A Comparative Cost Assessment of Low Carbon Process Heat Between Solar Thermal and Heat Pumps

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Abstract

Lower temperature renewable process heat derived from the sun can be generated from solar thermal collectors and a photovoltaic powered heat pump. To determine which can produce lower cost heat under certain technical and financial parameters, a robust methodology was developed to determine the maximum solar thermal project investment for it to remain the lower cost technology. This result can also serve as a target for the solar thermal industry to ensure its role in the future of renewable heat.

The assessment methodology was used in a case study analysis, consisting of typical industrial process heat load and temperature profiles, meteorological conditions, technology costs and performance. Results indicated that for constant energy demand processes when a heat pump can operate the majority of the year, a photovoltaic heat pump system delivers lower cost heat. In a typical five day one shift work week where a heat pump has limited access to a heat source, solar thermal remains the lower cost heat provider. For the same five day one shift case but without a constrained heat source, allowing the heat pump to operate for 2000 hours a year, solar thermal plants must be built for less than 250 €/m^2_{ap} in low irradiation regions like Copenhagen and 525 €/m^2_{ap} in high irradiation regions like Chile or North Africa. For solar thermal to remain a primary renewable heat provider in the future, project investments should consistently be less than 200 €/m^2_{ap}.

The presented results are highly variable based on numerous technical and financial parameters. Therefore the use of the methodology described in this work is critical to quickly determine which technology produces lower cost solar derived renewable heat.

Keywords: process heat, solar thermal, PV, heat pump, techno-economic, renewable heat

1. Introduction

A major result of the climate change conference in Paris was the decision to attempt to limit the rise of Earth’s global temperature at century’s end to no greater than 1.5 °C. One major sector, Industry, accounted for 28% of global final energy use and 11% of emissions from heat and electricity production (IPCC, 2015). If the 1.5 °C goal is going to be achieved, swift action must be taken to replace all sources of carbon emissions. One such option is the use of the sun to generate renewable industrial process heat typically below 150 °C.

Two main technologies can convert solar irradiance to thermal energy; either directly through solar thermal (ST) collectors or indirectly via photovoltaics (PV) and an electrically driven vapor compression heat pump. Numerous studies have been conducted within the domestic sector which compares and/or utilizes both technologies for hot water production and space heating. In the industrial sector, where load profiles, temperature levels, and project specific costs are drastically different, few studies to date have been conducted to compare these two solar heating technologies. Meyers et al (2015; 2016) have developed a comparison methodology between solar thermal and direct resistance heating photovoltaics, crafting unique terms such as the levelized cost of heat (*LCOH*) ratio and project investment ratio (IR). These terms allow for a quick comparison of technology based on their project turn-key specific capital investments. Pérez-Aparicio et al. (2017) has subsequently undertaken similar methodological approaches, incorporating the use of PV powered heat pump, though is limited in its flexibility to adapt to different meteorological conditions, process temperatures (only 200 °C was tested), technology performance, and future costs. These results were also not supported by energetic simulation. The work presented here has expanded upon the prior Investment Ratio methodology of Meyers et al. (2016) and has incorporated the use of heat pumps to develop a universally applicable method to assess which technology can produce lower cost heat for nearly any possible combination of meteorological, technical, and financial parameters.

doi:10.18086/swc.2017.26.08 Available at http://proceedings.ises.org

2. Methodology

The analysis conducted within this work is an expansion of prior research (Meyers et al., 2015; 2016). Within this publication, detailed solar thermal and PV simulations were conducted and correlations made which determined the lower cost heat provider based on local solar irradiation, process temperature, and technology capital cost. The current work expands upon this methodology to include a PV electricity powered vapor compression heat pump.

2.1 Solar simulations and technical basis

2.1.1 Solar Thermal

The solar thermal (ST) plant design and simulation methodology has been described in Meyers et al. (2016) to calculate solar yields under various process loads, temperatures, and meteorological conditions with different collector types. The ST plant was designed to work in conjunction with an already existing heating facility, serving as a "fuel saver" when solar thermal energy is available, either directly or through a thermal store. In summary, two phases of simulations took place via TRNSYS, with a model that was validated through a currently operating industrial solar heating plant in Germany (Lauterbach, 2014; Schmitt et al., 2015). The first phase were "Infinite Load Case" (ILC) simulations which determined the maximum annual specific ST yield ($q_{sol}^{ST,ILC}$ in $kWh_{th}/(m^2{}_{ap} \cdot a)$) for 800+ global cities for four non-concentrating collectors (flat plate, flat plate double glazed, evacuated tube, compound parabolic (CPC)) at various mean process temperatures ($T_{P,m}$). The yields were considered as a "maximum" because the process load was constant and had a large heat demand which allowed for the exclusion of a thermal store and second heat exchanger (only the collector field, solar loop heat exchanger and pipes/pumps were modeled). This reduced the mean collector temperature and thus maximized yield.

The second phase consisted of the "Practical Load Case" (PLC) simulations which incorporated more realistic conditions found in industry. These conditions included various process load profiles (one or three shifts, operating five or seven days a week), load magnitude (quantity of daily energy required relative to installed solar field size), and storage volume. Only nine sites were simulated due to the computational intensity, but they represented a wide span of annual solar irradiation (H in kWh/m^2a), annual average daytime temperature ($T_{amb,day}$), with annual specific ST yield results reported ($q_{sol}^{ST,PLC}$) in $kWh_{th}/(m^2{}_{ap} \cdot a)$. To reduce dimensionality, a differential temperature term was coined, called T_{diff}, which was the difference between the mean process temperature ($T_{P,m}$) and annual average daytime temperature ($T_{amb,day}$). This term highly influenced the annual yield results.

