Renewable Thermal Energy Systems Designed for Industrial Process Solutions in Multiple Industries

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Abstract

Industrial decarbonization can and must be accelerated by removing fossil fuels from the provision of process heat. Doing so at temperatures less than 250°C which accounts for about 2/3 of industrial process heat (IPH) but is not receiving the attention of areas such as steel and cement, is a particularly promising opportunity. This paper looks at the results of two case studies for understanding the economics and potential for renewable thermal energy systems (RTES) in hybrid configurations to provide IPH. The first case study looks at using district heat as an input for a heat pump--three cases were run harvesting energy from ambient water (5°C), sewage water (20°C), and a solar collector (35°C). The second case study looks at the use of linear Fresnel collectors (LFCs) coupled with phase change material (PCM) thermal energy storage (TES) for direct steam generation (DSG). Accounting for elevated costs of infrastructure for each heat source, the levelized cost of heat (LCOH) of the first case study ranged from \$4-\$10 per million British Thermal Units (MMBTU). For the second case study modeling LFCs with PCM and TES, the results show that a LCOH of \$9-\$15 per MMBTU is possible, depending on the direct normal irradiance.

Keywords: SIPH, RTES, CST, DSG, heat pumps, LCOH, Industrial Decarbonization, TEA

1. Background

The need for renewable heat in industry is vital for the next decade and beyond. Global industrial heating applications are estimated to be approximately 20% of the total global energy consumed (IRENA, 2019). This energy is overwhelming supplied by the burning of fossil fuels, principally coal and natural gas, to produce the heat or steam. As the world looks to decrease emissions, industrial decarbonization and the reduction of fossil fuels through renewable alternatives is becoming an increasingly important topic but has been under-researched. Recent work from the National Renewable Energy Laboratory (NREL) found that significant opportunity for solar industrial process heat (SIPH) exists in the United States. Estimates indicate that nearly 2/3 of the industrial thermal demand in 2014 in the United States is less than 250°C, which is ideally suited to solar and renewable heat systems (McMillan et al., 2021). Concentrating solar thermal (CST), photovoltaic (PV), and grid coupled heat pumps can be considered in stand-alone or hybrid configurations (e.g., where multiple technology options couple to provide temperatures at different levels) of renewable thermal energy systems (RTES). Such systems can provide low to medium temperature heat less than 250°C (Akar et al., 2021), but need costs to decrease to increase deployment. Two areas examined in this paper are district heating and food/beverage processing.

District heating is a strong candidate for heat pump application, as heat pumps are already used extensively in space heating. For an effective district heating system, the distributed water or steam should be elevated to temperatures ranging from 50°C-100°C for hot water, and above 110°C for steam systems (Nielsen and Sørensen, 2016; Thorsteinsson, 2008). Heat pumps currently provide district heating with aggregated thermal capacity of 1.58 GW across 11 European countries (David et al., 2017). The U.S. has considerably lower deployment of heat pumps though it does have an estimated 1.5 GW of operational district heating systems which utilize hot water for campuses and cities. These systems could potentially benefit from heat pump augmentation (EIA, 2018).

Dairy and food processing sites have been repeatedly found theoretically and practically suitable for stand-alone RTES use. The steam and heat needs can be readily supplied by RTES, such as CST for animal food processing and dairies (Kurup and Turchi, 2015). For example, in Switzerland, an operating parabolic trough system uses water-glycol which provides heat for the milk processing (Kurup et al., 2017). Recently in the United States, CST systems where hot water and steam are produced have been installed at a New York farm and a California dairy processing facility (Skyven Technologies, 2020, 2019). Prior work has also identified breweries as potentially viable for renewable heat, for example when a stand-alone RTES provides heat for the process (Kurup and Turchi, 2020).

doi:10.18086/swc.2021.29.01 Available at http://proceedings.ises.org

2. Introduction

A simplified framework for RTES selection and heat provision (at the overall site level) has been developed (Akar et al., 2021). To better understand commercially viable near-term hybrid RTES solutions, specific hybrid RTES generation code modules or tools were built based on the framework (Akar et al., 2021), and initial results were highlighted in a following paper(Kurup et al., 2021). Those results were to understand the heat generation (i.e., technological performance) from these hybrid RTES models and were not applied to specific end-use cases.

This paper highlights the application of the hybrid RTES framework and newly developed code modules for specific case studies. The models and results explore the techno-economic analysis (TEA) and potential of stand-alone and hybrid RTES applied to potential district heating and food processing applications. Two main case studies are explored in detail. The first case study focuses on high-temperature heat pumps (HTHPs) for district heating and the variables that influence their economics. The second case study uses linear Fresnel collectors (LFCs) for direct steam generation (DSG) coupled with a phase change material (PCM) thermal energy storage (TES) system for food/beverage processing application. This paper builds upon work and the opportunities identified for SIPH in the U.S. (McMillan et al., 2021), and looks to focus it on specific industries of interest and high economic potential. The results for both case studies highlight the levelized cost of heat (LCOH) for different RTES options in meeting the district heating or industrial load.

In parallel with these RTES analyses, an HTHP model has been developed to characterize the opportunity for waste heat valorization in industries with suitable temperature requirements (90 – 150°C). The python-based model produces LCOH and economic outputs (e.g., payback period, internal rate of return) based on a given industrial process and technology characteristics such as compressor-type and refrigerants. This model has been used to investigate the economic potential of HTHPs in the dairy and brewing industry, and, for the purposes of this paper, will be used for assessing district heating applications.

