Joint Institute for Strategic Energy Analysis

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Renewable Thermal Hybridization Framework for Industrial Process Heat Applications

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Abstract. Solar industrial process heat (SIPH) technologies, such as concentrating solar power collectors, could economically replace the steam or heat needs at many industrial sites by providing high-temperature heat transfer fluids (HTFs) such as pressurized water, synthetic-oil, or direct steam. Renewable thermal energy systems (RTES) could be hybridized with different renewable options e.g., flat plate collectors with parabolic trough collectors, or combined with existing heat supplies (e.g., fossil fuels), to give options for targeted SIPH applications, industrial decarbonization and the reduction of fuel consumption. Hybrid solutions and thermal energy storage will be important for the dispatch of heat at optimal times needed by the demand side of the buildings and industrial applications. At present, there is no integrated modeling tool for hybrid RTES, and this paper highlights the development of a renewable thermal hybridization framework for IPH use that is built from existing tools like System Advisor Model. The long-term vision for the framework (through significant further research) is to develop a coupled hybrid energy generation and cost analysis tool, where the tool could help the user in determining the most suitable and cost-effective technologies for their applications. Ongoing work will look to add costs for RTES options and further refinement on the selection of suitable technologies. This future tool could calculate the levelized cost of heat of various RTES hybrid options, by taking the user's solar resource, fuel costs, industrial heat demand profile, available land, and other factors into account to determine the applicability into their process.

LITERATURE REVIEW

Industrial process heat (IPH) applications require different temperature ranges, quantities, and rates of thermal energy [1]. Hybrid solutions and thermal energy storage (TES) would play an important role for dispatching heat at optimal times needed by the industrial heat demand. Denmark is a good example where hybrid renewable thermal energy system (RTES) solutions are being deployed and are cost competitive today with the current regional natural gas costs. One example of a hybrid system combines flat plate collectors (FPCs) and concentrating solar power (CSP) parabolic trough collectors (PTCs) coupled in series, with water storage, and has been operational since 2015 [2]. This hybrid RTES connects to the existing gas fired district heating system and can meet approximately 30% of the town's annual district heating needs [3], [4]. Another example for low to medium temperature hybrid RTES options is a PTC solar field with an aperture area of 627 m^2, that provides 120°C heat to a dairy that is utilized as part of the milk processing in Switzerland [5]–[7]. As an example for higher temperature industrial applications, in Shams-1 plant a CSP system with a natural gas boiler boosts the temperature up to 540°C steam [8], [9]. This type of hybridization could be highly valuable for key industries.

The National Renewable Energy Laboratory (NREL) has a well-established tool for modeling solar heat systems called System Advisor Model (SAM) [10]. In SAM, stand-alone RTES technologies such as glazed and evacuated tube FPCs for solar water heating (SWH), linear Fresnel collectors (LFCs), and PTCs can already be modeled to evaluate the thermal yield. SAM's CSP models for IPH can use PTC and LFC technologies, that can either deliver heat to a liquid-heat transfer fluid (HTF), or directly via direct steam generation (DSG). Currently, the public version of SAM (2020.2.29) can do single system modelling very well but it is not yet capable of hybrid RTES modelling at different temperatures or combining technologies such as FPCs and CSP together.

METHODOLOGY

A variety of tools and platforms, such as SAM, can provide accurate hourly thermal yield simulations from single renewable energy (RE) technology options, including FPCs or CSP for SIPH [7], [11]. At present, there is no single tool that can help the industrial user, to model and combine hybridized RTES options for their site, considering their solar resource and operating conditions. We have investigated a variety of approaches to hybridize RTES at different temperatures or combinations of technologies and developed an initial modeling framework. The premise for hybrid RTES solutions is that novel heat generation solutions can be modelled (e.g., performance and techno-economic analysis, helping the user with future developments to find low-cost heat options for their site. This hybridization framework starts by creating a heat stream and raising the temperature of that stream by various combinations of RE technologies and other sources such as fossil fuels, renewably derived fuels, or electric heating in multiple stages, with options for TES and/or waste heat recovery (WHR) (FIGURE 1).

