Renewable Thermal Energy Systems: Modeling Developments and Future Directions (Report 3)

Sertaç Akar, Parthiv Kurup, Matthew Boyd,
Elizabeth Wachs, and Colin McMillan

National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
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Preface

This report is Part 3 of a three-report series that evaluates means to provide heat for industry and buildings via current and prospective renewable thermal energy system (RTES) technologies. The RTES project has undertaken initial research focused on technologies that could be suited for industrial process heat applications at different temperature levels, and, where possible, gathered performance and cost data for these technologies. This project did not directly evaluate RTES for distributed residential or commercial applications, and it did not include documented cases or modeling of RTES using geothermal, biomass, waste heat, renewable fuels, or hydrogen production.

The three technical reports are summarized as follows:

- *Renewable Thermal Energy Systems: Characterization of the Most Important Thermal Energy Applications in Buildings and Industry (Report 1)*: summary of thermal demands of U.S. industry and buildings, and relevant hybrid RTES configurations. Available at: https://www.nrel.gov/docs/fy23osti/83019.pdf.
- *Renewable Thermal Energy Systems: Systemic Challenges and Transformational Policies (Report 2)*: discussion of socio-technical characteristics of RTES, innovation challenges, and supporting policies. Available at: https://www.nrel.gov/docs/fy23osti/83020.pdf.
- ***Renewable Thermal Energy Systems: Modeling Developments and Future Directions (Report 3)*, this report: energy yield and performance modeling of RTES, techno-economic analysis via case studies, and proposed development of a user decision support tool.**

Acknowledgments

NREL does not endorse the companies specified in this report, and any mention is strictly for research purposes only.

List of Acronyms

Btu	British thermal unit
CO_2	carbon dioxide
CSP	concentrating solar power
DNI	direct normal irradiance
DOE	U.S. Department of Energy
DST	decision support tool
DSG	direct steam generation
EU	European Union
EIA	U.S. Energy Information Administration
FPC	flat plate collector
HTF	heat transfer fluid
IEA	International Energy Agency
IPH	industrial process heat
kWh	kilowatt-hour
kWh_{th}	kilowatt-hour thermal
kW_{th}	kilowatt thermal
LCOH	levelized cost of heat
LFC	linear Fresnel collector
MECS	Manufacturing Energy Consumption Survey
MWh	megawatt-hour
MWh_{th}	megawatt-hour thermal
MW_{th}	megawatt thermal
Mcf	thousand cubic feet
MMBtu	million BTU
NREL	National Renewable Energy Laboratory
NAICS	North American Industry Classification System
PCM	phase change material
PTC	parabolic trough collector
PV	photovoltaics
RTES	renewable thermal energy systems
SAM	System Advisor Model
SIPH	solar industrial process heat
TES	thermal energy storage
TMY	typical meteorological year
U.S.	United States

Executive Summary

Increasing global energy consumption, increasing population, expansion of all types of produced goods and food, and the climate crisis have necessitated increasing the share of renewable heat in industry, which is vital for both decarbonization. The aim of this work is to evaluate current and prospective renewable heat technologies in stand-alone and hybrid configurations, together with their technical capabilities, performance, and cost. Renewable thermal energy systems (RTES) for buildings and industrial applications have been investigated using techno-economic analysis to determine their potential economic and environmental impacts.

A key hypothesis of the project is to address the issue of few hybrid RTESs being in operation by providing examples or modeling efforts of hybrid RTESs where possible. The work has also highlighted conditions where an RTES could be competitive in the United States. Research has found that stand-alone RTESs can readily provide heat up to a specified temperature level but typically are unable to reach higher temperature levels. Nearly two-thirds of the industrial thermal demand in 2014 in the United States was less than 300°C (McMillan et al. 2021a). Temperature ranges of U.S. manufacturing industries and cumulative energy consumed in 2014 (McMillan 2019) ideally suits to solar thermal and other RTES configurations. The initial framework has evolved over time to consider the selection of RTES technologies and heat provision that hybrid systems can step up to 300°C temperature level for industrial applications.

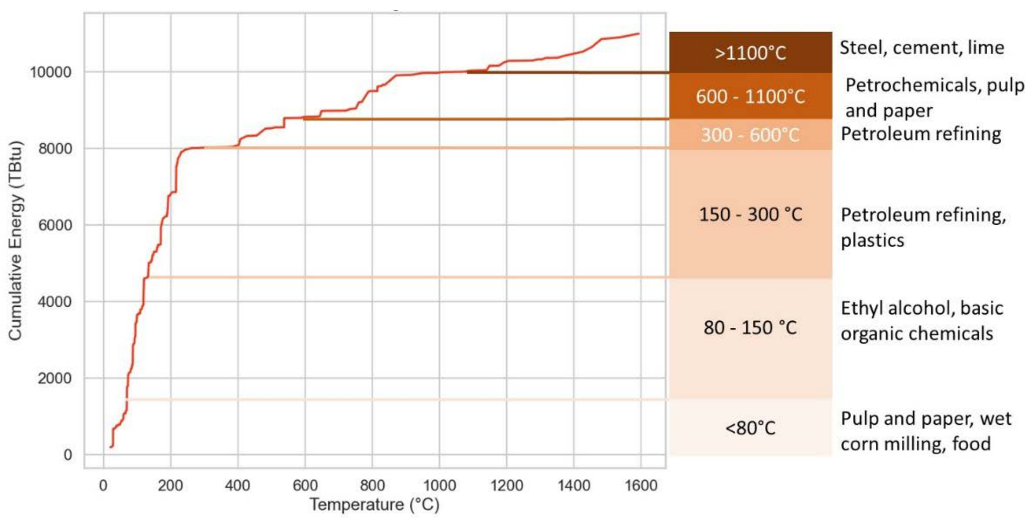

Figure ES- 1. Temperature ranges of U.S. manufacturing industries and cumulative energy consumed in 2014 (Data from McMillan [2019])

In this context, two hybrid RTES pilot simulation models have been developed as test cases. The first is a hybrid system that couples flat plate collectors with parabolic trough collectors and thermal energy storage (TES). This case was selected to validate with a real hybrid solar district heating case study from Taars, Denmark. The total annual thermal generation of the system modeled in in the System Advisor Model (6,104 MWh) was very close to today's operational system (6.083 MWh) in Denmark.

The second case was direct steam generation via linear Fresnel collectors coupled with phase change material (PCM) TES, which includes a natural gas boiler backup system for times when the solar field and PCM-TES are unable to provide sufficient energy. This model was selected to show how to optimize the share of solar energy in the energy mix of the hybrid system design for the industrial application resulting in a competitive levelized cost of heat for current market conditions

This report also highlights the basis and vision for a future expanded decision support tool that allows the consideration of RTES/hybrids for industrial applications. A decision support tool that evaluates multiple hybrid RTES configurations to optimize for the lowest levelized cost of heat has not previously been developed as an open-source platform and would be an important contribution for simulating a variety of heat generation options. Some of the main outcomes from this work include initial technical feasibility and understanding the barriers and opportunities for RTES in stand-alone or hybrid configurations coupled with fossil or renewable fuels for buildings and industrial process heat applications. The outcome of this work is to inform the vision, design, and development of strategic research and development pathways, including a future decision support tool for RTES that could be used in industrial applications. Furthermore, system design, development, and deployment of RTES will require capable decision support tools that can incorporate these many factors.

The complexity of process heating systems, which frequently involve multiple layers of integration as well as myriad competing options on the RTES side, create a murky decision space. If the tool suggests or a user selects an inappropriate RTES option, options that are feasible, reliable, and cost-competitive may be excluded from consideration. This can happen when a system is designed only for the top range of heating needs, for example, but it can also happen if other criteria are ignored.

A decision support tool specifically designed for industrial process heat can draw on much of the technical backbone already present in parabolic trough modules that exist in System Advisor Model version 2020.2.29 r3 (Patch 3), SSC 242 which is released on July 31, 2020 (NREL 2020). But its development requires further input from industry and community-based organizations to understand other criteria that may be necessary for wider adoption of RTES. A decision support tool geared toward industrial process heat may be able to aid in the establishment of standard pathways for hybrid RTES in industry while providing a repository for industry data related to these implementations and a user community.

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1 Introduction

As the world looks to decrease greenhouse gas emissions, industrial decarbonization through renewable alternatives is becoming an increasingly important topic. The heat for industry accounts for 34% of total industry energy need, but less than 5% of this energy need is met by renewables (Kumar, Hasanuzzaman, and Rahim 2019). The aim of this work is to evaluate current and prospective renewable heat technologies in stand-alone and hybrid configurations via modeling, together with their technical capabilities, performance, and cost. The initial framework that has been developed by the National Renewable Energy Laboratory (NREL) (Akar, Kurup, McTigue, and Boyd 2021) has evolved over time to consider the selection of renewable thermal energy system (RTES) hybrid technologies that can step up temperature levels as needed for industrial applications.

The remaining portion of Section 1 considers the background and framework conceptualized for RTES from a technology perspective. Section 2 provides a brief literature survey on the current use of renewables for industrial process heat (IPH), Section 3 details the hybrid models developed in this work, and Section 4 highlights the hybrid RTES model validation against an operational solar district heating site in Denmark. Section 5 highlights the results from the second hybrid RTES model for a direct steam generation linear Fresnel collector coupled with phase change storage. Section 6 continues the analysis and undertakes techno-economic analysis. Section 7 follows with near-term solutions where natural gas can potentially be reduced in the provision of IPH at selected temperatures. Section 8 highlights an initial vision for a future decision support tool focused on industrial application. Finally, Section 9 presents possible future actions.

1.1 Background

The goal of this work on renewable heat via RTES for industry (both in stand-alone and hybrid configurations) is to evaluate current and prospective technologies for:

- Technical capabilities, performance, and cost
- RTES system integration into buildings and industrial applications
- RTES potential economic and environmental impacts via techno-economic analysis
- Strategy and focus for research and development pathways.

This project has undertaken initial research of technologies that could be suited for IPH applications at different temperature levels and where possible gathered performance and costs of these technologies.

Techno-economic analysis for this project is possible and is highlighted in case studies where sufficient information exists to couple both the modeled energy yield and performance of the RTES and the estimated costs of installation based on the location.

With few deployed RTES (either in stand-alone or hybrid configuration) examples for industrial applications in the United States, this project begins addressing key challenges faced by end users. This report neither covers RTES for distributed residential or commercial applications nor considers biomass, renewable fuels like renewable natural gas, or hydrogen production. Biomass could also be used in an RTES and is used by many industries to supplement or replace fuels like natural gas (REN21 2021). Key challenges for developing and using RTES for IPH and district heating include but are not limited to (Akar, Kurup, Belding, et al. 2021; Akar, Kurup, McTigue, et al. 2021; McMillan et al. 2021):

- The low price of U.S. industrial natural gas relative to the world
- The diversity of RTES designs that can potentially meet the quantity, quality, and temperature needed by the IPH load
- The diversity of industrial processes for the technologies to be applied to
- The varied operating temperatures and thermal power requirements
- The operational constraints (schedule and variable demand) of the process heat loads
- The locational and spatial constraints (e.g., within existing plant configurations and footprints) available for a technology to provide heat alongside the existing fuel system
- The capital (particularly for brownfield industries producing low-cost commodity materials with very thin margins) and operating costs of the new system. This is associated with the business model the technology developer can utilize.

Through research over time, an initial framework has been developed that considers RTES selection and heat provision (at the overall site level), and how hybrids can step up the temperature levels (Akar, Kurup, McTigue, and Boyd 2021).

1.2 Hybrid RTES

A key hypothesis of the project is that coupling RTES solutions together (i.e., into hybrid RTES solutions) can be both economically and energetically viable. This project has addressed the issue of few hybrid RTESs being in operation by providing examples or modeling efforts of hybrid RTESs where possible. The work has also highlighted conditions where an RTES could be competitive in the United States. Research has found that stand-alone RTESs (e.g., solar water heating via flat plate collectors [FPCs]), can readily provide heat up to a specified temperature level (McMillan et al. 2021) but typically are unable to reach higher temperature levels. Nearly two-thirds of the industrial thermal demand in 2014 in the United States (McMillan et al. 2021) was less than 300°C, as shown in Figure 1. This temperature range is ideally suited to solar thermal and other RTES configurations.

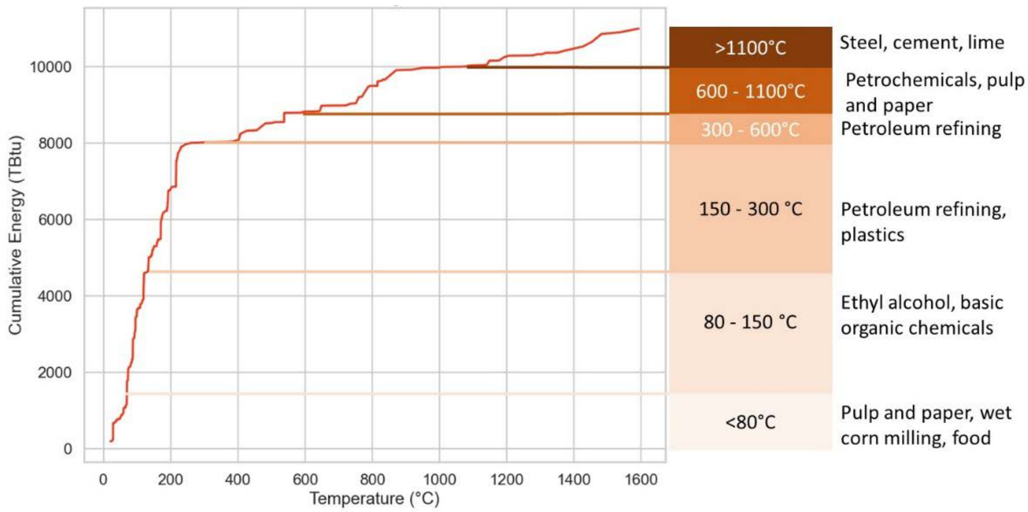

Figure 1. Temperature ranges of U.S. manufacturing industries and cumulative energy consumed in 2014 (Data from McMillan [2019])

The simplified framework shown in Figure 2 represents a broader set of systems that can be hybridized with the conventional options. Concentrating solar thermal, photovoltaics (PV), and grid-coupled heat pumps can be considered stand-alone RTES configurations to provide temperatures at different levels if they are backed up with a thermal energy storage (TES) or some other source of energy to handle solar variability. Such systems can readily provide low- to medium-temperature heat less than 300°C, but costs still need to decrease to be competitive with natural gas, which is a factor for increasing deployment. The hybrid approach of coupling generation technologies could help step up the temperature scale at lower cost, highlighted in Figure 1, while reducing the fuel needs.

A hybrid approach could utilize existing well-established technologies together (e.g., FPCs and parabolic trough collectors [PTCs]) in a combined system. An example of a real hybrid RTES is the Taars FPC-PTC site in Denmark where the two technologies augment an existing natural-gas-fired district heating system (Aalborg CSP 2015).

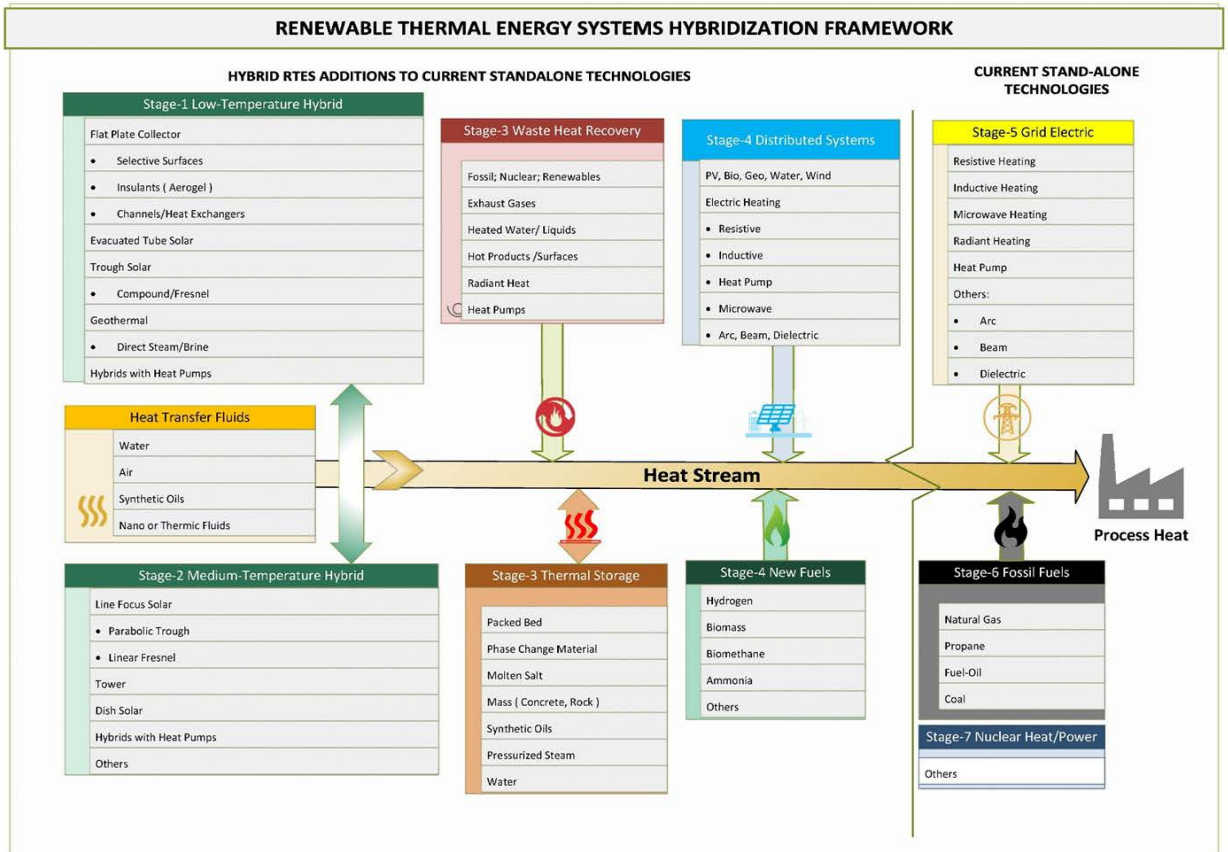

Figure 2. Simplified RTES hybridization framework showing possible combinations of renewable and other sources in stages to raise the temperature of the heat stream to meet the IPH demands

A sample list of the solar thermal and other thermal technologies that are suitable for hybridized solutions with respect to their temperature scales are outlined in Figure 3. These technologies include heat sources such as PTCs, linear Fresnel collectors (LFCs), and power towers to receive, move, store, and valorize heat. We use optimization techniques to determine which combinations would be most suitable for a given industrial process in a specific location. Additionally, it is also possible to contemplate the hybridization of solar-thermal-based configurations with existing fossil-fired systems as retrofits or greenfield applications. These hybrid systems could provide an option that would be less disruptive to existing operations while also providing fossil-offset benefits, rather than a full fuel replacement.

