Methodology for the Optimal Design of PEV Charging Systems with Multiple Chargers and Distributed Resources

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Abstract— **Increased penetration of plug-in electric vehicles (PEVs) will necessitate deployment of numerous PEV chargers. Pairing these chargers with renewable distributed generation (DG) and storage can potentially alleviate negative impacts on the distribution grid and help meet renewable portfolio goals. The optimal design of such integrated charging systems depends on many factors, including geographic location and charging profiles. This paper presents an optimization methodology for designing integrated PEV charging systems with multiple chargers and distributed resources. This methodology is used to investigate optimal designs for charging systems at a retail business and on a university campus. When PEV charging can introduce a demand charge, it is shown that the optimal design depends on the time of charging and the level of existing load. When non-negligible distribution system losses exist between charger locations, it is shown that the optimal size and location of DG and storage depends on the charging profile of the different chargers and the distribution efficiency.**

Index Terms—**distributed power generation, electric vehicles, energy storage, linear programming, mixed integer linear programming.**

I. INTRODUCTION

Plug-in Hybrid Electric Vehicles (PHEVs) and Electric Vehicles (EVs), collectively referred to as Plug-in Electric Vehicles (PEVs), have been entering the US market for over two years. As of September 2012, nearly 45,000 PEVs have been sold in the US [1], and by one estimate this number will grow to 770,000 by 2020 [2]. While most charging may take place at home, a public charging infrastructure is also needed to extend PEV driving range and for convenience. Such an infrastructure would include chargers installed at workplaces, retail stores and street side parking. Some work on deploying public chargers has already been initiated [3]. One such initiative supported by the US Department of Energy is the EVProject which intends to deploy 8,000 residential chargers, 5,000 non-residential chargers, and 200 dc fast chargers in the US. Among the key findings from this project and other studies is that public chargers can incur substantial operating costs and strain the distribution grid [4], [5].

One way to reduce PEV charging costs, mitigate negative impact on the grid, and help achieve renewable portfolio goals is to pair PEV chargers with renewable distributed generation (DG) and/or energy storage. Some companies are already beginning to explore this possibility as a commercially feasible endeavor [6]-[9]. However, it is unclear what architectural combination and control methodology makes the most practical sense in terms of cost and performance. In the past, methodologies have been developed to size stand-alone (i.e., non-grid connected) renewable DG and/or storage systems for non-PEV loads [10]-[13]. However, these methodologies do not address the design of grid-interfaced DG and/or storage systems, with their unique constraints and objective functions, to meet PEV charging requirements. An optimization methodology for the design of systems with a single grid-interfaced charger and a single renewable generator and a single storage unit was presented in [14]. This methodology is adequate for evaluating residential charger systems, as they typically only involve a single charger, but is inadequate for systems with multiple chargers, as is generally encountered in public charging systems.

This paper introduces a methodology for optimally designing systems with multiple grid-interfaced PEV chargers that also integrate multiple renewable DG and storage units. This optimization framework and the system lifecycle cost model it uses are described in section II. Section III presents the details of the optimization methodology including the design constraints. We apply this methodology to determine and explore optimal designs for two public charging cases in section IV. Finally, section V presents our conclusions.

II. OPTIMIZATION FRAMEWORK AND SYSTEM LIFECYCLE COST MODEL

There are many different ways to configure and control a system with multiple PEV chargers, renewable DG and/or storage. In our framework, a fully designed system that meets all specifications is referred to as a design. The design may or may not include renewable DG, storage, and a grid connection. Different designs can be developed using

alternate technologies for renewable generation and storage. Alternative configurations can also be conceived depending on whether renewable DG and/or storage is centralized or distributed as shown in Fig. 1.

To identify optimal designs, we need a quantitative measure that captures the system attributes of interest: cost, efficiency, and reliability. In our framework, we optimize for system lifecycle cost, which by including initial capital costs as well as energy and maintenance costs (which in turn depend on system efficiency and reliability) incorporates all three system attributes of interest.