The purpose of the initial framework is to highlight how hybrid RTES options can meet varying levels of temperature and heat demands. We recognize that heat provision at the site is complex. Both IPH and district heating applications have their own unique heat demand and annual heat profiles [1], [12]. Today, this heat demand is primarily met by fuels such as natural gas (NG), propane, or fuel-oil. Our approach is to analyze the replacement or offsetting of primary fossil fuel energy with hybrid RTES systems, carbon-free fuels, and energy dispatch through TES. This framework can also be expanded to use WHR systems; however, this is not currently scheduled and will need to be examined in the future. Other important components of this framework are high efficiency burners, boilers, and heat exchangers. By creating paths for the provision and dispatch of renewable heat through RTES hybrid options, e.g., modelling and techno-economic analysis of delivered heat, each potential path can be improved through further research and development (R&D). This framework eventually could lead to an integrated tool, with RTES hybrid options. SAM is one key platform used to develop some of the hybrid models highlighted.

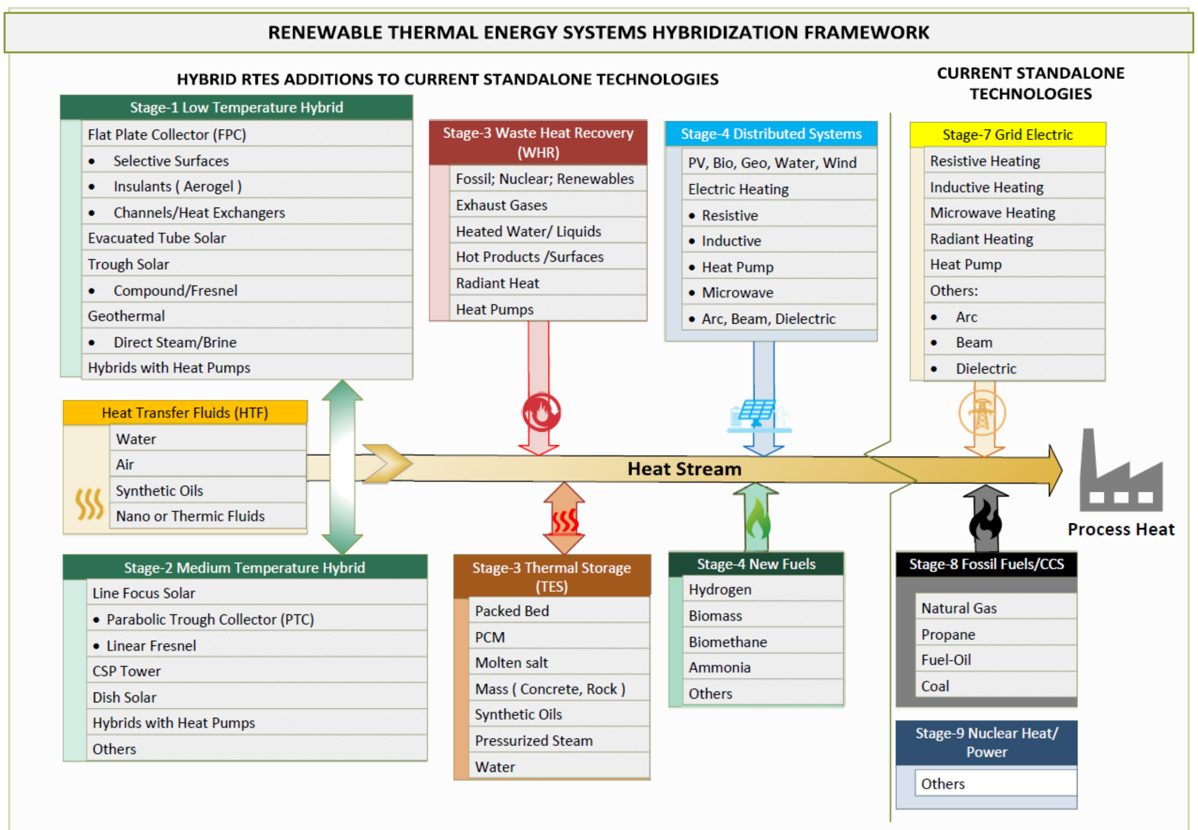

FIGURE 1. Overview of the RTES hybridization framework showing possible combinations of renewable and other sources in stages to raise the temperature of the heat stream to meet the IPH demands.