Correction factors (F_{corr}^{PLC}) were calculated to adjust results from the ILC to the nine representative PLC cases, by simply dividing the PLC yield by the ILC yield for the same simulated cities ($F_{corr}^{PLC} = q_{sol}^{ST,PLC} / q_{sol}^{ST,ILC}$).

2.1.2 Photovoltaic Heat Pump

The photovoltaic driven heat pump (PVHP) plant was the combination of a PV plant installed on a factory's roof with a heat pump connected to a heat demanding industrial process. The PV plant was connected to the industry's internal electrical grid. When the PV plant generated electricity, it first went to power the HP and any deficit or excess was "bought" from or "sold" to the internal grid at no cost. This meant that the existing electrical infrastructure on site served as free exchange mechanism. In this light a HP, with a known Coefficient of Performance (COP in units of kW_{th}/kW_{el}), was operated only when needed using "banked" PV generated electricity. The annual thermal energy generated by the PVHP system (q_{sol}^{PVHP}) is shown in eq. 1, with the annual specific PV generated electricity denoted E_{sol}^{PV} in $kWh_e/(kW_p \cdot a)$.

$$q_{sol}^{PVHP}\left(kWh_{th}/\left(kW_p \cdot a\right)\right) = E_{sol}^{PV} \cdot COP \qquad \text{(eq. 1)}$$

This model, while not a true PVHP direct coupled system as seen in the household sector, does better represent typical industrial conditions. The onsite electrical demand of typical industries is often significantly larger than a PV plant could generate on its roof, meaning that all PV electricity would be internally consumed and not fed into the grid. Secondly, a PV plant would never be directly coupled with a HP because factories nearly always have an electrical grid connection and operating an electrically isolated HP directly off PV would require batteries to smooth transient and control HP performance. For both reasons, this design was not investigated.

The peak power or size of the HP relative to the PV plant was scaled to consume every kWh of the annual PV generated electricity. This symbolized that the heat is 100% renewable and zero carbon (ignoring the required carbon to produce the components and refrigerant leakages), thus similar to an ST plant. The HP peak power (P_{peak}^{HP}) was calculated by multiplying the annual solar PV yield (E_{sol}^{PV}) by a known onsite estimated *COP*, then divided by the number of full load operating hours (*FLH*) per year that the HP was expected to operate (eq. 2), in units of Watt thermal (HP) per Watt peak (PV). *FLH* and *COP* can be determined through knowledge of the industrial process and availability of a fitting heat source, often by conducting an energy audit. Through this equation, it is shown that smaller heat pumps are required when operating more hours and larger heat pump for fewer, in order to consume the same annual PV generated electricity.

$$P_{peak}^{HP}\left(kW_{th}/kW_p\right) = E_{sol}^{PV}\left(\frac{kWh_e}{kW_p}\right) \cdot COP\left(\frac{kW_{th}}{kW_e}\right)/FLH\,(h) \qquad \text{(eq. 2)}$$

The heat pumps (HP) used for this assessment were electrical powered vapor compression. An increasing number of industrial grade devices are currently on the market with heating performances well over 100 °C, capacities greater than 100 kW_{th} of heat, and with a *COPs* ranging between 2 and 5, depending on the source and sink temperature (Wolf et al., 2014). These types of HPs are very suitable to deliver similar levels and quantities of heat as ST. For this assessment, annual average HP *COPs* were assumed to be used, taking into account small changes due to part load operation during the year. Through the advent of multiple parallel compressors and variable speed drives currently available for industrial HPs, the variability in COP is quite small through the normal operating range. A small buffer tank was also recommended by HP suppliers to reduce temperature transient in both the source and sink side of the HP. Due to its relatively small size (15 l/kW_{th}), thermal losses were less than 0.5% of the overall HP generated heat and thus ignored.

Solar PV yields were determined through TRNSYS simulations for the same 800+ sites of the ILC using a well-known mono-silicon panel from a global producer, incorporating module temperature and irradiance dependent efficiency modifiers. A correlation between PV solar yield (E_{sol}^{PV}) in kWh_e/kW_p and the local irradiation (*H*) and latitude (φ) was created so an expected PV yield (necessary for heat pump sizing and economic considerations) can be quickly estimated when investigating a solar process heat plant at a specific site (eq. 3).

$$E_{sol}^{PV}(kWh/kWp) = \theta_0 + \theta_1 \cdot H + \theta_2 \cdot \varphi \qquad \text{(eq. 3)}$$

2.2 Solar Heating Project Investment

Specific solar thermal project investment (I_{ST} in €/m^2_{ap}) was the total turn-key cost for all components (collectors, store, pipes, pumps), installation, and process integration to realize a plant, inclusive of any locally available subsidies or financial support mechanisms. The project investment (I_{ST}) varied widely based on technology choice, integration difficulty, thermal store size, and installer expertise. Typical I_{ST} values can range from less than 250 €/m^2_{ap} for 10,000+ m^2_{ap} plants in Denmark to over 800 €/m^2_{ap} for smaller installations with high quality collectors, though typical values are between 300..600 €/m^2_{ap} for projects larger than 500 m^2_{ap} (BAFA, 2016), with subsidy.