The general system configuration for which we develop the system lifecycle cost model has J levels of distribution voltages. At each level there can be PEV chargers, renewable DG, and storage units. Fig. 2 shows this concept for $J = 3$. In general, at level j (ranging from 1 to J), there are N_j PEV chargers, and there can be up to M_j renewable DG units and L_j storage units. We consider systems with only one grid connection, as this is the most practical configuration given current metering and billing approaches that do not differentiate between power delivered from a neighboring distributed generator and that from a distant generation plant.

The total system lifecycle cost, C, is modeled as:

$$C = C_{DG} + C_S + C_G + C_M, \qquad (1)$$

where C_{DG} and C_S are the initial capital costs for the renewable DG and the storage units, respectively, including any costs associated with their power electronic interfaces; C_G is the cost associated with getting energy from the grid, and C_M is the maintenance cost of the system. Collectively C_G and C_M represent the operating costs of the system over its lifetime. Note that while the system includes PEV chargers in addition to renewable DG, storage and a connection to the grid, the charger cost is not included in the system lifecycle cost model since it will have the same cost across the design space.

The initial capital costs of all the renewable DG and storage units are modeled as:

$$C_{DG} = \sum_{j=1}^{J} \sum_{i=1}^{M_j} (C_{DG,0(ji)} + C'_{DG(ji)} \cdot P_{DG,r(ji)}) \; , \qquad (2)$$

$$C_S = \sum_{j=1}^{J} \sum_{i=1}^{L_j} (C_{S,0(ji)} + C'_{S(ji)} \cdot P_{S,r(ji)} + C''_{S(ji)} \cdot E_{S,r(ji)}) \; , \qquad (3)$$

where $P_{DG,r(ji)}$, and $P_{S,r(ji)}$ are the power ratings of the ith renewable DG and the ith storage unit at the jth level, respectively, and $E_{S,r(ji)}$ is the energy storage capacity of the ith storage unit at the jth level. For notational compactness we will also refer to these as the j-i^{th} component, and where
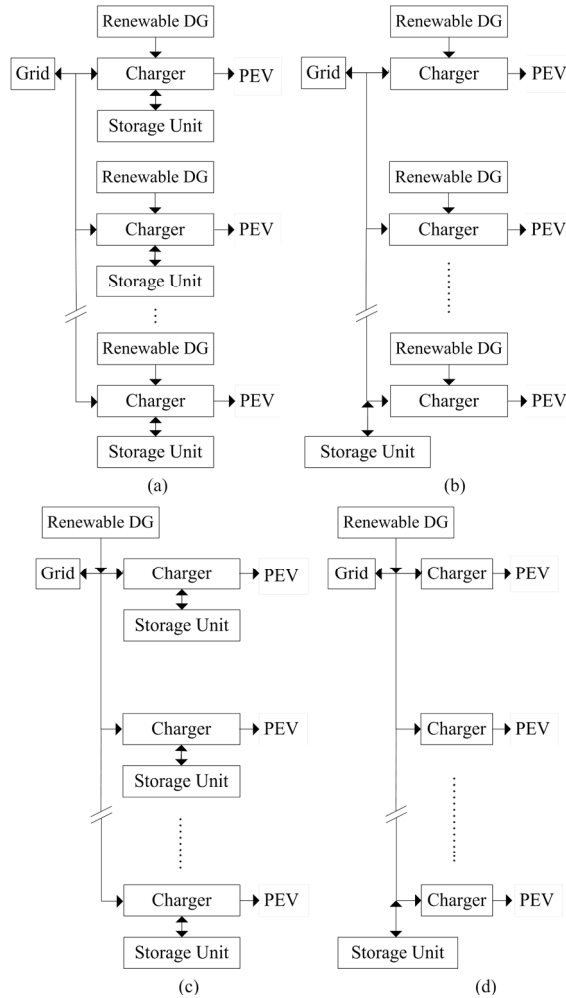