MODELLED SCENARIOS

We have developed an initial framework and a variety of approaches to hybrid system modeling for RTES at different temperatures or combinations of technologies. We developed three hybrid RTES models, as innumerable hybrid RTES models can be made. Initial models to test key hybrid systems are designed based on commercially available solar heat technologies such as FPCs, LFCs and PTCs, which are suitable for integration with TES and conventional natural gas combustors on industrial sites [1]. The modelled scenarios highlighted in this paper are listed below, and the initial results of these three scenarios are presented in another publication by the authors [13]:

- FPCs and PTCs with TES
- PTC retrofit to a natural gas combustor.
- DSG LFCs and Phase Change Material (PCM) storage

Scenario 1: FPC and PTC with Thermal Storage

The first scenario uses a customized SAM code (which is not available in public version yet) to model FPC and PTC fields and combines them with a heat exchanger. This scenario is designed to generate 4 MW_{th} of thermal power, with solar multiple of 2 and a thermal storage capacity of 8 hours. The FPC portion of the system is using a water glycol mix as the HTF and heat (up to 90 °C) is transferred to the PTC side of the system via a heat exchanger. The PTC system is designed to use either pressurized water (for 150 °C end-use applications) or Therminol VP-1 (for 300 °C end use applications (FIGURE 2). The hybrid system is combined with a TES for an IPH application. The benefit of this hybrid system is that it can potentially reduce the plant cost relative to a PTC-only plant having the same output specifications. The lower temperature heating can be achieved by cheaper FPCs, while the higher temperature heating outside the range of the FPCs is accomplished by the PTCs.

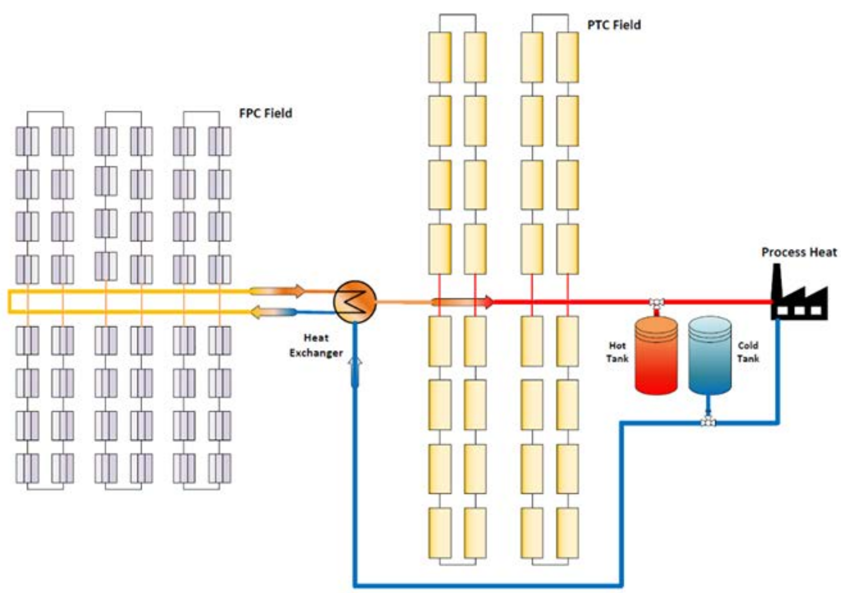

FIGURE 2. Hybrid FPCs and PTCs design with TES using a water glycol mix as HTF in FPC field and pressurized water (or synthetic oil as HTF in PTC filed and the TES.