Specific PVHP project investment (I_{PVHP} in €/W_p electric) was dependent on three factors, the specific PV field investment (I_{PV} in €/W_p), the specific HP investment (I_{HP} in €/kW_{th}) and the relative HP peak power

(P_{peak}^{HP}) as already discussed in eq. 2. The specific PV investment (I_{PV}) for megawatt scale projects is in the range of 1 €/W_p (Fraunhofer ISE, 2015). The specific HP investment (I_{HP}) is rather application and technology dependent, but values ranging between 200 and 800 €/kW_{th} can be expected (IEA Annex 35, 2014; Wolf et al., 2014). The HP contribution to the overall PVHP investment was determined by multiplying the relative HP peak power by the specific HP investment, shown in eq. 4.

$$I_{HP(PV)}(€/W_p) = P_{peak}^{HP}\left(\frac{kW_{th}}{kW_p}\right) \cdot I_{HP}\left(\frac{€}{kW_{th}}\right) \quad \text{(eq. 4)}$$

Subsequently, the overall specific PVHP investment per Watt peak (electric) is shown in eq.5.

$$I_{PVHP}(€/W_p) = I_{HP_{PV}} + I_{PV} \quad \text{(eq. 5)}$$

Expected values of P_{peak}^{HP} and I_{PVHP} are shown in Tab. 1. For the few example cases, the HP investment was typically smaller than PV, which is why values were expressed in units per W_p electric (PV) instead of thermal (HP).

Tab. 1 – Example calculation to determine the overall PVHP investment in relation to the installed PV power

E_{sol}^{pv} (kW_eh/kW_p)	COP (kW_{th}/kW_e)	FLH (h)	P_{peak}^{HP} (kW_{th}/kW_p)	I_{HP} (€/kW_{th})	$I_{HP(PV)}$ (€/W_p)	I_{PV} (€/W_p)	I_{PVHP} (€/W_p)
1000	2	4000	0.5	400	0.2	1.25	1.45
1250	3	2000	1.87	400	0.75	1.25	2
1500	4	1000	6	400	2.4	1.25	3.65

2.3 Financial Analysis

By expressing the turn-key PVHP plant investment per W_p electric, a similar methodology can be used from Meyers et al. (2016). In this work, the two technologies were compared by their dividing their installed specific capital investments, called the Investment Ratio (*IR*), a value which was calculated when the Levelized Cost of Heat (*LCOH*) of both were equal (Louvet et al., 2017). This methodology can be altered to fit this comparison by simply replacing the I_{PV} with I_{PVHP} and q_{sol}^{PV} with q_{sol}^{PVHP}.

For each infinite load simulation case (800 cities, 4 ST collectors, 3 process temperatures and 1 PV), ST and PVHP yields were calculated, assuming a known COP. Using the equivalent *LCOH* equation (eq. 6) and parameters in Tab. 2, I_{ST} and I_{PHVP} were iterated until convergence was found.

$$LCOH_{ST} = \frac{\boldsymbol{I_{ST}} + \sum_1^n \frac{OM_{ST}}{(1+DR)^n}}{\sum_1^n \frac{q_{sol}^{ST}\cdot(1-SD)^n}{(1+DR)^n}} = \frac{\boldsymbol{I_{PVHP}} + \sum_1^n \frac{OM_{PVHP}}{(1+DR)^n}}{\sum_1^n \frac{q_{sol}^{PVHP}\cdot(1-SD)^n}{(1+DR)^n}} = LCOH_{PVHP} \quad \text{(eq. 6)}$$

Tab. 2 – The required parameters to calculate the *LCOH*

Parameter	Definition	ST Value	PVHP Value
$\boldsymbol{I_{ST,PV}}$	Investment (/m^2_{ap} , /W_p)	Variable	
$\boldsymbol{OM_{ST,PV}}$	Operation and Maintenance (% of $I_{ST,PVHP}$)	2% (VDI, 2014)	1.75% (VDI, 2012; Shimura et al., 2016)
DR	Discount Rate	6.40% (Ondraczek et al., 2015)	
SD	Degradation Rate	0.4%/a (Fraunhofer ISE, 2016)	0.5%/a (Jordan and Kurtz, 2013)
n	Years of Operation	20 (Duffie and Beckman, 2013)	

Using the iterated I_{ST} and I_{PVHP} per simulation case when their heat costs were equal, the Investment Ratio ($IR^{CPC}_{ILC,local}$) was calculated in eq. 7. The superscript indicates which collector was being assessed and the subscript depicts the Infinite Load Case (ILC). Also in the subscript, the "*local*" denoted the calculated *IR* for that specific case of local meteorological conditions and is a precise value. The resulting "*local*" Investment Ratios were generalized as a function of T_{diff}, *H*, and *COP*, determined through linear regression in eq. 8, noted with "*gen*" in the subscript. $IR^{CPC}_{ILC,gen}$ is graphically depicted in section 3.1.1. The subscripts "*local*" and "*gen*" can be interchanged within the other equations in this work, as they approximately equal each other due to the regression analysis. A "*market*" subscript is the site specific known investment for heat pump, PV and solar heating plants to be realized, known by local installers.

