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Analysis of Hybrid CPV Retrofit on Parabolic Trough Powerplants with Storage

Hannah O'Hern[1], Matthew Orosz[1] and Todd Otanicar[1, a)]

[1]Department of Mechanical Engineering, The University of Tulsa, 800 S Tucker Dr., Tulsa, OK, 74104, USA

[a)]Corresponding author: ocar@utulsa.edu.

Abstract. Retrofitting an existing parabolic trough plant with a bolt-on PV apparatus is an economical way to increase the yield of a plant. The annual generation is increased by 34% for the plant modeled but there is decrease in the amount of stored thermal energy. The retrofit has a detrimental effect on the generation in the late afternoon when the plant has thermal energy storage, but is the least expensive way to achieve increased generation at a plant.

INTRODUCTION

Energy storage is a critical determinant of grid stability with a high percentage of renewables in the generation portfolio. Concentrating solar thermal power (CSP) has the potential for grid scale energy storage on timescales up to 24 hours [1], through thermal energy storage (TES). Globally TES has been deployed at over 1000MWh at Solana and Crescent Dunes (USA), Andasol and Extresol (Spain), and other sites [2]. Comparatively, photovoltaics (PV) are limited to direct injection into the grid in the absence of mature, high throughput battery storage technology. TES is less expensive to install than PV with battery storage or with conventional natural gas combustion turbines [3]. Additionally, TES has been shown to have efficiencies greater than 97% [4]. However, PV plants are operated and maintained with relatively better economy and are two to three times less expensive to install than a CSP plant of similar generation capacity.

A hybrid retrofit systems has been proposed to combine the advantages of both systems via superimposed spectral filtering and concentrating photovoltaics (CPV) on existing parabolic trough CSP infrastructure [5]. A numerical energy balance model for a retrofit parabolic trough collector is deployed in an hourly simulation using plant characteristics and typical meteorological year (TMY) data for a location of interest. The effect of the retrofit on the output of CSP plants with existing TES is now considered.

The time of day price of electricity offtake is an important economic factor driving the use of storage in solar power generation. Peak solar generation hours do not correspond to peak energy usage or high electricity prices. Adding TES allows CSP plants to shift production to later in the day during high electricity price periods [6]. As solar technologies continue to penetrate the energy generation portfolio, the ability of plants to shift generation to later in the day will become increasingly important to avoid excess capacity during peak sun hours [7]. The necessity of aligning generation and usage hours has been well documented [8–10].

There are three main types of thermal storage: sensible heat storage, latent heat storage, and thermo-chemical heat storage. Latent heat storage systems using salt mixtures are the most mature and widely utilized [6]. For parabolic trough CSP plants, two-tank indirect storage technology is used for over half of the plants that have TES [4,11]. There are many ways to determine the effect of TES both on a single plant and on the generation portfolio. The most common approach is an economic "price-taker" model, which bases the dispatch of storage on historic electricity prices. Other models assume fixed dispatch schedules [12]. The control scheme used to determine the ideal time to dispatch storage has a large effect on the performance of the plant [13].

Of the 99 operating parabolic trough CSP plants worldwide, 46% have an associated TES facility [14]. The average plant aperture area based on the amount of storage is shown in Table 1. A case study in the US southwest is considered

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to determine the effect of adding the retrofit to existing plants with TES, particularly with respect to generation later in the day.

TABLE 1. Average field aperture size for plants with the same amount of TES.

Hours of Storage	Aperture Area (m^2)
0	358086
2.5	800000
3	82960
4.5	869800
6	2233958
7.5	513745
8	510120
9	457733

Hybridized Retrofit

The hybridization of CSP and CPV technologies combines the energy storage capabilities of CSP with the economy of PV conversion. Retrofitting an existing parabolic trough collector CSP plant with a spectral splitting filter reflecting optimal wavelengths to a CPV receiver is expected to increase the annual power output of the plant, while taking advantage of the existing primary optics. Therefore, a hybrid retrofit of a CSP plant would be an economical option to increase the annual power output, while still utilizing the energy storage capabilities of CSP. An arrangement for such a retrofit is shown in Figure 1.