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 procedure is similar to the sizing of a regular PTC-only 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. The equations of the heat transfer are present in the SAM [10].

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.

This variable intermediate temperature requires the plant controller to be more sophisticated than 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. System optimization must account for these over yearly environmental conditions that may influence the subsystems differently and cause interactions.

The SAM software already includes the full technical and financial models for the separate RE systems and, including other reasons like a large user base and optimization capabilities, is thus a good platform for developing the hybrid models. Needed SAM developments for modeling hybrid RTES include first refactoring component models for sharing across systems, generalizing integration methods, control and optimization for subsystems and combinations thereof, 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.

Scenario 2: PTC Retrofit to a Natural Gas Combustor

The second scenario is designed to use a PTC solar field with a liquid Therminol VP-1 HTF providing heat to both air feed and fuel streams of a natural gas combustor system. This is expected to be suitable for hybridization of existing industrial systems that use natural gas combustor today. The exit temperature of the PTC system ranges between 180 °C and 300 °C, and the outlet of the natural gas combustor is designed to feed the medium temperature IPH application at 300 °C or a high temperature application at 1,000 °C (FIGURE 3). IPSEpro (a commercial software) is used to calculate heat balances, enthalpies, and simulate processes for the heat exchanger and natural gas combustor in this scenario [14], [15].

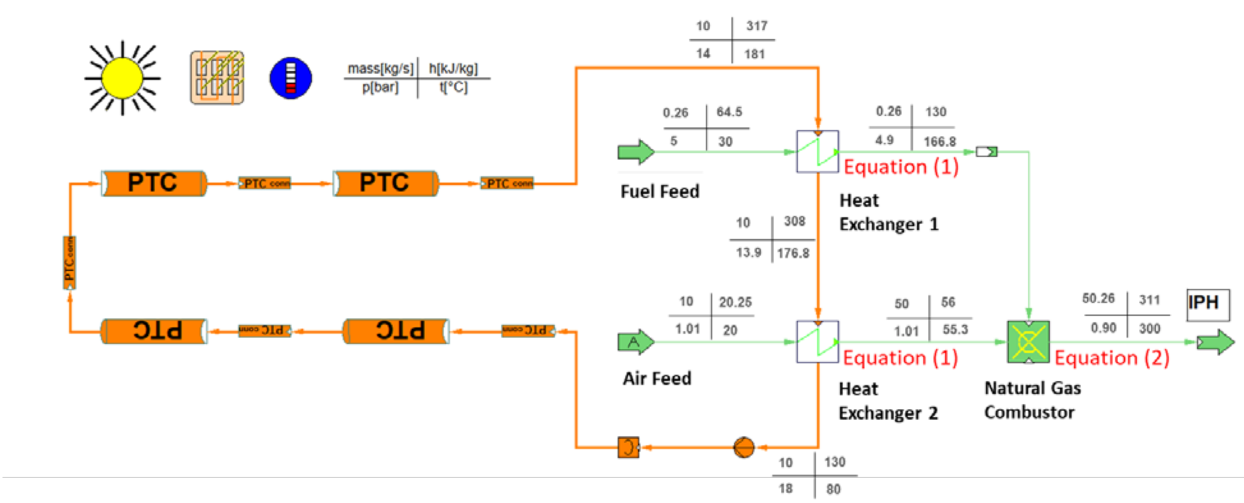

FIGURE 3 IPSEpro process flow diagram for PTC system retrofitted to an existing natural gas combustor via dual heat exchangers.