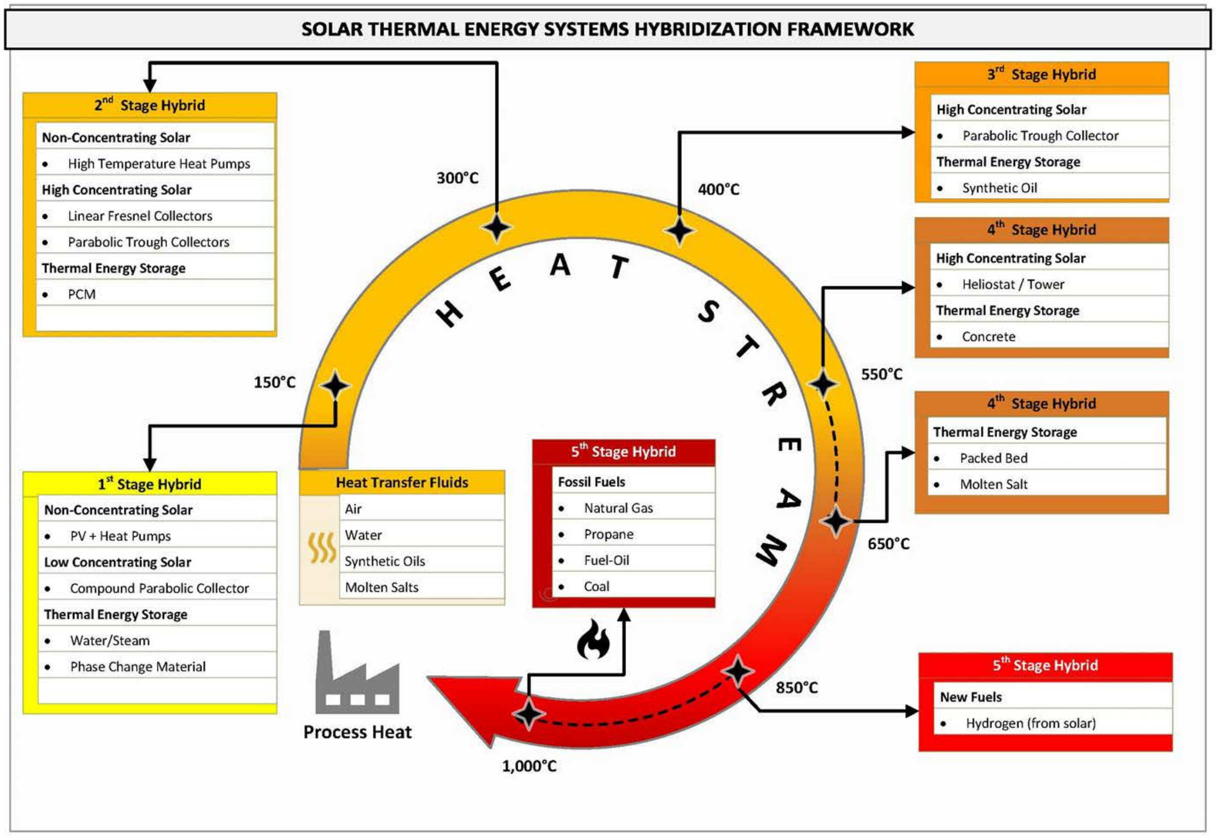

Figure 3. Renewable thermal technologies that are suitable for hybridized solutions with respect to their temperature scales.

(Systems can be hybridized with the broader set of conventional options shown in Figure 2 by using technologies within the same stage or their adjacent stages.)

1.3 Need for RTES Modeling Improvements

To better understand commercially viable near-term hybrid RTES solutions, specific hybrid RTES generation code modules or tools were built based on this framework (Akar, Kurup, McTigue, and Boyd 2021), and initial results were highlighted in a following paper (Kurup et al. 2020). 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. To improve the research and analysis in this project, we developed RTES models and selected industries that are similar to real deployed examples of RTES for IPH application. For example, dairy and food processing sites in the United States have begun demonstrating concentrating solar thermal systems where hot water and steam are utilized (Skyven Technologies 2020; 2019). An accompanying report (Kurup, McMillan, and Akar 2023) highlights the heat use in industry and buildings.

To address these disparate challenges, case studies were selected and evaluated in this project to strategically cover these key factors, such as steps up to the IPH temperatures required. As part of this project, the NREL team collaborated with developers to consider potential net economic and environmental impacts of certain case studies. The results from the case studies are presented in2021 SolarPACES conference (Akar, Kurup, Belding, et al. 2021). The case studies in this report summarize those results and add further validations and sensitivities.

Some of the main outcomes from this work include initial technical feasibility and understanding the barriers and opportunities for RTES in stand-alone or hybrid configurations coupled with fossil or renewable fuels for buildings and IPH applications. The outcome of this work is to inform the vision, design, and development of strategic research and development pathways, including a future decision support tool (DST) for RTES that could be used in industrial applications. Furthermore, system design, development, and deployment of RTES will require capable DSTs that can incorporate these many factors.

2 Brief Literature Survey on Use of Renewables for Industrial Process Heat

Industrial process heating technologies can be divided into fuel-based, steam-based, and electric (Schoeneberger et al. 2020). Biomass is the largest source of renewable fuels and represents a heterogeneous mixture, from agricultural wastes to black liquor. Hydrogen and ammonia can be manufactured via electrolysis powered by renewables, thereby potentially substituting for fossil fuels, although requiring different equipment for their combustion, storage, and transport. Still, the low power-to-power efficiency of the green synthetic fuels means that it is much less efficient to use them for process heat or power when electricity or storage can be used (Philibert 2017).

Steam can be produced by hybrid RTES, variously combining non-tracking systems such as FPCs (with or without vacuum insulation—the insulation allows a higher temperature range; without the insulation FPCs are more suitable for preheating due to lower temperature ranges), evacuated tube collectors, and compound parabolic collectors as well as concentrating solar thermal systems, including PTCs (most common), LFCs, power tower, and dish Stirling. Electrification is one of the major strategies for increasing the proportion of energy met by renewables (Philibert 2017), and renewable technologies for electric heating include PV-resistance, PV-induction, and heat pumps (Schoeneberger et al. 2020). Industries are also working to change industry-specific processes to avoid emissions—for example, multiple pathways are being developed for steel production, such as electrowinning (Serna Ruiz 2020), direct reduction of iron (Hybrit undated), and molten electrolysis (Boston Metal 2019). Such processes change the parameters of necessary process heating, such as converting from a high-temperature process to a low- or medium-temperature one or removing the direct combustion step in favor of an electric process.

2.1 United States

A recent analysis (McMillan et al. 2021) reviewed technical opportunities for solar IPH (SIPH) in the United States at the county level with hourly simulation and consideration of land resource (not including facility-level operations and land availability) for deployment of three solar thermal and four PV-based heat technologies. The study showed that global statistics mask large variations between geographic regions: U.S. industrial energy demand was highest (~77%) for temperatures below 500°C, whereas most demand (~66%) in the European Union (EU) was for temperatures higher than 500°C. The difference is due to the relative importance of chemicals and pulp and paper sectors (U.S.) versus cement and iron and steel (EU) as users of process heat (McMillan et al. 2021). Petroleum refining was the U.S. industry with the largest demand for IPH (McMillan et al. 2021). Close to 60% of U.S. petroleum refining is in Texas (32%), Louisiana (17%), and California (10%) (EIA 2021c).

Sizing for winter or summer specifications made a large difference in the total demand that could be met by SIPH; winter sizing allowed more heating need to be met but required more space (McMillan et al. 2021). Storage was important in enabling SIPH to meet a higher level of demand. Some takeaways from the study were that temporal load matching provides a greater barrier than temperature for finding SIPH solutions, and that parabolic trough with storage has the greatest technical potential to meet IPH needs, followed by PTC alone, then linear Fresnel (all assuming summer peak demand sizing) (McMillan et al. 2021). Challenges include a mismatch between available solar resource and demand, land use needs, cost, process disruption, capital intensity of existing equipment with long associated payback period, concerns about downtime during installation, complexity of available hybrid systems, and technological risk, particularly due to lack of familiarity, domestic expertise, and successful demonstration projects. Beyond the technical potential for SIPH, McMillan et al. and others have noted other challenges to the adoption of the technologies, which can be problematic at the installation level, firm level, or system level. The second RTES report, *Renewable Thermal Energy Systems: Systemic Challenges and Transformational Policies*, frames the challenges for RTES with a much broader perspective (McMillan et al. 2023).

Another study examined process heat needs based on reporting to the greenhouse gas reporting program, which provides a publicly available data source that can be leveraged to estimate industrial heat demand (McMillan et al. 2016; McMillan and Narwade 2018; McMillan and Ruth 2019). This allowed a detailed study of heat demand for industries, including petroleum refining, iron and steel mills, pulp and paper, chemical manufacturing, food manufacturing, wet corn milling, lime manufacturing, and potash, soda, and borate mineral mining, and the suitability of technologies including SIPH, small modular reactors (nuclear), and geothermal energy to meet these various process heating demands. They found that SIPH and small modular reactors could supply the heat needed to petroleum refineries, chemical manufacturing, and potash, soda, and borate mining, whereas geothermal was most suitable for wet corn milling (McMillan et al. 2016).

A previous study found that major industries in California specifically could meet their process heat needs from concentrating solar power (CSP) (Kurup and Turchi 2015) based on state-level available solar resource and potential demand for industrial process heat. In that work, the chemicals industry had the largest demand for IPH (based on 2010 Manufacturing Energy Consumption Survey [MECS] data and 78% of the sectoral IPH demand was estimated to be less than or equal to 260°C [Kurup and Turchi 2015b]).

2.2 International

The opportunity space for SIPH was reviewed by Farjana et al. (2018), who suggest integration of SIPH via:

1. Preheating of working fluid
2. Steam distribution
3. Direct coupling of SIPH to the process.

They also suggest looking at temperatures of the processes themselves rather than of the working fluid to avoid overstating the true heating need to be met by SIPH (Farjana et al. 2018).

Philibert (2017) performed an industry-specific assessment of the potential for the use of renewable-based technologies, including green fuels, electrification met with renewables, or renewable-based process heat such as biomass or SIPH, focused on the largest energy consumers and greenhouse gas emitters. Philibert (2017) notes a heterogeneous landscape for solar process heat, with most installations made up of non-concentrating collectors such as flat-plate and evacuated tube collectors, whereas the larger parabolic trough installation in Oman dwarfs them in total potential. Philibert (2017) also notes that this dichotomy likely follows because of geographic limitations on the suitability of concentrating technologies as well as their higher price point.

Notably, most of the studies reviewed consider technologies besides renewable thermal systems alone, including energy efficiency (Schoeneberger et al. 2020), electrification (with or without renewables) (Wei, McMillan, and de la Rue du Can 2019; Sharma et al. 2017; McMillan et al. 2021), biomass (Sharma et al. 2017), green fuels (Sharma et al. 2017), and nuclear (McMillan et al. 2016). Studies highlight trade-offs that may be of interest to policymakers, such as technologies that might have implementation in a higher number of facilities (e.g., preheating via flat plate collectors; interventions in food drying) versus fewer facilities with higher capacity at each one (e.g., focus on refining). They also highlight trade-offs that may be necessary for consideration in a decision support model, such as cost and size versus storage hours and potential load substitution, summer versus winter sizing, ecological considerations, and technology readiness level.

3 Hybrid Model Development in RTES

In this context, two hybrid RTES pilot simulation models have been developed as test cases. The first test case is a hybrid system that couples FPCs with PTCs and TES. This case was selected to validate with a real hybrid solar district heating case study from Taars, Denmark. The second test case is direct steam generation (DSG) via LFCs coupled with phase change material (PCM)-TES, which includes a natural gas boiler backup system for times when the solar field and PCM-TES are unable to provide sufficient energy. This model is selected to represent ways to optimize the share of solar energy in the energy mix of the hybrid system design for the industrial application resulting in a competitive levelized cost of heat (LCOH) for current market conditions.

3.1 Flat Plate Collector and Parabolic Trough Collector Hybrid Model

This hybrid case scenario is modeled by combining FPCs with PTCs using a stand-alone version of the NREL System Advisor Model (SAM). The model is coded with the PySAM coding language and uses solar water heating and CSP process heat parabolic trough modules that exist in version SAM 2020.2.29 r3 (Patch 3), SSC 242: July 31, 2020 (NREL 2020). In the hybrid system two separate heat transfer fluids (HTFs) are used for the FPC solar field (glycol/water mix), and the PTC system (pressurized water or Therminol-VP1). The two systems are connected by a heat exchanger in Figure 4. At present, this hybrid model is available as an internal version at NREL.

The FPC system preheats the glycol/water mix (30/70) from 38°C to 70°C, then the heat is transferred to the PTC system via the heat exchanger. Next, the PTC system raises the temperatures ranging between 90°C and 150°C using pressurized water, or up to 300°C using Therminol VP-1 as the HTF, depending on end-use heat requirements. The mass flow through the FPC array is directly proportional to the mass flow through the PTC array to maximize the effectiveness of the heat exchanger. The hybrid system is combined with a two-tank TES, including one hot and one cold tank, which adjusts the mass flow and the temperature of the heat stream going to the process heat application. One of the most important potential benefits of this hybrid system is to reduce the size of the PTC solar field and the overall plant cost relative to a larger stand-alone PTC plant having the same thermal output. Recently, a hybrid thermal plant was built in Denmark that uses an array of FPCs (Figure 4) to preheat the HTF to an intermediate temperature before it enters the field of parabolic trough collectors. The benefit of this hybrid system is that it can potentially reduce the plant cost relative to a trough-only plant having the same output specifications. The lower temperature heating can be achieved by cheaper FPCs, whereas the higher temperature heating outside the range of the flat plates is accomplished by the PTCs. There is potential for low-cost LFCs to be used instead of the FPCs, though a direct example of this in the field has not been found.

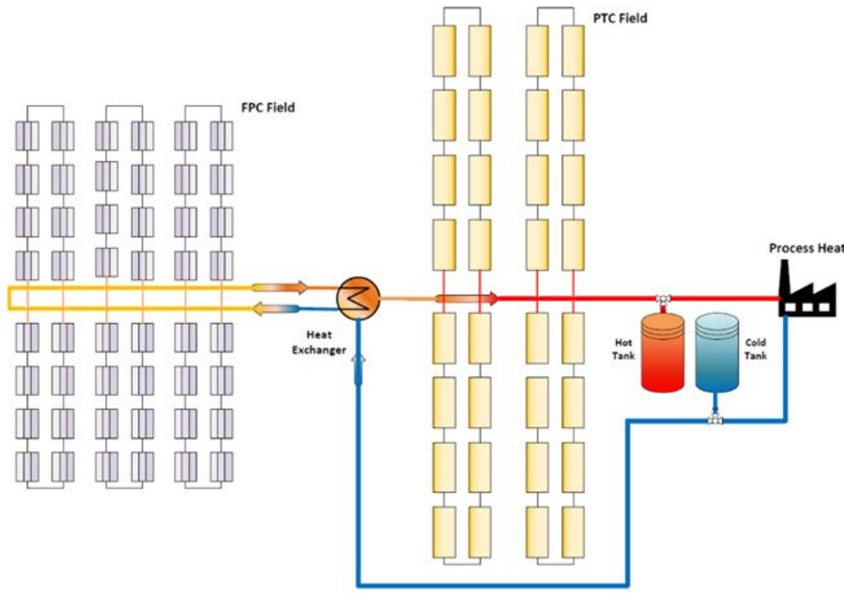

Figure 4. Schematic for a hybrid FPC and PTC system coupled with TES

The hybrid FPC and PTC plant is sized according to the desired process heating power, temperature, hours of thermal storage, mass flow constraints, and the nominal temperature into and out of the FPC field. The sizing of the FPC system in SAM is still a manual process, which allows the user to define the system based on their requirements. The details of the SAM module development and user interface can be found in Appendix A. The design mass flow is dictated by the design plant power and temperature and, in turn, determines the number of FPCs in parallel. The temperature rise from the cold inlet to the intermediate temperature determines the number of FPCs in series. This sizing is performed at a constant standard ambient temperature and irradiance; however, because the FPCs are stationary and experience a range of cosine losses throughout the day and seasons, the intermediate heat exchanger temperature is always changing.

Other important model features for the FPC system are:

- Increasing the number of PTC assemblies per loop will increase the temperature to the TES/process heat. If this temperature surpasses the set point, the controller will increase the field mass flow to maintain this set point.
- Lowering the system/PTC mass flow will lower the FPC mass flow, causing its HTF temperature to increase and thus increase its heat loss.
- Increasing the number of PTC loops will increase the heat rate (thermal power) to the TES/process heat and will charge the TES faster.
- Increasing the number of FPCs will increase the heat transferred to the system and the temperature into the PTCs. Increasing the number of FPCs in series will increase the temperature on the FPC side of the heat exchanger and thus increase the FPC heat loss.
- Increasing the ratio of FPCs in series to those in parallel while keeping the total number of collectors the same has less of a direct effect on the temperature into the PTCs when using a heat exchanger, minus the FPC heat loss.
- Mass flow rate affects the system temperatures and thus heat loss but otherwise does not affect the heat generation.

The sizing procedure for PTCs is very similar to that for a stand-alone plant. The heating power dictates the total size of the field, the process heat temperature dictates the number of PTCs in series, and the mass flow constraints of the PTCs dictate the number of subfields. However, with the hybrid plant, the PTC field is sized using a higher inlet temperature, resulting in fewer PTCs in series.

This variable intermediate temperature requires the plant controller to be more sophisticated than for a regular PTC or regular FPC plant. The controller is similar to the PTC-only plant, where the mass flow through the entire system regulates the outlet temperature. The PTCs are also still used to provide a high-temperature limit control via defocusing or pointing away from the sun. However, model convergence for this hybrid plant requires more algorithmic logic, as the PTCs cannot easily predict their variable inlet temperature iteration to iteration. Hybrid plant sizing is also more sophisticated to simultaneously hit the power and temperature output targets while having coupled subsystem controls. The mixed integer linear programming algorithm is one of the proven methods to optimize the operating temperature in a system consisting of a concentrating solar thermal field with thermal storage, hybridized with a natural gas boiler (Kamerling, Vuillerme, and Rodat 2021). Techno-economic optimization must account for these yearly environmental conditions that may influence the subsystems differently and cause interactions.