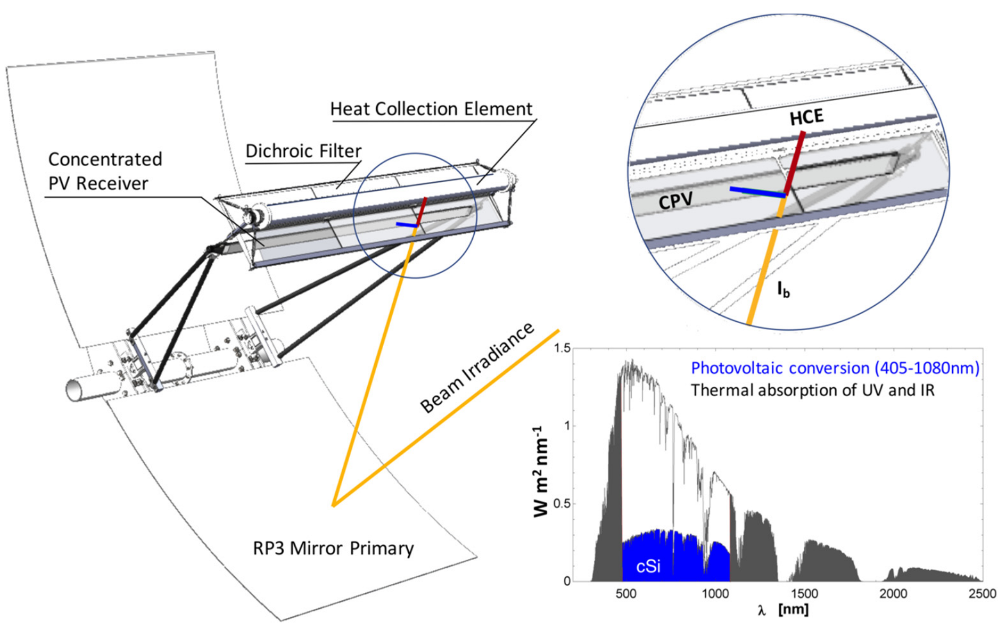

FIGURE 1. Hybrid CSP-CPV retrofit on a parabolic trough collector (RP3 outer mirrors not shown). Inset shows a detail of the secondary optics and the AM1.5 band of photovoltaic conversion (lower right).

A dichroic filter is attached in a plane between the primary mirror and the focal line of the parabolic trough mirror. The filter splits the spectrum such that wavelengths efficiently used by the CPV cell are reflected down to the CPV receiver while the remaining pass through the dichroic mirror to the heat collection element. The diversion of part of the solar spectrum away from the HCE results in a reduced CSP power output, however, the CPV power output increases the net output of the plant due to its higher in-band conversion efficiency. To understand the performance of such a proposed hybrid CSP-CPV system it is necessary to perform a yield estimation (monthly and annual energy output) based on design and location, and critically determines the financial merit of a proposed solar plant; particularly to understand the effect of the retrofit on a plant with TES.

MODEL DESCRIPTION

Predicting monthly and annual energy output based on design and location is an important input in the development cycle of solar energy projects and critically determines the financial merit of a proposed solar plant. There are many commercial software packages (PVSyst, Helioscope, etc.) in use for determining the annual yield of a solar PV power plant. The System Advisor Model (SAM) is a free software developed by NREL [15] that is utilized for both performance and detailed financial modelling. While SAM and other specialized tools are capable of modelling PV, parabolic trough CSP and CPV plants, there is no commercially available platform that can simulate a hybrid of both CSP and CPV, and in particular with reference to spectral dependencies e.g. the secondary optics used in the retrofit our team is developing with support from the U.S. Department of Energy (DOE) Advanced Research Projects Agency (ARPA-E) FOCUS program [16]. To address this gap an annual simulation was created based upon the steady state energy balance model developed by Forristall [17] for use in evaluating CSP performance and the five-parameter model developed by De Soto [18] to determine PV yield. The model is extended to include the effects of the secondary optics, particularly the decrease in thermal output from the associated spectral filtering, while including the spectral performance of the integrated CPV system [5]. Additionally, the model keeps track of the state of charge of the TES to determine when to charge or deploy the storage. The logic of the model is shown in block diagram form in Figure 2. This control strategy assumes that for each hour of operation all available thermal power from both the solar field and TES is used to run the powerblock at maximum capacity. When it is not possible to run the powerblock at full capacity, all the thermal load is directed to TES. This strategy does not optimize TES dispatch based on time of day or tank temperature, which are common optimized control strategies; however, this is the same strategy assumed by SAM [19,20].

