Value of Injection from Residential PV with Storage for the Bulk Power System

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***Abstract*—This paper presents a model to assess the value of power injection from residential installations, with photovoltaic (PV) generation and/or electric storage, to the main grid. This model is posed as a multi-period two-stage stochastic economic dispatch, including ramping constraints and operating reserves, from the point of view of a central operator. Two sources of uncertainty are distinguished and represented as mid- and short-term scenarios: mid-term variability along the year and short-term forecasting errors. A case study, based on the Spanish power system, is presented to show the value of injection on both the operation costs and CO2 emissions. Results obtained allow us to provide some recommendations on the deployment of these residential installations.**

***Index Terms*—Injection, residential PV, residential storage, Stochastic Economic Dispatch, system operation cost, CO_2 emissions.**

I. Introduction

As a part of sustainable development strategies, a transition toward energy generation based on renewable resources is being promoted in many countries. A key aspect in that transition is the regulatory framework, that sets the allowed actions, as for instance the injection to the main grid from residential installations. On this regard, the value of that injection for the bulk power system is quantified in this paper using the Spanish system as case study. Until recent times (5th October 2018), the Spanish regulation was quite restrictive about injection from residential installations.

There is a wide literature on the transition toward an energy generation system mainly based on renewable resources. Most studies considering injection from residential installations do not deal with the impact of allowing or not that injection; instead, they jointly consider other aspects as the impact of the total amount of renewable generation and/or storage in the system.

For instance, [1] analyzes the impact of large-scale distributed storage in Texas on: Integration of intermittent renewable generation, reliability, ancillary services, and reduction of system expansion cost (network and generation). A literature review on the impact of renewable integration in the bulk power system is provided in [2].

The transition toward a renewable based energy system in Ontario is studied in [3] taking into account: Renewable generation, storage, demand management and electric vehicles. A transition to a fully renewable system taking into account system expansion (network and generation), but no storage, is presented in [4]. The value of large-scale storage in a system with high levels of renewable generation is studied in [4], but residential installations are not explicitly considered.

Electric storage is compared to net metering in [5] for residential photovoltaic (PV) in Italy, concluding that it is more profitable to use net metering than installing storage.

The optimal sizing and capacity matching of PV and storage in residential applications is considered in [6], for a number of load profiles and a wide range of geographic regions.

This paper focuses on the value of power injection from residential installations. A number of configurations for the Spanish case are studied here considering: Different degree levels of installation deployment, upper bound for allowed injection/consumption, and the rate between PV and storage. The main contributions are the study of: i)An upper bound for the value of those injections regarding system operation cost, ii) The impact on system CO_2 emissions, and iii) The recommended size of PV and storage for the average residential installation depending on the allowed injection.

In the rest of the paper, a general description of the proposed model is given in Sec. II, the mathematical formulation in Sec. III, the case study and results discussion in Sec. IV, and finally the conclusions in Sec. V.

II. Model Description

This model aims at analyzing the value of power injection, from residential PV and storage system to the main grid, through the evaluation of two relevant values: The expected system operation cost and the CO_2 emissions. A stochastic problem is presented to simulate the whole year in a large number of different configurations, including: The number of users installing residential PV and storage systems, the capacity of each one of these technologies, and the possibility, or not, to inject power from residential users to the main grid. In order to keep the computational effort tractable, the following assumptions are made: 1) Large-scale generation units are merged by technology, 2) Network constraints are considered through power flow bounds given as exogenous parameters, and a sensitivity analysis is performed on those bounds, 3) The whole year is modeled through a set of representative days that takes into account the changing conditions along the year, each representative day leads to a

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stochastic problem and the resulting set of problems are solved independently. Annual expected results are achieved by weighting every representative day solution. 4) The 24-hour problem corresponding to a representative day is a two-stage Stochastic Economic Dispatch (SED) in which the short-term scenarios, used to simulate estimation errors in uncertain parameters, are included in the second stage of the problem. More details about the uncertainty treatment, the large-units modeling and the classification of the costumers are presented in the remaining part of this section.

A. Uncertainty

In order to take into account the inherent uncertainty both in the short-term (day) and in the mid-term (year), two types of uncertainty sources are considered: Short-term estimation errors model the uncertainty of the power generated by wind and PV units in the day-ahead problem, while the mid-term variability of demand, hydro generation, pumped storage availability, and renewable generation (PV and wind) of large-scale utilities along the year is included through the definition of different representative days. Hence, short-term scenarios are included in the SED (the higher the number of short-term scenarios, the higher the computational burden to solve each SED problem), while mid-term scenarios model are used to develop the set of representative days. It is worth mentioning that data corresponding to each mid-term scenario are exogenous parameters inside each SED problem. Historical data are employed to define both short- and mid-term scenarios and their probabilities or weights, respectively.