3.2 Direct Steam Generation Linear Fresnel Collectors and Phase Change Material Thermal Storage

This hybrid model is designed as a DSG-LFC system coupled with PCM-TES including a natural gas boiler backup (Figure 5). The model was developed in a MATLAB platform using SAM hourly outputs of a modeled LFC solar field including thermal power output, average steam quality, outlet temperature, and mass flow. In addition to the direct normal irradiance (DNI), other weather conditions are also taken from the weather file for a given location. The model can use different collector specifications. The TES using steam is modeled using a PCM that surrounds a pipe through which evaporating or condensing steam passes. The MATLAB code uses routines developed by Paul Farres-Antunez (Cambridge University) and Josh McTigue (NREL), which are based partly on work from Sharan, Turchi, and Kurup (2019) and McTigue (2016).

PCMs are well suited for integration with systems like LFCs that can generate direct steam and use it as the working fluid at various temperatures. In the TES, both media (steam and PCM) go through a phase change that allows the temperature profiles to be matched, which improves the effectiveness of heat transfer (Sharan, Turchi, and Kurup 2019).

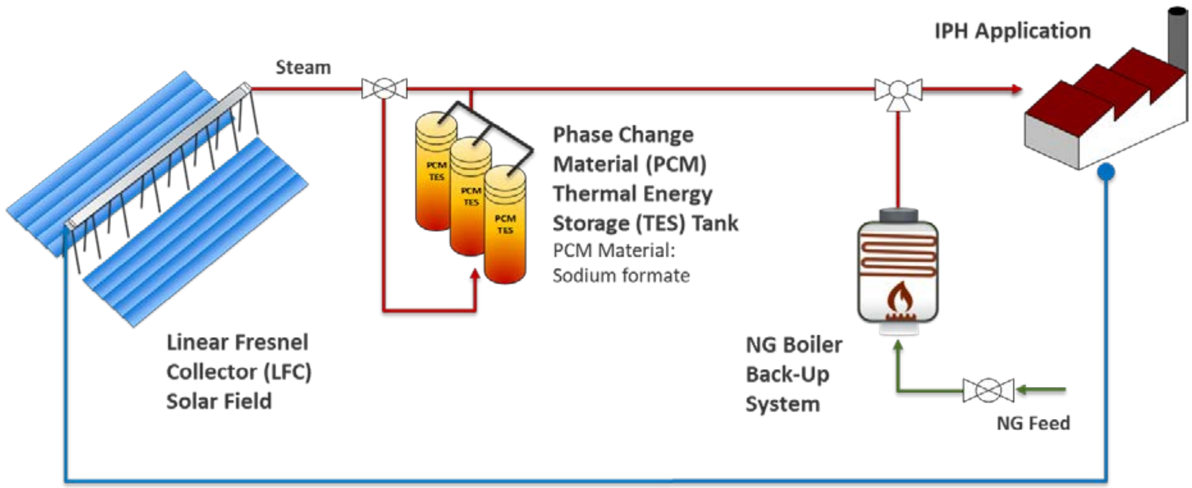

Figure 5. Schematic for the base case design of the hybrid DSG-LFC system coupled with PCM-TES and backup natural gas boiler

During the model development, we created six different versions of MATLAB code[1] to improve the system's flexibility and capacity factor. In the first version, PCM TES modules are charging simultaneously, powered by the solar resource, and when solar energy is not available, discharging one at a time to provide power to the load. In the second version, both steam and PCM are assumed to change phase at the same time, but they may have variable temperatures. In the third version, we tried a new steam routine because the unsteady steam terms seemed to be small. The fourth version had further simplifications in the steam model by assuming a steady-state solution for each instance in time. A step forward only in the PCM equation in time is used, and the steam profile is iterated based on this. We also included further calculation of the heat transfer coefficients. The PCM equation is written in terms of enthalpy, which improves the stability of the solution. In the fourth version, we also added charge and discharge modes. In the fifth version, the program is separated into different files to make a better program structure. Finally, in the sixth version, significant improvement is undertaken for the dispatch optimization of the thermal storage based on the solar field size and best fit to the load profile to minimize the use of the natural gas boiler backup system.

The storage modules comprise tubes of inner diameter, (d_i) outer diameter (d_o) and length (L) through which the steam flows, as shown in Figure 6. These tubes are surrounded by the PCM layer of thickness $t_{\mathrm{PCM}} = (d_o - d_i)/2$. The total volume of PCM $V_{\mathrm{PCM,tot}}$ is determined by considering the total energy to be stored $V_{\mathrm{PCM}} = \pi\{(d_o^2 - d_i^2)/4\}\cdot \mathrm{L}$. For a thermal power input of P_{TES} that lasts for a time of τ_{chg}, the energy (E) stored is given by:

$$E = P_{\mathrm{TES}}\tau_{\mathrm{chg}} = \rho_{\mathrm{PCM}} V_{\mathrm{PCM,tot}} \mathcal{L} \qquad (1)$$

where ρ_{PCM} is the PCM density and $\mathcal{L}$ is the latent heat of phase change assuming constant heat exchange and the PCM temperature stays constant.

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[1] MATLAB code is open source and publicly available via GitHub. Please contact authors for access (sertac.akar@nrel.gov).

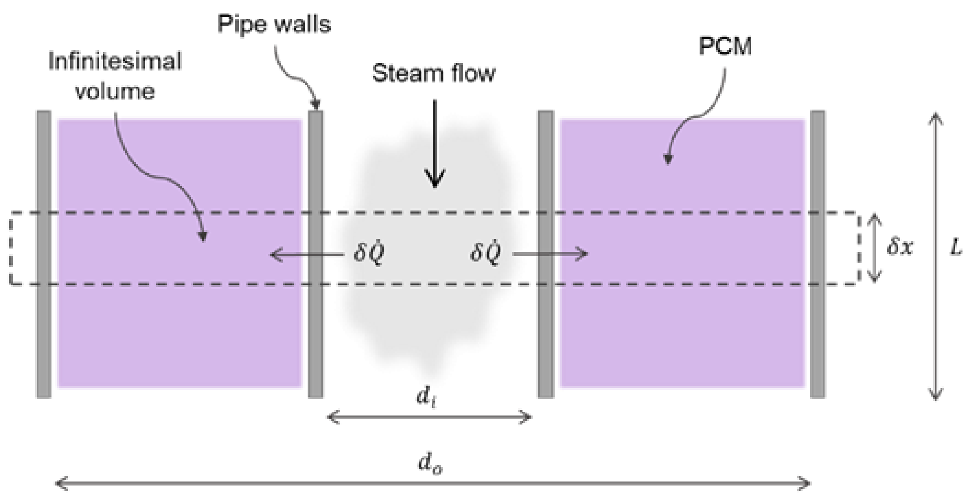

Figure 6. Schematic of the geometry of a section of the PCM TES

Where $\dot{Q}$ is heat flow and *x* is vertical distance

3.2.1 Technical Model Parameters

The DSG-LFC system is modeled in SAM, and the PySAM code is integrated into MATLAB, allowing adjustment of the model using the same modeling tool. The default LFC system is selected from SolAtom's optical characteristics such as the incidence angle modifiers. The model also allows a user to run data over a subset of the data (i.e., 2 weeks from spring, summer, autumn, winter) or a full set of weather data (365 days). The list of LFC solar field model input parameters is summarized in Table 1.

Table 1. List of Linear Fresnel Collector Solar Field Model Input Parameters

Parameter	Default Value	Explanation
Location	California	Selected from input file that overwrites all parameters related to that specific state, such as natural gas price, CO_2 tax credit, weather file, DNI, etc.
Solar multiple	2	Solar multiple that defines the size of the solar field in m^2
DNI	950	Target DNI, (W/m^2)
LFC selection	"SolAtom"	Specifies detailed aspects of the LFC system, based on specified optical characteristics
Aperture	26.4	Aperture of a single module—this will be updated to meet the required solar multiple
Modules	12	Number of modules in a loop
Loop	6	Number of loops
Weather data subset	"True"	True: User may only wish to run over a subset of the data. This example takes 2 weeks from spring, summer, autumn, winter. False: the full set of 365 days of weather data is used.
Load profile	312120	User can specify the North American Industry Classification System (NAICS) number directly, or type the name of the options such as "cheese," "brewery," "pulp mill," "petrochemicals," "thread mill," etc.

The model is also designed to have the flexibility to adjust the TES input in MATLAB. A list of key TES model input parameters is summarized in Table 2.

Table 2. List of Key TES Model Input Parameters

Parameter	Units	Default Value	Explanation
Load	W	1,000,000	Design thermal load
Duration	h	6	Nominal duration of charge for TES
Psat_c	Pa	5,500,000	Saturation pressure during charging condition
XS_c	n/a	0.6	Initial dryness fraction of steam during charging
Psat_d	Pa	3,500,000	Saturation pressure during discharging condition
XS_d	n/a	0.0	Initial dryness fraction of steam during discharging
Specific heat	J/kg K	1,216	Specific heat capacity of liquid PCM (sodium formate)
Density	kg/m^3	1,920	Density of liquid PCM (sodium formate)
Thermal conductivity	kJ/m^2 K/s	5	Thermal conductivity of PCM (sodium formate)
Latent heat	J/kg	245,000	Latent heat of PCM (sodium formate)

3.2.2 Economic Model Parameters

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, natural gas 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 Table 3.

Table 3. List of Key Economic Model Parameters for the LCOH Calculations

Parameter	Units	Default Value	Explanation	Reference
Natural gas price	$/MMBTU	7.37	File containing natural gas prices at the plant gate in $ per 1,000 cubic feet for each state (default value is for California)	(EIA 2021d)
PCM cost	$/m^3	1,000	Material cost for PCM (sodium formate)	(McTigue et al. 2022)
Steel cost	$/m^3	8,000	Steel cost	(Fastmarkets 2021)
Manufacturing cost factor		1.6	Cost factor to transform materials into finished product	(Boothroyd Dewhurst Inc. 2020)
TES cost	$/kWh$_{th}$	25[c]	Unit cost of TES system. If this value is >0, then it is used to calculate TES cost rather than using the cost of steel, PCM, and manufacturing.	(McTigue et al. 2022)
LFC cost	$/m^2	175	Unit cost of the LFC system	(Kurup et al. 2017)
Natural gas boiler cost	$/kW$_{th}$	250	Unit cost of a natural gas boiler	(Dorotić, Pukšec, and Duić 2020)
CO_2 price[a]	$/metric ton	17.71	Carbon price applied for emissions	(ICAP 2021)
Emissions	kg/Wh	1.81E-04	CO_2 emissions from burning natural gas. Source: 117 pounds per MMBTU	(EIA 2021c)
O&M	%	5	Yearly operations and maintenance cost, as a fraction of total capital cost	(NREL 2020)
Project lifetime	years	25	Lifetime	(NREL 2020)
Method	n/a	"discount"	Economic method used to calculate LCOH. Can be "discount" or "FCR."	(NREL 2020)
Discount rate[b]	%	10	Discount rate for the economic model	(NREL 2020)
Inflation	%	2.5	Inflation rate	(BLS 2020)
IRR	%	10	Internal rate of return	(NREL 2020)
Debt fraction	%	60	Project debt fraction. SAM is 0.60.	(NREL 2020)
Debt IR	%	8	Debt interest rate	(NREL 2020)
Tax rate	%	40	Tax rate	(NREL 2020)
Depreciation	n/a	[0.20 0.32 0.20 0.14 0.14]	Depreciation factors [0.20 0.32 0.192 0.1152 0.1152 0.0576] for a 6-year recovery period	(NREL 2020)
Construction IR	%	0	Construction interest rate smaller than new assumption to make cash flow from financing (CFF) =1. (SAM value greater than % 0.08)	(NREL 2020)

[a] Minimum price available at auction per ton of CO_2 emissions in December 2020, in California's Cap-And-Trade Program (ICAP 2021)

[b] Conservative discount rate for a high-risk technology

[c] Value is in 2020 dollars

4 Model Comparison

4.1 Comparison of FPC-PTC Model With Taars Solar District Heating

FPCs have higher efficiencies than PTCs at low temperatures, but their efficiency declines as temperatures increase to typical supply temperatures (70°C and 95°C) of district heating (Tian et al. 2017). However, PTCs retain their high efficiency at these temperatures. To maximize the advantages of FPCs (higher efficiencies at low temperatures) and PTCs (higher efficiencies at high temperatures) for a district heating network, a hybrid solar collector field with 5,972 m^2 FPCs and 4,039 m^2 PTCs in series was constructed in Taars, Denmark (Tian et al. 2017). Originally, the district heating system used natural gas boilers at a peak capacity of 9.10 MW_{th}. The solar district heating was designed for a 9.10 MW_{th} peak power, which retrofits to the existing system composed of two natural gas boilers and two tanks of TES with a total volume of a 2,430 m^3 (Figure 7). The district heating network supplies hot water for space heating and domestic hot water for about 850 buildings with about 1,900 residents (Tian et al. 2017). The design principle of the hybrid system is that the FPCs preheat the return water from the district heating network to a temperature ranging between 70°C and 75°C, and then the PTCs increase that to higher temperatures between 75°C and 95°C to deliver heat to the district heating network (Table 4).

Table 4. Hybrid System Specification in Taars, Denmark, District Heating System Compared to the Modeled System in SAM

Parameter	Units	Taars, Denmark	SAM Model
Annual heat net generation	MWh_{th}	6,083	6,474
FPC field (m^2)	m^2	5,972	5,971
PTC field (m^2)	m^2	4,039	4,038
FPC collector	n/a	Lochinvar & Arcon-Sunmark[b]	Lochinvar
HTF in FPC loop	n/a	Glycol/water mix (30/70)	Glycol/water mix (30/70)
PTC collector	n/a	Aalborg	EuroTrough ET150
PTC receiver	n/a	Archimede Solar Energy HCEOI-12	Siemens UVAC 2010
HTF in PTC loop	n/a	Pressurized water	Pressurized water
FPC inlet temperature	°C	38–42	38
PTC inlet temperature	°C	70–75	70
PTC outlet temperature	°C	75–95	90
Storage tank volume[a,b]	m^3	2,430	2,417
Heat sink power to load	MW_{th}	n/a	4.75
Solar multiple	n/a	n/a	1.92
Peak power	MW_{th}	9.10	9.12

[a] 30 hours of thermal energy storage

[b] Heat boost collector 50%, heat store 50%

A glycol-water mixture of 30/70 is used as the HTF for the FPC loop, and pressurized water is used as the HTF in the PTC loop. The PTC system can raise the temperatures up to 150°C using pressurized water, depending on end-use heat requirements. When higher temperatures are needed (i.e., 300°C), the HTF needs to be replaced by a synthetic oil such as Therminol VP-1. The SAM model was developed to validate the results of the solar field to 1 year of operational data from the SIPH site. The SAM weather file for Taars was developed using on-site measurements from the Tylstrup DNI and ambient temperature.

The cumulative yearly thermal energy yield of the solar field simulated through the internal NREL SAM model was 6,474 MWh, corresponding to an overestimation of 6.4% compared to the measured thermal output of 6,083 MWh, which was given by Aalborg as the most recent annual generation capacity at the Taars plant.

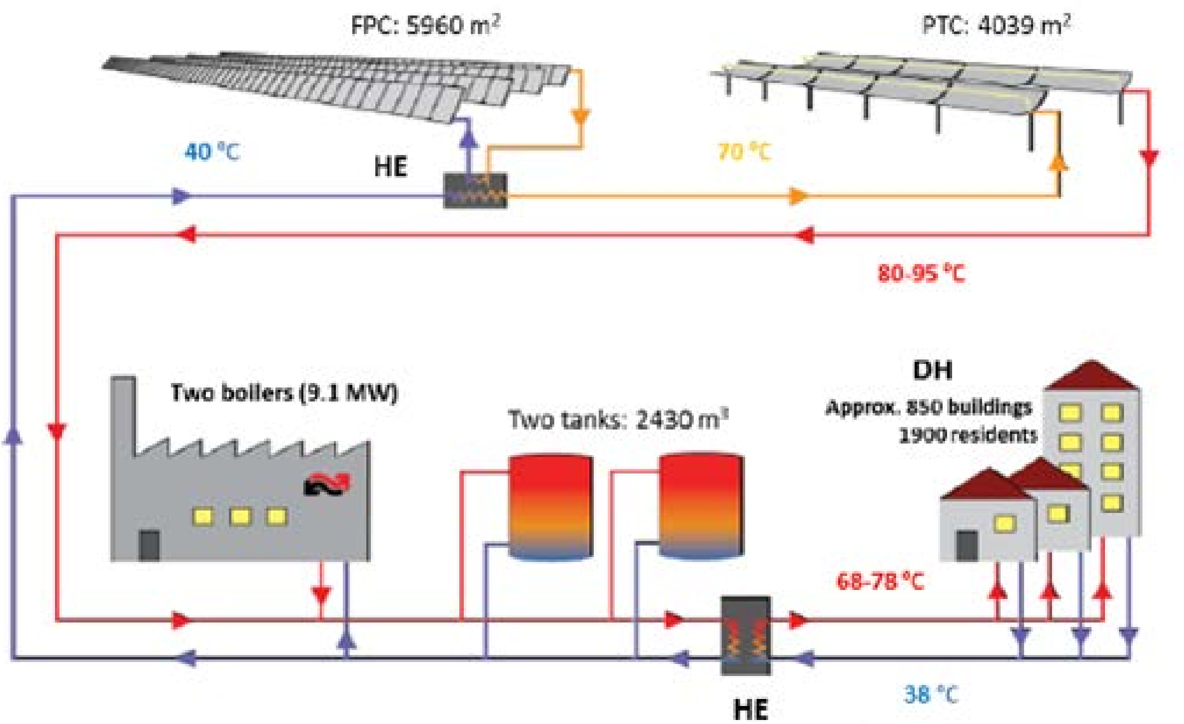

Figure 7. Simplified illustration of the Taars solar district heating system coupled with natural gas boilers and TES (Tian et al. 2017)

The monthly generation data are acquired from Tian et al. (2017) and represent the modeled case in 2016 with an annual heat generation of 4,651 MWh_{th}, which is 23% less than the thermal generation in the Taars system in 2021. Also, the model was using weather data between September 2015 and August 2016, which has an average DNI of 983 kWh/m^2 per year while the system modeled in SAM uses typical meteorological year (TMY) data for Tylstrup, Denmark, with an average annual DNI of 1,151 kWh/m^2 (Figure 8). To be able to make a comparison to the SAM model, a modification is made to the monthly generation values presented in Tian et al. (2017), and most recent site operations, generation capacity, and TMY conditions are reflected. A comparison of the Taars solar district heating modified 2015–2016 monthly generation and simulated SAM TMY results for monthly heat output is shown in Figure 9.