Fig. 1. Sample alternative configurations for integrating EV charging, renewable energy sources and storage into the electric grid: (a) fully distributed renewable sources and storage, (b) distributed renewable sources but centralized storage, (c) distributed storage but centralized renewable source, and (d) centralized renewable source and storage.
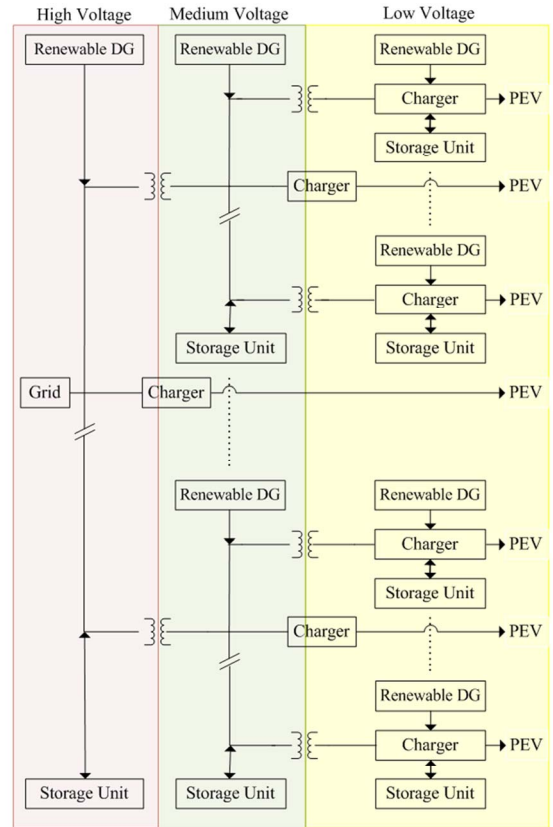

Fig. 2. A configuration of PEV charging with three levels of distribution voltages (high, medium, and low). All possible locations for the renewable DG and storage units are shown.

obvious we will omit this reference completely. $C_{DG,0(ji)}$ and $C_{S,0(ji)}$ are the fixed costs of the j-i[th] renewable DG and storage units, respectively, while $C'_{DG(ji)}$ is the variable cost of the renewable DG and $C'_{S(ji)}$ and $C''_{S(ji)}$ are the variable costs of the storage units with respect to power rating and energy rating, respectively.

The cost associated with getting energy from the grid is modeled as:

$$C_G = C_{G,0}\frac{T_{life,sys}}{T_{bp}} + C''_G\frac{T_{life,sys}}{T_{bp}}E_{G,r} + C'_G\frac{T_{life,sys}}{T_{bp}}P_{G,r} \quad , \qquad (4)$$

where $E_{G,r}$ is the energy drawn from the grid over a billing period T_{bp}; $P_{G,r}$ is the peak power drawn from the grid; and $T_{life,sys}$ is the lifetime of the system, i.e., the amount of time for which the charging system is expected to be used. The first two terms of (4) capture the consumption charge (consisting of distribution and energy charges) and the third term represents the demand charge. If the peak power drawn from the grid is less than the demand charge level, the demand charge will be zero.

By modeling the maintenance cost as a cost associated primarily with the cost of replacing the renewable DG and the storage unit at the end of their respective lives, maintenance cost is given by:

$$
\begin{aligned}
C_M = \quad & \sum_{j=1}^{J}\sum_{i=1}^{M_j} C_{DG,0(ji)} \cdot \text{int}\left(\frac{T_{life,sys}}{T_{life,DG(ji)}}\right) \\
& + \sum_{j=1}^{J}\sum_{i=1}^{L_j} C_{S,0(ji)} \cdot \text{int}\left(\frac{T_{life,sys}}{T_{life,S(ji)}}\right) \\
& + \sum_{j=1}^{J}\sum_{i=1}^{M_j} C'_{DG(ji)} \cdot \text{int}\left(\frac{T_{life,sys}}{T_{life,DG(ji)}}\right) \cdot P_{DG,r(ji)} \qquad (5) \\
& + \sum_{j=1}^{J}\sum_{i=1}^{L_j} C'_{S(ji)} \cdot \text{int}\left(\frac{T_{life,sys}}{T_{life,S(ji)}}\right) \cdot P_{S,r(ji)} \\
& + \sum_{j=1}^{J}\sum_{i=1}^{L_j} C''_{S(ji)} \cdot \text{int}\left(\frac{T_{life,sys}}{T_{life,S(ji)}}\right) \cdot E_{S,r(ji)} ,
\end{aligned}
$$

where $T_{life,DG(ji)}$ and $T_{life,S(ji)}$ are the expected lives of the renewable DG and the storage units, respectively, and int() is the floor function which rounds its argument down to the nearest integer. The cost and time duration parameters used in (2)-(5) are also defined in Table I. Additionally, Table I lists the values for these parameters as used in this paper. For DG we only consider solar photovoltaic (PV) generators and for storage we only consider lead-acid storage units.