To initialize the annual simulation, standard TMY data, available from, e.g. NREL [21], is used, consisting of a set of 8760 hourly values for ambient weather conditions. Only the direct normal irradiance (W/m^2) and dry bulb temperature (˚C) are necessary to run the model, as well as the aperture area, powerblock capacity, and amount of storage for the specific plant. The simulation calculates the PV power output, CSP power without the retrofit, CSP power with the retrofit, TES state of charge and the total power output of the hybrid system, for any given CSP

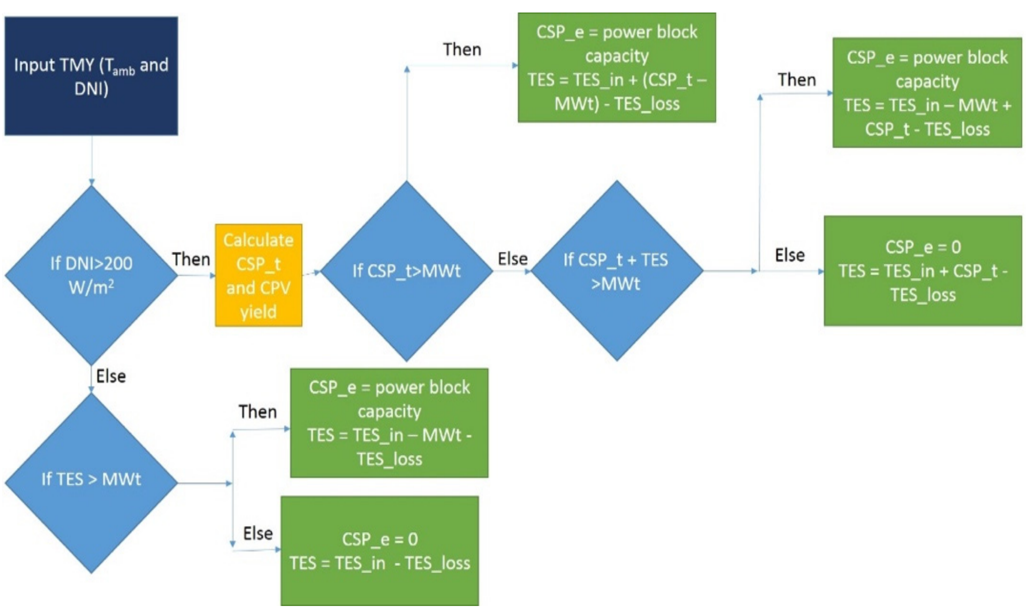

FIGURE 2. Storage Model Block Diagram

plant every hour for a year, based on the TMY data, as well as the plant aperture and power block capacity. The correlation equations used to run the annual simulation are shown in Equations 1, 3, 4, 5, and 6. Equation 2 is a modified heat engine efficiency based on typical HTF outlet temperature of an operating parabolic trough [22]. The spectral distribution is considered in the full physical model for determining the PV efficiency. In the simplified empirical model it is handled by considering the energy weighted transmission into the HCE (0.225 factor in equation 4), and the energy weighted reflection into the PV cell (0.775 factor in equation 5). Carnot efficiency is thermodynamically ideal and therefore physically unrealizable. In practice, the modified heat engine efficiency of Equation 2 better predicts the maximum efficiency of a heat engine, considering the limitations due to the rate at which heat can be exchanged. The TMY data is read into the numerical simulation program and the dry-bulb temperature and irradiance is applied at each time step to the equations to calculate the CSP and the CPV power output in MW. The simulation can be applied to any existing CSP plant as long as four parameters are known: aperture area (A), ambient temperature (T_{amb}), beam irradiance (I_b), and power block capacity.