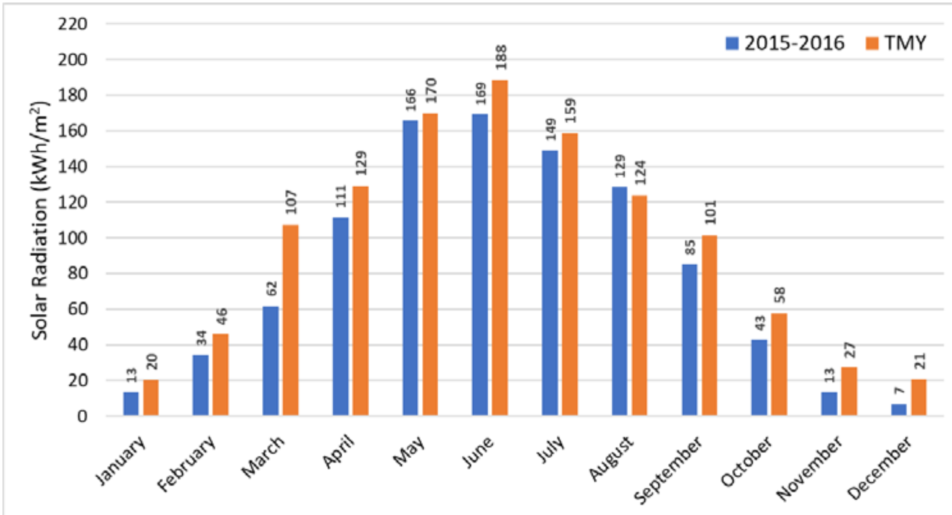

Figure 8. Comparison of 2015–2016 solar radiation with a typical meteorological year (TMY) for Taars, Denmark.

DNI data are between September 2015 and August 2016.

On the one hand, the modified monthly generation values of the FPC field vary highly from the SAM results—up to 90%—for the winter months between November and January due to differences in DNI values between 2016 and the TMY. On the other hand, the adjusted monthly generation data vary up to 10% for the spring and summer months between April and October. The modified generation values for the spring and summer months are relatively higher than the SAM model, varying up to 15% and as low as 3% in May. This range is within the acceptable correlation limits for monthly generation.

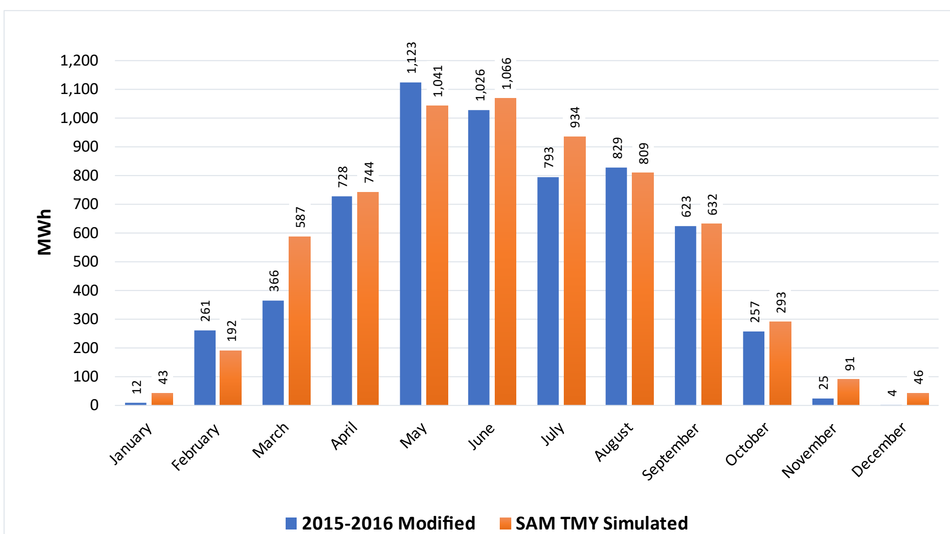

Figure 9. Comparison of Taars solar district heating modified 2015–2016 monthly generation and simulated SAM TMY results for monthly heat output

The annual average temperature profile of the hybrid system modeled in SAM are shown in Figure 10. While the temperature at the peak time of the day is around 80°C on average, a temperature of 90°C can be reached for the months of April, May, June, July, August, and September. Monthly average temperature profiles of the hybrid system modeled in SAM for each month are shown in Figure 11.

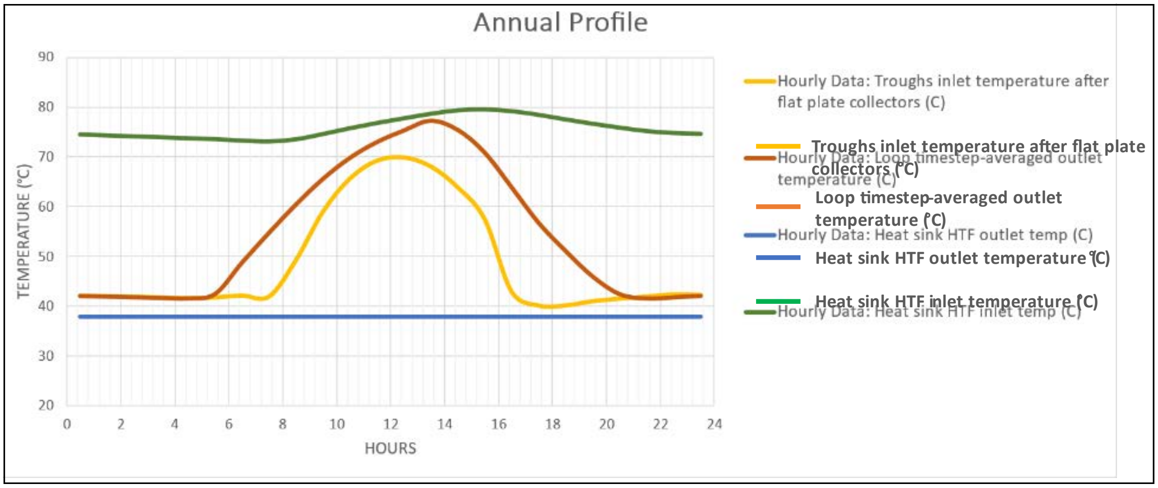

Figure 10. Annual average temperature profile of the modeled hybrid system

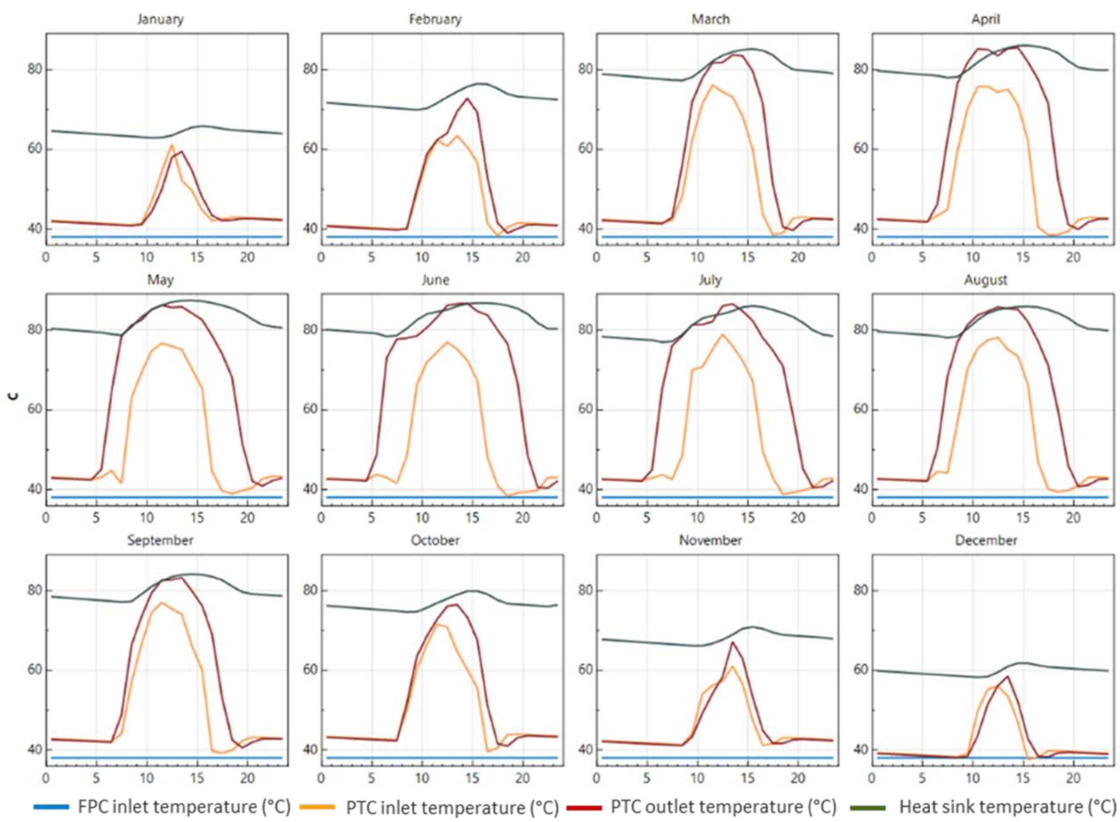

Figure 11. Monthly average temperature profile of the modeled hybrid system

A weekly thermal power generation profile and TES charging and discharging power from the month of June are shown in Figure 12. The blue line shows the net heat gain from the FPC field, and the green line represents the net heat leaving in the HTF, which is the sum of heat gain from the FPC and the heat gain from the PTC. The heat sink power of the hybrid system is shown by the orange solid line. TES charging and discharging power are shown in the bottom graph of Figure 12 as red and green solid lines, respectively.

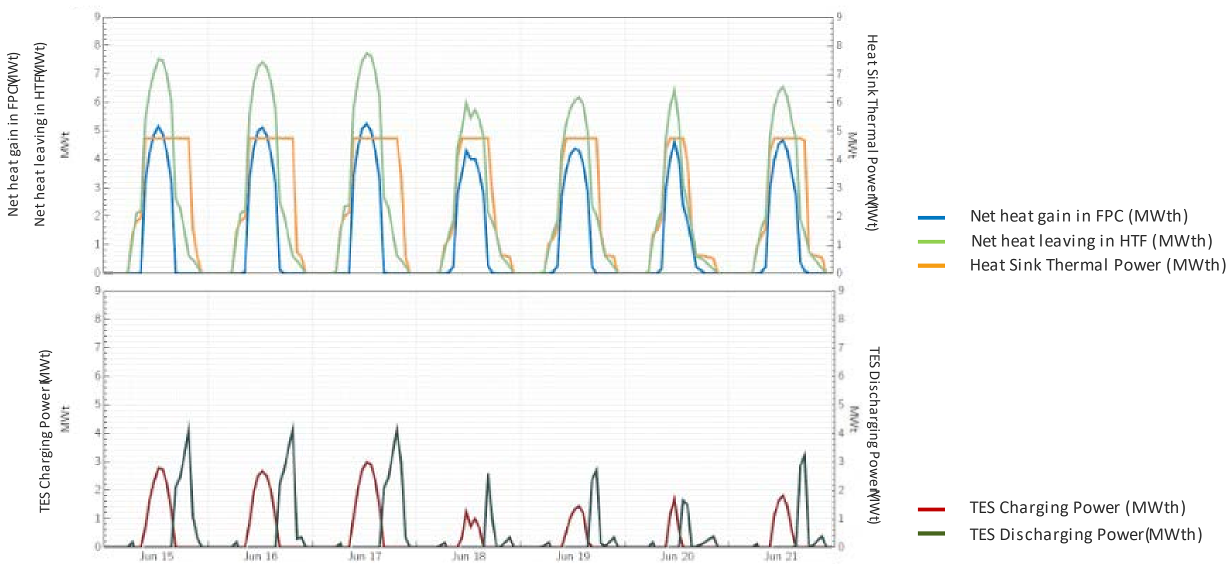

Figure 12. Typical thermal output profile of the hybrid system during one week in June

The hourly thermal power generation profile from a typical summer day (June 17th) where sunrise is at 4:56 a.m. and sunset is at 9:57 p.m. is shown in Figure 13. The yellow solid line represents the net heat gain from the FPC field, and the black dotted line represents the net heat gain from the PTC field. The orange solid line represents the field thermal power leaving the HTF before the TES. The blue dashed line represents the charging power to the TES and the green dashed line represents the discharging power for TES. Net heat sink power is the red solid line in the graph.

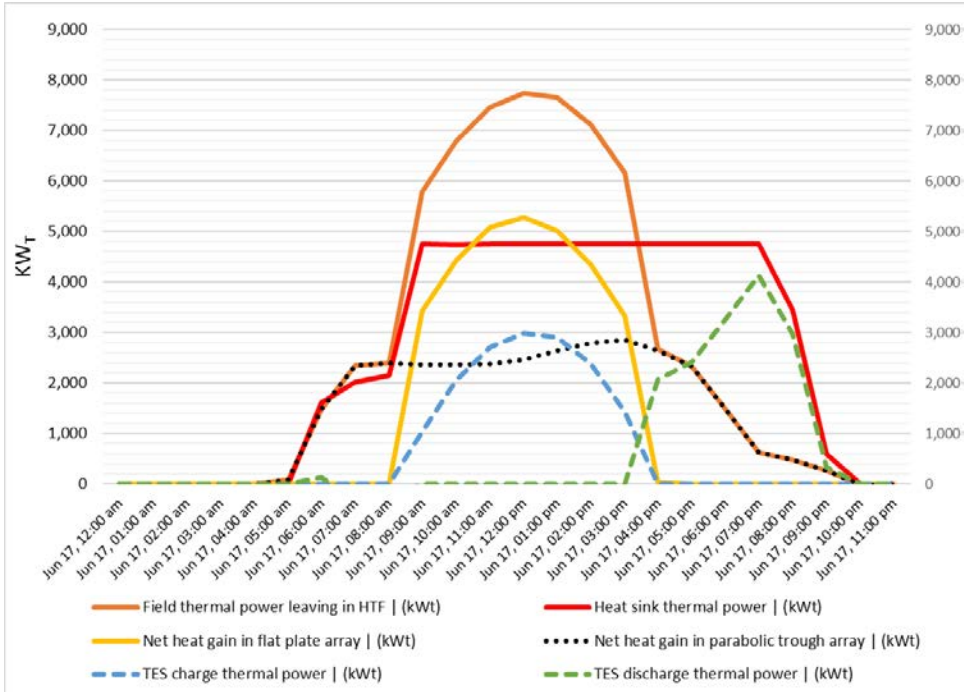

Figure 13. Hourly thermal output profile, charging, and discharging power from June 17

5 Model Results

5.1 DSG-LFC and PCM Model Results

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 a DSG-LFC coupled with PCM-TES and a natural gas boiler backup system to improve the system's flexibility and capacity factor. Note that this case study is for a greenfield site, and therefore site-specific data would be needed to guarantee meeting the industrial load.

The DSG-LFC system is designed for a 1 MW_{th} capacity with a solar multiple of 2 and target steam quality of 0.75 and is modeled in SAM. For this modeling effort, SAM 2020.11.29 was 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).

In this case study, we used the SolAtom® modular LFC (Kraemer 2020), and the optical characterization and incidence angle modifiers were provided by SolAtom. The hybrid model can also use different collector specifications based on the incidence angle modifiers. Sodium formate is selected as the PCM for the TES with 6 hours storage capacity for the base case, due to its 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, Turchi, and Kurup 2019).

The selected test sites of Pittsburgh, Pennsylvania; Tucson, Arizona; and Lancaster, California, 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). These test sites represent the U.S. Northeast and Southwest. As of 2020, the annual average industrial natural gas price (at the plant gate) estimated by the Energy Information Administration (EIA) was $3.29 per thousand cubic feet (Mcf) or $3.17 per MMBTU (EIA 2021d; 2021b). 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 2021a). Table 5 shows the 2020 average industrial natural gas prices and conversions used in the analysis.

Table 5. 2020 Average Industrial Natural Gas Prices and Conversions (EIA 2021d; 2021b)

	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 8 a.m. and 10 p.m. and 0.2 MW_{th} constant between 12 p.m. and 6 a.m. It ramps to 1 MW_{th} between 6 a.m. and 8 a.m. in two steps (0.47–0.75 MW_{th}) and fades down to 0.2 MW_{th} in two steps (0.75–0.47 MW_{th}). This is similar to food processing/dairy sites in the United States (NAICS 2021). For modeling simplicity, an 8-week test model was defined with 2 weeks in winter, 2 weeks in spring, 2 weeks in summer, and 2 weeks in fall, which sums to 1,345 hours of thermal power profile.

An annual simulation model has been developed for the DSG-LFC and PCM-TES hybrid system by using a multiplier of 6.5 for the 8-week model. This is for increasing the simulation run time without significant error between the 8-week model and a full annual simulation. The test runs for the 8-week model and the annual model were done repeatedly and resulted in less than 10% difference in every iteration. Thus, the 8-week model was found to be sufficient for the accuracy of the analysis. The annual model can be used for more detailed techno-economic analysis where a site-specific characterization is needed. Solar heat generation, thermal storage, curtailed solar energy, heat from natural gas and heat load profiles for a representative 2-week timeline (1 week from winter and 1 week summer) are shown for California (Figure 14), Arizona (Figure 15), and Pennsylvania (Figure 16).