HTHPs move heat rather than generate it. Taking advantage of waste heat streams, heat pumps can output more thermal energy than their input in electrical energy, allowing them to potentially improve energy efficiency while reducing the carbon intensity of heat provision. Their combination of increased efficiency, cost savings, and emissions reductions make HTHPs a promising component of industrial electrification. HTHPs are not a new technology, though a global focus on industrial decarbonization has brought renewed interest in how they might contribute to the reduction of fossil fuel use to meet IPH demands. HTHPs up to 90°C have been commercially available since the 1980s, but in the past decade have seen increased interest and an increased number of commercially available models. Though it is technologically possible (as some pilot projects have demonstrated) to lift temperatures up to 150°C and theoretically beyond (Zühlsdorf et al., 2019). The case study presented here will examine the techno-economic potential for HTHPs to supply heat for district-level systems in the United States, a relatively untapped market for these promising technologies. Europe has a history of using HTHPs for various industrial processes, but countries have found them particularly suitable for serving district heating systems (Neves and Mathiesen, 2018). Globally as of 2018 there were more than 20 heat pump models available from 13 identified manufacturers (Arpagaus and Bertsch, 2020). The analysis will evaluate the LCOH of an HTHP for district heating and variables that affect its overall cost of heat delivery. Although this is a U.S. focused case study, it has relevance to other energy markets with a low ratio of natural gas to electricity prices—a challenging energy price environment for heat pump economics. It is worth noting that heat pumps become increasingly competitive as the ratio of natural gas to electricity prices increases.

The second case study uses LFC-DSG coupled with PCM-TES to improve the system's flexibility and capacity factor. The LFC-DSG system is modelled with the System Advisor Model (SAM) which evaluates the annual performance of the solar system. PCMs are chosen as the storage medium as they have relatively high energy densities. Sodium formate has been selected as the storage medium, which has a melting temperature of 258°C. PCMs store energy in the latent heat of the phase change and can be used to produce steam at the phase change temperature, which improves the effectiveness of heat transfer (Sharan et al., 2019). The LFC- DSG system must generate steam at a higher temperature than this so that the steam produced melts the PCM. In this example, the LFC-DSG system designed to produce steam at 5 bar, 270°C and a steam quality of 75%. The steam properties (temperature, mass flow rate, and steam quality) are calculated hourly for the year depending on the available solar resource. The annual performance of the model has been validated with an operating solar field (Kurup et al., 2017).

3. Case study results

3.1. Case Study 1: Standalone HTHP System for District Heating up to 90°C

The case study presented here investigates HTHPs in district heating applications. District heating systems utilize hot water or steam to provide thermal services from a central energy plant to cities, communities, or campuses in a simple and efficient manner. Heat pump driven district heating, while largely unpracticed in the U.S., has been deployed to serve a wider array of European cities over the past 40 years, particularly in Scandinavian regions (Jakobs and Stadtlander, 2020). This disparity can be attributed to past European electrification initiatives, greater general familiarity of heat pump systems in European markets, and European industrial policy that provides greater security for firms, all of which fosters a greater appetite for risk and encourages centralized utilities for shared infrastructure like district heating systems, and established expertise in district heating systems (Werner, 2017).

A model was developed to simulate the performance of HTHPs based on published methodologies (Arpagaus et al., 2018; Bergamini et al., 2019; Kosmadakis et al., 2020) This model was used to assesses the technical performance and economic implications of heat pump-driven district heating in a variety of common scenarios informed by operating conditions of existing European plants and adapted to U.S. energy prices.

In European heat pump-driven district heating systems, the most common sources of waste heat are sewage water, ambient water, and industrial waste heat. To model how HTHPs would perform district heating functions using the listed waste heat sources and in combination with solar technologies, this analysis considered three different source temperatures: 5°C, to represent ambient water sources; 20°C, to represent both sewage water and ground source geothermal sources; and 35°C, to represent both solar thermal preheating systems and industrial waste heat sources. When solar preheaters were used, an elevated capital cost was also assumed to account for the additional expense of the solar thermal collectors. The typical capacity of such district heating configurations ranges between 2-20 MW (David et al., 2017).

Heat pump-driven district heating systems in Europe deliver hot water between 60°C and 90°C (David et al., 2017). It is also a goal of future district heating systems to reduce needed temperatures to 50°C as lower temperatures reduce energy lost to the ambient environment and increase system efficiency (Averfalk and Werner, 2018; Buffa et al., 2019), so this analysis included heat sink temperatures between 50°C and 90°C, in ten-degree increments, to examine how heat pumps would perform across this range. The model used in this analysis can select an optimal refrigerant from a library of over 30 options based on maximum temperature and temperature lift. Because the vast majority of operating heat pump-driven district heating systems in Europe use either R134a or ammonia as refrigerants (David et al., 2017) , and R134a is widely being phased out due to its global warming potential, this analysis uses a test case with ammonia as the refrigerant for all scenarios, as well as a test case allowing the model to choose a refrigerant.

The study produced LCOH values for heat pump systems in different configurations and was done parametrically to examine the effects of heat pump performance on the final system economics. The basic heat pump system examined using waste heat at a range of reasonable temperature from 5°C to 35°C to provide hot water from 50°C to 90°C. Using the methodology as described in Kosmadakis and provided in eq. 1-5, ammonia was used as a heat pump refrigerant and a resulting coefficient of performance (COP) of the heat pump was calculated based on refrigerant physical properties, compression ratio of the refrigerant (PR), compression efficiency (ε_{PR}), compressor isentropic efficiency (ε_{is}), and overall compressor efficiency (ε), (Kosmadakis et al., 2020). Kosmadakis et al., suggest ε_{is} values of 60-70% for a two-stage system, this study uses a slightly higher default ε_{is} (75%) to compensate for the lower output temperature range. For the 70°C-80°C delivery temperatures, the refrigerant-based COP was validated against real-world data as reported by European heat pump operators in the range of 3.5-4.0 (David et al., 2017) .

$$COP_{Real} = \frac{\dot{Q}_h}{\dot{W}_c} \quad \text{(eq. 1)}$$

$$\varepsilon_{is} \in [0.2, 0.95] \text{ and } \varepsilon_{is} = 0.75 \text{ by default} \quad \text{(eq. 2)}$$

$$\varepsilon_{PR} = 0.95 - 0.125 \times PR \quad \text{(eq. 3)}$$

$$\varepsilon = \varepsilon_{is} \cdot \varepsilon_{PR} \quad \text{(eq. 4)}$$

$$COP_{Refrigerant-Estimate} = \frac{\varepsilon_{is}\varepsilon_{PR}(h_3 - h_2)}{(h_2 - h_1)} \approx \frac{\dot{Q}_h}{\dot{W}_c} \quad \text{(eq. 5)}$$