$$\eta_{CSP} = a_0 + a_1 * T_{amb} + \frac{a_2}{I_b} \tag{1}$$

$$\eta_{mod,heat\ engine} = 1 - \sqrt{\frac{T_{amb} + 273}{663}} \tag{2}$$ [22]

$$CSP\_original\ (MW) = \frac{\eta_{CSP} * \eta_{mod,heat\ engine} * I_b * A}{1000000} \tag{3}$$

$$CSP\_retrofitted\ (MW) = \frac{\eta_{CSP} * \eta_{mod,heat\ engine} * (0.225 * I_b) * A}{1000000} \tag{4}$$

$$CPV\ (MW) = \frac{A * ((b_0 * 0.775 * I_b) - b_1 - (b_2 * T_{amb} * 0.775 * I_b) - (b_3 * 0.775 * I_b{}^2))\Big/32}{1000000} \tag{5}$$

$$TES_{loss} = c_1 * TES_{SOC,in} + c_2 * ArcCosh\left(c_3 + c_4 * TES_{SOC,in}\right) - c_5 - c_6 * TES_{SOC,in} * T_{amb} - c_7 * TES_{SOC,in}{}^2 \tag{6}$$

The coefficients in Table 2 represent the empirical constants determined through regression with the detailed model developed and based upon the equations outlined above. The resulting coefficients gave the best fit for the empirical model to match the detailed physical model.

TABLE 2. Values of coefficients for annual simulation

Coefficient	**Value**
a_0	0.81123
a_1	0.000133
a_2	-34.4304
b_0	5.644508
b_1	7.367557
b_2	0.000626
b_3	0.000269
c_1	0.000831
c_2	3.498752
c_3	2.055137
c_4	0.001482
c_5	4.371873
c_6	7.3788e-6
c_7	2.1414e-9

The parameters needed to simulate the Solana plant are outlined in Table 3.

TABLE 3. Parameters used for annual simulation

Parameter	Value
A	Aperture Area (190,338 m^2)
T_{amb}	Ambient Dry Bulb Temperature
I_b	Beam Irradiance
$TES_{SOC,in}$	Thermal Energy Storage State of Charge from previous time step

RESULTS

For a plant without storage, the retrofit increases the annual yield by over 35% [5]. For plants with storage, the annual yield is still increased by approximately 35%. The majority of the generation is shifted to the middle of the day. This may reduce the efficacy of storage. Another case is considered, where PV is added side-by-side with an existing plant to achieve the same increase in annual yield as the retrofit, but with no effect on the storage. The side-by-side PV case allows generation further into the afternoon hours, but is more expensive than the retrofit.

Case Study

The CSP model, without storage, has been previously validated using the Genesis plant in the Mojave desert (33.6650°N, 114.9948°W) [5]. In this study, the Solana plant, near Phoenix, AZ (32.550°N, 112.580°W), is used as a case study. The Solana CSP plant features linear parabolic trough collectors in a solar field with and aperture area of 2,233,598 m^2, a solar multiple of 1.5, and average annual power block output of 672,500 MWh [23]. This facility has a steam Rankine power block of 280 MW net capacity and six hours of TES [24]. The model assumes that the entire solar field aperture area is retrofitted with the hybrid CPV system.

In order to thermally and electrically validate the storage model, a comparison must be made between the modeled CSP component without the retrofit and the published measured output of the plant. The model calculates the output for every hour of the year. These results are then summed into monthly production values for meaningful comparison with the published data. The model for the thermal delivery of the HCE overpredicts the published output of the Solana plant by a factor of approximately 1.4 on average, which is consistent with solar multiple value for the plant (the amount that the plant is oversized in comparison to the thermal requirement for that power block) [25]. The modeled data was multiplied by a coefficient of 0.75 to minimize the differences between the modeled and observed output at Solana. The minimizing factor is used to account for maintenance or operational issues and any deviation in the meteorology conditions at the Solana site and the measurements in Phoenix, AZ. If the plant were operating its peak efficiency for the entire year and there were no differences in reported and actual meteorology this factor would not be necessary.