This scenario is a potential near-term representation of what industrial sites could utilize to hybridize their current existing system with a renewable thermal input and as such reduce fuel consumption. TES was excluded to simplify the first iteration of this modelling scenario. The solar field in FIGURE 3, with an annual capacity factor of 24%, is set up to deliver temperature ranging from 180 °C to 300 °C via an HTF (Therminol VP-1) and the heat is transferred to both natural gas fuel stream and air feed streams by heat exchangers using the basic energy balance equation given below.

$$\left(m_{\mathrm{feed}_{\mathrm{hot}}} * \left(h_{feed_{hot}} - h_{drain_{hot}}\right)\right) * \left(1 - \frac{Q_{loss}}{100}\right) = Q_{trans}$$
$$\left(m_{\mathrm{feed}_{\mathrm{cold}}} * \left(h_{drain_{cold}} - h_{feed_{cold}}\right)\right) = Q_{trans} \tag{1}$$

Where, h_{feed_hot} is the enthalpy of Therminol VP-1 before the heat exchanger, h_{drain_hot} is the enthalpy of Therminol VP-1 after the heat exchanger, h_{feed_cold} is the enthalpy of air feed or natural gas fuel streams before the heat exchanger, and h_{drain_cold} is the enthalpy of air feed or natural gas fuel streams after the heat exchanger, m is the steam mass flow, Q_{loss} is the heat loss and Q_{trans} is the heat transferred.

Pre-heated natural gas and air feed streams are connected to the natural gas combustor to provide the IPH application 300 °C or 1,000 °C heated combustion air, by using the enthalpy-based energy balance equation below.

$$\left(h_{\mathrm{air\_feed}} * m_{air\_feed}\right) + \left[\left(h_{fuel} + HV\right) * m_{air\_feed}\right] = \left(h_{\mathrm{drain}} * m_{drain}\right) + Q_{rad} \tag{2}$$

Where, $h_{\mathrm{air\_feed}}$ is the air feed enthalpy, m_{air_feed} is the air feed mass flow, h_{fuel} is the fuel enthalpy, HV is the heating value, $h_{\mathrm{drain}}$is the process heat stream enthalpy, m_{drain} is the process heat stream mass flow, e, and Q_{rad} is the radiant heat flux.

Optimization of the delta temperature rise across the air stream heat exchanger and natural gas heat exchangers will need to be investigated to highlight the best natural gas offset. Today's technology for solar thermal application can offset a limited amount of natural gas consumption for an energy intense process application. The optimization in the future will show whether the natural gas offset can be increased, for example by increasing the heat delivered to the air stream. The economic analysis would highlight aspects such as net present value (NPV) and payback once the costs of the hybrid RTES are identified, to then determine the LCOH as found in other analysis [16].

The results of a recent NREL study showed that as the solar field outlet temperature gets closer to the IPH demand, higher NG offsets can be achieved for a given annual capacity factor of 24% [13]. When TES is added up to 8hrs of storage capacity, the overall capacity factor can be increased to approximately 50% based on the direct normal irradiance (DNI) conditions. We are planning to add an optimized dispatch model to the variable temperature PTC solar field, where the HTF can provide heat to the natural gas and air streams entering the natural gas combustor. Other alternative scenarios such as co-operation of PTC and natural gas burner to provide process heat in two separate streams, and waste heat recovery with a recuperator after the natural gas burner could also be analyzed to compare the effectiveness of the use of hybridization and systems costs.

Scenario 3: DSG LFCs with PCM Thermal Storage

The third scenario uses DSG LFCs coupled with TES which uses PCMs to improve the system's flexibility and capacity factor. Hybrid system design and specifications are summarized in FIGURE 4. PCMs store energy in the latent heat of the phase change and can thus achieve relatively high energy densities [17]. PCMs are also well suited for integration with systems that use steam as the working fluid [17]. For this scenario, the LFC DSG system is modelled using SAM, however current version of SAM is not capable of modeling PCM storage system. Thus, thermal storage is modeled by custom-made program developed in MATLAB. SAM is only used to generate the hourly thermal and steam outputs from the LFC array for a year, which is an input to the MATLAB model. Relevant data, such as the steam mass flow rate, steam quality and temperature, is then read into the PCM storage program which determines the sizing of the thermal storage system, the hours in which charging and discharging take place, and the transient thermodynamic performance of the storage system.