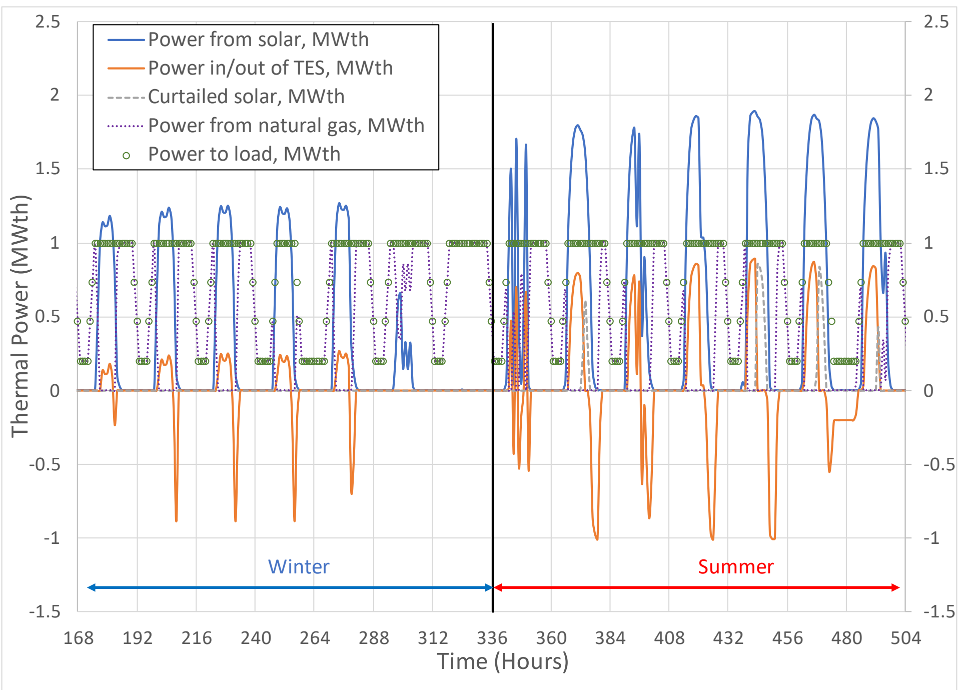

Figure 14. Solar heat generation, thermal storage, curtailed solar energy, heat from natural gas, and heat load profiles for a representative 2-week period (1 week from winter starting from the 168th hour and 1 week from summer starting from the 336th hour) in California

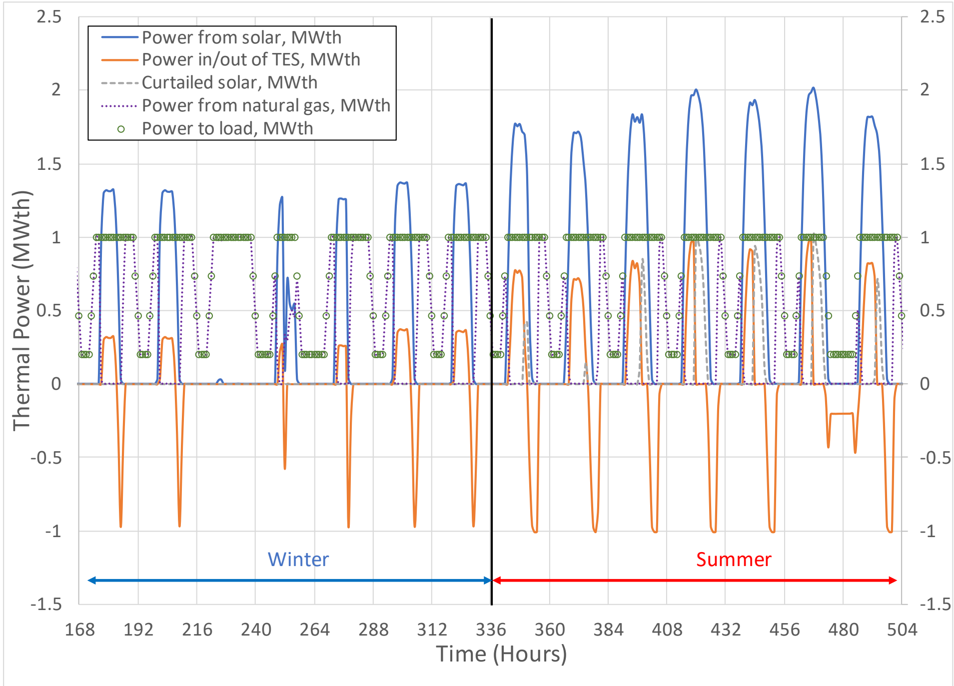

Figure 15. Solar heat generation, thermal storage, curtailed solar energy, heat from natural gas, and heat load profiles for a representative 2-week period (1 week from winter starting from the 168th hour and 1 week from summer starting from the 336th hour) in Arizona

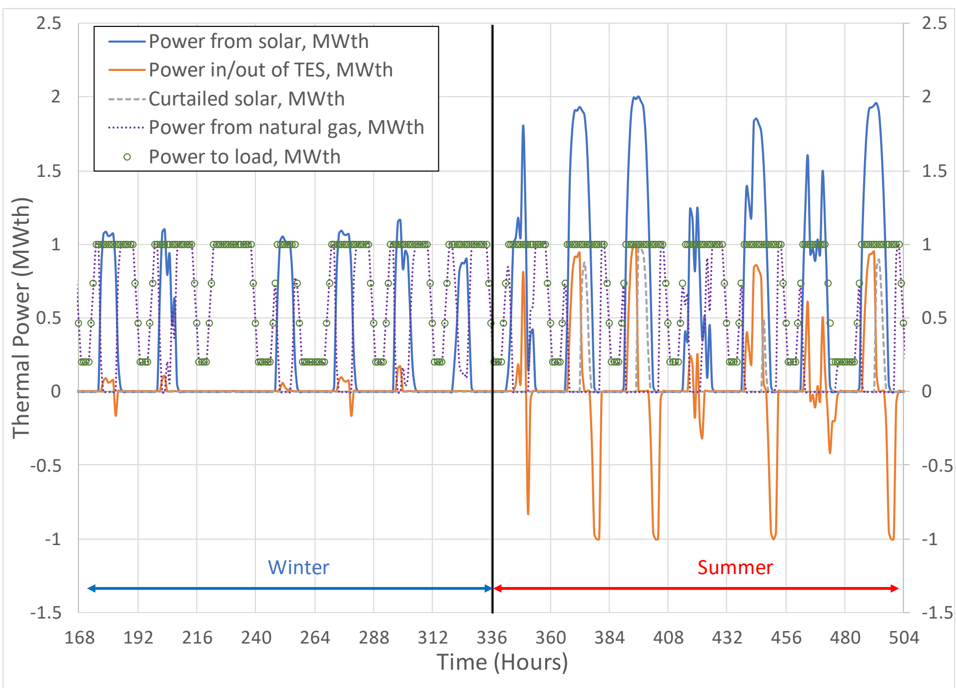

Figure 16. Solar heat generation, thermal storage, curtailed solar energy, heat from natural gas, and heat load for a representative 2-week period (1 week from winter starting from the 168th hour and 1 week from summer starting from the 336th hour) in Pennsylvania

6 Techno-Economic Analysis

6.1 DSG-LFC and PCM Model Techno-Economic Analysis

Techno-economic analysis was utilized for three geographic locations and four variations based on their solar field size and TES capacity. The base scenario for all three locations is designed for a solar multiple of 2 and a TES duration of 6 hours. The financial assumptions from Table 3 are used for the LCOH calculations. The base case also assumes no CO_2 adder, but the impact of a CO_2 adder is also reflected in the scenarios.

Results of the techno-economic analysis 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 (Table 6). Without the CO_2 adder, this results in a LCOH of \$0.046/kWh$_{th}$ (\$13.54/MMBTU) for Pennsylvania, \$0.032/kWh$_{th}$ (\$9.41/MMBTU) for Arizona, and \$0.039/kWh$_{th}$ (\$11.44/MMBTU) for California (Table 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 in Arizona. Curtailed solar energy is calculated as the difference between solar heat generated and the heat load. 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. LCOH is calculated by dividing the lifetime cost of the system by the lifetime heat generation.

Table 6. Summary of Results for the Hybrid System Design in Pennsylvania, California, and Arizona

State	Solar Field (m^2)	Storage Time (hours)	Solar Share in Total Load (%)	Curtailed Solar Energy (%)	Storage Efficiency (%)	LCOH With CO_2 Adder \$/kWh$_{th}$[b]	LCOH With CO_2 Adder \$/MMBTU	LCOH Without 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[a]	**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
PA	2,890	12	26.30	0.00	60.76	0.048	14.09	0.051	14.91
CA	2,700	6	40.33	1.78	89.21	0.041	11.92	0.038	11.26
CA[a]	**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
CA	2,700	12	40.20	0.01	72.87	0.042	12.32	0.044	12.98
AZ	2,667	6	39.90	1.68	64.19	0.032	9.43	0.030	8.68
AZ[a]	**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
AZ	2,667	12	40.32	0.03	63.64	0.036	10.45	0.033	9.79

[a] Base case

[b] Conversion Factors: 1 cubic ft of natural gas = 1,030 Btu; 1 Btu = 0.000293071 kWh$_{th}$

However, as shown in Figure 17, at the present cost, the DSG-LFC and PCM-TES system (which has a LCOH of $0.032/kWh$_{th}$ [$9.43/MMBTU]) is not yet fully competitive with the natural-gas-only system, which has a LCOH of $0.026/kWh$_{th}$ ($7.16/MMBTU) in Arizona. In Pennsylvania, due to the high natural gas prices, the LCOH of the hybrid RTES is very competitive with the stand-alone natural gas boiler system and has a LCOH of $0.046/kWh$_{th}$ ($13.54/MMBTU). The annual average natural gas price observed in the United States has not always been as low as 2020; the highest annual average natural gas price in 2008 was $9.65/Mcf, or $9.30/MMBTU (EIA 2021a; Ritchie and Dowlatabadi 2017). For instance, in 2008, natural gas was 3 times more expensive for industrial consumers than in 2020 (EIA, 2021d). Storage efficiency can be as high as 84.7% for 6 hours of thermal storage in California.

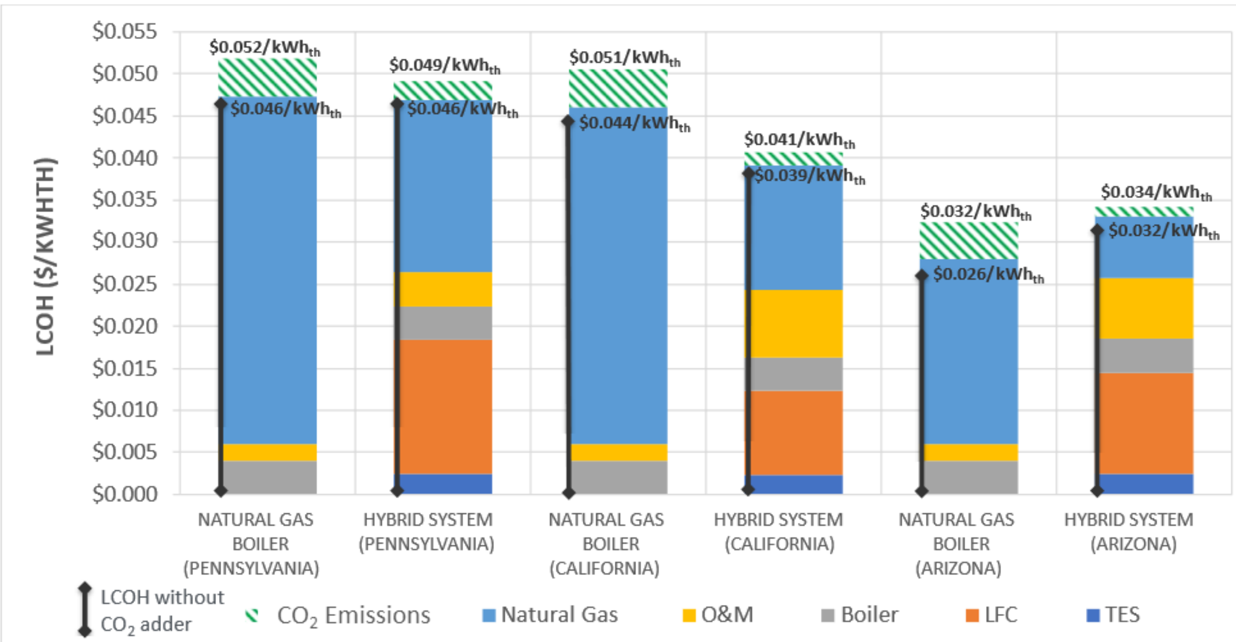

Figure 17. Comparison of system LCOH for the natural gas boiler and the hybrid system of DSG-LFC with PCM TES and natural gas boiler backup scenario in Pennsylvania, California, and Arizona (Base Case: solar multiple of 2, and 6 hours of thermal storage)

The capital cost of the hybrid system is estimated between $1,022/kW and $1,095/kW, which includes the $250/kW natural gas boiler backup system cost. Since 1 MWh$_{th}$ equivalent of natural gas has 0.185 tons of CO_2 emissions, this hybrid system can also provide up to 4,096 MWh$_{th}$ of natural gas offset in the base case, 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. The hybrid system is very cost effective by this measure in California and breaks even in Pennsylvania without considering any CO_2 adder.

A sensitivity analysis was conducted to determine the break-even point for the hybrid system to have the equivalent LCOH as the stand-alone natural gas boiler system by changing the LFC cost and the natural gas price while keeping all other parameters constant. The LFC and natural gas price break-even points for the hybrid system modeled in Pennsylvania, California, and Arizona with the CO_2 adder are shown in Figure 18 and Figure 19, respectively. The break-even points for the LFC cost represent the optimal solar field cost that would make the hybrid system competitive with the stand-alone natural gas boiler system. Similarly, the break-even point natural gas price represents the lowest natural gas price that would make the hybrid system competitive at that given location.

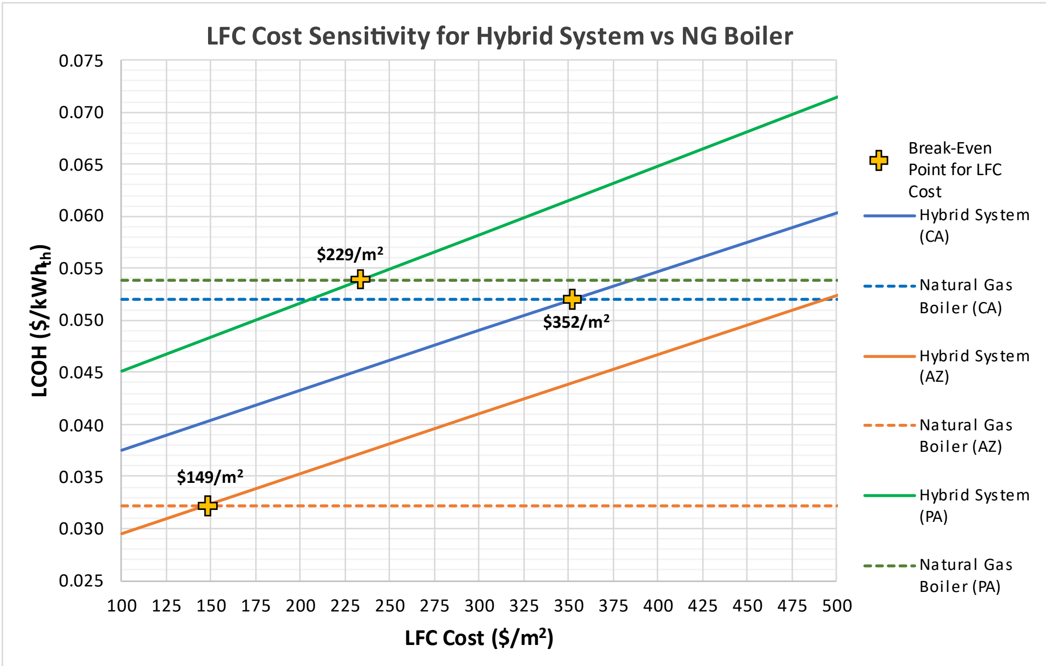

Figure 18. LFC cost sensitivity and break-even point for hybrid system in Pennsylvania, California, and Arizona with CO_2 adder

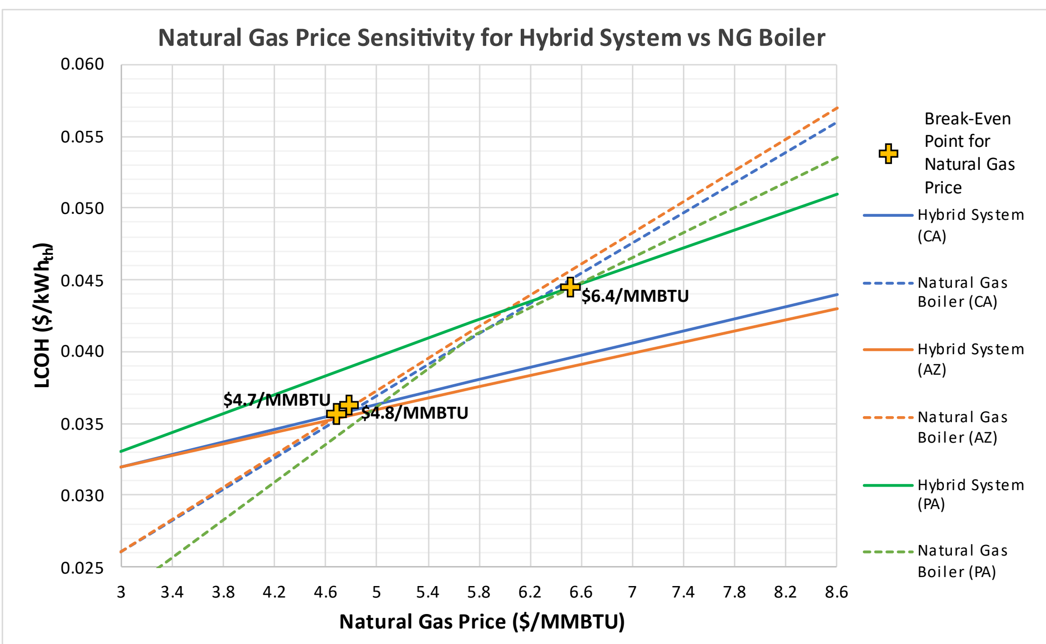

Figure 19. Natural gas price sensitivity break-even point for hybrid system in Pennsylvania, California, and Arizona with CO_2 adder

Maximizing the share of solar energy in the DSG-LFC hybrid system design is not the most feasible solution for industrial applications due to high resulting LCOH. Optimizing the hybrid system would get it to its most competitive point with a natural-gas-only system, but then it may or may not be cost-competitive for a new case or perhaps a retrofit case. 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). However, at present there is no nationwide carbon price system or mechanism for industry in the United States. 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 break-even point for LCOH can be achieved if the LFC unit cost is equal to or lower than the represented LFC and natural gas prices in Table 7. In other words, a LFC system which is equal or cheaper than the break-even price can make the make the hybrid system viable and feasible regardless of the CO_2 adder. Similarly, the break-even point for LCOH can be achieved if the natural gas price is equal to or greater than the represented values in Table 7.

Table 7. Break-Even LFC and Natural Gas Prices for the Hybrid System to Have the Equivalent LCOH as the Stand-Alone Natural Gas Boiler System With and Without CO_2 Adder of $17.71 per Metric Ton

	Break-Even LFC Cost ($/m^2) (With CO_2 Adder) $/m^2	Break-Even LFC Cost ($/m^2) (Without CO_2 Adder) $/m^2	Break-Even Natural Gas Price (With CO_2 Adder) $/MMBTU	Break-Even Natural Gas 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

The LCOH results for Arizona show that the present cost of the DSG-LFC and PCM-TES system is not yet fully competitive with the natural-gas-only system without the CO_2 cost adder. For Arizona, LFC systems would need to be installed at costs of $149/m^2 with the CO_2 cost adder to be competitive. Without the adder, the unit cost would need to be as low as $76/m^2 to be competitive. However, the hybrid system LCOH in California could be competitive and even better than stand-alone natural gas boiler systems due to the higher 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 stand-alone natural gas 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. In Europe, such hybrid systems may be a low-cost option for a variety of cases due to implemented higher CO_2 prices and higher natural gas prices. The LFC cost was $175/m when the NREL analysis[2] was completed for a specific design in 2021 (Akar,

[2] NREL worked with SolAtom to determine the LFC cost for their specific collector design based on their most recent installation in Spain. The installed cost of the LFC system was in 2020 dollars.

