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Techno-Economic Feasibility of Solar Powered Electric Vehicle Charging Stations in West Virginia

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Techno-Economic Feasibility of Solar Powered Electric Vehicle Charging Stations in West Virginia

Housseem Eddine Younes

Problem Report submitted
to the Statler College of Engineering and Mineral Resources
at West Virginia University
in partial fulfillment of the requirements for the Master's degree of
Energy System Engineering

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Morgantown, West Virginia

2020

Keywords: Photovoltaics, Electric Vehicles, Battery Storage, Techno-economic analysis

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ABSTRACT

Techno-Economic Feasibility of Solar Powered Electric Vehicle Charging Stations in West Virginia

Housseem Eddine Younes

This project explores the techno-economic feasibility of installing a photovoltaic (PV) system to power electric vehicle (EV) charging stations in West Virginia. A case study of a parking garage charging station is considered. The PV system performance and economic feasibility are assessed for two different system configurations and two financial scenarios. Two system variations one including PV only and another with on-site storage battery are modelled using the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory. Initial technical specifications of the PV system, battery system and EV chargers were selected as a reference case. Through parametric simulation, the variation of PV system size with battery capacity shows trade-offs between achieving maximum self-consumption and sufficiency and profitability of the system. Furthermore, cost sensitivity and two financing scenarios including direct ownership of the system and a Power Purchase Agreements (PPA) were investigated. The impact of net-metering and trading renewable energy credits on the return of investment is also discussed. Based on the data derived in this research, the following conclusions can be derived: (1) The PV-EV charging station is economically not feasible compared to grid-EV charging system when the environmental benefit is not accounted for; (2) when electricity produced by PV is converted to gasoline on a vehicle mileage operation basis, the PV-EV scenario is feasible when the price of gasoline is \$2.35/gallon or higher without accounting for the environment benefit and differences in vehicle cost; (3) PV system is feasible if the green energy is sold to a high-tech company with the market price of \$100/MWh considered; (4) PV system is feasible if the system is owned by a third-party and the PPA price is less than 7 cents/kWh.

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LIST OF ABBREVIATIONS AND SYMBOLS

Abbreviation	Definition
AC	Alternating Current
DC	Direct Current
EV	Electric Vehicle
EVCS	Electric Vehicle Charging Station
EVSE	Electric Vehicle Supply Equipment
ITC	Investment Tax Credit
PPA	Power Purchase Agreement
PV	Photovoltaic
RPS	Renewable Portfolio Standard
SAM	System Advisor Model
SREC	Solar Renewable Energy Credit
STC	Standard Test Conditions
TMY	Typical Meteorological Year

Variable	Unit	Definition
C	Ah	Battery capacity
CF_{net}	\$	Net Cashflow
C_{max}	Ah	Maximum battery capacity
CO ₂ (no PV)	Tons	CO ₂ emission without PV
CO ₂ (with PV)	Tons	CO ₂ emission with PV
DHI	W/m ²	Direct Horizontal Irradiance
DNI	W/m ²	Direct Normal Irradiance
E_{evdemand}	kWh	Total energy demand
E_{exported}	kWh	Energy delivered from PV to the grid
E_{imported}	kWh	Energy delivered from the grid
$E_{\text{max,charge}}$	kWh	Maximum battery charging energy
$E_{\text{max,discharge}}$	kWh	Maximum battery discharging energy
E_{PV}	kWh	Total photovoltaic energy production
$E_{\text{PVtobattery}}$	kWh	Energy delivered from PV to battery
E_{PVtoPV}	kWh	Energy delivered to EV from PV
E_{PVused}	kWh	Energy directly used from PV
ESC	kWh	Self-consumed energy
GHI	W/m ²	Global Horizontal Irradiance
NPV	\$	Net Present Value
P_{battery}	kW	Total power delivered by the batterie
$P_{\text{battery,max}}$	kW	Maximum battery charging power
PBP	Years	Payback period

P_{charging}	kW	Battery charging power
P_{demand}	kW	Load power demand
$P_{\text{discharging}}$	kW	Battery discharging power
P_{grid}	kW	Total power delivered by the grid
P_{pv}	kW	Total power delivered by PV
SCR	%	Self-Consumption Rate
SOC	%	State of Charge
SSR	%	Self-Sufficiency Rate
V	V	Battery voltage
ΔCO_2 (on-site)	%	CO ₂ reduction on-site
ΔCO_2 (total)	%	CO ₂ reduction in total

1 INTRODUCTION

The United States (US) filed a complaint against Volkswagen (VW) on behalf of the United States Environmental Protection Agency (EPA) in 2016, following VW's violations of the Clean Air Act regarding 590,000 diesel vehicles sold in the U.S. The violation which has been discovered by researchers at West Virginia University, consisted in Volkswagen's altering of algorithms and calibrations that caused emissions from the vehicles to perform differently under normal operation than during emission testing. On-road emissions were revealed to be 9 to 38 times higher than the limit [1] . The discovery led to a settlement in which VW agreed to spend \$14.7 billion to fund projects intended to make up for the additional pollution that the diesel engines produced. \$2.7 billion were allocated to an Environmental Mitigation Trust that would allow states to mitigate some of the damage done by VW to the environment. As required by the Trust Agreement, West Virginia has been named a "beneficiary" of the Environmental Mitigation Trust. Therefore, West Virginia is eligible to claim its trust allocation of \$12.1 million. According to the West Virginia beneficiary mitigation plan submitted in 2019 [2], West Virginia intends to allocate 5% of these funds to projects related to the installation of electric vehicle charging equipment, with an emphasis on locations within, or near, the campuses of West Virginia University.

Currently, all the EV charging stations in West Virginia use the utility grid to supply the energy demand. However, relying on the grid to power EV charging stations may not really have a significant benefit on the environment. In fact, the claim about EVs having zero emissions is a common misconception, unless the energy used to power the EV is produced using a carbon-free and clean source. According to the research conducted by the National Renewable Energy Laboratory (NREL) [3], in regions where the grid has a high carbon intensity, the carbon dioxide (CO₂) emissions reduction is not significant. This is especially true in West Virginia where 92%

of the electricity is produced by burning Coal and around 5 % is produced by renewable energy sources [4]. The combination of solar photovoltaics (PV) with electric vehicle supply equipment (EVSE) can help address these issues. In recent years, the PV-EV charging stations (PV-EVCS) gained more attention due to the continuous decline in PV system costs, the increasing the number of EVs and the concerns about the harmful effects of greenhouse gases [5].