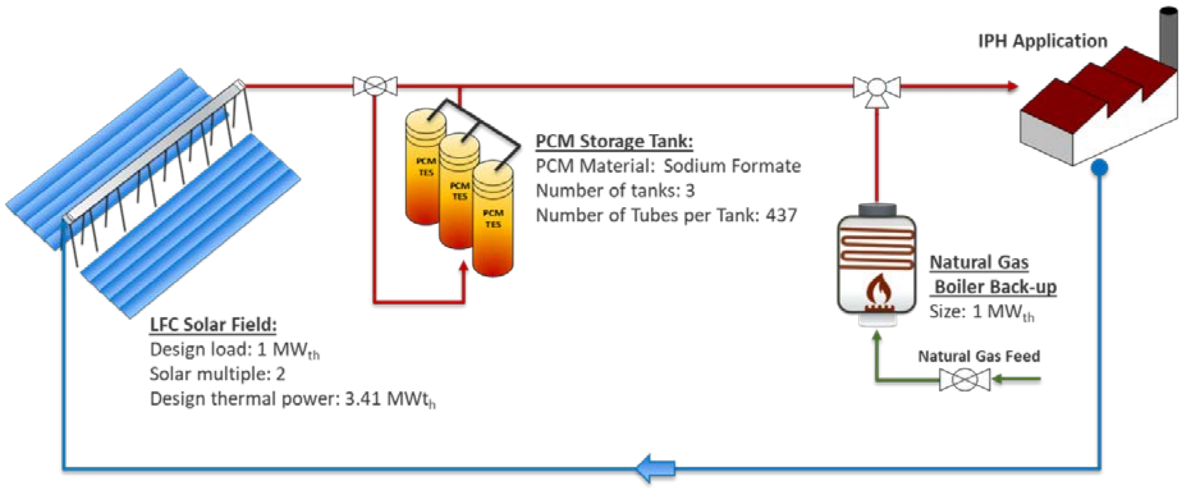

FIGURE 4 Hybrid system design and specifications for a linear Fresnel collector (LFC) direct steam generation (DSG) and phase change material (PCM) with natural gas boiler back-up. (LFC design load is set as 1 MW$_{th}$, PCM material is selected as sodium format, and the natural gas boiler back-up size is set the same as LFC system size).

The system is designed to satisfy a thermal power of P_{load} which is required by the load. The solar field is set up to deliver a thermal power of P^0_{solar} at the maximum solar irradiance (normally around 1000 W/m^2), where the superscript 0 indicates design conditions. The solar field is typically oversized by a factor known as the solar multiple f_{SM}, such that $P^0_{\text{solar}} = f_{\text{SM}}P_{\text{load}}$, which ensures that the solar field can deliver the required power even when the solar irradiance is less than the maximum value. The thermal storage system is set up to be charged whenever $P_{\text{solar}} > P_{\text{load}}$ and to be discharged when $P_{\text{solar}} < P_{\text{load}}$. The thermal storage geometry is designed by considering the maximum charging power which is $P^0_{\text{TES}} = P^0_{\text{solar}} - P_{\text{load}} = P_{\text{load}}(f_{\text{SM}} - 1)$.

The total steam mass flow rate into the storage during charging is calculated by assuming that the steam enters with the design quality q^0 determined by the solar field, and that the steam is fully condensed in the storage. The design charging mass flow rate is therefore

$$\dot{m}\,^0_{\text{chg}} = \frac{P^0_{TES}}{h_i(p_{\text{chg}}, q^0) - h_o(p_{\text{chg}}, q = 0)} \tag{3}$$

where, h is the enthalpy at the inlet i and outlet o, respectively, p_{chg} is the steam pressure during charge, and q is the quality. Similarly, the design mass flow rate during discharge is calculated to generate steam with a quality of q^0 and is given by

$$\dot{m}\,^0_{\text{dis}} = \frac{P^0_{\text{load}}}{h_o(p_{\text{dis}}, q^0) - h_i(p_{\text{dis}}, q = 0)} \tag{4}$$