$$IR^{CPC}_{ILC,local} = I_{ST}/I_{PVHP} \text{ in units of } (€/m^2_{ap})/(€/W_p) \quad \text{(eq. 7)}$$

$$IR^{CPC}_{ILC,gen} = \theta_0 + \theta_1 \cdot H + \theta_2 \cdot \sqrt{T_{diff}} + \theta_3 \cdot H \cdot T_{diff} \quad \text{(eq. 8)}$$

Using the calculated Investment Ratio for the Infinite Load Cases, one can determine the maximum ST investment required for it to remain the lower cost heating technology. Initially, the $IR^{CPC}_{ILC.local}$ is calculated from the simulation results and regression analysis (eq. 8). Next, a correction factor ($F^{CPC}_{corr,PLC}$) is determined using the simulation results which adjusted the ILC solar yields to a more typical value expect in real solar heating plants under industrial conditions, called "Practical Load Case". The $F^{CPC}_{corr,PLC}$ value typically ranges between 0.7 and 0.95 depending on the load profile, graphically shown in section 3.1.2. By multiplying these together (eq. 9), a more accurate Practical Load Case Investment Ratio ($IR^{CPC}_{PLC.local}$) is calculated which takes into account typical process load conditions and thermal losses.

$$IR^{CPC}_{PLC.local} = IR^{CPC}_{ILC,local} \cdot F^{CPC}_{corr,PLC} \quad \text{(eq. 9)}$$

Next, market insight is required for the known technology costs at a specific location. One must individually calculate the market price for a PVHP plant ($I_{PVHP,market}$) using eq. 2, 4, and 5, and then multiple this by the local PLC Investment Ratio ($IR^{CPC}_{PLC.local}$ in eq. 9) to determine the maximum ST investment ($I_{ST,local}$) a plant can be to remain the lower cost technology again PVHP (eq. 10).

$$I_{ST,local} = I_{PVHP,market} \cdot IR^{CPC}_{PLC.local} \quad \text{(eq. 10)}$$

Quite simply, if the known market investment for solar thermal ($I_{ST,market}$) is less than $I_{ST,local}$, then ST is the lower cost renewable heat producer. If not, PVHP produces heat at a lower price (eq. 11).

$$\begin{cases} ST\ chosen,\ I_{ST,market} < I_{ST,local} \\ PVHP\ chosen,\ I_{ST,market} > I_{ST,local} \end{cases} \quad \text{(eq. 11)}$$

3. Results

The thermal yield simulation results can be viewed in a prior publication (Meyers et al., 2016). The graphical depiction and required equation parameters of the Investment Ratio (*IR*), Correction Factor ($F^{CPC}_{corr,PLC}$), and PV Yield (E^{PV}_{sol}) are shown in section 3.1.1, 3.1.2, and 3.1.3 respectively, all required to for the economic comparison. Section 3.2 provides a short example of how to use the methodology. A focus is given to the CPC collector for this section, but graphs and equations for other cases will be made available in future publications.

3.1 Key Calculation Parameters

3.1.1 Investment Ratio

The generalized form of the ILC Investment Ratio for CPC collectors as a function of solar irradiation (*H*) and differential between mean process and annual average daytime temperature (T_{diff}) was explained in eq. 8. The resulting parameter coefficients for a CPC collector are shown in Tab. 3. The regression had a root mean squared error (RMSE) of 2.7% and an R^2-adj of 0.982 with all parameters having a p-value less than 0.05, indicating significance.

Tab. 3 – The linear regression derived parameters to calculate the generalized Investment Ratio for Infinite Load Cases using a CPC collector

	$IR_{ILC,gen}^{CPC}$				
COP	1	2	3	4	5
θ_0	1064	532	355	266	213
θ_1	0.066	0.033	0.022	0.016	0.013
θ_2	-83.0	-41.5	-27.7	-20.8	-16.6
θ_3	5.92E-04	2.96E-04	1.97E-04	1.48E-04	1.18E-04

The resulting plot of this regression equation is shown in Fig. 1. The x-axis hosted the site and process dependent T_{diff}, ($T_{p,m}$ – $T_{amb,day}$). The global horizontal irradiation (H) is showed on the y-axis. The intersection of two selected points on the x- and y-axes, defined by its color and contour lines, was the Investment Ratio for various *COPs*, shown on the right hand side. The values on the contour lines of Fig. 1 were for a *COP* of one, essentially an electrical heater. This value helped, along with the color scheme, to orientate oneself to the right hand side table and subsequently determine the $IR_{ILC,gen}^{CPC}$ dependent on the *COP* of a HP.