Other than the environmental benefits, integrating PV in charging stations has the potential to produce significant cost savings for the system owner. Connecting multiple EVSE to the grid, for example in the case of workplace charging, can result in high demand charges caused by spikes in power usage. These demand charges are a significant portion of the electricity bill for commercial customers. They are determined by the highest 15-minute peak occurring for each billing cycle. By adding PV, the peak demand can be lowered leading to significant savings on the electricity bill. However, careful design of the system is necessary for the project to be technically and economically viable.

One of the major disadvantages of PV is the variability of energy production [6]. The research done by Mesentean et al. [7] discusses how this can be mitigated by adding local storage battery along with the PV array and EVSE. The battery is charged by the excess solar energy and then discharged when the PV generation is not enough to meet the load. The battery can also contribute to reducing peak demand and minimize its effect on the grid [8]. However, a battery is an expensive component which increases the capital cost of the system and may make the system economically infeasible. Several works on the optimization of the system design to increase its profitability have been reported. Multivariable optimization of the PV system and battery size was addressed by Dai et al. [9] using a modelling approach with the target of minimizing the overall cost of energy consumed. The amount of avoided emissions was however not considered in

choosing the optimal design. Research conducted by Gudmunds et al. [10] investigated the effect of battery size on the self-sufficiency rate, however the analysis was limited to a residential application.

1.1 Review of solar state policies

When designing a PV system, it is important to consider economics and regulations. Currently, the major barrier for large-scale deployment of PV systems in West Virginia is the high upfront costs, poor return on investment and lack of supporting policies [11].

The economics of solar systems are largely dependent on Federal and State policies. Currently, tax-paying system owners can decrease their costs through an investment tax credit (ITC) offered as an incentive by the Federal Government. ITC is an incentive given to the system owner as a percentage of the total investment. The ITC is currently at 26% and is set to decrease to 22% in 2021 and a permanent 10% after 2022. ITCs are a very important incentive for solar systems since they reduce investment costs and allow faster payback periods. However, they are offered only to tax paying owners. University campuses, schools, churches or government entities who don't pay taxes are not eligible for this incentive. Such entities may be able to profit from installing PV systems by entering into Power Purchase Agreements (PPA) [12]. A PPA is an agreement with a third-party to install and operate a PV system while paying them a fixed price for the energy produced, usually below the utility rate. These contracts are typically set for a specified period usually between 15 and 25 years. PPAs are legal in 28 states including Virginia, Ohio, Pennsylvania, Maryland, and Georgia, but not in West Virginia yet.

Additionally, in many states, solar system owners can increase savings through a net-metering program. Net-metering is a program offered by utilities that credits solar system owners

for the excess amount of energy they export to the grid. Any excess energy produced by the solar system is injected in the grid and adds a monthly kWh credit that gets subtracted from the monthly bill. Any remaining credits are rolled over to subsequent months and any credits left at the end of the year are sold at a rate equal to the utility energy rate. Net-metering is offered in West Virginia for all utilities.

PV system owners can also increase their return on investment by trading solar renewable energy credits (SRECs) in specific markets. SRECs are environmental certificates generated for each MWh produced by the PV system. Currently there is no market for trading SRECs in West Virginia as there is no Renewable portfolio standard (RPS) in the state. System owners can still trade SRECs in the Ohio market. In addition, many corporations like Google, Amazon and Facebook buy SRECs to offset their greenhouse gas emissions and meet their corporate sustainability goals.

Figure 1: US States with SREC markets [13]

Table 1 illustrates the regulatory and financial programs available in West Virginia:

Table 1: Summary of Solar policies in West Virginia

Structure	Is it available in WV?
Net metering	Yes
Tradeable SRECs	Yes (out of state)
Power Purchase Agreements	No
Investment tax credits	Yes

1.2 Problem report objectives

In this report a commercial PV system for an EVCS was modeled in the System Advisor Model (SAM) software in order to determine its feasibility in West Virginia. Two system variants were considered: PV only and PV with battery storage. The EV charging load was estimated and the energy production was calculated based on weather data from WV. The PV array and system sizes were varied to determine the optimal design under different cost scenarios and financing options. The contributions of this research consist in:

- Demonstrating the environmental and economic benefits of PV-EV systems compared to grid-charged EVs and gasoline vehicles.
- Investigating the economic feasibility of the PV system under different policies, costs and financing options.
- Determining the effect of different PV system and battery sizes on the energy performance and the economic feasibility of the system.

2 MATERIALS AND METHODS

This chapter details the data sources and simulation tools used to model the PV-EV charging station and perform the financial analysis.

2.1 Weather data

The PV system performance and financial analysis are calculated using SAM [14]. SAM is a free software developed by the National Renewable Energy Laboratory (NREL) in collaboration with Sandia National Laboratories with funding from the Department of Energy (DOE). It is used for predicting the performance of renewable energy systems and analyzing the financial feasibility of residential, commercial, and utility-scale grid-connected projects. SAM performs detailed performance and financial analysis for a variety of photovoltaic system configurations, including PV only and PV with Storage for peak shaving analysis. Tools for optimization, parametric, statistical analysis and user-defined scripts are also available. Typical Meteorological Year (TMY) weather datasets are used as input to calculate the hourly production of the PV system. TMY files are available for many locations in the United States. Each file consists of an hourly weather dataset derived from long term measurements. The data are processed by selecting "typical" months to represent the long-term properties of the data. The input files include the following datasets:

- Direct normal (beam) irradiance, DNI (W/m^2)
- Diffuse horizontal irradiance, DHI (W/m^2)
- Dry-bulb temperature ($^{\circ}\text{C}$)
- Dew-point temperature ($^{\circ}\text{C}$)
- Relative humidity (%), for single-year files only

- Atmospheric pressure (mbar)
- Wind speed at 2 meters above the ground (m/s)
- Wind direction (°E of N)
- Albedo: Ratio of diffuse radiation reflected by the ground surface

By summing the beam, diffuse and reflected components of the solar irradiance the global horizontal irradiance (GHI) is calculated. Figure 2 shows the monthly average GHI in W/m^2 in Morgantown WV.