Heat pump capital expenditure (CAPEX) and energy costs significantly affect heat pump economics. For the CAPEX of heat pumps, low-cost (\$150/kW) and high-cost (\$300/kW) scenarios were evaluated which are based on the maximum per kW electricity drawn by the heat pump system and are conservatively consistent with literature reports of HTHP capital costs (Kosmadakis et al., 2020; Meyers et al., 2018). However, in the case of the combined solar thermal flat plate collector (FPC) and heat pump it was assumed that additional capital costs increased the cost of the combined system to \$700/kW (low-cost) or \$850/kW (high cost) to include both the solar thermal collectors and thermal energy storage. In both situations, a low cost heat pump (\$150/kW) was assumed, with a low and high FPC cost of \$550/kW and \$700/kW (IRENA, 2021). The FPC unit cost is estimated to be between \$400/m^2 and \$600/m^2 with no assumed interconnection costs (NREL, 2021). Future analysis should include additional work on the price breakdown of these components when hybridized and additional characterization of a hybrid system's operational requirements. It was also assumed that the electricity procured by a municipality would be relatively low-cost and on the order of \$0.05/kWh, (note: this figure incorporates an estimate of total demand charges amortized into the \$/kWh estimate). Tab. 1 summarizes these inputs to the heat pump model. For all cases, the high temperature output of the heat pump was estimated at 50°C, 60°C, 70°C, 80°C, and 90°C.

Unlike natural gas boiler systems, in which costs are mostly associated with fuel, the majority of costs in heat pump systems are capital costs. This means that a heat pump increases its value and lowers its LCOH at higher capacity factors. The capacity factor (CF) is calculated as the thermal output of the heat pump over a year divided by the maximum potential thermal output for a year as given in eq. 6.

$$CF = \frac{Annual\ Heat\ Pump\ Thermal\ Output\ (MWh)}{Heat\ Pump\ Thermal\ Capacity\ (MW) \times 8760\ hours} \qquad \text{(eq. 6)}$$

In the cases presented below, the heat pump was assumed to have a CF of 0.3, operating approximately 2600 hours out of the year; this was based on milder climates (EIA, 2021a). In colder climates with longer heating days, or in systems where thermal energy is always used (such as in campus settings where steam systems are always needed), this CF could increase, which would in turn increase the competitiveness of the heat pump system. A subset of cases was re-run with a capacity factor equal to 1 (unrealistic but used as an upper-bound) and the LCOH showed a 10%-30% reduction, meaning the adoption value proposition of heat pumps could be strong in environments with higher and more consistent heating demand, though are likely bound by a 30% reduction from values shown.

Tab. 1: Capital costs and operating temperature ranges for heat pumps.

Heat Source	Cost Type	Waste Heat Temperature	Capital Cost	Temperatures
Ambient Water	Low Cost	5°C	\$150/kW	50°C, 60°C, 70°C, 80°C, 90°C
	High Cost		\$300/kW	
Sewage	Low Cost	20°C	\$150/kW	
	High Cost		\$300/kW	
Solar Collector - FPC	Low Cost	35°C	\$700/kW	
	High Cost		\$850/kW	

The results in Tab. 2 show, as would be expected, that the worst-performing heat pumps use the lowest temperature source (ambient water) and the best-performing use the highest temperature heat source (solar FPC). However, this is an expected result given the thermodynamic principles that govern heat pump COP. The purpose of the analysis is to help understand the trade-off between waste-heat upgrades and resulting LCOH. Because some waste heat sources demand significant additional CAPEX, the case with the best-performing heat pump system does not necessarily achieve the lowest LCOH. OPEX discrepancies are not considered in these calculations.

Tab. 2: Resulting COP from the heat pump model based on available waste temperature

	COP				
	50°C	60°C	70°C	80°C	90°
Ambient Water	4.50	3.74	3.19	2.78	2.45
Sewage	6.92	5.30	4.31	3.65	3.17
Solar Collector - FPC	14.02	8.62	6.30	5.00	4.16

Tab. 3: Resulting LCOH for temperature and cases

	LCOH ($/MMBTU)				
	50°C	60°C	70°C	80°C	90°
Ambient Water -Low Cost	$4.56	$5.29	$6.03	$6.76	$7.53
Ambient Water -High Cost	$5.63	$6.35	$7.08	$7.81	$8.58
Sewage – Low Cost	$3.35	$4.05	$4.73	$5.40	$6.06
Sewage – High Cost	$4.40	$5.10	$5.79	$6.45	$7.11
Solar Collector FPC – Low Cost	$6.05	$6.76	$7.44	$8.09	$8.73
Solar Collector FPC – High Cost	$7.10	$7.81	$8.49	$9.14	$9.78

From the data shown in Tab. 3, the lowest cost/best value LCOH was the system that used sewage waste heat as an input to the heat pump. This was true even when comparing high-cost sewage and low-cost ambient scenarios, which is useful as coupling a heat pump to a sewage plant would likely be a higher capital cost. In the case of installing a solar collector to provide input heat, additional capital costs increased the LCOH of this system's heat above that of the ambient water heat pump system's, meaning that the solar collector/heat pump system is not the most economic option for the cases and cost assumptions examined here (Fig. 1) especially in mild climates.