III. Optimization Methodology

We define an optimal architecture to be the one with the lowest system lifecycle cost, as modeled by (1). This cost depends on the ratings: $P_{DG,r(ji)}$, $P_{S,r(ji)}$, $E_{S,r(ji)}$, $P_{G,r}$ and $E_{G,r}$. These ratings depend upon the power drawn as a function of time t by the various PEV chargers, $P_{C(ji)}(t)$, as well as the design constraints and the power flow control methodology.

Design constraints arise from the maximum power that can be drawn from and delivered to the grid, $P_{G,max(p)}$ and $P_{G,max(n)}$, respectively; limits on the maximum rating of the renewable DG units, $P_{DG,max(ji)}$; the maximum power and energy rating of the storage units, $P_{S,max(ji)}$ and $E_{S,max(ji)}$, respectively; and the maximum and minimum state-of-charge allowed for the storage units, $SOC_{max(ji)}$ and $SOC_{min(ji)}$, respectively. These constraints can be expressed as follows:

TABLE I
COST AND TIME DURATION PARAMETERS USED IN THE SYSTEM LIFECYCLE COST MODEL

Parameter	Description	Value
$C_{DG,0(ji)}$	Fixed capital cost of the renewable DG ($)	200[1]
$C'_{DG(ji)}$	Variable capital cost of the renewable DG ($/kW)	4,400[1]
$C_{S,0(ji)}$	Fixed capital cost of the storage unit ($)	110[2]
$C'_{S(ji)}$	Variable capital cost of the storage unit depending on power rating ($/kW)	200[2]
$C''_{S(ji)}$	Variable capital cost of the storage unit depending on energy rating ($/kWh)	220[2]
$C_{G,0}$	Fixed distribution charge from the grid per billing period ($)	15
C'_G	Demand charge from the grid per billing period ($/kW)	10[3]
C''_G	Variable distribution and energy charge from the grid ($/kWh)	0.14
$T_{life,sys}$	Expected life of the system (yr)	20
$T_{life,DG(ji)}$	Expected life of the renewable DG (yr)	25
$T_{life,S(ji)}$	Expected life of the storage unit (yr)	6
T_{bp}	Length of billing period (yr)	1/12

Note: [1]For solar photovoltaic DG.
[2]For lead-acid electrochemical storage.
[3]This charge is only applied if the peak power drawn during a billing period is greater than 20 kW.
The cost and life parameters in this table are based on data and analysis presented in [15].

$$-P_{G,max(n)} \le P_G(t) \le P_{G,r} \le P_{G,max(p)}, \qquad (6)$$

$$0 \le P_{DG(ji)}(t) \le P_{DG,r(ji)} \le P_{DG,\max(p)(ji)} \quad , \qquad (7)$$

$$-P_{S,\max(ji)} \le -P_{S,r(ji)} \le P_{S(ji)}(t) \le P_{S,r(ji)} \le P_{S,\max(ji)}, \quad (8)$$

$$
\begin{aligned}
E_{S,r(ji)} \cdot SOC_{\min(ji)} \le E_{S(ji)}(t) \le E_{S,r(ji)} \cdot SOC_{\max(ji)} \\
\le E_{S,\max(ji)} \cdot SOC_{\max(ji)} \;,
\end{aligned} \qquad (9)
$$

where $P_G(t)$, $P_{DG(ji)}(t)$, and $P_{S(ji)}(t)$ are the instantaneous powers delivered by the grid, the renewable DG units, and the storage units, respectively; and $E_{S(ji)}(t)$ is the instantaneous energy stored in the storage unit. The maximum power available from the grid could be limited due to the limited rating of a distribution transformer or a feeder line. The limits on the DG and storage could be due to space constraints. For the analysis in this paper, $SOC_{max(ji)}$ and $SOC_{min(ji)}$ are taken to be 1 and 0.8, respectively.