Figure 2: Global horizontal irradiance in Morgantown, WV

2.2 Electric load data

EVSE power ratings differ depending on the type of charger. There are two types of charging: alternating current (AC) and direct current (DC). AC chargers supply power from the grid directly to the vehicle where a conversion from AC to DC happens inside the vehicle's on-

board chargers. In the DC charger the conversion happens outside of the vehicle and inside the charger itself. Level 1 is the slowest of the chargers, typically used for residential applications, it uses a 120V AC connection and supplies a power of about 1.4kW. Level 2 requires a 208/240V AC connection and has a power range of 6.6kW to 19.2kW. Charging times with level 2 charging are in the order of 4 to 8 hours and it is mostly used in commercial and public charging. Level 3 is the DC fast charger which can deliver between 50kW and 150kW in charging power. It is used in commercial and public charging and it can charge an EV in less than an hour. For this project, a 7.2kW AC level 2 from the manufacturer Leviton was used for calculations. Specifications are summarized in Table 2:

Table 2: Level 2 AC charger specifications

Charger designation	LEV-EVR30-B1C
Charger type	AC level II
Maximum charging current	30 A
Operating voltage	240V
Maximum charging power	7.2kW
Vehicle Connector type	SAE J1772
Operating temperature	-30°C to 50°C
Cable length	18 ft

Without real-world EV operation data, the prediction of the load for electric charging stations can be a very complex modeling task since it involves many uncertainties. To generate a load profile for the charging station, the number and type of vehicles, arrival schedule, travelled distance and average charging times must be assumed. In addition, the state of charge of each vehicle at the arrival and departure from the charging station must be known for each vehicle. A few methods can be found in the literature which are either data-driven or analytical. For example,

in the research conducted by Zhang et al. [15], the charging behaviors and charging time of different groups are analyzed, and a charging load model is developed using Monte Carlo simulation. In the research done by Islam et al. [16], the daily load profile for EVs was modelled for a workplace environment using a stochastic approach. These methods are beyond the scope of work of this project report. To avoid the use of unavailable data, a software package called HOMER grid was used to generate the aggregate load profile of a predetermined fleet of electric vehicles with an assumed number of variables.

The profile was constructed in HOMER grid based on a population of a 100 EVs including 4 of the most common models (Nissan Leaf, Tesla Model S, Chevrolet Bolt and BMWi3) (Figure 3). The proposed charging station will have 10 level 2 (7.2kW) charging ports. An average of 15 charging sessions per day is assumed and the daily arrival frequency (visits/hour) is set to a default workplace charging pattern in HOMER (Figure 4). The average charging time per session is set to 4 hours. The initial states of charges for vehicles at the beginning of each charging session are randomized within the software. To get a more realistic representation of the charging patterns during the year, HOMER allows the input of hourly and daily variability factors of the charging frequency and duration. The input parameters used are summarized in Tables 3 and 4:

Table 3: Electric vehicle fleet input parameters

Vehicle Model	Proportion of EV population	Maximum charging power (kW)	Average charging time (minutes)	Fuel economy (kWh/mile)
Nissan Leaf	25	6.6	240	0.3
Tesla Model S	25	16.5	240	0.29
Chevy Bolt	25	7.4	240	0.29
BMW i3	25	7.7	240	0.3

Table 4: Assumed variability factors for charging duration and arrival frequency

Property	Value
Charge duration Variability (%)	30
Day-to-day frequency Variability (%)	20
Timestep Variability (%)	10

Figure 3: HOMER grid EV setup interface

Figure 4 : Assumed EV arrival frequency for workplace charging

Based on the assumed input parameters, the hourly load profile is generated. Figure 5 shows how the load profile can vary for the first week of January. Over the year, the peak demand from the station is 72kW which corresponds to all charging plugs being used simultaneously at full power. The charging station will have a total of 4672 charging sessions per year.

Figure 5: Example of charging station load profile for the first week of January

2.3 PV/EV charging station simulation

In this report, two configurations of the PV-EV charging station are proposed: PV only and PV with a storage battery. In the first configuration the PV array and the EVSE are both connected to the grid. Since the EVSE used are AC level 2 type chargers, the PV array DC output is first converted to AC by an inverter and then supplied to the chargers. Any surplus electricity is exported to the grid. When the PV output is not enough due to low irradiance, the deficit is served from the utility grid. In the second configuration, a battery is added to the system. The battery is connected to the AC bus through a bidirectional converter. This converter has the role of converting the inverter's AC output power into DC in order to charge the batteries and converting the DC power discharged from the battery to AC in order to charge the EV (Figure 6).

The battery serves two purposes: storing the excess electricity and discharging when the PV output is not sufficient to meet the demand. The PV system first serves the EV load and any surplus is used to charge the battery first, when charging is allowed. Any surplus above what the battery can store is exported to the grid. If both the PV and the battery cannot satisfy the load, the deficit is covered by the grid. To maximize the self-sufficiency of the system, the battery is set to recharge only from the PV system.

Figure 6: PV-battery AC-connected System

2.3.1 PV performance model

SunPower SPR-X21-335-BLK was used as the PV module coupled with Fronius USA Symo 20.0 480V inverters. A 100kW DC PV system with 297 modules was selected for the baseline case. The system size was selected to provide 100% of the peak load demand of the charging station. SAM models the electrical characteristics of the PV module using the single diode model. It consists of an equivalent circuit comprising of a current source, a diode, a parallel resistor and a series resistor (Figure 7). For a PV module with N_s cells in series, and for a given irradiance and temperature levels, the I-V curve (Figure 8) of the PV cell is calculated by the following equation:

$$I = I_L - I_0 \exp\left(\frac{V + IR_s}{nV_{th}}\right) - 1 - \frac{V + IR_s}{R_{sh}} \quad (1)$$

I_L is the photo-generated current (A),

I_0 is the dark saturation current (A),

n is the diode ideality factor (unitless),

$V_{th} = N_s kT_c/q$ is termed the thermal voltage (V) for the module, which is determined from cell temperature T_c (K), Boltzmann's constant k (J/K) and the elementary charge q (coulomb),

k is Boltzmann's constant ($1.38066 \cdot 10^{-23}$ J/K),

q is the elementary charge ($1.60218 \cdot 10^{-19}$ coulomb),

R_s is the series resistance (Ω),

R_{sh} is the shunt resistance (Ω).

Values for R_s and R_{sh} are found in the selected PV module's datasheet.

Figure 7: Single diode model equivalent circuit

Figure 8: I-V characteristics of a PV cell for given irradiance and temperature levels

2.3.2 PV tilt angle

Module tilt and azimuth (orientation) angles are important parameters when designing PV systems. Studies have shown that in the northern hemisphere with panels facing south, the optimum tilt angle depends only on the latitude angle [17]. Duffie and Beckman [18] suggested an optimal tilt angle equal to the latitude $+15^\circ$, while Lunde and Gard [19] proposed an angle equal to the latitude $\pm 15^\circ$ for the winter and summer respectively. A common practice for fixed angle PV systems is to tilt the panels at the latitude of the location as this will yield optimal energy conversion over the entire year. To verify this assumption a parametric simulation for tilt angles

ranging from 0 to 90 ° was calculated in SAM to determine the maximum annual energy yield in kWh/kW (Figure 9). The optimal tilt angle was found to be 35° which is close to Morgantown's latitude of 39.61.