Kurup, McTigue, Cox, et al. 2021). The learning rate of the LFC solar field could be around 10% (Breyer et al. 2017), which expresses the percentage cost decrease per doubling of the solar field installed capacity.

For Arizona and California, the natural gas price would need to be $4.7/MMBTU and $4.8/MMBTU, respectively, including the CO_2 cost adder to be competitive, whereas the break-even natural gas price for Pennsylvania needs to be as high as $6.4/MMBTU. If the natural gas price becomes slightly higher—$5.8/MMBTU for Arizona, $5.9/MMBTU for California, and $7.6/MMBTU for Pennsylvania—the hybrid system would still be competitive without the CO_2 adder.

7 Natural Gas Reductions

To show how near-term RTES solutions could be utilized to reduce natural gas consumption in industrial settings, two models with tools built outside of NREL are highlighted.

7.1 Preheat by Solar PTC for the Natural Gas Boilers

IPSEpro was used to model the use of PTCs with a liquid HTF that provides heat input into the air and natural gas streams to feed a constant-load natural gas combustor that provides heat for an IPH application at 1,000°C or 300°C. IPSEpro is a software system for calculating heat balances and simulating processes. The thermal energy can be used to preheat the airstream entering the natural gas burner, the natural gas stream itself, or both streams. This scenario is a potential near-term representation of what industrial sites could use to hybridize their current existing system with a renewable thermal input and, as such, to reduce fuel consumption. To develop this hybrid RTES model, the first stage was to simulate a constant solar field outlet temperature, and then develop it further where a variable-temperature PTC solar field is used instead of a constant exit temperature.

The first test case of this scenario, the heated HTF (Therminol VP-1, a commonly used synthetic oil in CSP electricity generation plants) is set at a constant 300°C exit temperature from the solar field/RTES (e.g., with PTCs), and the air feed flow rate is set at 50 kg/s. Effectively, the RTES exit temperature is constant through the year. As mentioned for a high-temperature IPH application such as calcination, the outlet of the natural gas burner that feeds the IPH application is set to 1,000°C. IPSEpro is used to calculate heat balances and enthalpies and to simulate processes for the heat exchanger and natural gas burner. Figure 20 shows the base case natural gas burner without solar heating (Figure 20a) and the constant-temperature solar field heating of the natural gas and air streams (Figure 20b) prior to input into the natural gas combustor for the 1,000°C process heat application.

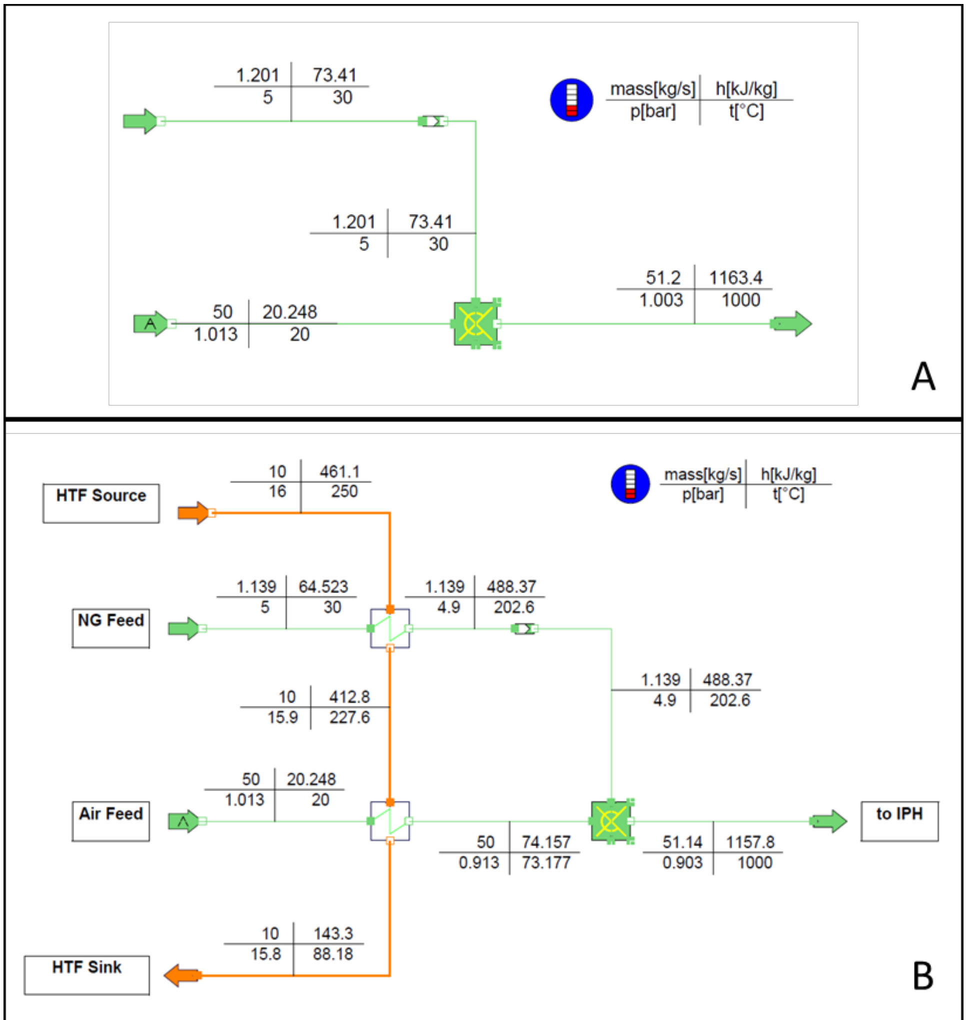

Figure 20**. PTC solar field and natural gas combustor for 1,000°C process heat application with air feed flow rate of 50 kg/s. (a) Base case natural gas burner without solar heating; (b) solar heating for both natural gas and air streams.**

The constant-temperature HTF can heat the natural gas and air stream separately, or as in Figure 20, both streams. Table 8 shows the impact of the heat input into the natural gas stream, the airstream, and then both. The biggest single impact is when the heated fluid from the solar field heats the airstream prior to entering the natural gas combustor, where due to the increased enthalpy of the air, slightly less gas is required (5% less) to reach the 1,000°C air temperature needed for the IPH application. Note that due to the 1.2 kg/s of natural gas and 50 kg/s of air for the base case, most of the energy from the HTF is used for the air heating. When the natural gas and air streams entering the natural gas burner are heated to 203°C and 72°C, respectively, through two separate heat exchangers, it is possible to reduce natural gas consumption by approximately 5% compared to the base case where no renewable heat is added (Table 8).

Table 8. Summary of Results from Constant Solar Field and Natural Gas Hybrid System Models for 1,000°C Process Heat Application With 50 kg/s Air Inlet Mass Flow to the Natural Gas Burner Heated by ~52°C–58°C

Heating From Solar Field	No Heating	Natural Gas Only	Air Only	Natural Gas and Air
Natural gas burner air feed temperature (°C)	20	20	78	72
Natural gas burner gas feed temperature (°C)	30	202	30	203
Natural gas mass flow (kg/s)	1.201	1.199	1.145	1.139
Change in natural gas mass flow (%)	0.0%	−0.1%	−4.7%	−5.1%

In the second test case (medium IPH temperature), the exit temperature of the solar field/RTES is set as 180°C, the air feed flow rate is set at 50 kg/s, and the outlet of the natural gas burner that feeds the IPH application is now 300°C. Note that due to the reduction in the IPH temperature (i.e., 300°C instead of 1,000°C), 0.301 kg/s of natural gas is needed compared to 1.2 kg/s for the 1,000°C application. When the natural gas and air streams entering the natural gas burner are heated to 161°C and 58°C, respectively, through two separate heat exchangers, it is possible to reduce natural gas consumption by approximately 13% compared to the base case where no renewable heat is added (Table 9).

Table 9. Summary of Results from Constant Solar Field and Natural Gas Hybrid System Models for 300°C Process Heat Application With 50 kg/s Air Inlet Mass Flow to the Natural Gas Burner

Heating From Solar Field	No Heating	Natural Gas Only	Air Only	Natural Gas and Air
Natural gas burner air feed temperature (°C)	20	20	59	58
Natural gas burner gas feed temperature (°C)	30	166	30	161
Natural gas mass flow (kg/s)	0.301	0.299	0.274	0.262
Change in natural gas mass flow (%)	0.0%	−0.3%	−9.0%	−13.0%

In the third case, a fully operational PTC system has been modeled with a variable HTF temperature (i.e., regular operation). The PTC system is designed to operate with a 24% capacity factor (approximately 2,076 hours of annual full load operation) and providing a maximum outlet temperature between 180°C and 300°C. Figure 21 shows the process flow diagram of the variable-temperature PTC solar field and natural gas burner model where both the natural gas and air streams are heated.

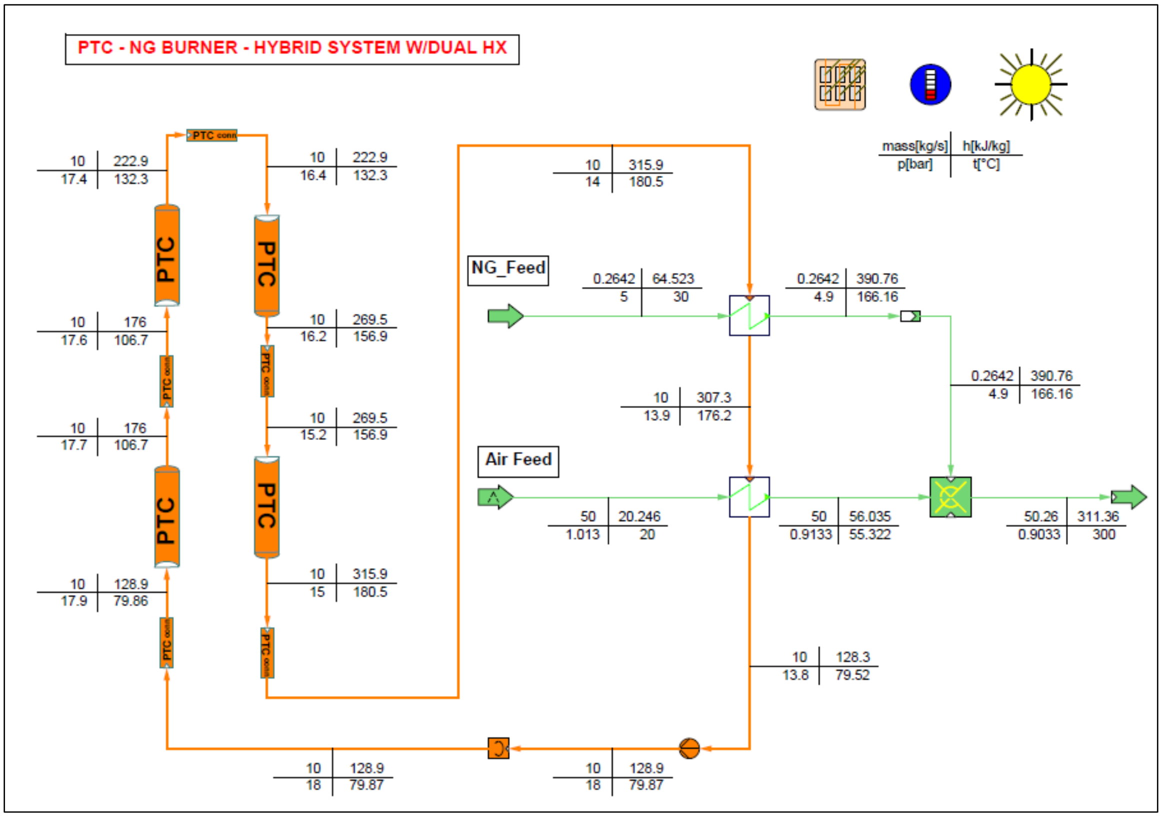

Figure 21. Variable-temperature PTC and natural gas combustor for 300°C process heat application with air feed flow rate set at 50 kg/s

The PTC outlet temperature can increase to 300°C, offsetting the need for natural gas consumption to service the 300°C process heat application. On a daily/annual basis, the overall reduction in natural gas mass flow is about 26%, given PTC capacity factors of about 24% as observed for overall annual weather patterns in the region (Table 10). This result is valid for a system without TES, which reduces the overall solar field capacity factor to about 24%, so the reduction of natural gas occurs within the sunlight hours of the day (8–9 hours). The natural gas savings would be higher with the addition of TES to the PTC system because the capacity factor could then increase up to 50% with a 6-hour storage.

Table 10. Change in Natural Gas Mass Flow with Respect to Variable-Temperature HTF from PTC System for 300°C Process Heat Application With 50 kg/s Air Inlet Mass Flow to the Natural Gas Burner

Heating From Solar Field	No Heating	180°C	200°C	250°C	300°C
Natural gas mass flow (kg/s)	0.301	0.262	0.256	0.242	0.223
Change in natural gas mass flow (%)	0.0%	−13%	−15%	−19%	−26%

7.2 DSG-LFC Retrofit Applications for Natural Gas Boilers

The results of the DSG-LFC showed that there would be significant fuel cost savings in retrofit applications (Table 11). Net annual volume natural gas savings could be bigger in high solar DNI locations such as California and Arizona, and smaller in low solar DNI locations such as Pennsylvania, ranging between $408k and $509k for the modeled system. However, the fuel cost savings would vary based on the natural gas price in that location. As an example, the dollar value of the annual fuel savings in California is ~$140k, which is almost twice that for Arizona.

Table 11. Comparison of Annual Natural Gas Fuel Savings in DSG-LFC Retrofit Applications to Natural Gas Boiler in Different States

State	California	Pennsylvania	Arizona
Fuel consumption for stand-alone boiler (m^3)	942,425	942,425	942,425
Fuel cost ($)	$259,076	$268,232	$134,964
Fuel consumption for hybrid system (m^3)	433,411	534,186	432,551
Fuel cost ($)	$119,146	$152,039	$61,945
Net natural gas fuel savings (m^3)	509,015	408,240	509,874
Fuel savings ($)	$139,930	$116,193	$73,018
Fuel savings (%)	54%	43%	54%

8 Vision for a Future RTES Decision Support Tool in Industrial Applications

Initial hybrid models such as the FPC-PTC hybrid model have been developed through this work. The purpose of such initial models was to better understand how to include hybrid model simulations in SAM[3], but they also motivate the vision of a tool for industrial end users and researchers to understand hybrid RTES options. Implementation of RTES and particularly solar thermal systems in industry is very low at the time of writing. Those interested in implementing such systems must currently do much of the research on their own. This section highlights the basis and vision for an expanded DST that allows the consideration of RTES/hybrids for industrial applications. First, the design and possibilities for the tool are outlined; next, current tools are compared for their existing capabilities; and finally, a potential plan for moving forward is laid out.

8.1 Future Vision

As solar thermal technologies become more widely adopted, a variety of analytical tools will be helpful. The first step is the development of a pre-feasibility tool targeted to decision-makers in a way that can help them choose the best options among possible technologies to investigate more carefully, providing them with a rough estimate of whether such an option will meet their basic criteria. This section is focused on such a tool. After a pre-feasibility study, before embarking on process design, a feasibility study is required. For this stage, a higher degree of accuracy is needed for cost estimates. Additional studies will be performed for site design once the project has been approved.

8.1.1 Goal, Scope, and Audience

The goal of the decision support tool is to provide pre-feasibility information to help speed up the adoption and deployment of stand-alone and hybrid RTES for IPH applications.

Specifically, the future DST should:

1. Reduce information barriers at the pre-feasibility stage of planning
2. Introduce standard pathways for the implementation of hybrid systems, which could help in cost reduction and therefore learning curves (this may be especially important for the industrial sector due to the heterogeneity of applications)
3. Set a pathway for the acquisition of data for comparison and validation
4. Document the economic case for hybrid and stand-alone RTES options, with and without varying financial conditions.

The existing capabilities of SAM can be leveraged to simulate the generation performance and provide the costs and related financial parameters for a variety of standard configurations of RTES, given a location (and hence ability to forecast DNI and other weather variables) and load profile. Additional user inputs regarding space, financial constraints, or other preferences would

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[3] SAM is primarily used for electricity generation simulation, rather than industrial process heat, but has some SIPH capabilities. More are planned.

be used to perform an optimization among the models and provide feedback to the user. Varying configurations could be highlighted to meet specific target goals. Most companies have multiple plants, so while the tool is envisioned as first serving the conditions for a single location, we also consider the potential to create a network of facilities. The conceptual flow for the envisioned tool is shown in Figure 22.

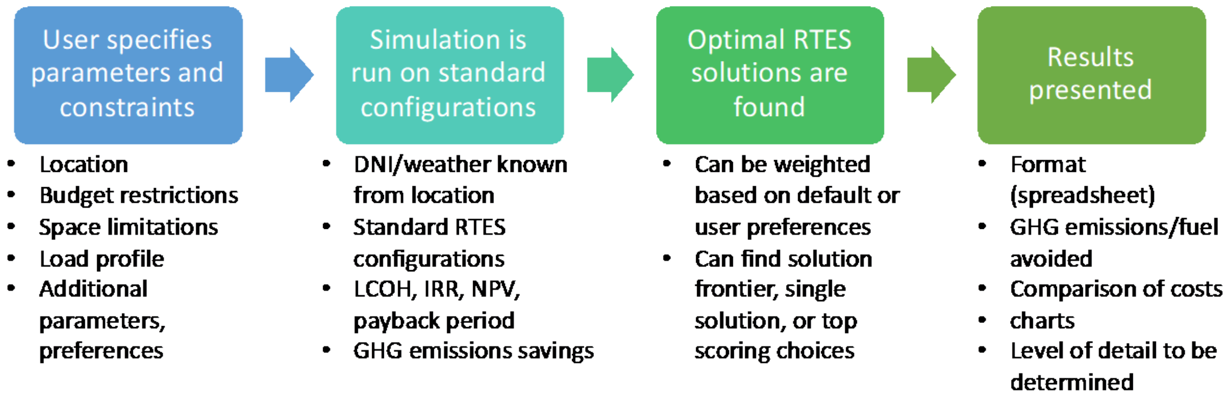

Figure 22. Flow for planned pre-feasibility decision support tool.

IRR = internal rate of return; NPV = net present value; GHG = greenhouse gas.