Additional constraints are imposed by physical laws and the connections between the components; including the following from energy conservation:

$$
\begin{aligned}
\sum_{j=1}^{J}\sum_{i=1}^{N_j} P_{C(ji)}(t) = P_G(t) &+ \sum_{j=1}^{J}\sum_{i=1}^{M_j} P_{DG(ji)}(t) \\
&+ \sum_{j=1}^{J}\sum_{i=1}^{L_j} P_{S(ji)}(t) \qquad (10) \\
&- \sum_{j=1}^{J}\sum_{i=1}^{N_j} P_{L(ji)}(t) \;,
\end{aligned}
$$

where $P_{L(ji)}(t)$ is the loss incurred by distribution system components. Also the instantaneous power from the renewable DG units satisfies:

$$P_{DG(ji)}(t) = P_{DG,r(ji)}f_{DG(ji)}(t) \qquad (11)$$

where $f_{DG(ji)}(t)$ is the normalized output power profile of the renewable distributed generation source, and will vary

between 0 and 1 due to variation in solar irradiation (or wind speed). Also the change in energy in the storage units is related to the power drawn from them by:

$$E_{S(ji)}(t) - E_{S(ji)}(t - \Delta t) = -\int_{t-\Delta t}^{t} p_{SC(ji)}(t') \cdot \sqrt{\eta_{ji}} \cdot dt'$$
$$-\int_{t-\Delta t}^{t} p_{SD(ji)}(t') \cdot \frac{1}{\sqrt{\eta_{ji}}} \cdot dt' \quad (12)$$

where in this model, $P_{S(ji)}(t)$ is divided into two components and incorporates the effect of the roundtrip efficiency of the storage unit, η_{ji}. One component, $P_{SC(ji)}(t)$, is non-positive when the j-i^{th} storage unit is charging. The second component, $P_{SD(ji)}(t)$, is non-negative when the storage unit is discharging. The sum of these two components will equal the power profile of the storage unit:

$$P_{SC(ji)}(t) \leq 0 , \quad (13)$$

$$P_{SD(ji)}(t) \geq 0 , \quad (14)$$

$$P_{S(ji)}(t) = P_{SC(ji)}(t) + P_{SD(ji)}(t) , \quad (15)$$

Another source of loss is the transformer. Approximating transformer loss as proportional to the power flowing through the transformer, we can be model it as:

$$P_{L(ji)}(t) = \left(1 - \eta_{T(ji)}\right) \times |P_{T(ji)}(t)| \quad (16)$$

where $P_{L(ji)}(t)$ is the instantaneous power loss due to the efficiency, $\eta_{T(ji)}$, of the transformer and $P_{T(ji)}(t)$ is the power passing through the transformer that relates to the chargers, renewable DG, storage units, and transformers downstream:

$$P_{T(ji)}(t) = \sum_i P_{C(ji)}(t) - \sum_i P_{DG(ji)}(t) - \sum_i P_{S(ji)}(t)$$
$$+ \sum_i P_{T((j-1)i)}(t) + \sum_i P_{L((j-1)i)}(t) \quad (17)$$

where the summation indices must match the charger, renewable DG, storage units, and transformers that are connected on the secondary side of the transformer. Other sources of loss are already incorporated into other aspects of the methodology. For instance, the inefficiency in the power electronics of the charger is incorporated into $P_{C(ji)}(t)$. Similarly, $f_{DG(ji)}(t)$ accounts for the conversion inefficiency from solar irradiance (or wind speed) to output power.

For steady state conditions, the system must return the storage unit to its original state-of-charge over some time period, T, i.e.,

$$E_{S(ji)}(T) - E_{S(ji)}(0) = -\int_0^T p_{SC(ji)}(t') \cdot \sqrt{\eta_{ji}} + \frac{p_{SD(ji)}(t')}{\sqrt{\eta_{ji}}} \quad (18)$$
$$= 0.$$

For the analysis in this paper, T is taken to be one day. Finally, the energy and instantaneous power drawn from the grid are related as follows:

$$E_{G,r} = \int_0^{T_{bp}} P_G(t') dt', \quad (19)$$

where $E_{G,r}$ is the energy drawn from the grid over a billing period T_{bp}

This optimization methodology is implemented using mixed integer programming in IBM ILOG CPLEX Optimization Studio.