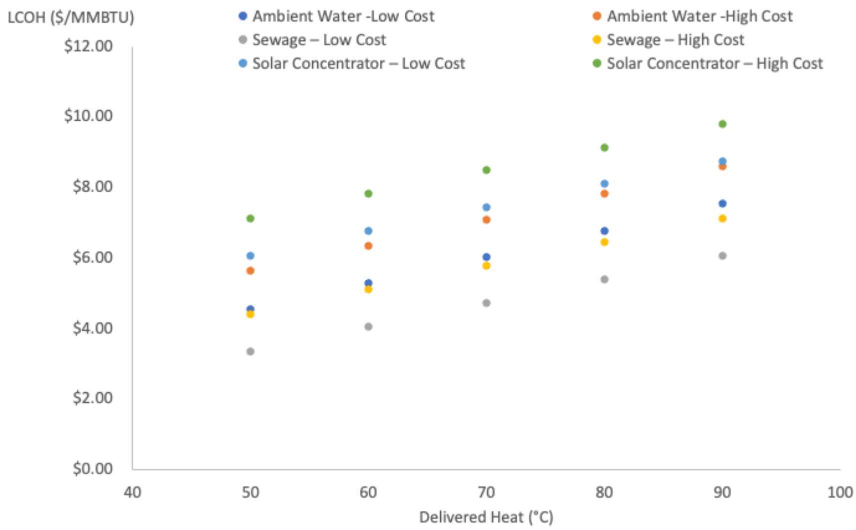

Fig. 1: LCOH for different types of heat pumps and the delivered heat of the scenarios.

3.2. Case Study 2: RTES in Food / Beverage Processing up to 270°C

This case study is designed for medium temperature (~270°C) industrial heat applications for food/beverage processing facilities such as dairies, breweries or distilleries that use steam for their processes. The case study uses an LFC-DSG coupled with PCM-TES and a natural gas boiler back-up system to improve the system's flexibility and CF. Note this is for a greenfield site, and a backup natural gas system therefore would be needed to guarantee meeting the industrial load. The LFC-DSG system is designed for a 1-megawatt thermal (MW_{th}) capacity with a solar multiple of 2 and target steam quality of 0.75 and modelled in SAM (Fig. 2). For this modeling effort, SAM 2020.11.29 has been used (NREL, 2021). The base case for the hybrid system is a solar multiple of 2 (~3,600 m^2 of LFC solar field) and 6 hours of PCM thermal storage. Alternative cases for parametric analysis are adjusted for 6-12 hours of storage with a solar multiple between 1.5 (~2,700 m^2) and 2.5 (~4,500 m^2).

PCMs store energy in the latent heat of the phase change and so are well suited for integration with systems that use steam as the working fluid since both media go through a phase change allowing the temperature profiles to be matched which improves the effectiveness of heat transfer (Sharan et al., 2019) In this case study, sodium formate is selected as the PCM for the TES with 6 hours storage capacity for the base case, due to low-cost ($0.40/kg). Sodium formate has a melting temperature of 258°C, latent heat of 245 kJ/kg, and heat capacity of 1.2 kJ/kg-K (Sharan et al., 2019).

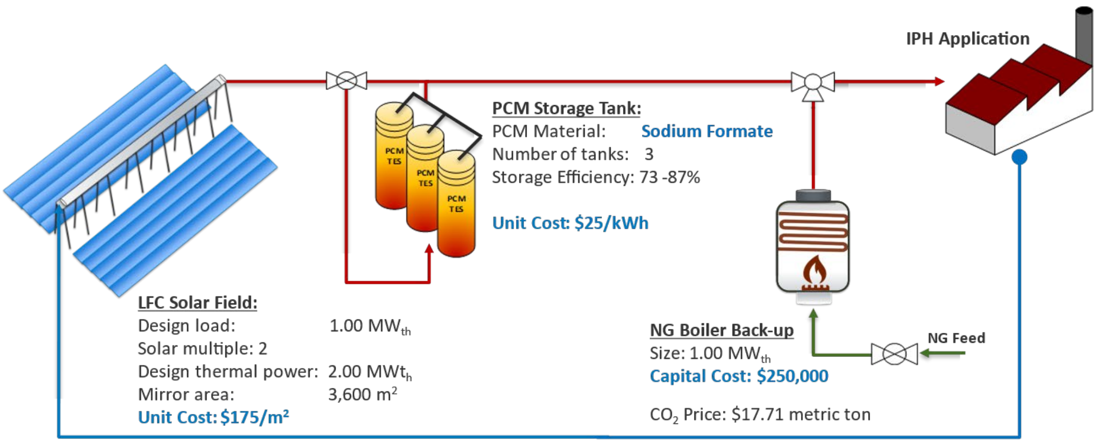

Fig. 2: Schematic for the base case design of the hybrid LFC-DSG system coupled with PCM-TES and back-up NG Boiler

A hybrid system model was developed using SAM hourly outputs of a modelled LFC solar field including thermal power output, average steam quality, outlet temperature, and mass flow. In addition to that the direct normal irradiation (DNI) and other weather conditions are also taken from the weather file. The model can use different collector specifications. In this particular case study, we used the SolAtom® modular LFC optical characterization and incidence angle modifiers (Kraemer, 2020).

Pittsburgh Pennsylvania, Tucson Arizona, and Lancaster California were selected as the test sites which have an average DNI of 4.10 kWh/m^2/day, 7.36 kWh/m^2/day, and 7.93 kWh/m^2/day respectively (NSRDB, 2020). This then allows the North-East of the United States, and the South-West to be represented. As of 2020, the annual average industrial natural gas price estimated by the Energy Information Administration (EIA) was $3.29 per thousand cubic feet (Mcf) or $3.17 per MMBTU (EIA, 2021b, 2021c). The lowest annual average natural gas price observed in the United States since 1995 was $2.71 per Mcf or $2.61 per MMBTU (EIA, 2021d). Tab. 4 shows the 2020 average industrial natural gas prices and conversions used in the analysis.