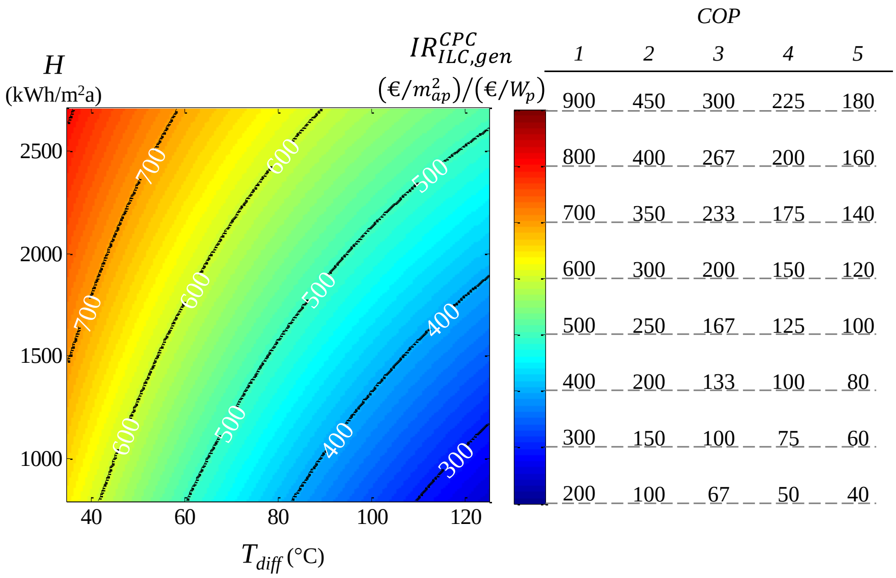

Fig. 1 – The results of a regression analysis from the energetic simulations which depict the Investment Ratio as a function of T_{diff} and H for a CPC collector under an Infinite Load Case

A brief observation of Fig.1 shows that the Investment Ratio increased as a function of global solar irradiation (H) and decreased due to a higher temperature difference between the process and ambient conditions (T_{diff}). This was expected, as this trend is in agreement with the solar collector efficiency equation (ISO, 2013). The performance of a PVHP system (or PV more specifically) was only slightly negatively influenced by higher ambient temperatures (i.e. increasing $IR_{ILC,gen}^{CPC}$).

3.1.2 Correction Factor

An example of a Correction Factor ($F_{corr,PLC}^{CPC}$) curve is shown in Fig. 2, for a seven day constant (three shift) load profile being heated with a CPC collector. The x-axis indicated the temperature difference (T_{diff}) between the mean process temperature ($T_{p,m}$) and the annual daytime average temperature ($T_{amb,day}$). The colored dots in the middle represented the average correction factor of the various locations and process temperatures, colored by their respective annual solar irradiation (*H*). The dashed vertical lines per colored dot illustrated the range of correction factors based on various daily specific load requirements and the optimum storage. The upper range of the dashed vertical line represented relatively smaller ST plants relative to the process load achieving higher solar utilization but lower solar fractions. The lower range represented the opposite, relatively large ST plants with higher solar fractions but lower solar utilizations. The black dots within the dashed line indicated the specific simulated cases. A clear decreasing trend of $F^{CPC}_{corr,PLC}$ is shown as T_{diff} increases, nearly independent of annual solar irradiation.

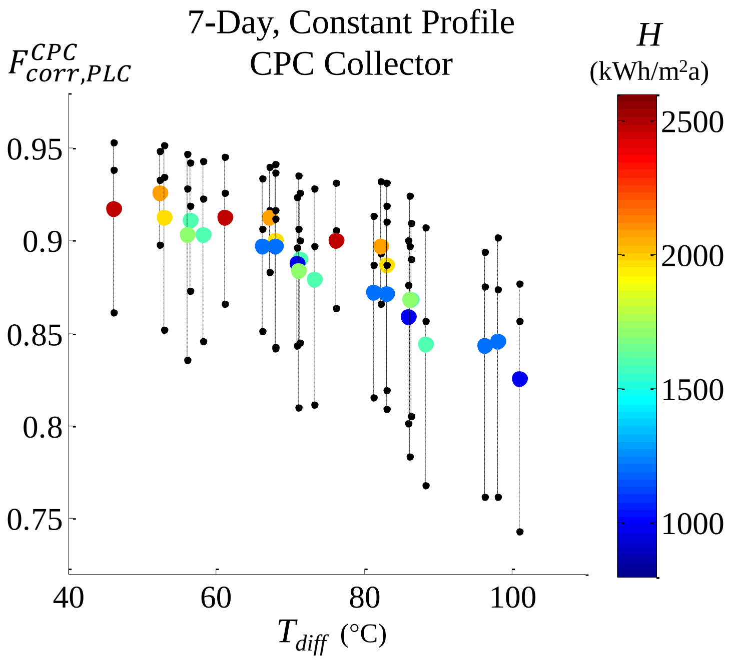

Fig. 2 – An assessment of the PLC correction factor for a 7 day constant load demand being met with a CPC collector

3.1.3 PV Yield

The specific yield of a PV plant in various climates can be calculated with numerous online tools and commercial software packages. While not specifically unique to this research, its presentation in a simple nomogram, calculated through numerous simulations and generalized with linear regression, is helpful for a quick assessment to later determine HP sizing and overall PVHP project investment. The resulting parameters from the linear regression (eq. 3) are show in Tab. 4, which had an RMSE of 2.81% and an R^2-adj of 0.972 with all parameters having a p-value less than 0.05, indicating significance.

Tab. 4 – Model coefficients used to estimate the specific PV yield with the global horizontal irradiation and latitude known for a location of interest

$E^{PV}_{sol,gen}$		
θ_0	θ_1	θ_2
-279.7	0.89	7.52

The results of this linear regression are plotted in Fig. 3. To use, a site's latitude (φ) in degrees was on the x-axis and its global horizontal irradiation (*H*) on the y-axis. Their intersection point was the estimated annual solar PV yield, in kWh_e/kW_p. The white dots indicate the sites used for the correlation at their specific φ and *H*. The model's parameter linked to *H* (θ_1) is 0.89, which is roughly a typical Performance Ratio for PV plants. Built into the latitude model parameter (θ_2) was also a crude ambient temperature correlation, so solar yield benefits not only from collector tilt at higher latitudes but also from lower ambient temperatures often observed there. Collectors were tilted to the site's latitude, minus 15 degrees with a minimum tilt angle of 15 degrees.