B. Large-scale generation units

The commitment of conventional units is not considered in order to reduce the computational effort associated to solve the corresponding mixed-integer linear-programming problem. Hence, as the resulting problem to be solved is a linear program and the power network is not included, the conventional units can be aggregated by technologies as only the expected generation of each group is taken into account. In this work, nuclear, coal-fired, combined cycle gas turbines (CCGT) and fuel units are included as large-scale conventional units. On the other hand, the remaining units in the main system are also merged by technology, but the inherent uncertainty, power availability or generation, related to these units is modeled through the mid-term and short-term scenarios. In this group, hydro and pumping units, large-scale wind power plants and large PV installations are included. Mid-term scenarios set the bounds for the available power from hydro units. The variability along the year of large wind and PV plants is taken into account through the mid-term scenarios, while the estimation error is modeled through short-term scenarios in the SED problem. The operation capacity reserve is committed in day-ahead (first-stage), and it is provided by conventional units. The power deployed from committed reserve is decided in the second stage problem, and it is bounded by the reserve scheduled in first-stage (day-ahead). The role of pumped storage units is limited to provide downward reserve power in the second stage problem.

C. Residential customers

The set of demand users are divided into two non-overlapping groups: i) Users that install PV and storage, and ii) Users that install neither PV nor storage. Users in each group are assumed to have a very similar behavior pattern and, as no network is considered, aggregated values for users in each group are considered, thus we have two equivalent users.

III. Model Formulation

The two-stage Stochastic Economic Dispatch (SED) problem, to be solved for each representative day of the year, is formulated in this section. In order to clarify the nomenclature, while keeping low the space required to formulate the model, the following criteria are used: Parameters are indicated in uppercase, while variables are in lowercase, adding a wide tilde for decisions in real time, indices with a single value are indicated in uppercase, while indices with several values are in lowercase.

The upper and lower bounds for the power scheduled in day-ahead ($p_{g,t}$ plus upward/downward reserve $r^{UP}_{g,t}/r^{DW}_{g,t}$) by conventional aggregated units in each period of time, t, are presented in (1) and (2), respectively. Constrains (3) and (4) include, respectively, the ramping capacity limitation, being Δ_t the duration of period t. Constraints (5) and (6) set the committed upward/downward ($r^{UP}_{g,t}/r^{DW}_{g,t}$) reserve capacity in day-ahead as the upper bounds for the power deployed from those reserves ($\widetilde{re}^{UP}_{g,t,s}/\widetilde{re}^{DW}_{g,t,s}$) in real time.

$$p_{g,t} + r^{UP}_{g,t} \leq \overline{P}_g; \quad \forall g \in G, \forall t \in T \tag{1}$$

$$p_{g,t} - r^{DW}_{g,t} \geq \underline{P}_g; \quad \forall g \in G, \forall t \in T \tag{2}$$

$$(p_{g,t} + r^{UP}_{g,t}) - (p_{g,t-1} - r^{DW}_{g,t-1}) \leq \Delta_t \cdot \overline{\Delta R}_g; \quad \forall g \in G, \forall t \in T \tag{3}$$

$$(p_{g,t-1} + r^{UP}_{g,t-1}) - (p_{g,t} - r^{DW}_{g,t}) \leq \Delta_t \cdot \underline{\Delta R}_g; \quad \forall g \in G, \forall t \in T \tag{4}$$

$$\widetilde{re}^{UP}_{g,t,s} \leq r^{UP}_{g,t}; \quad \forall g \in G, \forall t \in T, \forall s \in S \tag{5}$$

$$\widetilde{re}^{DW}_{g,t,s} \leq r^{DW}_{g,t}; \quad \forall g \in G, \forall t \in T, \forall s \in S \tag{6}$$

Constraint (7) is the power balance for PV. The sum of the wind generation scheduled in day-ahead $p_{V,t}$, the up/down corrections in real time ($\widetilde{p}^{UP}_{V,t,s}/\widetilde{p}^{DW}_{V,t,s}$) and the spilled power $\widetilde{p}^{SP}_{V,t,s}$, must equal the available power ($P^{AV}_{t,s}$), a parameter depending on the scenario s. The upper bound for downward/upward corrections are set in (8)/(9).