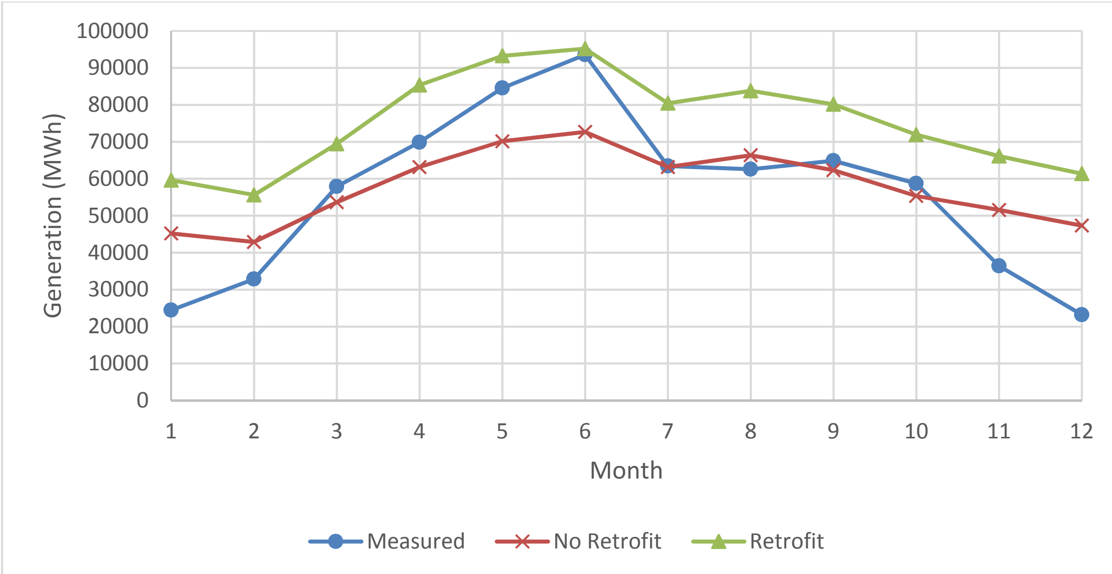

FIGURE 3. Published, un-retrofitted modeled, retrofitted modeled (MWhr) for each month of one year.

The minimizing factor is determined by forcing the square of the difference between the measured CSP values and the predicted initial CSP values to a minimum by multiplying the predicted values by the factor. This is accomplished by simultaneously solving for the minimizing factor and the least possible difference squared value. As shown in Figure 3, the model underpredicts in the summer and overpredicts in the winter; however, on an annual timescale the error is within 20%. This error may be attributed to model error, incorrect control scheme assumptions, or meteorological and operational factors specific to Solana.

The overall yield of the plant with the retrofit, as well as the measured CSP yield, is also shown in Figure 3. The minimizing factor applied to the model without the retrofit is again used by the thermal side of the model. The CSP yield is multiplied by the minimizing factor with the assumption that any operational issues causing error would continue to be problematic. The total yield of the plant is increased by 34%, as compared to the published yield of the plant.

While the annual yield of the plant is increased significantly by the addition of the retrofit, on a daily basis the retrofit constrains the deployment of the TES. Less thermal energy is delivered to the CSP portion of the receiver and therefore less thermal energy is available to be stored. One of the main advantages of TES is to be able to dispatch energy later in the day; the retrofit shifts the main production hours to the middle of the day. By comparing the generation of the original plant and the modeled retrofit plant, it is clear that there is a much steeper falloff of energy production in the afternoon for the retrofitted plant. This comparison was made for one representative summer day, as shown in Figure 4. The peaks in the retrofit generation represent when the CSP powerblock is used, because the model waits to use the powerblock until it can be run at full capacity and because a portion of the solar spectrum is diverted away from the HCE, the powerblock is only operated a few times a day after the retrofit is installed. The majority of the energy produced by the retrofit comes from PV. The powerblock is only operated twice a day in the winter and thrice a day in the summer, based on the representative days. Given a different control scheme, these peaks could be moved to later in the day, such that all of the available thermal energy is only used after there is insufficient irradiance for the PV cells to generate power.

One way to increase annual generation without sacrificing afternoon generation would be to add a greenfield PV array adjacent to the parabolic trough plant. Such a field was modeled in SAM [15], with a 34% increase over the measured annual production of the plant, so the retrofit and the side-by-side PV options generate the same amount of energy annually. The side-by-side PV does increase the generation in the middle of the day; however, because it does not reduce the thermal load available for storage, there is a less dramatic reduction of generation in the afternoon, also shown in Figure 4.