8.1.2 Inputs

While ideally the barrier to use the tool should be low, it will still be important for the tool to collect enough information from the user for the resulting scenarios to be useful. It is probably necessary to include heat demand profiles, available land area (e.g., roof or ground area adjacent to the plant), budget, solar resource, and site fuel costs to generate useful scenarios. It may be possible to formulate the tool to leverage default libraries in such a way that less specifics are needed for initial use. Some of the other criteria that users may need to specify are their criteria and concerns related to implementation, such as reliability, risk, payback period, employment impact (i.e., plant jobs affected by the change), benefits to local communities (i.e., does this provide an opportunity for a win-win? Can it be linked to a community initiative?), pollution issues and emissions savings. Since movement away from fossil fuels is driven not only by financial considerations but also by the desire to follow decarbonization goals as well as improving environmental, social, and governance profiles, this type of priority may need to be evaluated. Criteria and the level of detail required should be established by a stakeholder engagement process (Dalkey 1969; Dalkey and Helmer 1963; de Loë et al. 2016; Kattirtzi and Winskel 2020). A DST must accurately incorporate the values and priorities of decision makers within industry, including technical and economic specifications but not neglecting environmental, social, and political criteria, which are also key for many stakeholders.

8.1.3 Outputs

Outputs for the tool will include some of the parameters frequently discussed in the literature on energy systems, such as energy yield, LCOH, and changes in net present value based on parameters such as the project life, fuel savings, and payback period. Greenhouse gas emissions savings is one example of an environmental parameter that should be included, but others could include water use, pollution, or other life cycle impacts. Still, in part, the outputs will be dependent on the criteria that potential users establish during the stakeholder engagement period incorporated into the development of the tool. An analytical hierarchy process (Saaty 1987) (a multicriteria decision-making approach) should be incorporated into the tool, whether to select a single option or to prepare the weighted group of potential options for provision of process heat weighted according to the user criteria. For example, if a tool recommends a single option for the provision of heat, this may be easier to understand than multiple options. On the other hand, the choice of a single option may exclude options that the user might ultimately prefer due to additional considerations not included in the model.

Some of the questions to be considered are:

1. Level of detail users wish to receive
2. A single option for heat provision versus a group of options:
    a. How can potential solutions (i.e., technologies and configurations) be compared or contrasted?
    b. How is uncertainty handled?
    c. Which type of sensitivity analysis is conducted?
    d. What are the most probable errors and how are they conveyed to users?
3. How should results be presented?
    a. Which visualization should be presented?
    b. Which metrics should be included?

As part of thinking through the validity and usefulness of such a tool, the team asked certain key questions including:

- What function is the tool fulfilling—what is its job? Which aspects of the goal will the model not address?

The tool should be able to take in specifications of a particular plant (or set of plants) and select feasible RTES solutions. Load profiles for certain industries as available should be included or can be specified by the user to allow for the optimization of the solution in meeting the load and reducing natural gas consumption and emissions. The envisioned tool will be a pre-feasibility tool incorporating the technical backbone of an upgraded version of SAM but combined with a multicriteria optimization approach to select desirable RTES options. It will be used by analysts and engineers to determine technically appropriate and feasible options for the provision of process heat using hybrid and stand-alone RTES systems. As part of this, the tool will at a minimum provide the user with rough cost metrics such as the LCOH, the fuel saved, and the payback period.

- Who makes up the target audience?

The user must be cognizant of the design of their company's process equipment and heating demands. Ideally, the user has a knowledge of hourly heat loads and overall demands through the seasons. If not, sample load profiles should be available for similar industries.

- Who would be a typical user? Who else may be a user?

The primary users are expected to be decision makers undertaking a pre-feasibility of their site, such as analysts, researchers, and engineers. Sales personnel at renewable power companies may also find the tool useful to understand target markets and which of their products may be best suited to certain clients. The DOE Industrial Assessment Center program and users in that program may use the tool to suggest efficiency or environmental savings at a site level if decarbonized technologies are beneficial or would become feasible in tandem with other efficiency savings. National laboratory researchers could use this type of DST to perform regional or national scale analysis for specific industrial sectors, as was recently done for solar generation systems to start determining U.S. potential (McMillan et al. 2021). Note that this tool alone will not be able to provide the level of technical detail needed for site design or all the information necessary for national policy analysis. Still, the capabilities it will encapsulate will be an important first step in a larger effort as adoption increases.

- What are key concerns of the target and secondary audiences?

While some of the key concerns of the target audience are known, such as cost, reliability, risk, and emissions savings, a more comprehensive list should be elaborated in the initial stage of the model building.

- Whose needs will not be served by the tool?

This tool may not be helpful for people without sufficient knowledge of the current operations being replaced or the priorities and needs of the decision-makers. While default libraries will be available for some of the functionality, such as weather, conditions based on location, and some demand profiles available from prior studies, specific criteria for a given plant would not be known by people outside the plant ownership, limiting the usefulness of the analysis they could perform. It is important to note this because much of the movement toward decarbonization is driven by public sentiment, so the level of accessibility by the public determines to what extent they can use the tool (for example public interest groups have protested software used for integrated resource planning by utilities due to difficulties in accessing and using it).

- Which concerns are being excluded?

Since this tool requires familiarity with design specifics and technical parameters, concerns of stakeholders without this level of expertise may be excluded. For example, a tool designed for a similar purpose for geothermal technologies was based upon go/no-go criteria and desired internal rate of return. For this tool, maximum utility would be derived by knowing such financial data but also current fuel costs, available land envelope, and load profile of the plant. It may be possible to ameliorate this deficiency by providing or allowing the construction of defaults or averages for industry types. Still, there is a trade-off between the level of detailed information that can be obtained from the tool and the amount of information needed as input or the level of experience and knowledge of the user.

8.1.4 Planned Upgrades to the System Advisor Model

The publicly available SAM 2022.11.21 can serve as the basis for a future DST and has initial IPH modeling capabilities, including three heat generation modules (NREL 2021). The first is the solar water heating model, though this is not specifically for industrial applications but can be used to simulate potential solar water heating applications at industrial scales by using commercial-sized rather than residential FPCs. The next two are CSP process heat modules where the powerblock effects are removed to simulate heat generation (Turchi, Kurup, and Zhu 2016). The two CSP process heat modules are (1) a parabolic trough system with an oil HTF and (2) a linear focus DSG system, which includes DSG troughs and DSG linear Fresnel collectors. Both the CSP process heat modules have been validated against real operational data (Kurup et al. 2017).

With the growing interest and need for modeling IPH systems and the potential interaction with renewable heat generation sources, SAM capabilities and modules are likely to be extended with further funding from offices at the DOE such as the Solar Energy Technologies Office.

In the next few years, it is likely that SAM could be extended to include sensible-heat CSP power tower and linear Fresnel with molten salt models to the IPH framework. The aim is to leverage the electricity dispatch models to incorporate dispatch optimization for the sensible-heat SIPH models coupled to an IPH load with either steam or HTF delivered as the output. The intent is to optimize dispatch of the generation and stored energy in the TES to heat the industrial process. This is mainly driven by hourly schedules of process operation and the cost of heat. This type of heat optimization model (similar to the CSP electricity dispatch models) would look 24–48 hours ahead of the current schedules and try to use solar heat when it has the most value. The integration of this capability would allow more rigorous costing and could also be used in a future design tool that could optimize costs to choose the best size based on estimated lifetime.

For example, the cost of heat for an industrial user may vary over the day (e.g., varying electricity price or a potential future natural gas market where natural gas price can vary in the day), so the dispatch model will store heat when the cost is low and dispatch to the process when the cost is high. Furthermore, some processes may incur high start-up and shutdown costs. The dispatch model will determine when to run the process at part-load to avoid turning off the process (when solar provides a high fraction of the total heat). This proposed application of dispatch optimization is similar to the CSP-electricity dispatch optimization model, which is fairly adept at providing improved dispatch versus rules-based operating policies. For example, optimizing the dispatch of CSP electricity could increase a CSP plant's revenue by 15% or higher, dependent on the market (Chamberlain 2018). The first-order inputs are schedules and start-up costs. Process part-load is a second-order input that we can represent with an adjustable polynomial to calculate the "efficiency" of the part-load heat relative to design. Note that optimizing to maximize the value of offsetting another heat source with a time-dependent cost does not require a part-load process.

A planned key future SAM development will add and develop IPH load profiles that mimic different industrial heat loads. The aim will be to add known estimated industrial load profiles through work at NREL (McMillan et al. 2021) and also allow the user to upload or add individual heat load profiles. This will allow the user to have a heat load profile that varies over time (like industrial processes), and as such, the RTES system chosen will be coupled with the profile to determine how much of the hourly demand can be met by the RTES solution.

These updates will allow SAM to quantify SIPH scheduling, reliability, heat load matching, and cost savings for a given heat load profile and solar heat technology. It will also give SAM the capability to consider the value of dispatchable solar process heat in present and future markets. This future task will not attempt to develop hybrid IPH models that integrate multiple unconventional solar thermal heat sources together.

Further in the future, alternative TES options, such as latent heat (PCM) energy storage and solid-media storage, are likely to be explored and added to SAM. This will enable the development of storage component models that potentially are better suited for integration with a direct-steam solar field and an end use that requires steam. Some industrial sites use saturated or low-superheat steam. While this is a good fit with DSG field technologies, it is a poor exergetic match for conventional two-tank sensible-heat TES. Phase change storage technologies provide better exergetic heat transfer between a direct steam solar field and a steam end use. Solid-media storage, on the other hand, is better suited for high-temperature SIPH applications where other TES media such as molten salt decompose. The PCMs will be selected through a literature and industry review, using the cost, melting point, heat of fusion, and stability as selection criteria. Preference will be given to materials that are commercially available or deployed, have been or are planned to be used in a demonstration project, or that are promising commercial candidates. A default material selection will be sodium formate, which we have used in this and prior analyses for latent heat storage for steam (Sharan, Turchi, and Kurup 2019). The selection of a particle storage model will use similar criteria and will most likely use the particle storage model from the CSP generation 3 (Gen3) particle pathway (Sandia National Laboratories 2021).

8.1.5 Building Blocks

As part of the building blocks of the DST, data access for validating the models developed to support RTES deployments is needed. This will include different avenues to obtain operational data from plants such as utilizing contacts at Oak Ridge National Laboratory to gain access to companies and data as part of the "Better Plants Program." Load profiles and energy utilized (e.g., current natural gas) data will be investigated via thermal load tracking. Direct contacts at companies that have provided data in the past will be contacted, such as Rackam, who provided monthly load data for a brewery in California that was considering the use of concentrating solar thermal for a prospective site (Kurup and Turchi 2019). This avenue will be pursued again. Published case studies in literature and data from IEA Task 64, which NREL has access to, will also be used for validation efforts. Gaps analysis for future DST model development will be undertaken.

8.2 Overview of Existing Models

A pre-feasibility tool should present decision-makers with the ability to find the best decarbonized solutions for thermal needs. As outlined in previous sections, the tool should reflect standard configurations for a range of technologies. Common options include solar thermal (the focus of this report), but also solar PV to heat, electrification/electric-based technologies, and green fuels including biomass, hydrogen, ammonia, and natural gas. In the United States, some heat batteries are also under development. Hybridization with conventional systems or between decarbonized systems is also helpful. The tool must have the capability to work with thermal loads. Ideally, the tool would support a network of plants so that pre-feasibility could cover many facilities for a single company. Criteria that may be necessary for evaluation include economic criteria such as LCOH, internal rate of return, net present value, capital budget, operating expenses, and payback period, but also technical criteria such as technology readiness level, reliability, installation time frame, efficiency, availability, temperature range, and environmental, social, and governance criteria as discussed earlier. The evaluation of existing simulation and pre-feasibility tools in the renewable energy space allows the identification of current capabilities as well as areas that may require further development.

Since most considerations for adoption of RTES fall under the techno-economic category, many existing tools can be studied and used for the portion of the DST that require simulation. The tools typically require the user to specify the renewable system parameters, including typical meteorological year (weather), which may also be available for download, and installation size, equipment models, configuration, and storage. The models can then provide information about expected thermal power and financials. Most do not provide insight into many social, political, or environmental parameters (Cuesta, Castillo-Calzadilla, and Borges 2020).

Simulation models that can be used for the study of IPH applications as well as energy models that may not be suitable for IPH but do allow selection of various system components for energy systems are shown in Appendix B, along with key characteristics. The developer is identified, as well as whether the tool is available free of charge. For example, the NewHeat tool is proprietary, so not distributed widely, and RETScreen provides a free tool suitable for many applications but charges a nominal fee for full functionality. Tools range from allowing detailed simulation of single process units with high coverage of available technologies (TRNSYS) to systems-type models with less specification for individual components (CALLIOPE). For maximum flexibility, some researchers prefer to model using packages such as MATLAB and SCILAB, which require customization by the user. CALLIOPE has been the basis of open-source system models that are available for use as well. PySAM has similar functionality, allowing developers to create models based on the SAM Simulation Core.

Many simulation and systems models are focused on power generation from renewables; some models focused specifically on industrial applications have emerged, such as RESSSPI (Frasquet et al. 2018) and SHIP2FAIR (specifically for agricultural and food industries) (Royo-Pascual et al. 2020). Others, such as SAM and Greenius, are focused more generally on renewables with more attention paid to the types of installations suitable for power generation and less focus on industrial applications, although the rest of this report has documented SAM's capabilities, planned and existing, related to solar thermal technologies. SAM and Greenius both include fuel cells as one simulation option. SAM includes biomass combustion as well. Greenius allows some specifications around a backup boiler running on fossil fuels. These specifications allow some treatment of alternative fuels, but neither tool has a robust way of modeling green hydrogen or other green fuels as substitutions for industrial process heat or power. RETScreen, produced by the Department of Natural Resources of the Government of Canada, includes a pre-feasibility tool called the smart project identifier which provides a functionality similar to that envisioned in this tool. RETScreen also attempts to provide feasibility studies and includes a range of technologies, including some solar thermal as well as power and fuels, including both alternative and fossil fuels. Other energy tools are less focused on renewables, so have more functionality to include fossil-based sources and substitute different fuels with user-specified properties.

DER-CAM attempts to provide a pre-feasibility decision-support function similar to that envisioned here, although for microgrids rather than industrial applications (Stadler et al. 2014). In DER-CAM, the user provides information about the requirements, and the system suggests an optimal portfolio for meeting energy needs. The solar thermal components in DER-CAM are not described in available documentation, and at time of writing the developers had not responded with more information to allow a determination of which technologies are included.

The models range in their treatment of uncertainty and risk, with some models allowing more comprehensive handling such as Monte Carlo and others providing single estimates. Typically, the models include the environmental criteria of land area and greenhouse gas emissions; none of the models listed include further environmental criteria except systems models that estimate maximum renewable penetration or fraction of renewables. The social criteria included in iHOGA are employment and human development index. The political considerations in EnergyPRO are related to regulatory compliance. Greenius has a parameter allowing the user to set the maximum fossil fuel use permitted by law, but this is not included as a political parameter/result.

Taken together, the models shown include most of the functionality at a basic level needed for a mature DST for industries to consider inclusion of renewable technologies. Still, a more robust and updated set of technologies, built-in flexibility in applying the technologies, and a wider set of parameters—particularly social, environmental (besides greenhouse gas emissions and land area), and political concerns—are still needed. Energy efficiency has frequently been noted as an important area for analysis as well (McMillan et al. 2021), but is not included in most of the simulation tools. Where it is included, it is usually in the platforms where the user directly provides the input for energy use. More thought should be put into this area to avoid designing tools that answer the questions that are easiest to answer, rather than the ones decision makers are really trying to ask. Further treatment of sensitivity should also be considered since SAM is a likely basis for the planned DST. Appendix B shows the comparison between the tools reviewed and the capabilities of each.

9 Recommendations and Future Paths

One of the recommendations from this work is the continued development of SAM, which could form the basis of a future DST. The SAM software already includes the full technical and financial models for the separate renewable energy systems and, including other reasons like a large user base and optimization capabilities, is thus a good platform for further developing the hybrid simulation models. Needed SAM developments for modeling hybrid RTES include refactoring component models for sharing across systems; generalizing integration methods, control, and optimization for subsystems and combinations of systems; standardizing interfaces to allow use of these new generalizations; and improving the sizing routines, as previously described. These improvements are needed as hybrid systems add design and operational complexity, failure modes, and potential configuration incompatibilities. New user interfaces will also need to be added, similar to those for the single, non-hybrid system models in SAM. Developments for these hybrid models will continue to be progressively released in an open-source manner with stable versions released and publicized annually.

The second recommendation is to develop the DST, in addition to providing a resource for users inside and outside of industrial facilities, the DST could also aid in the overall adoption and diffusion of RTES in the United States. The process of determining needs of potential users and identifying use cases will also contribute to the understanding of how RTES are viewed by different industries and the roles different actors play in evaluating and integrating RTES. The DST could be promoted to groups that currently provide facility energy assessments, such as the Industrial Assessment Centers and state-level organizations, as part of a standard toolkit for reducing and decarbonizing energy use. Note that this is conceived of as a pre-feasibility tool; additional tools such as for specific design support or policy decision support may also be necessary as adoption of these technologies proceeds.

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Appendix A. SAM Module Development for the Flat Plate Collector–Parabolic Trough Collector Model

This model was developed using the code base for NREL's System Advisor Model, or SAM. SAM is a well-established open-source tool for modeling solar heat systems and is a good means of disseminating a custom model. In SAM, solar water heating with flat plate and evacuated tube collectors can already be modeled to evaluate the thermal yield. SAM's concentrating solar power (CSP) models for industrial process heat can use parabolic trough and linear Fresnel technologies to either deliver heat to a heat transfer fluid, like molten salt or oil, or it can deliver the heat directly to the steam used by the industrial process. The solar water heating and CSP annual thermal outputs from these models can be post-processed with financial models in SAM to calculate financial metrics such as levelized cost of heat and net present value.

Since the components for a parabolic trough plant are already in SAM, the first step in building this hybrid model was to create the flat plate collector (FPC) model. An integrated solar water heating system model is already in SAM, but its heat exchanger derates, hot water tank, supplemental electric heating, pumps, piping models, etc. needed to be decoupled from the flat plate collector array, which is all that is desired for the hybrid model (Figure 23). The lumped, flat plate array approximation was also replaced with a parameterized array of individual collectors. This allows control over the series and parallel configuration and more accurate modeling of the piping flow and heat loss between the collectors. Also, a new heat transfer fluid with respective property relations was added to SAM: a 50% propylene-glycol solution, to be used in this flat plate collector array.