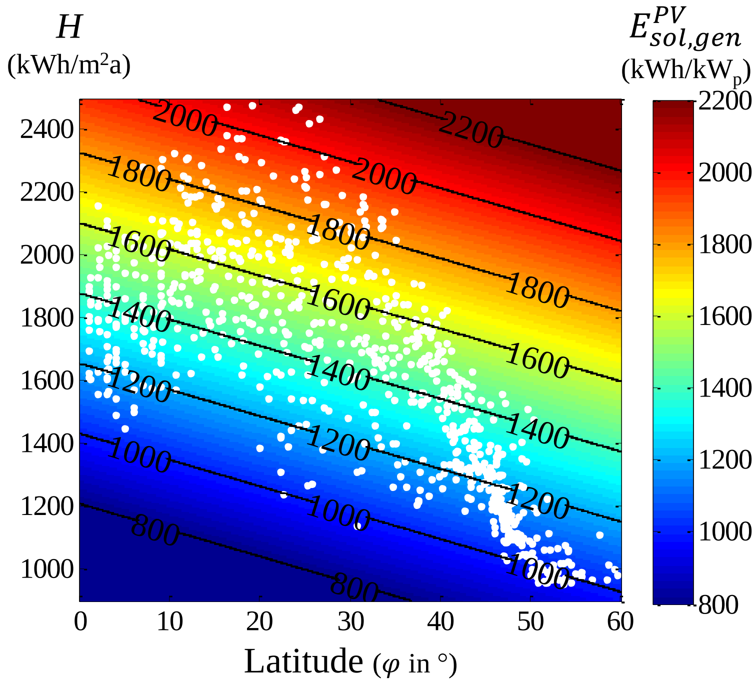

Fig. 3 – A graphical representation of the model used to estimate solar PV yield (E^{PV}_{sol})

3.2 Methodology Demonstration

To determine the use of the methodology, a step by step example is provided:

1 - Determine known process parameters through an energy audit, for example:

- Local meteorological conditions: H: 1250 kWh/m^{2}a, $T_{amb,day}$: 15 °C, φ: 40°
- Industrial process: 70..90 °C ($T_{P,m}$: 80 °C), operates 7 days a week for 3 shifts (Continuous profile)
- T_{diff}: $T_{P,m}$ - $T_{amb,day}$: 65 °C
- Waste Heat: Available 2000 hours per year (*FLH*: 2000)
- Estimated PV and HP figures – I_{PV}: 1.1 €/W$_p$, *COP* : 3 and I_{HP} : 500 €/kW

2- Use Fig. 1 or eq. 8 to calculate the Investment Ratio ($IR^{CPC}_{ILC,gen}$) with inputs of H, T_{diff}, and *COP*

- $IR^{CPC}_{ILC,gen}$= **175** in (€/m$^2_{ap}$)/(€/W$_p$)

3- Use Fig. 2 to estimate a Correction Factor ($F^{CPC}_{corr,PLC}$) with T_{diff} and the known process load profile

- $F^{CPC}_{corr,PLC} \approx$ **0.90**

4- Use Fig. 3 or eq. 3 to calculate E^{PV}_{sol} with inputs of H and φ

- $E^{PV}_{sol,gen}$ = 1133 kWh/kWp

5- Use eq. 2, 4, and 5 to calculate $I_{PVHP,market}$

- Size the Heat Pump: $P^{HP}_{peak}\left(kW_{th}/kW_p\right)$ = 1133·3/2000 = 1.7 kW$_{th}$/kW$_p$ (eq. 2)
- Heat Pump Investment: $I_{HP_{(PV)}}\left(€/W_p\right)$ = 1.7 · 500 = 0.86 €/W$_p$ (eq. 4)
- $I_{PVHP,market}\left(€/W_p\right) = I_{HP_{PV}} + I_{PV}$= 0.86 + 1.1 = **1.96** €/W$_p$ (eq. 5)

6- Use eq. 9 and 10 to determine the maximum ST Investment, $I_{ST,local}$

- $I_{ST,local} = I_{PVHP,market} \cdot IR^{CPC}_{ILC,gen} \cdot F^{CPC}_{corr,PLC}$ = **1.96·175·0.9** = **310** €/m$^2_{ap}$

When a ST plant can be built turn-key at this site ($I_{ST,market}$) for this industrial process for less than 310 €/m$^2_{ap}$, solar thermal is the lower cost renewable heat technology (eq. 11).

4. Case Study

Using the described methodology in this work and the stepwise procedure highlighted in section 3.2, case studies have been performed to estimate the maximum $I_{ST,local}$ under numerous conditions for an industrial process requiring heating from 60..90 °C with a CPC.

4.1 Boundary Conditions

Three site locations were chosen which had different levels of solar irradiation and ambient temperature. The “High” case had an H: 2400 kWh/m^{2}a and $T_{amb,day}$: 29 °C, the “Mid” case H: 1600 kWh/m^{2}a and $T_{amb,day}$:19.5 °C, and the “Low” case H: 1000 kWh/m^{2}a and $T_{amb,day}$: 10.5 °C. By using this range of meteorological parameters, a band of all feasible $I_{ST,local}$ was displayed.