IV. PUBLIC CHARGING CASE STUDIES

In this section we apply the developed optimization methodology to the design of charging systems at a retail business and on a university campus. In both cases, we consider a configuration with one grid connection point, two charging locations, and three possible locations for renewable DG and storage as shown in Fig. 3. In the university campus, the two charging locations are two parking garages, each with multiple chargers.

A. PEV Charging at a Retail Business

The case we consider here is that of a retail business looking to deploy two 7.2 kW PEV chargers on its property in order to draw additional customers. The electric utility that services its region charges a per kilowatt demand charge on the full peak power if the peak power drawn exceeds 20 kW. The peak power drawn by this retail business before the installation of the chargers is below the demand threshold. However, the addition of the PEV chargers can raise its peak power draw above this threshold and increases its electricity costs substantially.

In this paper, we evaluate two different PEV charging system design options for this business: (a) installing the PEV chargers only and incurring the demand charge, and (b) also installing solar photovoltaic (PV) DG and lead-acid electrochemical storage in an attempt to stay below the demand charge level. In both cases, we consider scenarios with and without net metering, i.e., the electric utility allows reverse power flow into the distribution grid and bills only for the net energy used (as long as it is not negative). In all cases, we use the average daily solar irradiation profile of Los Angeles, CA [16]. For our analysis, we assume that the PEV charging profile is either as shown in Fig. 4(a) (daytime charging only, centered around noon), or as shown in Fig. 4(b) (daytime and nighttime charging). Finally, we assume that the two chargers are located sufficiently close to each other so that any distribution losses are negligible and can be ignored. Since distribution system losses are ignored in this case study, any optimal design that requires the use of DG and storage always selects a single DG unit and a single storage unit. This is because both DG and storage units have a fixed cost component independent of their rating.
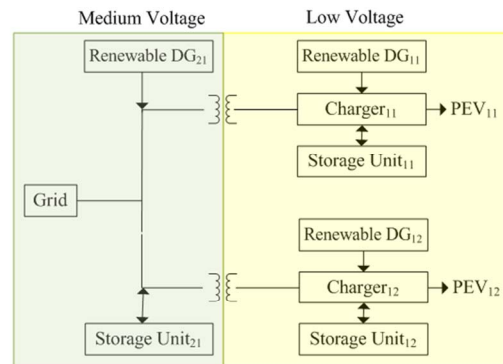

Fig. 3. A PEV public charging system configuration with two distribution voltage levels. This configuration has two charging locations and three possible locations for the renewable DG and storage units.

Fig. 5 shows the system lifecycle cost of the optimal design as a function of the retail business' existing non-PEV load for four different conditions: utility imposes demand charge or does not, and in each case with or without net metering. Fig. 5(a) presents these results using the charging profile of Fig. 4(a), and Fig. 5(b) uses the profile of Fig. 4(b). In all cases, net metering results in lower system lifecycle costs as the energy purchased from the grid is reduced to zero. This is due to the fact that generating electricity from a solar PV in Los Angeles, CA is cheaper than purchasing energy from the grid over the 20-year system life.

Another interesting observation is that the choice of installing a DG and a storage unit depends on when the PEV charging is expected to take place and the existing load. As can be seen from Fig. 5(a) when the PEV charging is only during the day and coincident with solar PV output, it is more economical to avoid the demand charge regardless of the existing load. However, when PEV charging also occurs after sunset the decision to avoid the demand charge will depend on the existing load, as seen in Fig. 5(b). Without net metering, if the existing load is below 13.95 kW, then it is more economical to install a renewable DG and storage unit to avoid the demand charge. Beyond a 13.95 kW existing load, it is more economical for the retail business to incur a demand charge than to purchase an increasingly larger renewable DG and storage unit. With net metering, the breakeven point is 13.55 kW.