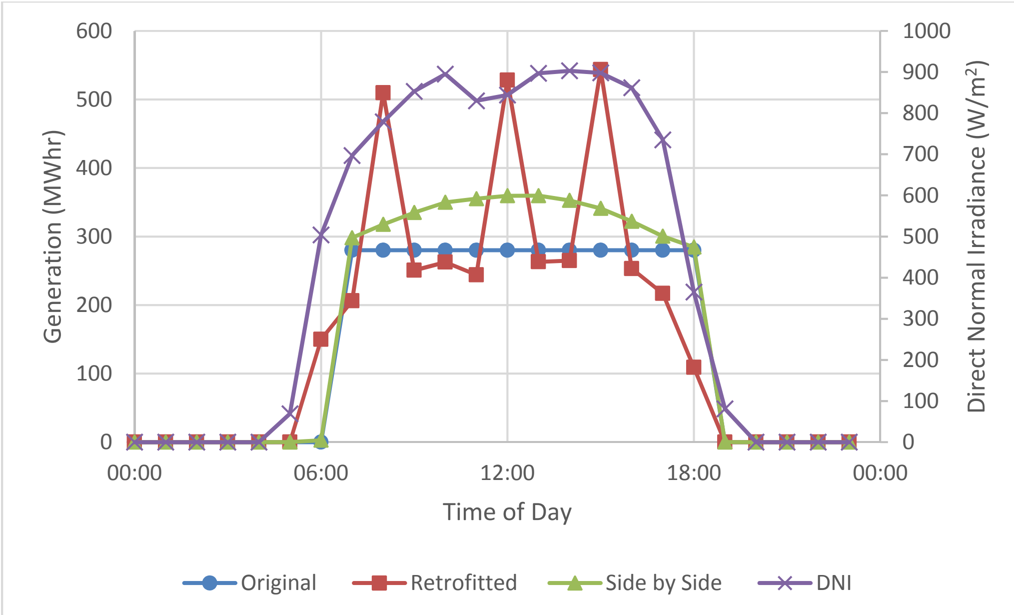

FIGURE 4. Original, Retrofitted, and Side by Side PV plant generation for one summer day, July 12th. The direct normal irradiance for that day is plotted on the right axis.

From a time of day perspective, the side-by-side PV case is superior to the retrofit; however, from an economic perspective, the retrofit is less expensive than the PV, as shown in Table 4. The PV cost was assumed to be \$2/W [26], representing the current average installed cost of utility scale solar PV plants. This estimate may be high due to the ever declining installation prices of PV [27], but until the price of PV falls to under \$1/W the retrofit will continue to have a lower capital cost. The internal rate of return (IRR) and levelized cost of electricity (LCOE) are calculated assuming a 30 year power purchase agreement (PPA) at a tariff of \$0.05/kWhr and an interest rate of 8%.

TABLE 4. Economic comparison of retrofit and side-by-side cases, assuming a PPA of 30 years at a tariff of \$0.05/kWhr and an interest rate of 8%.

	Retrofit	**Side-by-Side PV**
Percent Increase	34%	34%
Capital Cost (\$)	142,800,000	190,400,000
Internal Rate of Return	23%	17%
Levelized Cost of Energy (\$/kWh)	0.0141	0.0187

CONCLUSIONS

A correlation based model was developed to simulate parabolic trough plants with storage if a hybrid retrofit were added. Based on a case study of the Solana plant in AZ, USA, it was determined that the model was capable of simulating the plant without the retrofit within 17% error annually. The model does not optimize the storage, instead it runs the powerblock as often as possible. It is likely that Solana uses an optimized control scheme and therefore the different operations of the plant may result in error. The proposed retrofit could increase the annual generation of the plant by 34%. The retrofit, while increasing the annual yield, decreases the generation later in the day. This effect may be detrimental because the largest energy demand is later in the day [8–10]. Another way to increase the yield of the plant is to add PV next to the CSP plant. If the same annual increase were added in PV, the discharge of storage later in the day would not be effected; however, this option is not as economical as the retrofit, but if significant time of day pricing is part of the power purchase agreement a side-by-side approach could be better at longer storage times. The optimal control scheme for the proposed retrofit could alter the time of day discharge of the storage, and therefore take advantage of any significant time of day pricing making the retrofit as attractive long term as the side-by-side option. Further work is necessary to determine the optimal control scheme for a retrofitted plant with storage.

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