$$p_{V,t} + \widetilde{p}^{DW}_{V,t,s} - \widetilde{p}^{UP}_{V,t,s} + \widetilde{p}^{SP}_{V,t,s} = P^{AV}_{t,s}; \quad \forall t \in T, \forall s \in S \tag{7}$$

$$p_{V,t} + \widetilde{p}^{DW}_{V,t,s} + \widetilde{p}^{SP}_{V,t,s} \leq \overline{P}_V; \quad \forall t \in T, \forall s \in S \tag{8}$$

$$\widetilde{p}^{UP}_{V,t,s} \leq \overline{P}_V; \quad \forall t \in T, \forall s \in S \tag{9}$$

Aggregated wind generation in the main grid is modeled by constraints (10)-(12), that are analogous to (7)-(9) for PV.

$$p_{W,t} + \widetilde{p}^{DW}_{W,t,s} - \widetilde{p}^{UP}_{W,t,s} + \widetilde{p}^{SP}_{W,t,s} = P^{AW}_{t,s}; \quad \forall t \in T, \forall s \in S \tag{10}$$

$$p_{W,t} + \widetilde{p}^{DW}_{W,t,s} + \widetilde{p}^{SP}_{W,t,s} \le \overline{P}_W; \quad \forall t \in T, \forall s \in S \tag{11}$$

$$\widetilde{p}^{UP}_{W,t,s} \le \overline{P}_W; \quad \forall t \in T, \forall s \in S \tag{12}$$

The upper and lower bounds for the hydropower scheduled ($p_{H,t}$ plus up/down reserve capacity $r^{UP}_{H,t}/r^{DW}_{H,t}$), in the day-ahead, are presented in (13)/(14). The upper bound in (13) depends on the available power (P^{AH}_t) set by the representative day for which the problem is solved (mid-term scenario). Constraints (15)/(16) set the committed upward/downward ($r^{UP}_{H,t}/r^{DW}_{H,t}$) reserve capacity in day-ahead as the upper bounds for the power deployed from those reserves ($\widetilde{re}^{UP}_{H,t,s}/\widetilde{re}^{DW}_{H,t,s}$) in real time. Constraint (17) is the energy balance for energy stored in the reservoirs: Energy ($\widetilde{soh}_{t,s}$) at the end of a period t in scenario s depends on the energy at the end of the previous period (being $SOH_{0,s}$ the energy level previous to the first period, an input parameter with the same value $\forall s$), the energy added due to pumping ($\widetilde{re}^{DW}_{P,t,s}$), and the energy released because of the deployment of reserves and the power scheduled in day-ahead, where parameter $\eta_H < 1$ is the efficiency to transform energy in the reservoir to power. The lower/upper bounds for energy in the reservoir are set in (18). Constraint (19) stands for the upper bound to the deployment of downward reserve from pumping.

$$p_{H,t} + r^{UP}_{H,t} \le P^{AH}_t \cdot \overline{PH}; \forall t \in T, \forall s \in S \tag{13}$$

$$p_{H,t} - r^{DW}_{H,t} \ge 0; \forall t \in T \tag{14}$$

$$\widetilde{re}^{UP}_{H,t,s} \le r^{UP}_{H,t}; \quad \forall t \in T, \forall s \in S \tag{15}$$

$$\widetilde{re}^{DW}_{H,t,s} \le r^{DW}_{H,t}; \quad \forall t \in T, \forall s \in S \tag{16}$$

$$\widetilde{soh}_{t,s} = \widetilde{soh}_{t-1,s} + \eta_H \cdot \Delta_t \cdot \widetilde{re}^{DW}_{P,t,s} - \frac{\Delta_t}{\eta_H} \cdot (p_{H,t} + \widetilde{re}^{UP}_{H,t,s} - \widetilde{re}^{DW}_{H,t,s}); \quad \forall t > 1, \forall s \in S \tag{17}$$

$$\underline{SOH}_t \le \widetilde{soh}_{t,s} \le \overline{SOH}_t; \quad \forall t \in T, \forall s \in S \tag{18}$$

$$\widetilde{re}^{DW}_{P,t,s} \le P^{AP}_t; \quad \forall t \in T, \forall s \in S \tag{19}$$