B. PEV Charging at a University Campus

The second case we consider is that of a Los Angeles, CA university campus looking to install ten 7.2 kW PEV chargers in each of two parking garages for its staff. The parking garages are far enough apart that distribution system losses cannot be ignored. We also assume that the university must always pay a demand charge due to its existing load, hence that is not an important design consideration. For this study, we assume that the charging will occur only during the day, as that is when most staff will be on campus. To explore the optimal design decisions we consider the four aggregate charging profiles for the two garages shown in Fig. 6.

The first observation we make is that for any of these charging profiles (all of which are coincident with solar PV output) the optimal design is one that employs DG and storage. This result is true even if there is no limit on the amount of peak power that can be drawn from the grid and holds true because solar PV is competitive given the average Los Angeles solar irradiation profile. However, if charging is required at night and there is no limit on the power that can be drawn from the grid, then the optimal solution does not include solar PV and storage.

We also analyze the impact of various levels of distribution system losses on the design decisions by varying the efficiency of the transformers. It is observed that the number of DG and storage units in the optimal design depends on this efficiency, as can be seen from Fig. 7. When the transformer efficiency is very high (above 99.93%) the optimal design is one that uses a single DG and storage unit. However, when the transformer efficiency is below this level the optimal design uses two DG units but still only one
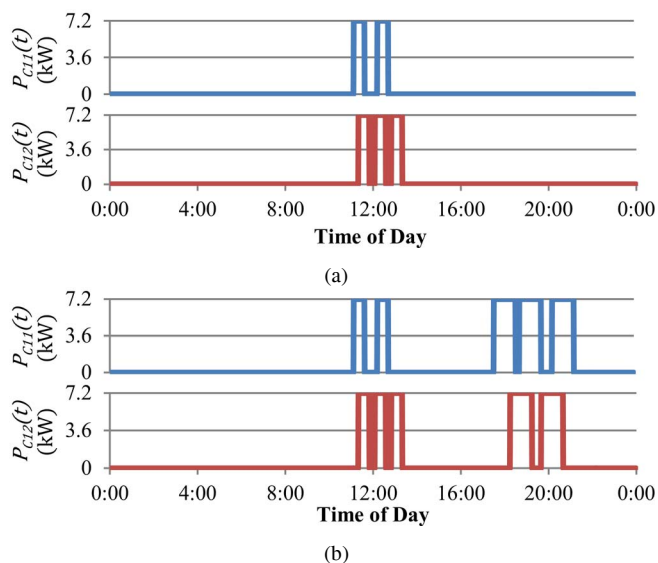

Fig. 4. Retail business PEV charging profiles for (a) daytime only charging and (b) daytime and nighttime charging.
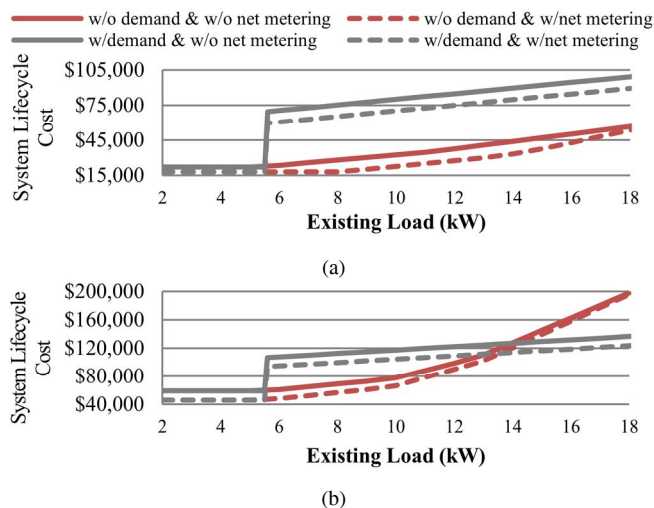

Fig. 5. System lifecycle costs for varying levels of existing load for the two PEV charging profiles of Fig. 4: (a) daytime only charging and (b) daytime and nighttime charging.

storage unit. The extra fixed cost of the additional DG unit is less than the cost of energy lost in the transformer when trying to charge the PEVs in the second location. However, the fixed cost of storage is so much higher that it is still optimal to use a single storage unit. The location of the DG and storage unit depends on the two aggregated charging profiles. The storage unit is located next to the garage whose charging profile draws the most energy. On the other hand, when only one DG is selected it is located next to the garage whose charging profile draws the most power.