Figure 9: Determination of the optimal PV tilt angle in Morgantown, WV

2.3.3 Inverter and DC/AC ratio

The PV array produces DC electricity and the role of the inverter is to convert the DC power to AC to be used by the AC load. The inverter power is often sized to be less than the PV array because the latter rarely produces power to its full nameplate power also called the standard test condition (STC) capacity. The DC/AC ratio also defined as the inverter's load ratio is the ratio of array DC power to the AC power of the inverter. When the DC/AC ratio is high, the PV array produces more power than what the inverter can handle. The inverter will then drop the voltage level to reduce the power and the lost power is known as the clipping loss of the inverter. A healthy design will minimize clipping losses and a typical value for DC/AC ratio is 1.2. With a 100kW

DC PV array, the inverter total AC power is 80kW AC. For this project four of the Fronius USA symo 20.0 kW AC inverters were considered.

2.3.4 Battery storage model

A 100 kWh/ 25kW lithium-ion battery is chosen for the baseline case. The maximum and minimum states of charge (SOC) are set to 95% and 15%, respectively (an 80% depth of discharge). The addition of a battery storage to the PV-EV charging station is meant for balancing electricity supply and demand. At each time step of the simulation the energy balance is governed by the following equation:

$$P_{pv} + P_{battery} + P_{grid} - P_{demand} = 0 \quad (2)$$

The battery's SOC is calculated at each time step to determine the maximum energy that can be charged or discharged. The reason is that batteries have limitations on the amount of power they absorb or deliver since excessive power can increase thermal losses, decrease overall efficiency and possibly damage equipment. At each time step the charging or discharging power is limited by the rated power selected for the battery:

$$P_{charging} < P_{battery,max} \quad (3)$$

$$P_{discharging} < P_{battery,max} \quad (4)$$

The battery SOC must also be limited to avoid overcharging or deep cycling. At each time step the maximum amounts of energy that can be used to charge or discharge the battery are calculated by [20]:

$$E_{\max, discharge} = V \left[C - C_{\max} \frac{SOC_{\min}}{100} \right] \quad (5)$$

$$E_{\max, charge} = V \left[C_{\max} \frac{SOC_{\max}}{100} - C \right] \quad (6)$$

where V is the voltage, C is the capacity at the last time step in Ah, $C_{\max}$ is the rated capacity of the battery and $SOC_{\min}$ and $SOC_{\max}$ are the minimum and maximum states of charge in %, respectively. The state of charge therefore always obeys the following constraint at each simulation timestep:

$$SOC_{\min} \leq SOC(t) \leq SOC_{\max}$$

2.3.5 Performance metrics

2.3.5.1 Self-Consumption rate

The self-consumption rate (SCR) is defined as the ratio of the energy self-consumed from the PV system (E_{SC}) to the total PV production (E_{PV}) [21]. By adding a battery to the system, the self-consumption can be increased since it stores the excess PV energy and discharges it later when the PV production is not sufficient to meet the load. In this case, the self-consumed energy E_{SC} can be expressed as the sum of the PV energy used directly E_{PVtoEV} and that which comes from the battery $E_{BatterytoEV}$:

$$E_{SC} = E_{PVtoEV} + E_{BatterytoEV} \quad (7)$$

The SCR is calculated by the following expression:

$$SCR \% = \frac{E_{SC}}{E_{PV}} \quad (8)$$

From the above equations the energy exported to the grid can be calculated:

$$E_{exported} = E_{pv} - E_{SC} \quad (9)$$

$$E_{exported} = E_{pv} - SCR * E_{pv} \quad (10)$$

$$E_{exported} = E_{pv} (1 - SCR) \quad (11)$$

2.3.5.2 Self-sufficiency rate

Similarly, the self-sufficiency rate (SSR) reports how much the self-consumed energy covered the load demand [21]. It is calculated as the ratio of the self-consumed PV energy over the total energy consumption ($E_{EVdemand}$). This means that the higher the SSR value the higher the degree of independence from the grid. The SSR is calculated by the following expression:

$$SSR \% = \frac{E_{SC}}{E_{EVdemand}} \quad (12)$$

From the above equation, the amount of energy imported from the grid can be calculated as:

$$E_{imported} = E_{EVdemand} - E_{SC} \quad (13)$$

$$E_{imported} = E_{EVdemand} - SSR * E_{EVdemand} \quad (14)$$

$$E_{imported} = E_{EVdemand} (1 - SSR) \quad (15)$$

2.3.5.3 Emissions

The annual energy needs from the proposed charging station are 102,783.93 kWh/year. Considering an average fuel economy of 0.29 kWh/mile for the EV models selected, this amounts to approximately 354,427 miles of travelling distance per year. For the same travelled distance and

considering a fuel efficiency of 27.9 miles per gallon (MPG) for a gasoline car [22], this would be equivalent to approximately 12,703.5 gallons of fuel consumption per year. According to the EIA [23] the burning of one gallon of gasoline releases 8.9 kg of CO₂, this will amount to 124.5 of tons of CO₂ per year.

In a similar way, the emissions resulting from charging the EVs from the grid can be estimated. For the same distance travelled per year, considering a specific emissions value of 1 kg CO₂ per kWh for a grid using coal as an energy source [24] , this will amount to 113.5 tons of CO₂ per year. It is clear that in terms of emissions, charging EVs from the grid is in fact comparable to a regular gasoline car (only 9.5% less emissions) hence the interest in using solar.

Considering the case of solar charging, we can calculate the amount of CO₂ saved. The interest of using PV with EV charging is to minimize the amount of energy imported from the grid. PV has zero CO₂ emissions, however as explained in the previous sections the role of the self-consumption and self-sufficiency rates is important to know how much solar energy is being used to offset the emissions and how much grid energy was used. The self-consumption rate reflects the amount of PV production that was consumed directly during EV charging and the self-sufficiency rate is the amount of demand covered by the direct use of the solar energy.

Assuming both rates are 100%, this means that all the energy was directly used and all of it was able to offset the demand. In this case, the emissions for the EVs will be zero.

Table 5 illustrates the mileage-based emissions comparison between gasoline vehicles, grid charged EVs and solar charged EVs:

Table 5: CO₂ emissions using gasoline, grid charged EVs and solar charged EVs

Property	Gasoline Car	Grid-charged EVs	Solar-charged EVs
Travelled distance (miles/year)	354,427	354,427	354,427
Fuel economy (MPG or kWh/mile)	27.9	0.29	0.29
Fuel consumption (Gallons or kWh)	12,703.5	102,783.93	102,783.93
Emissions (kg of CO ₂ /Gallon or kWh)	8.9	1	0
Total emissions (tons of CO ₂ /year)	124.5	113.6	0

The emission reduction from PV can be seen from two perspectives: the first one is on-site emissions, which means the amount of CO₂ reduction achieved from directly supplying the charging station with solar electricity. The second way to evaluate emissions is the overall CO₂ balance. As explained in the previous sections, the PV satisfies the load first then exports the surplus to the grid which means the exported energy also contributes to reducing emissions even if the energy was not directly used on-site.

