million gallons) storage tank on the delivered cooling is shown in Figure 10. By filling the storage when cooling opportunities are low, it is possible to meet the cooling opportunity for much of the summer. There is a notable period in the summer where the cooling opportunity is above the chiller load for several days. As a result, the storage is not filled during this period, and the maximum cooling that can be delivered is 12 MW_{th}. Table 2 shows the annual cooling opportunity, delivered cooling, and revenue potential for several cases based on 2017 data. Addition of a 5000 m^3 tank raises annual revenue from $2.1 million to $2.4 million for the Eastman plant scenario with a 12-MW_{th} chiller.

Increasing the storage size further allows for seasonal storage of cold water, which may help to provide the required cooling load during the long period of high ambient temperatures that is observed in the summer. However, Table 2 indicates that this is unlikely to be a cost-effective solution. For instance, quadrupling the storage size to 20 000 m^3 (5.3 million gallons) only leads to a 1.6% increase in the delivered cooling, and an almost negligible increase in revenue. This size approaches the benefit of an infinite-capacity storage tank.

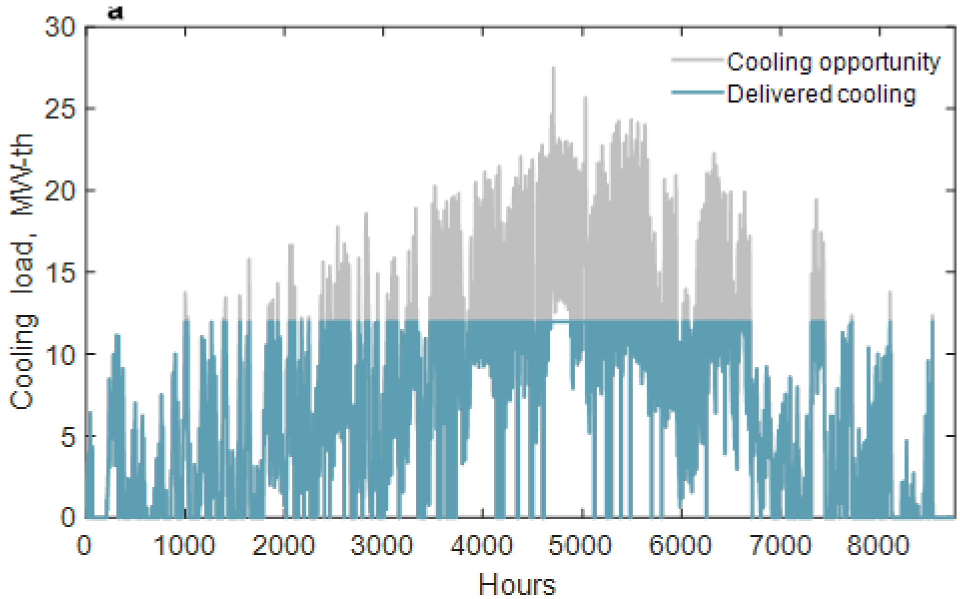
Table 2: Annual results for different storage tank volumes.

		Eastman plant (12-MW_{th} chiller)				Merchant plant (18-MW_{th} chiller)			
Storage volume	m^3	0	5000	20 000	Infinite	0	5000	20 000	Infinite
Max cooling capability	GWh_{th}			105.1				157.7	
Cooling opportunity	GWh_{th}			60.3				89.1	
Delivered cooling	GWh_{th}	52.2	56.5	57.4	60.3	82.0	85.1	85.7	89.1
Delivered water	m^3 (billions)	2.4	2.6	2.6	2.7	3.7	3.8	3.9	4.0
Excess water	m^3 (billions)	2.4	2.2	2.1	0.0	3.4	3.3	3.2	0.0
Additional energy	GWh_e	67.8	74.3	75.7	80.3	118.5	122.9	123.8	128.7
Additional revenue	M$	2.1	2.4	2.4	2.6	3.4	3.6	3.6	3.8

A similar pattern is observed for the merchant plant, although revenues are higher because the plant is generating more power. These results indicate that installing a modest quantity of storage is worthwhile to distribute cooling loads over the course of a day, but that seasonal storage is unlikely to be profitable.