V. CONCLUSIONS

In this paper we have presented an optimization methodology for designing integrated PEV charging systems with multiple chargers, renewable DG and storage units. The methodology minimizes system lifecycle cost (including capital, energy and maintenance costs) and accounts for battery round-trip efficiency and distribution system losses.
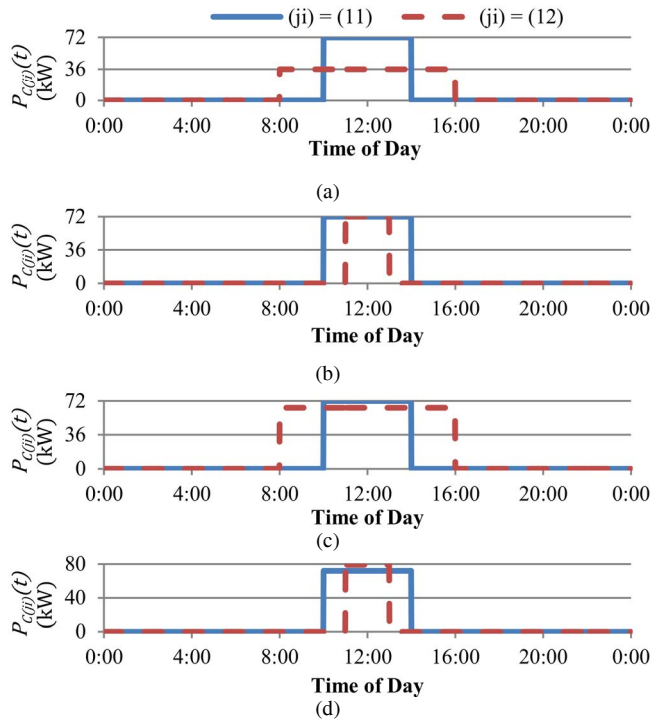
Fig. 6. The four PEV charging profiles analyzed in the university campus case study. The two profiles indicate the aggregate power drawn by the ten chargers installed in each of the two parking garages. In each scenario, one garage draws 72 kW for 4 hours. The other garage draws as follows: (a) the same amount of energy but at half the power, (b) the same amount of power but only half the energy, (c) 10% less power but more energy, and (d) 10% more power but less energy when compared to the first garage.
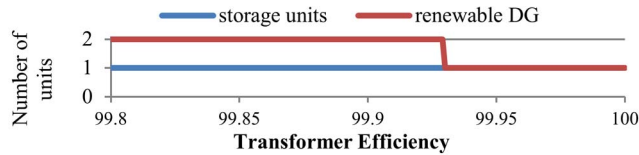

Fig. 7. Optimal number of DG and storage units in the optimal design as a function of transformer efficiency, assuming charging profiles of Fig. 6(a).

To demonstrate its usefulness, this methodology is used to study optimal system designs for two public charging case studies.

In the case of a retail business looking to deploy two PEV chargers and investigating whether or not to also deploy renewable DG and storage to avoid a demand charge, it is shown that if charging is coincident in time with DG power production, the optimal design is one that uses solar DG and the minimum amount of lead-acid storage needed to limit the amount of power drawn from the grid to below the level that triggers a demand charge. However, if charging is not completely coincident with DG power production, the optimal design decision depends on the level of existing load. When net metering is allowed, the general design decisions do not change; however the level of existing load at which the breakeven between a system with and without renewable DG and storage is achieved changes.

In the case of a university campus looking to deploy multiple chargers in two parking garages located far enough apart that that distribution system losses between charger locations cannot be ignored, it is shown that the number, size and location of the renewable DG and storage unit depends on, among other things, the level of coincidence between PEV charging and renewable DG power production and the amount of distribution system losses. In all the cases analyzed, one storage unit is optimal and it is located close to the PEV chargers that draw the most energy

ACKNOWLEDGMENT

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