In reality, the on-site emissions in the solar charging case will not be offset by 100%, depending on the SSR value. For example, if the SSR value is 50%, that means that half of the energy is still being imported from the grid and therefore only half the of the on-site emissions were reduced. However, part of the energy produced by the PV may have been exported to the grid later, which will count towards the total emission reduction of the PV. The interest in optimizing the PV system design is to eliminate the on-site CO₂ emissions without oversizing the system such that it becomes uneconomical. On an annual basis, the on-site CO₂ emissions can be calculated as the CO₂ avoided when the vehicles are charging [25] :

$$\Delta CO_2 \%(on-site) = \frac{CO_2(No\ PV) - CO_2(with\ PV)}{CO_2(No\ PV)} \quad (16)$$

Where the CO₂ emissions without PV is the product of the energy in kWh and the specific emissions (in kg of CO₂/kWh:

$$CO_2(No\ PV) = CO_{2Specific} * E_{EVdemand} \quad (17)$$

And the CO₂ emission with PV is the product of the specific emissions and the imported grid energy:

$$CO_2(with\ PV) = CO_{2Specific} * E_{imported} \quad (18)$$

Combining the expression above, the on-site emission reduction can then be expressed as:

$$\Delta CO_2 \%(on-site) = \frac{E_{EVdemand} - E_{imported}}{E_{EVdemand}} * 100 \quad (19)$$

Similarly, the total emission reduction can be expressed as the total amount reduced by the PV system. In this case, the total reduction may have a value above 100% if the total energy produced is larger than the EV energy demand:

$$\Delta CO_2 \%(total) = \frac{E_{PV}}{E_{EVdemand}} * 100 \quad (20)$$

2.3.6 Input costs and financial parameters

The following tables list all the cost and financial parameters used in the simulation:

Table 6: PV system costs

Variable	Value
Module cost	0.35\$/Wdc
Inverter cost	0.22\$/Wdc
Battery cost	\$400/kWh
Balance of system equipment	0.25\$/Wdc
Installation labor	0.12\$/Wdc
Installer margin and overhead	0.65\$/Wdc
Permitting	0.11\$/Wdc
Contingency	3% of capital cost
Operation and maintenance	\$16/kW

Table 7: EVSE costs

Variable	Value
EV charger cost	\$729/unit
Installation	\$1,000/unit
Operation and maintenance costs	\$400/unit/year

Table 8: Financial analysis parameters

Variable	Value
Analysis period	25
Inflation rate	2.50%
Real discount rate	6.40%
Nominal discount rate	9.06%
Income tax	21%
Insurance	0.5% of system cost
PV degradation	0.5%/year

Table 9: Utility rates (based on Monpower General service ‘C’ tariff [26])

Charge	Value
Fixed charged	\$40
Energy charge	3.588cents/kWh
Demand charge	\$15.71/kWh

2.3.7 Financial metrics

2.3.7.1 Net present value

The net present value (NPV) is used to evaluate the financial attractiveness of the PV project. The NPV is the sum of the annual differences between the revenues (cash inflows) and expenditures (cash outflows), discounted to the present time.

The cash inflows consist in:

- The investment tax credit (a onetime payment at the beginning of the project).
- The annual energy and demand savings that result from solar charging.
- Net-metering revenue from selling remaining kWh credits at the end of each year.
- Annual revenue from selling SRECs.

The cash outflows consist in:

- Investment costs (a onetime expenditure at the beginning of the project).
- Annual operation and maintenance costs.
- Annual insurance and income taxes.

Because of PV cell degradation, the energy savings decrease over time. To account for this, the degradation of PV cell is also included in the calculation of the NPV in SAM. For this research a 0.5% annual degradation was assumed.

If the NPV of the project is positive, it means that the revenues offset the initial and ongoing expenditures associated with operating the system and the project is financially attractive. A negative NPV means that the by the end of the project lifetime, the costs are more than the benefits.

The NPV is calculated by the following expression:

$$NPV = \sum_{n=0}^N \frac{CF_{net}}{(1 - d_{nominal})^n} \quad (21)$$

where CF_{net} is the net cashflow, $d_{nominal}$ is the nominal discount rate and N is the project period.

2.3.7.2 Simple payback period

The PV system generates savings by avoiding the electricity charges associated with charging the EV from the grid. In this case, the payback period (PBP) can be defined as the number of years it takes the project net cashflow to offset the initial investment costs of the PV system. The PBP can also be defined as the time it takes for the NPV to become zero or greater. The shorter the payback period, the sooner it takes for the project to become profitable. Typically, a payback less than 15 years for PV is considered an attractive investment. If the payback is more than the lifetime of the project the system is not considered. The PBP is expressed as:

$$PBP(years) = \frac{Investment\ costs}{Annual\ savings - Annual\ operating\ costs} \quad (22)$$

The PBP of the project can also be evaluated by comparing the savings from the EV charging scenarios with gasoline vehicles operating for the same annual mileage. In this case, the cash inflows can be defined as the fuel savings associated with EV charging instead of operating a fleet of gasoline vehicles. For example, if we consider an average gasoline price of \$2.35/gallon in West Virginia [27], an annual travelled distance of 354,427 miles and a gasoline fuel economy of 27.9 MPG, the yearly gasoline fuel costs will be \$29,853/year. In the case of EVs being charged from PV, considering an energy generation cost of 10 cents/kWh and assuming the vehicles are entirely charged with solar, the annual fuel costs are \$10,287/year. The annual savings are the difference in fuel costs between gasoline and PV charging which amounts to \$19,266.225/year. Accounting for annual maintenance and operating cost of PV, the payback period is 11 years.

The comparison is summarized in Table 10:

Table 10: PV-EV versus gasoline vehicles

Property	Gasoline car	PV-EV
Annual travelled distance	354,427	354,427
Fuel economy (MPG or kWh/mile)	27.9	0.29
Annual energy required (gallons or kWh)	12,703.5	102,783.93
Fuel cost (\$/Gallon or \$/kWh)	2.35	0.10
Annual fuel cost (\$)	29,853.225	10,287
Fuel cost (\$/mile)	0.084	0.03
Annual fuel savings (\$/year)	0	19,266.225
Annual operating costs (\$/year)	0	5,264
Investment cost (\$)	-	161,950
Total savings for 25 year (\$)	-	481,656.375
Payback period (years)	-	11

2.3.7.3 SREC pricing

The baseline price for selling the SRECs is set to the latest bid of 8.5\$/SREC in the Ohio market. These prices can vary considerably throughout the year. Figure 10 shows the fluctuation of the SREC price during the last two years.