Three process load profiles were selected to represent a range of potential $I_{ST,local}$. The first case, denoted in green, was a constant load profile, requiring heat 7 days a week for three shifts, during which a heat pump can operate continuous at 8000 full load hours (FLH) a year. The correction factor ($F^{CPC}_{corr,PLC}$) was estimated to be 0.90. The second, denoted in blue, was a typical weekly operating process (5 days) for only one daytime shift (8 hours), where a heat pump can operate full time at approximately 2000 hours per year. The third case, in red, was the same as the second, only that the heat source for the heat pump was constrained. This reduced its operating full load hours to 500 per year. The correction factor ($F^{CPC}_{corr,PLC}$) was estimated to be 0.80 for both the second and third case, though the graph is not depicted in this publication.

For the remaining required parameters I_{PV}, COP and I_{HP}, a range was given spanning the current highest and lowest thresholds. From pessimistic to optimistic, the ranges were for 2..0.5 €/W$_p$ (I_{PV}), 2..5 (COP), and 800..200 €/kW (I_{HP}).

4.2 Results

The case study results are displayed in Fig. 4. The x-axis is comprised of the range of pessimistic to optimistic values of I_{PV}, COP, and I_{HP}, from left to right. Each column of values noted on the x-axis were the input parameters to calculate $I_{ST,local}$ for the three process load profiles and three site locations. It was recognized that for real cases these values will not be as orderly but it serves to demonstrate how $I_{ST,local}$ on the y-axis is influenced by the parameters. Three process load cases are represented by their noted colors. The three site locations are identified by their location within each color band. The “High” case was always located on the upper edge, the “Low” case on the lower edge, and the “Mid” case was appropriately in the middle.

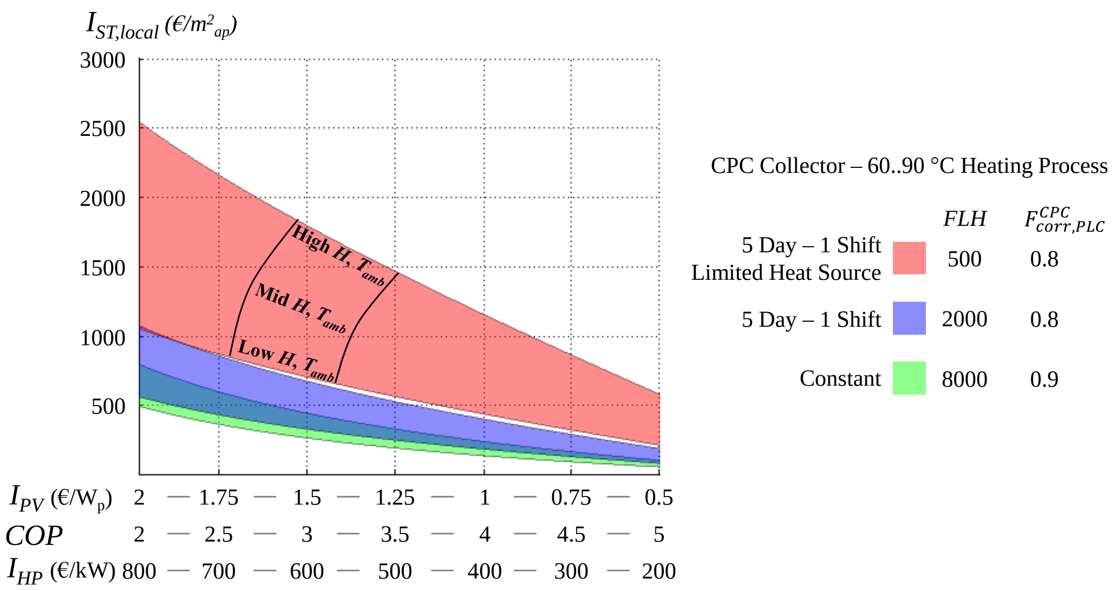

Fig. 4 – The case study results, illustrating the span of potential $I_{ST,local}$ values for numerous process inputs

Fig. 4 shows clear trends which immediately elucidate the sensitivity of certain parameters on $I_{ST,local}$. First and most obvious was that as the main PVHP financial and operating parameters (I_{PV}, COP, and I_{HP}) go from pessimistic to optimistic along the x-axis, $I_{ST,local}$ reduces significantly meaning PVHP became more competitive. Second, the process load has a marked influence. The PVHP plant is most competitive against ST (lowest $I_{ST,local}$) during a constant profile in which a heat pump can operate for nearly the whole year, shown in the green band at the bottom of Fig. 4. In turn the PVHP is least competitive (highest $I_{ST,local}$) during a 5 Day – 1 Shift process with limited heat pump operation (500 *FLH*), visible in red at the top of Fig.4. Site location or more specifically the greater available solar irradiation and ambient temperature positively influence $I_{ST,local}$, making ST more competitive when installed in more sunny and warmer regions. The area above an $I_{ST,local}$ of 1000 €/m$^2_{ap}$ should be of little interest because any well-built ST plant can be built for less, making any result above this value automatically in favor of ST over PVHP. To focus on $I_{ST,local}$ values less than 1000 €/m$^2_{ap}$, Fig. 4 was truncated into Fig. 5 by zooming in the region of interest on the y-axis.