It is desirable for the charging and discharging mass flow rates to be roughly equal as this ensures that storage will charge and discharge more uniformly. However, the charging mass flow rate typically exceeds the discharging mass flow by a factor close to f_{SM}. As such, the storage is divided into several modules and the number of modules is given by $N_{\text{modules}} = \dot{m}^0_{\text{chg}} \,/\, \dot{m}^0_{\text{dis}}$. All modules are charged simultaneously, but during discharge they are discharged one at a time. Therefore, the mass flow rate through a module is always close to $\dot{m}^0_{\text{dis}}$.

The storage modules comprise tubes of diameter d_i and length L through which the steam flows, as illustrated in FIGURE 5. These tubes are surrounded by the PCM layer of thickness $t_{\text{PCM}} = (d_o - d_i) \,/\, 2$. The total volume of PCM $V_{\text{PCM,tot}}$ is given by considering the total energy to be stored. For a thermal power input of P_{TES} that lasts for a time of τ_{chg}, the energy stored is given by

$$E = P_{\text{TES}}\tau_{\text{chg}} = \rho_{\text{PCM}}V_{\text{PCM,tot}}\mathcal{L} \tag{5}$$

where, ρ_{PCM} is the PCM density and $\mathcal{L}$ is the latent heat of phase change. The steam mass flow rate and PCM thickness are then calculated by considering an energy balance and the rate of heat transfer. The governing energy equations are then solved numerically, following the methodology in Ref. [17], to find the steam enthalpy and PCM melted fraction. For condensing flow, the heat transfer coefficient correlations derived by Shah are used [18], while for convective and nucleate boiling heat transfer the correlations presented by Kandliker and Balasubramanian are used [19]. Several modifications, beyond the scope of this article, were made to the methodology of Ref. [17] to improve the accuracy and stability of the solution.

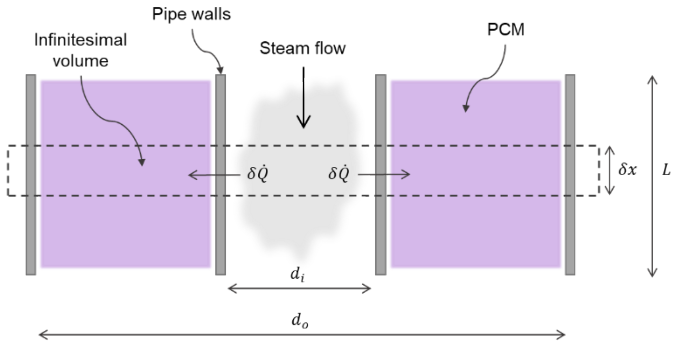

FIGURE 5 Schematic of the geometry of a section of the phase change material thermal energy storage. The TES comprises many of these tube bundles to form a module. Several modules are then linked together as in FIGURE 4

This PCM model enables the design and performance of a combined LFC and PCM TES system for IPH applications to be investigated. The framework uses SAM to calculate the LFC performance which is then used to undertake hourly calculations in a custom-made model of the thermal storage system. The above framework enables the sizing of the solar field and thermal storage to be investigated. By calculating the hourly behavior, the annual performance of the system can be evaluated.

FUTURE WORK

The long-term vision for the framework (through significant further R&D) is to develop a coupled hybrid energy generation and cost analysis tool, where the tool could help the user in determining the most suitable and cost-effective technologies for their applications. This project has developed an initial framework for the energy yield and selection of different RTES technologies in different stages based on temperature, system type, fluid type, and technology performance. Ongoing work will look to add costs for RTES options and further refinement on the selection of suited technologies. This future tool could calculate LCOHs of various RTES hybrid options, taking the user's solar resource, fuel costs, industrial heat demand profile, available land, and other factors into account to determine the applicability in their process.

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