Figure 10: SREC market bids fluctuation [13]

3 RESULTS AND DISCUSSION

3.1 Reference case: PV system without energy storage

3.1.1 Analysis of system performance

Figure 11 shows the hourly production profile of the PV system versus the load demand at each hour of the first week in January (top) and May (bottom). It can be seen that both profiles vary considerably from day-to-day. The sample week in January shows that even under low irradiance, the 100kW system can cover the energy needs of the proposed charging station and reduce its peak demand most of the time, confirming the assumption that PV can be a reliable way to power EV charging stations even with variability in the production profile. In the sunniest periods of the year, the system generates surplus electricity and exports energy into the grid. The proportion of self-consumed energy and degree of grid independence can be understood further by looking at the monthly self-consumption (SCR) and self-sufficiency rates (SSR) of the installation in Figure 12. For example, an SCR of 67% in January means that 67% of the energy that was produced was consumed on-site by the charging station and the rest was exported to the grid. At the same time, the SSR had a value of 49% meaning that almost half of the demand was covered by PV output and the other half was imported from the grid. Over the entire year, the PV system produced 129,300 kWh, exported 54,007kWh to the grid and imported 27,956kWh from the grid. These values translate into an annual SSR of 72% and an SCR of 58%. 82.7 tons of CO₂ were reduced on-site (72% reduction). This reduction corresponds to the amount avoided by directly supplying EVs with solar energy. Given that the system exports more energy into the grid, the total amount of emissions reduced was 143 tons of CO₂, which is more than the CO₂ emissions of the charging station.

Figure 11: Hourly PV output and charging station load demand for sample weeks in January (top) and May (bottom).

Figure 12: Monthly self-consumption and self-sufficiency rates

Figure 13 shows the monthly peak demand reduction by the PV system. Peak demand is effectively reduced by the PV system in each month by up to 35kW in April. Overall energy charges were reduced by \$4,618.57 and demand charges by \$3602.15, a total of \$8,221 of savings per year on the electricity bill.

Figure 13: Peak demand reduction with 100kW PV system

The system also generates revenue through net-metering by selling the cumulated energy credits at the end of the year. Every month, the system injects the excess electricity which is the difference between the production and the load in that month (Figure 14). In each month, if the production exceeds the load, the excess injected into the grid is cumulated with the amount from the previous month. If the load exceeds the production, the electricity used from the grid is compensated by the kWh credits already earned in previous months. In total, a \$1,021 revenue was generated through net-metering.

Figure 14: Monthly PV production, electricity load and excess energy

Additionally, the system generates revenue from trading SCREs. With an energy production of about 129 MWh, 129 SRECs were sold at a price of \$8.5/SREC adding a total revenue of \$1,096.5. Considering an investment tax credit (ITC) of 26%, the net present value amounted to -\$85,617 with a simple payback period of 24 years. It is clear that despite the electricity savings and the significant CO₂ reductions, the system is not financially attractive since it has a negative NPV.

3.2 Sensitivity analysis for the PV only case

3.2.1 System capacity

Three system sizes were compared in this sensitivity analysis: 50 kW, 75kW and 100kW. All other financial input parameters were kept constant. The results are summarized in the Table 11:

Table 11: Summary of PV system performance for different array sizes

Parameter	System 1	System 2	System 3
PV system size	50 kW	75kW	100kW
Energy yield (kWh/year)	64,570.80	96,998.74	129,300.60
Energy imported from the grid (kWh)	45,942.60	345,91.3	27,956.30
Energy exported to the grid (kWh)	9878	27,264	54,007.80
Self-consumed energy (kWh)	56841.3	68192.62	74827.6
Annual self-consumption rate (%)	88	70.3	58
Annual self-sufficiency rate (%)	55	66	72
Electricity bill savings (\$)	5120.8	6580.42	8220.84
Net Present Value (\$)	-36,887.6	-59,173.3	-85,617.4
Simple Payback Period (years)	19.3	21.9	24
Cost of energy (\$/kWh)	0.0987	0.0985	0.0985
CO ₂ reduced on-site (tons)	62.8	75.4	82.7
CO ₂ reduced on-site (%)	55	66	72
Total CO ₂ reduced (tons)	71	107	143
Total CO ₂ reduction (%)	57	86.3	115

Results from varying the PV system size show that decreasing the system size increases the amount of energy imported from the grid and decreases the energy exports. This is also reflected in the SCR and SSR values. By decreasing the system size, a larger portion of the energy produced is self-consumed. The SCR increases from 58% for the 100kW PV system to 88% for the 50kW system. On the other hand, the SSR values follow the opposite trend. By reducing the system size, the EVCS relies more on the grid, the SSR decreases from 72% in the case of the 100kW PV system to 55% for the 50kW system. This is also reflected in the amount of on-site emissions reduced: the 50kW system reduces on-site emissions by 55% compared to 72% for the 100kW system. Moreover, it can be seen that superior SSR values result in increased on-site and total emission reduction but also lower NPVs. Decreasing the system size to 50 kW resulted in the highest net present value. However, it is still negative making the project financially infeasible.

3.2.2 Cost per installed capacity

The analysis for the reference case was calculated assuming an installed cost of \$1.83/Watt according to NREL's 2018 cost benchmark for PV installations in the U.S [28] . The module price was set to 35cents/ and 22 cents/Watt for the inverter. Figure 15 shows the impact of price variation on the net present value. A decline by 50% in the PV module and inverter price can increase the NPV by 17.5% and 11.6% respectively. In both cases however, the NPV remains negative and the project is not financially viable.