Tab. 4: 2020 average Industrial Natural Gas Prices and conversions for U.S., Arizona, California, and Pennsylvania (EIA, 2021b, 2021c)

	2020 Natural Gas Industrial Price ($/Mcf)	**2020 Natural Gas Price ($/MMBTU)**	**2020 Natural Gas Price ($/kWh$_{th}$)**
United States Average	3.29	3.17	0.011
Arizona	3.98	3.84	0.013
California	7.64	7.37	0.025
Pennsylvania	7.91	7.63	0.026

The heat load profile is set as 1 MW$_{th}$ constant between 8am and 10pm, 0.2 MW$_{th}$ constant between 12pm and 6am, ramping up to 1 MW$_{th}$ between 6am and 8am in two steps (0.47 – 0.75 MW$_{th}$) and fading down to 0.2 MW$_{th}$ in two steps (0.47 – 0.75 MW$_{th}$). This is similar to food processing/dairy sites in the United States (NAICS, 2021). For modeling simplicity, an 8-week test model has been defined with 2 weeks in winter, 2 weeks in spring, 2 weeks in summer and 2 weeks in fall which sums up to 1,345 hours of thermal power profile.

The model is designed to optimize the solar field size and the thermal storage capacity to meet a competitive LCOH. The summary of financial key inputs including the LFC system unit cost, PCM TES system unit cost, NG boiler total cost, carbon price, system lifetime and discount rate (10% for high-risk, 8% for moderate-risk, 7% and less for low-risk technologies) for the LCOH calculations are given in Tab. 5. The scenarios have been tested with and without the CO_2 cost. It is assumed that the same CO_2 price in California can be applied to Pennsylvania and Arizona, even though at present these two states do not currently have a carbon price.

An annual simulation model has been developed by using a multiplier of 6.5, though the 8-week model. Solar heat generation, thermal storage, curtailed solar energy, heat from natural gas and heat load profiles for representative two-week timeline (one week from winter and one week summer) are shown for California (Fig. 3), Arizona (Fig. 4) and Pennsylvania (Fig. 5).

Tab. 5: Summary of key inputs for the LCOH calculations (*Minimum price available at auction per ton of CO_2 emissions in December 2020, in California's Cap-And-Trade Program (ICAP, 2021), **Conservative discount rate for a high-risk technology)

LFC System Cost ($/m^2)	PCM System Cost ($/kWh$_{th}$)	CO_2 Price* ($/metric ton)	1 MW$_{th}$ NG Boiler Cost ($)	O&M (% of CAPEX)	System Lifetime (years)	Discount Rate** (%)
175	25	17.71	$250,000	5%	25	10%

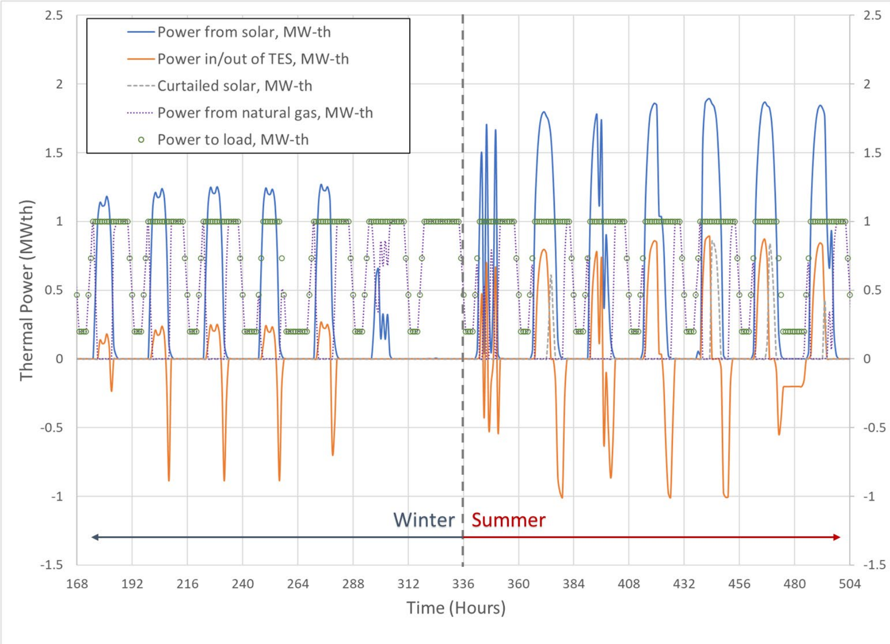

Fig. 3: Solar heat generation, thermal storage, curtailed solar energy, heat from natural gas and heat load profiles for representative two-week timeline (one week from winter starting from 168th hour and one week summer starting from 336th hour) in California

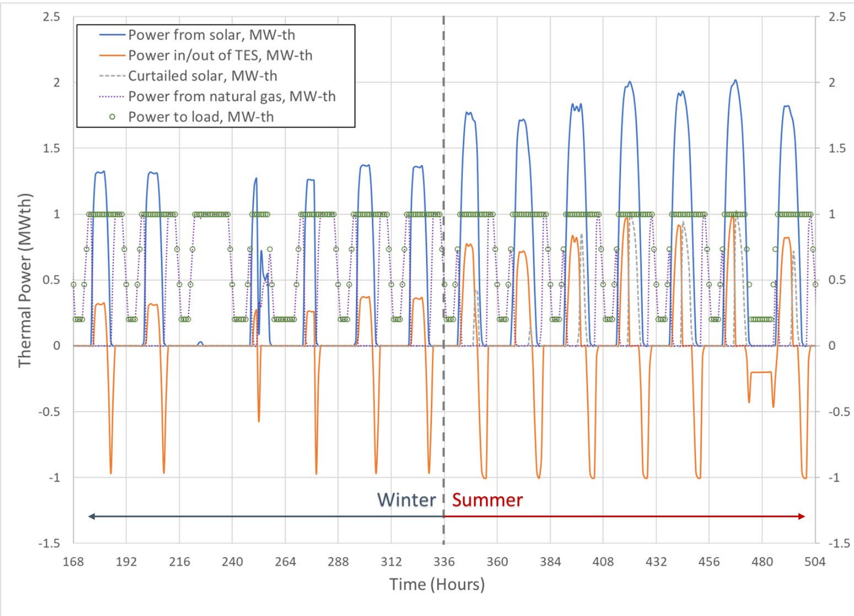

Fig. 4: Solar heat generation, thermal storage, curtailed solar energy, heat from natural gas and heat load profiles for representative two-week timeline (one week from winter starting from 168th hour and one week summer starting from 336th hour) in Arizona