Constraint (20) is the upper bound for consumption capacity, where $\widetilde{d}_{t,s}$ and $\widetilde{y}_{t,s}$ are the power from the main grid consumed by users to meet their demand and charge their storage, respectively. On the other hand, (21) is the upper bound for injection capacity to the main grid (average value for the real network), where $\widetilde{vg}_{t,s}$ and $\widetilde{yg}_{t,s}$ are the power injection to the main grid from the users' PV units and storage respectively. Constraint (22) is the power balance to meet the users' demand from the main grid ($\widetilde{d}_{t,s}$), the storage ($\widetilde{b}_{t,s}$) and the PV unit ($\widetilde{vd}_{t,s}$). Constraint (23) is the power balance for the available PV power: To charge the storage ($\widetilde{vb}_{t,s}$), to meet the demand ($\widetilde{vd}_{t,s}$), to be injected to the main grid ($\widetilde{vg}_{t,s}$), or spilled ($\widetilde{vs}_{t,s}$). Constraints (24)/(25) are the upper bounds to the power consumed/injected from/to the storage. The energy balance in the storage (battery) is modeled by (26), while (27) sets the battery state of charge must have the same value at the beginning and at the end of the day. Constraint (28) sets the bounds for the admissible values of battery state of charge.

$$\widetilde{d}_{t,s} + \widetilde{y}_{t,s} \le \overline{L}; \quad \forall t \in T, \forall s \in S \tag{20}$$

$$\widetilde{vg}_{t,s} + \widetilde{yg}_{t,s} \le \underline{L}; \quad \forall t \in T, \forall s \in S \tag{21}$$

$$\widetilde{d}_{t,s} + \widetilde{b}_{t,s} + \widetilde{vd}_{t,s} = D^1_{t,s}; \quad \forall t \in T, \forall s \in S \tag{22}$$

$$\widetilde{vb}_{t,s} + \widetilde{vd}_{t,s} + \widetilde{vg}_{t,s} + \widetilde{vs}_{t,s} = P^{AV}_{t,s}; \ \forall t \in T, \forall s \in S \tag{23}$$

$$\widetilde{y}_{t,s} + \widetilde{vb}_{t,s} \le B^{CH}; \quad \forall t \in T, \forall s \in S \tag{24}$$

$$\widetilde{b}_{t,s} + \widetilde{yg}_{t,s} \le B^{DCH}; \quad \forall t \in T, \forall s \in S \tag{25}$$

$$\widetilde{soc}_{t,s} = \widetilde{soc}_{t-1,s} + \Delta_t \cdot \eta_{CH} \cdot (\widetilde{y}_{t,s} + \widetilde{vb}_{t,s}) - \frac{\Delta_t}{\eta_{DCH}} \cdot (\widetilde{b}_{t,s} + \widetilde{yg}_{t,s}); \ \forall t \in T, \forall s \in S \tag{26}$$

$$\widetilde{soc}_{1,s} = \widetilde{soc}_{|T|,s}; \quad \forall s \in S \tag{27}$$

$$\underline{EB} \le \widetilde{soc}_{t,s} \le \overline{EB}; \quad \forall t \in T, \forall s \in S \tag{28}$$

It should be noted that constraints (20)-(28) correspond to users with PV and storage (estimated demand $D^1_{t,s}$); while users without PV nor storage are modeled by a demand parameter (estimated demand $D^0_{t,s}$). In the case injection to the main grid is not allowed, variables $\widetilde{vg}_{t,s} = \widetilde{yg}_{t,s} = 0$ are fixed to zero.

Constraints (29)/(30) stand for the upper and lower bounds for the required system upward/downward reserve to be committed, numerical coefficients come from the Grid Codes, for Spain they are [7], $\underline{\Gamma} = 0.9$, $\overline{\Gamma} = 1.1$, $\underline{\Lambda} = 0.5$, and $\overline{\Lambda} = 1$. Constrains (31)/(32) set the power balance between the used and the provided upward / downward reserves. Constraint (33) is the power balance for the whole system, where ($\widetilde{h}_{t,s}$) is a slack variable modeling the unserved power.