Figure 15: Installation cost sensitivity analysis

3.2.3 Solar renewable energy credit price

SRECs constitute an additional value stream for the project that can make it highly profitable depending on the market prices. One SREC is earned for every MWh generated by the

solar PV system. In states that have a Renewable Portfolio Standard (RPS), utilities must buy SRECs to provide proof that RPS goals are being met. SRECs can also be sold to private companies like Google and Amazon who use them to meet corporate sustainability goals and offset their carbon footprint. Since West Virginia doesn't have an RPS, SRECs in the state have no value, however PV system owners in WV can still trade their SRECs in the Ohio market. For this simulation, the most recent bid price for SRECs in the Ohio market was set to 8.5\$/SREC as of 2020. According to SRECtrade [13] prices in Ohio fluctuated between 5\$ and 25 \$ between 2018 and 2020. The impact of varying SREC prices in this range on the feasibility of the project can be seen in Figure 16. For example, at a SREC price of 25\$ the NPV increases by about \$12,000 (14%) compared to the reference case. This however doesn't have much impact on the feasibility of the project because of the low SREC price. In other states such as Massachusetts and New Jersey for example SRECs can be traded for as high as \$300. Figure 17 shows how the system can make profits by selling SRECs in high demand markets or to large corporations. The prices were varied between \$10/MWh and \$300/MWh. The project reaches the break-even point at a price cap of \$100/MWh. At a price of \$300/MWh the system generates close to \$200,000 in profit with a payback period of less than 5 years (Figure 18).

Figure 16: Variation of the net present value with SREC prices in Ohio

Figure 17: Variation of the net present value with SREC prices

Figure 18: Variation of the simple payback period with SREC prices

3.2.4 Electricity price growth rate

The reference case assumed an energy charge of 3.58cents/kWh and a demand charge of \$15.571/kW, with no annual escalation rate. The escalation rate analysis considers the expected electricity price inflation over the lifetime of the PV project (25 years). As electricity becomes more expensive, the PV system should yield more savings over the years. In this scenario, the escalation was varied from 0% (reference) to 2.5% with 0.5% increments. As shown in Figure 19 the impact on the net present value is not significant, as in the most aggressive scenario (2.5% escalation rate), the NPV increases by \$17,593 (20%) and remains negative. This can be attributed to the fact that savings will occur in the far future where they are heavily discounted and therefore do not impact the NPV as much.

Figure 19: Variation of the net present value with electricity escalation rate

3.2.5 Third-party ownership

As discussed in the previous scenarios, the financial model assumed was a direct ownership of the system. Even with the investment tax credit, net-metering and SREC trading scenarios, the project remains financially unattractive with a negative NPV. In this analysis the third-party ownership, i.e the PPA is evaluated to check its financial implications. Although currently PPAs are not offered in West Virginia, it is interesting to analyze how implementing them would affect the feasibility of the solar project. In the PPA financial model, there are no upfront costs, the PV system is owned by the system developer and the beneficiary (customer) of the system pays a fixed rate called the PPA price. This scenario is calculated from the perspective of the customer and it is assumed that the latter retains ownership of the generated SRECs. PPA pricing can vary depending on the state, the solar developer and the terms of the PPA. To determine at which price level a PPA becomes financially attractive option for this system in WV, the NPV is calculated for a range of PPA prices from 4 cents/kWh to 12 cents/kWh which is an average range for commercial

PV installations across the U.S. The annual escalation rate for the PPA price is set to 1%/year. As shown in Figure 20, the PPA pricing can determine whether the project is financially attractive or not. Locking the PPA price below 7 cent/kWh results in a positive NPV and the project becomes financially feasible.

Figure 20: Variation of net present value with the PPA price (cents/kWh)

3.3 System 2: PV system with battery storage

So far, it was shown that the only way to make the project profitable (positive NPV) is to sell SRECs at a price of \$100/MWh or use a PPA with a price below 7 cents/kWh. In this second analysis, all the financial parameters are re-set to default, and we are interested in studying the financial and environmental implications of adding battery storage. The simulations are performed in SAM using the 100kW PV system from the reference case with the addition of a 500V, 100 kWh/25kW lithium-ion battery.

3.3.1 Analysis of system performance

Figure 21 shows the hourly power flows from the PV panels, battery and grid for a sample day in May. As expected, the PV system charges the batteries when excess is available (for example from 8am to 10am) and exports power to the grid whenever excess is available, but the battery is fully charged (from 12am to 5pm). The battery intervenes to reduce the evening peak demand when the PV system output is not enough (5pm to midnight). Results in Figure 23 show the effectiveness of the battery in reducing monthly peak demand. For example, up to 40kW was reduced in May compared to 35kW in the PV only case, and overall electricity charges were reduced by 63%. The addition of the battery also increased the self-consumption rate to 64% and the self-sufficiency to 81% (compared to 58% and 72% in the reference case). This highlights the role of the battery in maximizing the use of surplus PV and decreasing reliance on the grid.

The system saves \$9,933 in energy and demand charges (20% more bill savings compared to the case with PV only). However, the net present value is still negative at -\$104,117 which is lower than the no battery case meaning that the bill savings do not offset the added cost of the battery. It is evident that the addition of a storage battery has some benefits in maximizing the use of PV when EVs are charging and reducing peak demand when PV is not available. However, the NPV may be further optimized by varying capacity bank size along with the PV array size.

Figure 21: Power dispatch for the PV+storage system for a sample day in May

Figure 22: Daily variation of battery state of charge

Figure 23: Peak demand reduction for the PV+battery case

3.4 Sensitivity analysis for the PV with storage case

3.4.1 Battery and PV system size

To examine the financial and environmental implications of differently sized battery banks, the battery size was varied from 0 to 150kWh with increments of 25kWh, and three PV system sizes were considered: 50kW, 75kW and 100kW. Figures 24,25 and 26 show the variation of the NPV, SSR and SCR with PV and battery system size.

Figure 24: NPV with varying PV system and battery size

Figure 25: Variation of the self-sufficiency rate with PV and battery size

Figure 26: Variation of the self-consumption rate with PV and battery size

It is clear from Figure 24 that increasing the battery capacity up to 25kWh results in an improvement in the net present value for all PV system sizes. However, beyond 25 kWh the additional battery cost becomes greater than the electricity bill savings. However, in all cases considered the NPV remains negative. Furthermore, as seen in Figure 25, increasing the battery size from 0 to 150kWh also increases SSR values for all system sizes considered which means that on-site CO₂ emissions are also increased because the battery maximizes the use of the surplus PV electricity.

Combining these results, it can be deduced that properly sizing the PV array and battery can positively impact the profitability of the system without significantly undermining emission reduction. For example, with a 75kW PV system, adding a 25kWh battery results in an NPV of -

\$50,801 which is higher compared to a 100kW PV system with no battery which has an NPV of - \$85,617. This is a 40% increase in the NPV which is significant even though both systems still have negative NPVs. On the other hand, the 75kW PV/ 25kWh battery system reduces on-site emissions by 68% compared to 72%, a difference of only 4%.