The analysis so far uses a simple dispatch model, whereby stored cold water is delivered whenever opportunity exists. However, it is likely that a more sophisticated control strategy could make better use of the storage to take advantage of the variations in electricity prices. To illustrate the benefit that dispatch control can provide, a simple model is implemented here. Figure 11 shows the reported distribution of electricity prices for each hour of the day. It is notable that prices fluctuate more significantly during daytime hours, and that variations are minimal between 8 pm and 4 am. A better dispatch model would avoid any cooling during these low-value hours and instead fill the storage tank to be available to provide cooling during more profitable hours. Such a dispatch algorithm is presented in Table 3 for the Eastman plant and the merchant plant with a storage volume of 5000 m^3. Although this dispatch method produces less cooling energy over the course of the year, the energy is provided at higher-value times and the “additional revenue” increases as a result. This suggests that dispatch strategy needs to be optimized along with chiller capacity and storage capacity.

Results are also presented in Table 3 for smaller chillers. These smaller chillers can generate almost as much revenue as a larger chiller without the improved dispatch model. For instance, a 25% smaller chiller at the Eastman plant generates only 12% less revenue than the 12-MW_{th} chiller. The cost of the chiller *and geothermal system* will both be reduced by 25%. More sophisticated control strategies may be able to further increase revenues at reduced costs. This optimization process is part of the ongoing project.



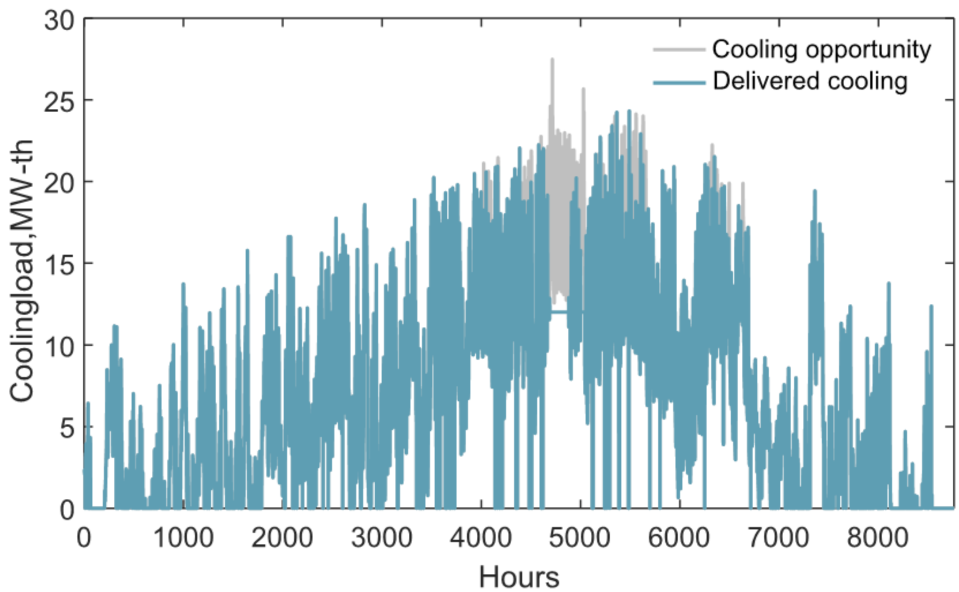


Figure 10. The hourly cooling load that is required, and the cooling load that is supplied to the Eastman co-generation plant with a 12-MW_{th} chiller: (top) No storage, (bottom) with 5000 m^3 storage.