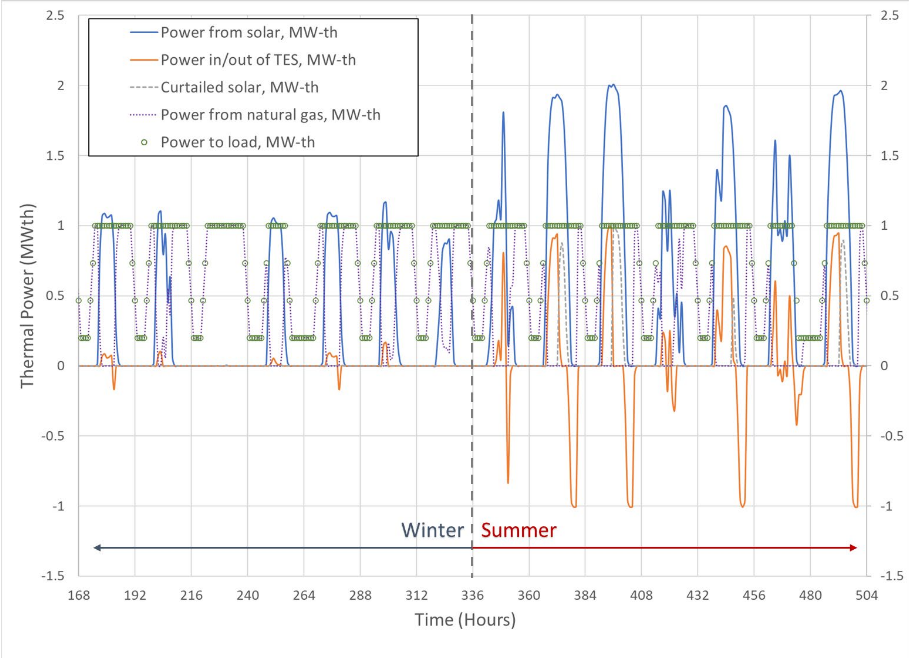

Fig. 5: Solar heat generation, thermal storage, curtailed solar energy, heat from natural gas and heat load for representative two-week timeline (one week from winter starting from 168th hour and one week summer starting from 336th hour) in Pennsylvania.

Results show that in the base scenario, ~3,600 m^2 of LFC solar field and 6 hours of PCM TES can provide up to 51% of the thermal load by solar energy, which leads to a significant reduction in natural gas consumption (Tab. 6). This results in a LCOH of \$0.049/kWh$_{th}$ (\$14.26/MMBTU) for Pennsylvania, \$0.034/kWh$_{th}$ (\$9.85/MMBTU) for Arizona, and \$0.041/kWh$_{th}$ (\$11.98/MMBTU) for California (Fig. 6). The solar energy share of the total thermal load can be up to ~65% for a ~4,500 m^2 LFC solar field with 12 hours of PCM thermal storage. However, as seen in Fig. 6, at the present cost of the DSG-LFC and PCM TES system it is currently not yet fully competitive with the natural gas only system which has a LCOH of \$0.032/kWh$_{th}$ (\$9.43 /MMBTU) in Arizona. This is mostly due to low natural gas price in 2020 and O&M cost. The annual average natural gas price observed in the United States was not always as low as 2020, the highest natural gas price was observed in 2008 as \$9.65 per Mcf or \$9.30 per MMBTU (EIA, 2021d). Thermal storage efficiency is the ratio of the energy provided to the energy needed to charge the storage system, which accounts for the energy loss during the storage period and the charging/discharging cycle. Storage efficiency can be as high as 84.70% for 6 hours of thermal storage in California.

Tab. 6: Summary of results for the hybrid system design in Pennsylvania, California, and Arizona (Conversion Factors: 1 cubic ft of natural gas = 1,030 Btu, 1 Btu = 0.000293071 kWh, *Base Case)

State	Solar Field (m^2)	Storage Time (hrs)	Solar Share in Total Load (%)	Curtailed Solar Energy (%)	Storage Efficiency (%)	LCOH with CO_2 adder \$/kWh$_{th}$	LCOH without CO_2 adder \$/MMBTU	LCOH with CO_2 adder \$/kWh$_{th}$	LCOH without CO_2 adder \$/MMBTU
PA	2,890	6	26.01%	2.02%	63.41%	0.047	13.89	0.045	13.07
PA*	3,973	6	34.33%	4.57%	78.79%	0.049	14.26	0.046	13.54
PA	4,966	12	41.32%	0.32%	60.57%	0.051	14.95	0.052	15.17
CA	2,700	6	40.33%	1.78%	89.21%	0.041	11.92	0.038	11.26
CA*	3,600	6	50.98%	6.46%	84.70%	0.041	11.98	0.039	11.44
CA	4,501	12	63.32%	0.61%	72.76%	0.042	12.23	0.043	12.51
AZ	2,667	6	39.90%	1.68%	64.19%	0.032	9.43	0.030	8.68
AZ*	3,556	6	51.69%	6.85%	87.19%	0.034	9.85	0.032	9.41
AZ	4,455	12	64.42%	3.21%	79.32%	0.035	10.40	0.037	10.87