Table 12: Summary of PV system performances with the battery

Parameter	System 1	System 2	System 3
PV size (kW)	50	75	100
Battery size (kWh)	25	25	25
Annual Yield (kWh)	64,432.8	9,6834.8	129,140.4
Energy from the grid (kWh)	44,868	33,369	26,714
Energy to the grid (kWh)	8,640.9	25,882	52,606.5
Self-consumed energy (kWh)	57,915	69,414	76,069.37
Self-consumption rate (SCR %)	86	72	58.5
Self-sufficiency rate (SSR %)	56	68	74
Electricity bill savings (\$/year)	6,621	8408.5	10231.33
Net present Value (\$)	-31,051	-50,801.60	-75,222
Simple payback period (years)	15.95	17.8	19.9
On-site CO ₂ emissions reduced (tons)	64	76.7	84
On-site CO ₂ emissions reduced (%)	56	68	74
Total CO ₂ emissions reduced (tons)	71	107	143
Total CO ₂ emissions reduced (%)	57	86	115

3.4.2 Battery cost

Taking the optimal case of a 50kW and 25kWh battery in terms of NPV, we evaluate the impact of battery cost on the feasibility considering a battery price between \$150/kWh and \$650/kWh (Figure 27).

Figure 27: variation of NPV with battery cost for the optimal case

Decreasing the battery costs from 400\$/kWh to 150\$/kWh increased the net present value by 17% however it remains on the negative side.

3.4.3 Third-party ownership

In the third-party ownership scenario, the energy is bought at a fixed rate which is the power PPA rate. The price of energy was set to 10 cents/kWh with an annual escalation rate of 1%. Figure 28 highlights the variation of the net present value for a battery capacity range of 0

to 150kWh. A positive NPV can be obtained for specific combinations of PV and battery system size. It can be seen that there is an optimal battery size above which the NPV starts to decrease. This is due to the fact that the monthly energy and demand cost reductions become lower than the monthly PPA payments. Compared to the direct ownership model, all combinations resulted in a negative NPV which highlights the advantage of using a PPA to finance the project.

Figure 28: Variation of the net present value with PV system and battery size for a PPA price of 10 cents/kWh

Table 13: Optimal cases for the PPA scenario

System	Battery (kWh)	SCR (%)	SSR (%)	NPV (\$)
PV=50kW	125	93.4	61.2	39254.9
PV=75kW	125	79.3	74.3	23993.77
PV=100kW	75	61.4	77.7	7837.9

4 CONCLUSIONS

This project studied the techno-economic feasibility of deploying a PV system for an EV charging station in West Virginia. Using a parametric simulation approach, different combinations of PV and battery system sizes were evaluated to determine their impacts on the system profitability in comparison with grid charging. Two financial models were investigated: direct ownership and third-party ownership of the system. Furthermore, net-metering and the trading of solar renewable energy credits were considered. Based on the data derived in this research, the following conclusions can be derived:

- In terms of CO₂ emissions, charging EVs using the grid in West Virginia is comparable to fueling gasoline cars in order to obtain the same mileage.
- Compared to gasoline fueling, when a price of \$2.35/gallon is considered and without accounting for differences in vehicle costs, the PV-EV scenario is found to be economically feasible on the cost of fuel basis only.
- Under the current policies and a SREC price of \$8.5/MWh, charging EVs with PV in WV is not economically feasible compared to grid-EV.
- The PV-EV scenario becomes feasible if SRECs are traded for at least \$100/MWh, which is possible based on the observation of SRECs in Ohio.
- The PV-EV scenario becomes feasible if the commercial system owner chooses to enter a PPA with a maximum price of 7 cents/kWh.
- Optimal sizing of the PV system and the addition of battery storage to the PV-EV station can increase the financial performance of the system without significant reduction in the environmental benefits.

5 FUTURE WORK

A number of limitations which have not been discussed in this study should be addressed in future research. The first limitation consists in not considering the differences in vehicle costs, operation and maintenance expenditures when comparing the PV-EV option to gasoline vehicles. A second limitation is that the results are limited by the range of input parameters and assumptions chosen for this study. For example, the impact of different EV load profiles may yield different results in terms of system sizing and financial performance. Furthermore, the effect of weather on the heating and cooling energy loads may be accounted for when calculating the EV load profile. Moreover, the variation in EV charging patterns was left out of this study due to the uncertainty and difficulty in evaluating these factors. In addition, a larger range of PV and battery system sizes could be considered which will lead to more accurate results. For example, optimal financial and environmental results may be determined by an optimization algorithm instead of parametric simulations. Another limitation can be discussed when considering the PPA financing option. In this study, the economic benefit is assessed from the perspective of the system owner, however the financial analysis should be assessed from the perspective of the system developer as well.

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APPENDICES

Data used for the simulations:

1- Location and Weather file:

Table 14: Location and weather data

Location	Morgantown, WV
Latitude	39.61
Longitude	-79.94
Time zone	GMT-5
Elevation	306m
Average global horizontal irradiance (kWh/m ² /day)	4
Average temperature (°C)	11

Figure 29: Hourly solar global horizontal irradiance (W/m²)

2- PV module selection:

Table 15: PV panel specifications

Property	Unit	Value
Solar panel model	-	SunPower SPR-X21-335-BLK
Manufacturer	-	SunPower
Technology	-	Monocrystalline
Module power at STC	W	335
Current at Maximum Power Point (Imp)	A	5.85
Voltage at Maximum Power Point (Vmp)	V	57.3
Nominal Efficiency	%	20.5647
Short Circuit Current (Isc)	A	6.2
Open Circuit Voltage (Voc)	V	67.9
Module Performance Degradation Rate	%/year	0.5

Figure 30: I-V curve of the solar panel

3- Inverter selection:

Table 16: Inverter specifications

Property	Unit	Value
Inverter model	-	Fronius USA Symo 20.0-3 480V
Manufacturer	-	Fronius USA
Technology	-	String inverter
Maximum AC power	W	20000
Maximum DC power	W	20469.3
Nominal AC Voltage	V	480
Maximum DC Voltage	V	800
Maximum DC Current	A	28.749
Minimum MPPT DC Voltage	V	450
Nominal DC Voltage	V	712
Maximum MPPT DC Voltage	V	800

Figure 31: Inverter efficiency at different power output levels

4- Battery selection:

Table 17: Battery specifications

Battery type	Lithium ion
Battery Size (kWh)	100
Battery Power (kW)	25
Single Cell Capacity (Ah)	2.6
Battery Voltage (V)	500.4
Total Number of Cells	15985
Cells in Series	139
Strings in Parallel	115
Maximum Charge/Discharge power (kW)	24.937
Discharge Time (hours)	6
Maximum Charge/Discharge current (A)	50
Conversion Efficiency (%)	96
Depth of Discharge (%)	80
Initial State of Charge (%)	50

5- Electric vehicle load:

Figure 32: Average daily profile for the electric vehicle charging station

VITA

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