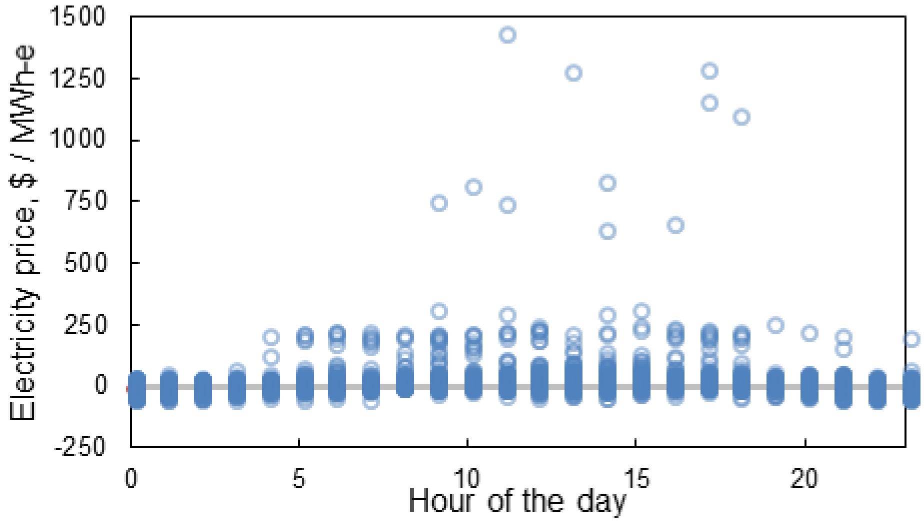


Figure 11: The distribution of electricity prices at each hour of the day for 2017 Southwest Power Pool, south hub LMP.

Table 3: Annual results for different chiller sizes and dispatch strategies. In strategy "A" cooling is dispatched whenever it is required. In strategy "B," no cooling occurs between 8 pm and 4 am, so that the storage is charged.

		Eastman plant				Merchant plant			
Chiller size	MW_{th}	9		12		13.5		18	
Dispatch strategy		A	B	A	B	A	B	A	B
Storage volume	m^3	5000	5000	5000	5000	5000	5000	5000	5000
Max cooling capability	GWh_{th}	78.8	78.8	105.1	105.1	118.3	118.3	157.7	157.7
Cooling opportunity	GWh_{th}	60.3	60.3	60.3	60.3	89.1	89.1	89.1	89.1
Delivered cooling	GWh_{th}	48.8	47.6	56.5	54.4	73.7	72.3	85.1	84.0
Delivered water	m^3 (billions)	2.2	2.1	2.6	2.5	3.3	3.3	3.8	3.8
Excess water	m^3 (billions)	1.3	1.4	2.2	2.3	2.0	2.0	3.3	3.3
Additional energy	GWh_e	62.7	63.4	74.3	72.8	106.0	104.2	122.9	121.2
Additional revenue	M$	1.9	2.2	2.4	2.5	3.1	3.3	3.6	3.7

3.0 Conclusions

This project seeks to assess the feasibility of integrating direct use of deep geothermal resources in natural-gas combined cycle power stations in the Sabine Uplift and Gulf Coast regions of Texas. A low-grade geothermal resource is tapped to drive absorption chillers for production of chilled water that is used to provide turbine inlet cooling at the compressor inlet of a natural-gas combined cycle power plant. Turbine inlet cooling is a proven commercial method of boosting power production during periods of high temperature and high prices.

The preliminary assessment of economics compares the cost of heat from the geothermal resource, as measured by levelized cost of heat (LCOH), using default values in GEOPHIRES 2, augmented by "best-guess" values based on the local geothermal resource. GEOPHIRES highlights that system capital cost is dominated by drilling costs, while geothermal energy production is dominated by thermal gradient (source temperature at depth) and injection temperature. The minimum injection temperature is controlled by the temperature required by the assumed absorption chiller. These parameters estimate a baseline-case cost of a single producer/injector well pair producing 6 MW_t at a cost of $12.7 million. This is prohibitively expensive for the application being considered, given the annual revenue from such a system is estimated at approximately $1 to 1.2 million with a 6 MW_t chiller. Several pathways are suggested for refining or improving the overall economics and will be explored in the ongoing project. These include:

- Optimize dispatch strategy simultaneously with chiller and storage capacity.
- Obtain drilling performance and cost data for East Texas (from the oil and gas sector) and compare with the drilling cost used in GEOPHIRES. The specific geology of the region may yield lower-cost drilling.
- Consider the use of abandoned oil & gas wells in the area for use in geothermal production and/or injection.
- Extend the injection-well temperature to lower temperatures to allow greater recovery of enthalpy from the brine. This requires evaluation of different absorption chiller designs and operating points.
- Explore additional uses of the geothermal heat or chilled water within the chemical plant as an additional or alternative value stream.

Lastly, system component costs will be refined through discussion with the project's industrial partners.

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