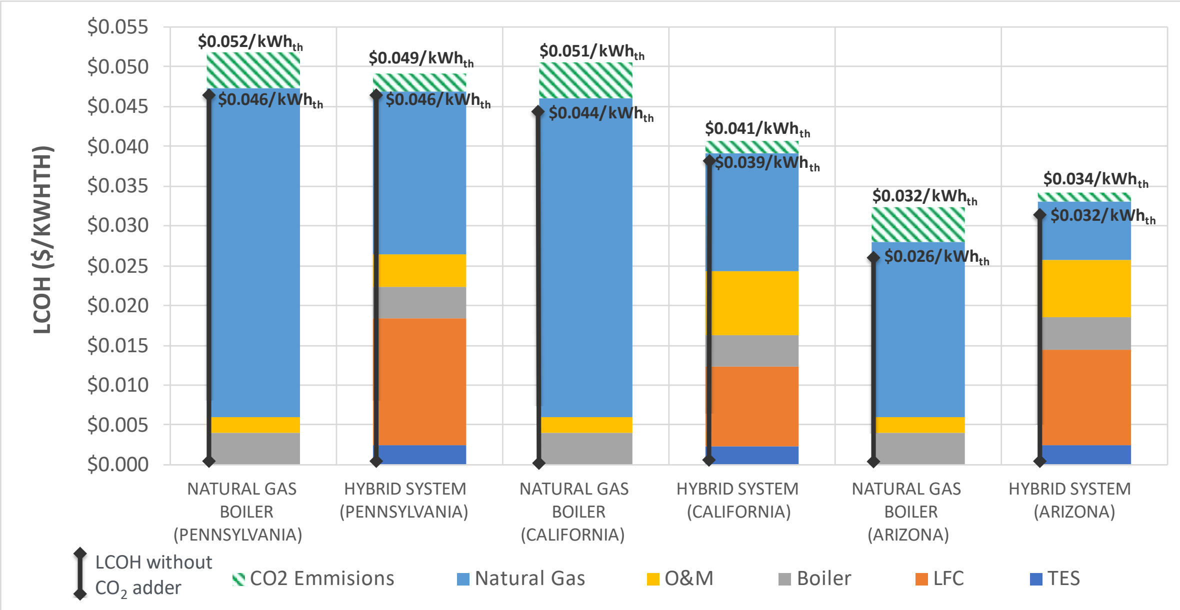

Fig. 6: Comparison of system LCOH for the natural gas boiler and the hybrid system of LFC-DSG with PCM TES and natural gas boiler back-up scenario in Pennsylvania, California, and Arizona (Base Case: solar multiple of 2, and 6 hours of thermal storage).

The capital cost of the hybrid system is estimated between $1,022/kW and $1,095/kW, which includes the additional $250/kW NG boiler back-up system cost. This hybrid system can also provide up to 4,096 MWh_{th} natural gas offset which is equivalent to 757 metric tons of CO_2 emissions in Arizona, 4,009 MWh_{th} (741 tons of CO_2) in California, and 2,720 MWh_{th} (508 tons of CO_2) in Pennsylvania.

A sensitivity analysis is conducted to determine the break-even point for the hybrid system to have the equivalent LCOH as the standalone NG boiler system by changing the LFC cost and the natural gas price while keeping all other parameters constant. The LFC and NG price break-even points for the hybrid system modelled in Pennsylvania, California, and Arizona with CO_2 adder can be seen in Fig. 7, and Fig. 8 respectively.

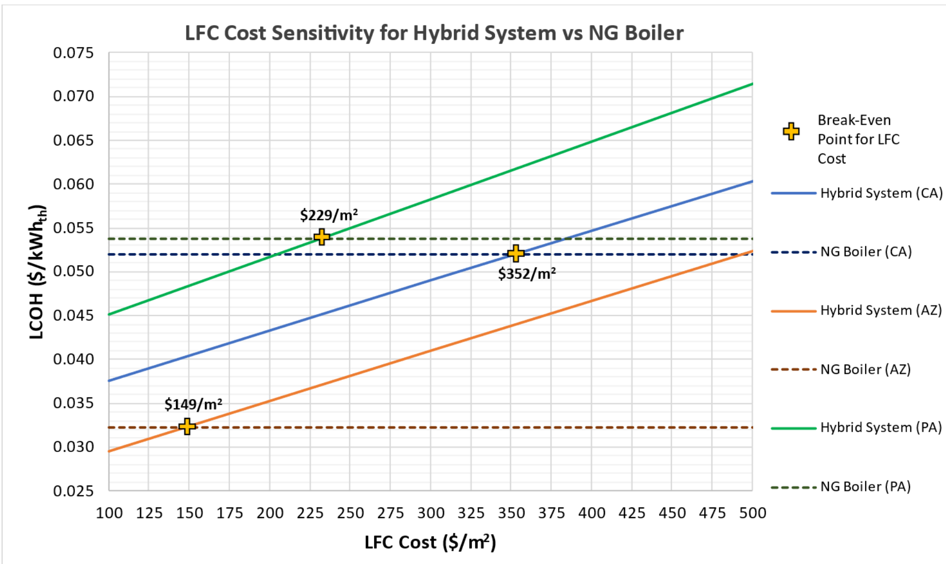

Fig. 7: LFC cost sensitivity and break-even point for hybrid system in Pennsylvania, California, and Arizona with CO_2 adder.

The break-even point for LCOH can be achieved if the LFC unit cost is equal to or lower than the represented values in Tab. 7. Similarly, the break-even point for LCOH can be achieved if the NG price is equal to or greater than the represented values in Tab. 7. The hybrid system can be feasible for an LFC system cheaper than the break-even price in Pennsylvania, Arizona, and California under the presented solar radiation, natural gas price, and the CO_2 credit.