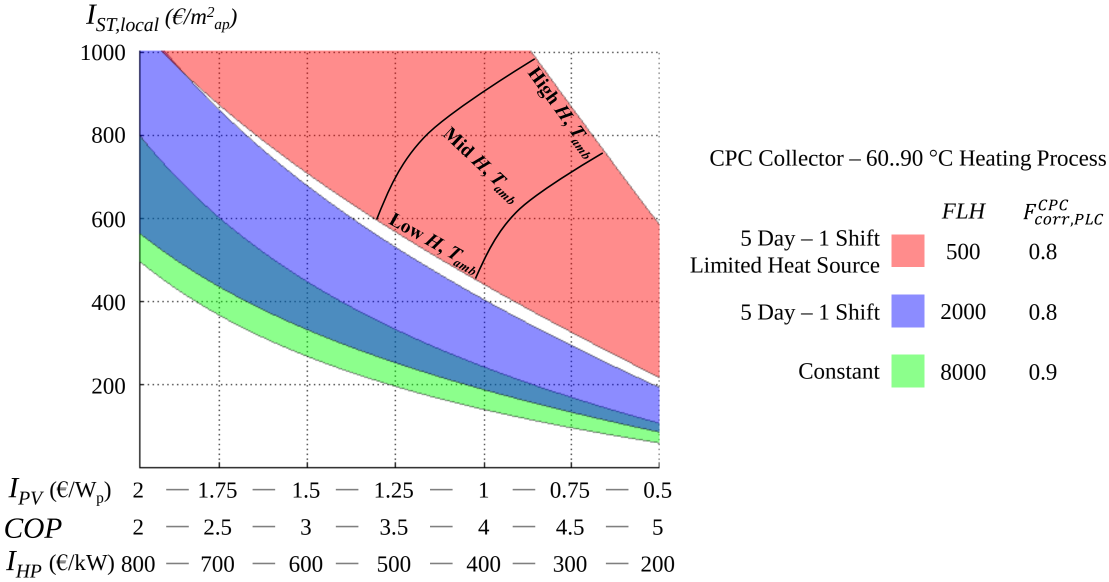

Fig. 5 – The case study results with a focus on $I_{ST,local}$ values less than 1000 €/m$^2_{ap}$

For the 5 Day – 1 Shift case with a limited heat source (red) in Fig. 5, the calculated $I_{ST,local}$ remains above 400 €/m$^2_{ap}$ for nearly every case, meaning that a well-built ST plant will remain the lower cost technology when FLHs are minimal. The opposite case, with a Constant load profile and a heat pump operating 8000 hours a year (green), indicated that for most situations, a PVHP will be the lower cost heat provider as $I_{ST,local}$ must be below 300 €/m$^2_{ap}$. ST can be competitive in cases when both PV and HP technologies are expensive and operate with a low *COP*. The final case, with a 5 Day – 1 Shift load (blue), both technologies could potentially be lower cost depending on the many boundary conditions. At current average PVHP technology costs (I_{PV}: 1.25 €/W$_p$, I_{HP}: 500 €/kW) with a reasonable *COP* of 3.5, $I_{ST,local}$ varied between 250 €/m$^2_{ap}$ to 525 €/m$^2_{ap}$ from the low to high solar irradiation and ambient temperatures locations. This range is the directly in-line with current $I_{ST,market}$ (BAFA, 2016), showing that the comparison between the two technologies is a stalemate, highly dependent on how cost effective can a ST plant be build. In the future, if PV and HP technology investments continue to reduce while HP performance increases, ST must similarly reduce investment below 200 €/m$^2_{ap}$ to remain the clear technology leader in the majority of industrial cases.

5. Conclusions

The quest for zero carbon process heat in industry often pits solar thermal and renewable electricity (by PV) powered heat pumps against each other. While any technology which reduces carbon emissions is welcome in the fight against climate change, industry often requires the lower cost path to reduce fossil fuel consumption and emissions. For the first time, a robust methodology based on numerous techno-economic simulations is presented which clearly determines which technology is less expensive when primary industrial process and technology parameters are known.

A comprehensive case study analysis was conducted which used the described methodology to determine the maximum specific investment a solar thermal plant can have in order to remain economically competitive against a heat pump operated with PV generated electricity. In cases when thermal energy is constantly required by an industrial process and a heat pump can operate for the majority of the year, PV heat pump plants will likely be the preferred technology. Contrary to this, if a heat pump can only operate 500 hours or less per year, solar thermal will be the lower cost technology in nearly all cases. In between these two, when the process load and heat pump both require/generate heat for 2000 hours per year at current PV and heat pump investments, the maximum ST investment was between 250 €/m^2_{ap} for low irradiation climates to 525 €/m^2_{ap} for high irradiation climates. Depending on how well or cost effective a solar thermal plant can be built, it can be the lower cost technology. For solar thermal to remain a competitive renewable heat technology and "future proof" itself against others, installed projects must achieve investment levels no greater than 200 €/m^2_{ap} to be the lower cost renewable heat technology in most meteorological and process conditions.

6. Acknowledgements

Funding: This work was supported by the People Programme (Marie Curie Actions) of the Seventh Framework Programme FP7/2007e2013/under REA grant agreement n 317085 [PITN-GA-2012-317085], commonly known at the SHINE (Solar Heat INtegration Network) Program (https://www.uni-kassel.de/projekte/solnet-shine/home.html).

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