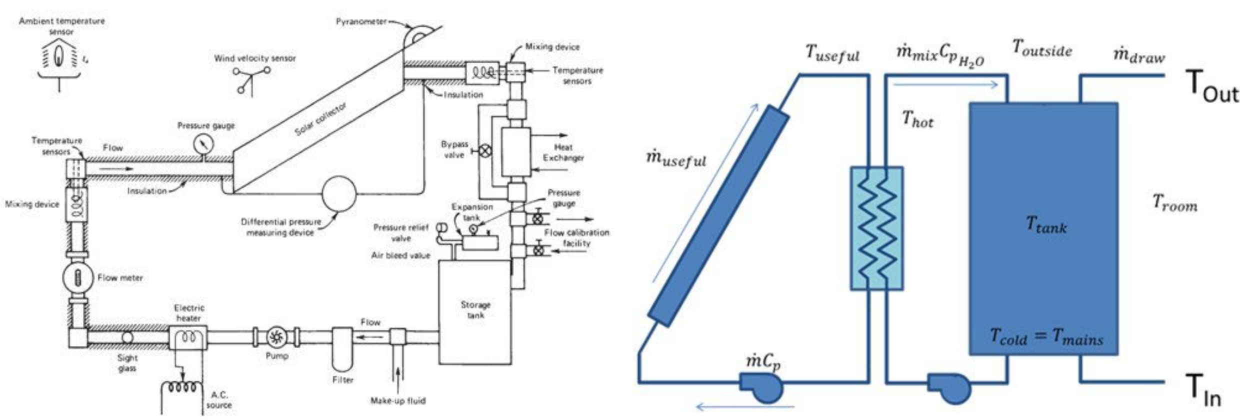


Figure 23. (left) Solar Energy Engineering, Duffie and Beckman; (right) SAM's translated solar water heating model

A heat exchanger was added between the flat plate and parabolic trough arrays (Figure 24). This was to decouple the two arrays and allow more independent operation, including having the arrays use different heat transfer fluids and running at different mass flows. This allows for more efficient operation and more accurate operation, regarding the intermediate temperature to the parabolic troughs.

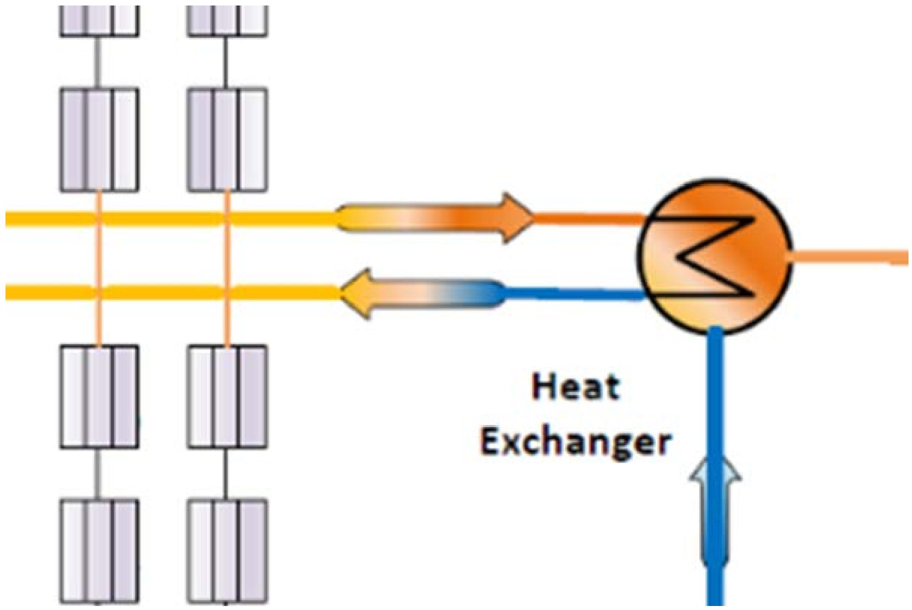


Figure 24. FPC-side heat exchanger

Decoupling the flat plate array meant the need for an additional pump and corresponding controller. This new controller regulates the flat plate array pump's mass flow in order to maximize the heat exchanger effectiveness, or basically the heat flow between the fluids at the given conditions. The controller also restricts the flow to the maximum allowed by the collectors.

Working together with the controller in the flat plate array model is also the new needed solver. This solver calculates the true temperatures in the array, in an iterative manner, as the solution cannot be solved explicitly. The algorithm for getting the array's inlet temperature to converge to a solution uses the array's heat gain and the inlet temperature at the parabolic trough collector (PTC) side of the heat exchanger.

For the PTC field, the sizing procedure is similar to the sizing of a regular PTC-only plant: where the heating power dictates the total size of the PTC field, the process heat temperature dictates the number of PTCs in series, and the mass flow constraints of the PTCs dictate the number of subfields. However, with the hybrid plant, the PTC field is sized using a higher inlet temperature, resulting in fewer PTCs in series (Figure 25).

The FPC field, however, is sized according to the design mass flow, the relatively constant process-heat outlet temperature, and the target intermediate FPC outlet/PTC inlet design temperature. The design mass flow is dictated by the design plant power and temperature, and in turn determines the number of FPCs in parallel. The temperature rise from the cold inlet to the intermediate temperature determines the number of FPCs in series. This sizing is performed at a constant standard ambient temperature and irradiance; however, since the FPCs are stationary and experience a range of cosine losses throughout the day and seasons, the intermediate temperature is always changing.

Lastly, the heat exchanger is sized to maximize its effectiveness for the design heat gain, fluids, and target approach temperatures. The effectiveness is the actual heat transfer from one fluid to the other, divided by the theoretical maximum.

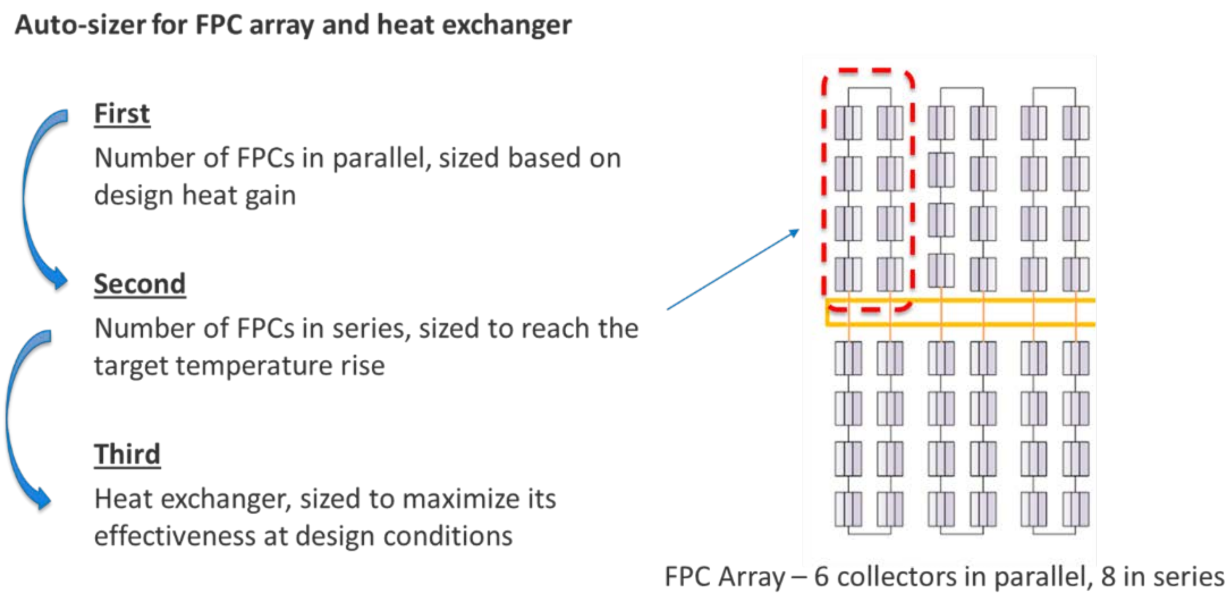


Figure 25. Auto-sizer for FPC array and heat exchanger

The hybrid FPC and PTC plant is sized according to the desired process heating power, temperature, hours of thermal storage, mass flow constraints, and the nominal temperature into and out of the FPC field. The sizing of the FPC system in SAM is still a manual process that allows the user to define the system based on their requirements. However, it can also be automatic if the user sets both the number of FPCs in parallel and in series to the value of "−1" in the "Inputs" browse, the FPC array will auto-size. In automatic sizing, the FPC field will be sized according to the design mass flow, the relatively constant process-heat outlet temperature, and the target intermediate FPC outlet/PTC inlet design temperature.

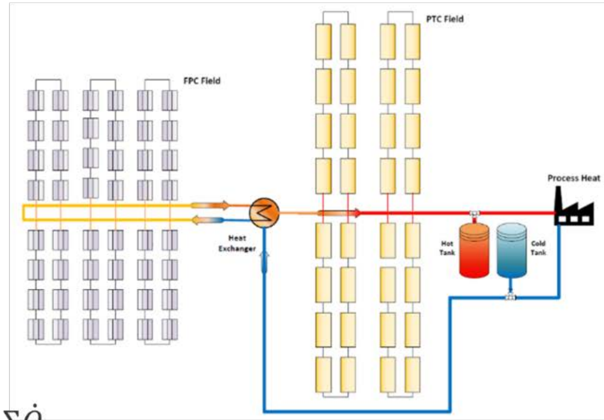
When sizing the hybrid system manually, the following effects need to be considered to keep the arrays operating within their temperature and mass flow constraint windows, at both design and operating conditions. The total number of FPCs affects the heat transferred to the system and thus the temperature into the PTCs. Increasing FPCs in series vs. parallel has a less significant effect on the intermediate temperature to the PTC array when using a heat exchanger (Figure 26.).

- Increasing the PTCs per loop will increase the temperature to the TES and process heat. If this temperature hits the set point, it will cause the PTC field mass flow to increase to maintain that temperature.
- Conversely, lowering the PTC mass flow will lower the FPC mass flow, causing its heat transfer fluid temperature to increase and subsequently its heat loss to increase.
- Increasing the number of PTC loops will increase the heat rate (thermal power) to the thermal energy system (TES)/process heat and will charge the TES faster.

Manual sizing

FPCs

$$\uparrow N_{FPC} \Rightarrow \uparrow \Sigma\dot{Q}_{FPC} \Rightarrow \uparrow T_{in,PTC}$$



PTCs

$$\uparrow N_{loop,PTC} \Rightarrow \uparrow T_{IPH} \Rightarrow \uparrow \dot{m}_{PTC}$$

$$\downarrow \dot{m}_{PTC} \Rightarrow \downarrow \dot{m}_{FPC} \Rightarrow \uparrow T_{FPC} \Rightarrow \uparrow \Sigma\dot{Q}_{loss,FPC}$$

$$\uparrow N_{loop,PTC} \Rightarrow \uparrow \Sigma\dot{Q}_{PTC} \Rightarrow \uparrow Q_{TES}$$

Figure 26. Manual sizing for the hybrid system

A schematic of this novel design is shown in Figure 26. In that schematic, starting on the left and progressing right, is the flat plate collector array, the heat exchanger, shown as an orange circle, the parabolic collector array (in yellow), then the thermal energy storage tanks, and finally the process heat. The system uses different heat transfer fluids in the flat plate and parabolic trough arrays, mostly due to their different operating temperatures, thus the need for a heat exchanger.

This constructed system will provide valuable data for validating a hybrid system model built in SAM, which will help determine the utility and financial viability of hybrid renewable thermal energy plants. As such, replicating this plant in SAM was one of this project's tasks.

Hybrid plant operation is more sophisticated than that for a regular PTC or FPC plant as it must simultaneously hit the desired process heating power and temperature output targets while contending with coupled subsystem controls. Additionally, the mass flow constraints and the nominal temperature into and out of the FPC field must be adhered to.

The system controller is similar to the PTC-only plant, where the mass flow through the entire system regulates the outlet temperature. The PTCs are also still used to provide a high-temperature limit control via defocusing or pointing away from the sun. However, model convergence for this hybrid plant requires more algorithmic logic as the PTCs cannot easily predict their variable inlet temperature iteration to iteration. More iterations, time step to time step, are also needed because of some confounding by the separate FPC controller as it works to optimize its heat exchanger operation (Figure 27). The customizations to the CSP controller needed for this hybrid system ensure robust solving across all feasible system designs and include modifications to numerous internal solver parameters, addition of new operating states and decision tree paths, and the addition of new failure modes and how to recover from them. Only one CSP controller can currently exist in the SAM framework, so all other models that use the controller are not operational in this customized version of SAM.

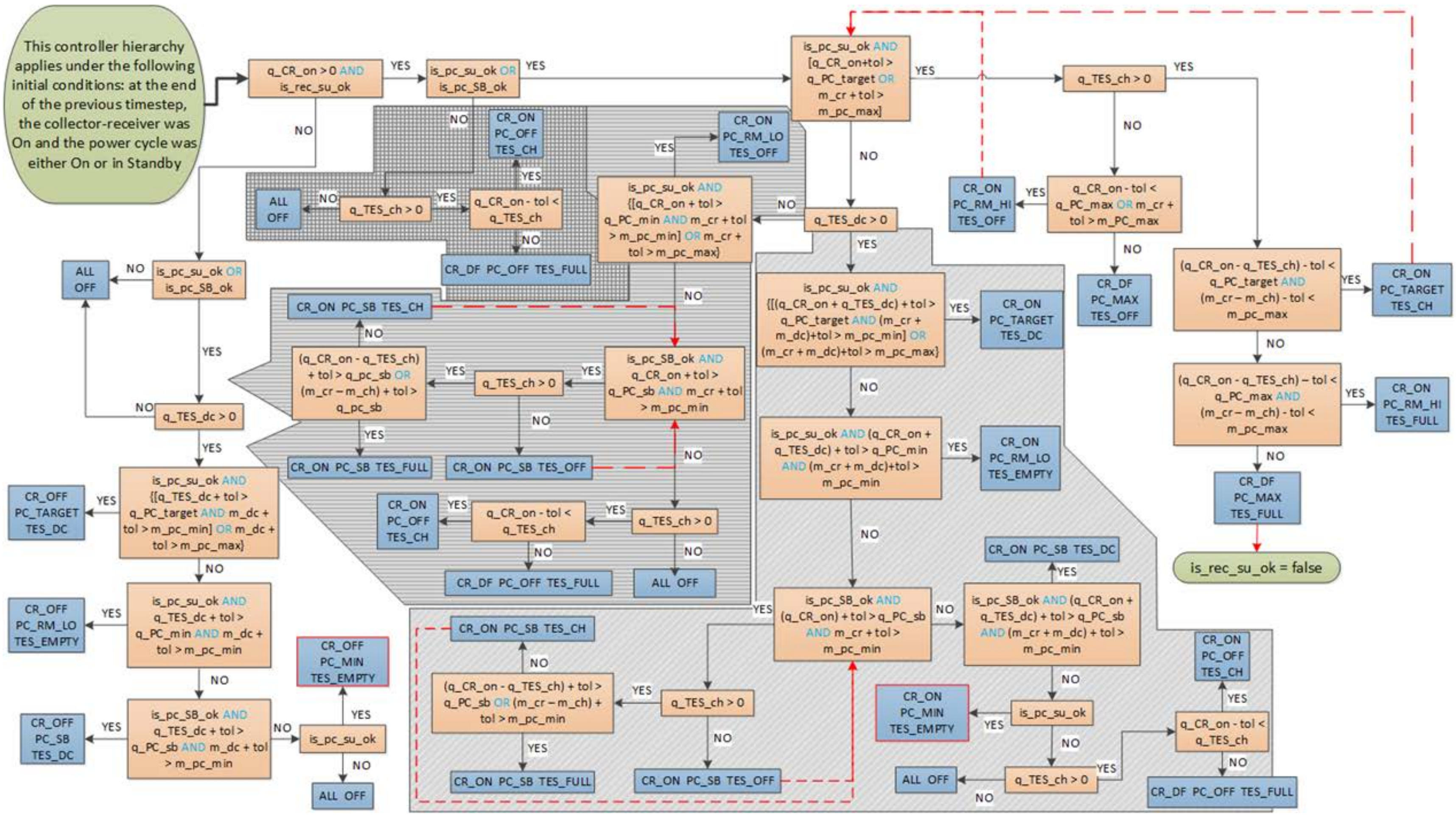


Figure 27. CSP Controller Logic—field and power block on

Appendix B. Simulation and Energy Systems Modeling Tools

Simulation and energy systems modeling tools with relevant functionality are compared according to the technologies covered and the parameters included in the results at time of writing.

Tool	Developer	Renewable Fuels	Flat Plate	Evacuated Tube Collectors	Concentrating Collectors	Electrification	Energy Efficiency	Storage	Technical	Economic	Social	Environmental	Political	single/system	Free?	Focus	URL
NewHeat	NewHeat		x	x				x	x	x				P	n	thermal	https://newheat.com
SHIP2FAIR	EU collaboration		x	x	x			x	x	x		x		S	y	thermal	http://ship2fair-h2020.eu/
ressspi	Solatom		x		x			x	x	x				S	y	thermal	https://www.ressspi.com
Polysun	Vela Solaris	x	x	x		x	x	x	x	x		x		SY	n	electricity, thermal	https://www.velasolaris.com/?lang=en
SAM	NREL	b	x		x			x	x	x		x		S	y	electricity, thermal	https://sam.nrel.gov
Greenius	DLR	x	x	x	x	x		x	x	x		x		S	y	electricity, thermal	https://www.dlr.de/sf/en/desktopdefault.aspx/tabid-11688/20442_read-44865/
RETScreen	Government of Canada	x	x	x	x	x	x	x	x	x		x		S	f/p	electricity, thermal	https://www.nrcan.gc.ca/maps-tools-and-publications/tools/modeling-tools/retscreen/7465
Homer	Homer Energy					x		x	x	X		x		SY	n	power	https://www.homerenergy.com
iHOGA	Universidad de Zaragoza	x				x		x	x	x	x	X		S	n	power	https://ihoga.unizar.es/en/
Compose	Aalborg University								x	x		X		S	y	cogeneration, power	https://www.energyplan.eu/othertools/local/compose/
DER-CAM	Berkeley Lab	x				x	x	x	x	x		x		SY	y	electricity, distributed	https://gridintegration.lbl.gov/der-cam
Calliope	Stefan Pfenninger								x	x				SY	y	energy systems	https://calliope.readthedocs.io/en/stable/
EnergyPRO	EnergySoft					x	x		x	x		x	x	B	n	building energy	http://www.energysoft.com
TRNSYS	Thermal Energy System Specialists, LLC	x	x	x	x	x	x	x	x	x				S	n	general, energy	https://www.trnsys.com
Matlab	Mathworks													NA	n	general	https://www.mathworks.com/products/matlab.html
SCILAB	Scilab													NA	y	general	https://www.scilab.org/

Notes: S: single; SY: system; B: buildings; P: proprietary; f/p: both free and paid versions are available—the free version does not incorporate full functionality. SAM includes only biomass in terms of renewable fuels, shown by ‘b’. Built-in functionality of tools includes at least some technical parameters, and almost always includes financial/economic parameters. Greenhouse gas emissions are the most common environmental parameter included, and most tools do not include social (e.g., jobs, human development index) or political parameters (e.g., regulatory feasibility).