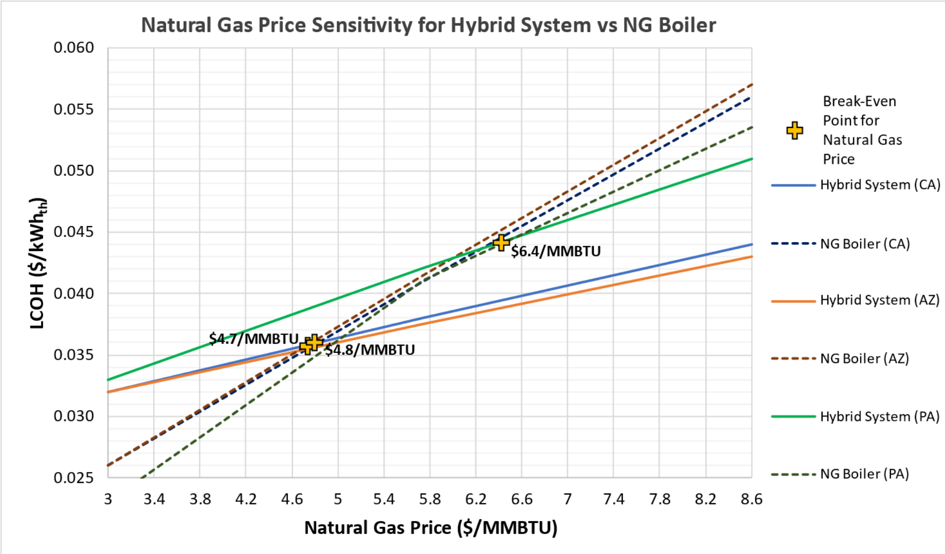

Fig. 8: Natural gas price sensitivity break-even point for hybrid system in Pennsylvania, California, and Arizona with CO_2 adder.

Tab. 7: Break-even LFC and NG prices for the hybrid system to have the equivalent LCOH as the standalone NG boiler system with and without CO_2 adder.

	Break-even LFC Cost (With CO_2 adder) $/m^2	Break-even LFC Cost (Without CO_2 adder) $/m^2	Break-even NG Price (With CO_2 adder) $/MMBTU	Break-even NG Price (Without CO_2 adder) $/MMBTU
PA	229	167	6.4	7.6
CA	352	267	4.8	5.9
AZ	149	76	4.7	5.8

4. Discussion

From the heat pump model, it can be seen there is a balance between heat pump performance and capital costs. Although the heat pump that is hybridized with solar energy has the best COP of the group, the added costs of the solar collector increase the LCOH above poorer performing heat pumps. In the cases examined, the most economically competitive heat pump was the heat pump delivering 50°C heat with sewage as a heat source. For this work, it was assumed the sewage connection infrastructure was negligible which would not be the case, but these findings are in line with many heat pumps systems that are tied to sewage as a waste heat source. Overall, the cases show that there is some value to using upgraded waste heat temperatures to boost heat pump performance depending on the interconnecting infrastructure, which will require future research to better quantify.

Maximizing the share of solar energy in the LFC-DSG hybrid system design is not the most feasible solution for the industrial application due to high resulting LCOH. Optimizing the hybrid system with the best mix of natural gas and solar (i.e., 50-50) would give a competitive LCOH, thus the hybrid system could be feasible with respect to a standalone NG boiler system or a retrofit application. To make this system more competitive with natural gas only boiler systems, a carbon price of $17.71/metric ton is added to the LCOH calculation, which is the minimum price at auction per ton of CO_2 emissions in California's Cap-And-Trade Program (ICAP, 2021). At present there is no carbon price system or mechanism for industry in the U.S. In addition to that, the natural gas price in the United States was not always as low as 2020. For instance, in 2008, it was three times more expensive than the natural gas price for industrial consumers in 2020 (EIA, 2021d). Further investigation will look at the increase in the natural gas price which would lead to an improvement in the break-even LCOH price of the hybrid system.

The LCOH results for Arizona show that at the present cost of the DSG-LFC and PCM TES system it is currently not yet fully competitive with the natural gas only system without the CO_2 cost adder. For Arizona, LFC systems should be installed up to $149/m^2 to be competitive with the CO_2 cost adder. Without the adder, the unit cost should be as low as $76/m^2. However, the hybrid system LCOH in California could be competitive and even better than standalone NG boiler systems due to high natural gas price. For California, LFC systems installed up to $267/m^2 can still be competitive without the CO_2 cost adder. With the CO_2 cost adder, the unit cost can be as high as $352/m^2. In addition to that, the hybrid system LCOH in Pennsylvania could be at break-even point compared to standalone NG boiler systems without the CO_2 cost adder. For Pennsylvania, LFC systems can be installed up to $167/m^2 and still be competitive without the CO_2 adder. With the CO_2 cost adder, the unit cost can be up to $229/m^2. Since the LCOH results are highly sensitive to energy prices, the volatility in natural gas prices can affect the feasibility of the RTES projects regardless of the renewable resource availability. As an example, in Europe, such hybrid systems may be a low-cost option for a variety of cases due to higher CO_2 prices and higher natural gas prices.

5. Future work

The work will continue to improve the LFC-DSG model by optimizing the system configuration and dispatch model. In addition to optimization, a series of sensitivity analyses are done including location, DNI, LFC solar field size, LFC installed cost, PCM thermal storage capacity, and natural gas boiler back-up size. The supporting infrastructure to increase adoption of heat pumps will be an important area for future research. Hybridization options for the HTHPs coupled with FPCs will be investigated. The capital cost considering economies of scale and learning in manufacturing, O&M cost and potential reductions, and system lifetime improvements will be investigated. Part of this future work will include a methodology to estimate the trade-off in capital cost investments vs. heat pump performance. As was seen in this study, upgrades to the waste heat stream can be cost-competitive (such as in the case of high-cost sewage vs. low-cost ambient to compensate for potential coupling costs), but up to certain costs can have diminishing returns depending on heat pump performance. The revenue creation through industrial heat generation, which will lead to an annual cash flow is likely to be investigated, and the payback period and internal rate of return for both greenfield hybrid system and retrofit applications would be calculated.

6. Acknowledgements

This work was authored by the National Renewable Energy Laboratory (NREL), operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. NREL does not endorse the companies specified in this paper, and any mention is strictly for research purposes only. Funding provided by the U.S. DOE of Energy Efficiency and Renewable Energy's Office of Strategic Programs and Advanced Manufacturing Office. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

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