$$\underline{\Gamma} \cdot R^{UP}_t \le r^{UP}_{H,t} + \sum_{g \in G} r^{UP}_{g,t} \le \overline{\Gamma} \cdot R^{UP}_t; \quad \forall t \in T \tag{29}$$

$$\underline{\Lambda} \cdot R^{UP}_t \le r^{DW}_{H,t} + \sum_{g \in G} r^{DW}_{g,t} \le \overline{\Lambda} \cdot R^{UP}_t; \quad \forall t \in T \tag{30}$$

$$\widetilde{p}^{UP}_{V,t,s} + \widetilde{p}^{UP}_{W,t,s} + \widetilde{d}^{UP}_{t,s} = \widetilde{re}^{UP}_{H,t,s} + \sum_{g \in G} \widetilde{re}^{UP}_{g,t,s}; \quad \forall t \in T, \forall s \in S \tag{31}$$

$$\widetilde{p}^{DW}_{V,t,s} + \widetilde{p}^{DW}_{W,t,s} + \widetilde{d}^{DW}_{t,s} = \widetilde{re}^{DW}_{H,t,s} + \widetilde{re}^{DW}_{P,t,s} + \sum_{g \in G} \widetilde{re}^{DW}_{g,t,s}; \quad \forall t \in T, \forall s \in S \tag{32}$$

$$\widetilde{d}_{t,s} + \widetilde{y}_{t,s} + D^0_{t,s} = p_{V,t} + p_{W,t} + p_{H,t} + \sum_{g \in G} p_{g,t} + \widetilde{d}^{UP}_{t,s} - \widetilde{d}^{DW}_{t,s} + \widetilde{h}_{t,s} + (\widetilde{vg}_{t,s} + \widetilde{yg}_{t,s}); \quad \forall t \in T, \forall s \in S \tag{33}$$

The objective function to be minimized (34) is the total expected operation cost. The first two terms in (34) involve first-stage variables (day-ahead): The first term include those costs related to the conventional units (scheduled generation and upward and downward reserve), while the second term include the same costs, but corresponding to the aggregated hydro units. It should be noted that the cost of PV and wind units in the main grid are null. On the other hand, the third term involve second-stage variables (real-time). Inside these costs, it may be differentiated: The costs related to upward and downward reserve deployment for conventional units in the first term and the aggregated hydropower in the second term, the downward reserve cost corresponding to aggregated pumping, and finally the cost of unserved energy.

$$\min_{\{Var.\}} \Bigg\{ \sum_{t\in T}\sum_{g\in G}(C_{RG}^{UP}\cdot r_{g,t}^{UP} + C_{RG}^{DW}\cdot r_{g,t}^{DW} + \Delta_t \cdot p_{g,t}\cdot VC_g) + $$
$$+ \sum_{t\in T}(\Delta_t \cdot VC_H \cdot p_{H,t} + C_{RH}^{UP}\cdot r_{H,t}^{UP} + C_{RH}^{DW}\cdot r_{H,t}^{DW}) + \quad (34)$$
$$+ \sum_{s\in S}\sum_{t\in T} Pr_s \cdot \Delta_t \cdot \Big[\sum_{g\in G}\Big(CE_{RG}^{UP}\cdot \widetilde{re}_{g,t,s}^{UP} + CE_{RG}^{DW}\cdot \widetilde{re}_{g,t,s}^{DW}\Big) + $$
$$+ CE_{RH}^{UP}\cdot \widetilde{re}_{H,t,s}^{UP} + CE_{RH}^{DW}\cdot \widetilde{re}_{H,t,s}^{DW} + CE_{P}^{DW}\cdot \widetilde{re}_{P,t,s}^{DW} + $$
$$+ \widetilde{h}_{t,s}\cdot CLL \Big] \Bigg\}$$

IV. Case Study and Results

Operation during one year for a stylized version with one single generator with the aggregated power for each technology of the Spanish power system is simulated by solving 24 Stochastic Economic Dispatch (SED) problems, of 24 hours each one. For each trimester in the year 6 mid-term scenarios are considered: 2 for demand $D_{t,s}$ (workdays, weekend), 3 for wind (low, medium, high), 1 for available PV, 1 for hydropower, 1 for available pumping capacity. Each SED problem includes 9 short-term scenarios in the second-stage ((3 for wind) $\times$ (3 for PV)).

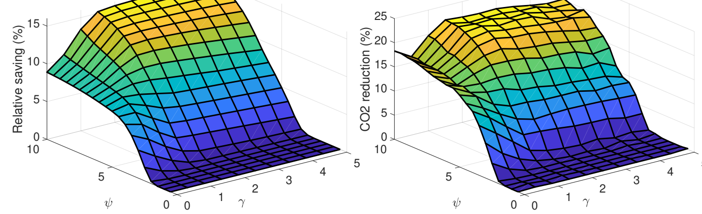
TABLE I
Summary of generators data (Spain 2017)

Tech.	Capa. (GW)	N. of units	Age (years)	Var. cost (€/MWh)	Ramp %/h	CO_2 ton/MWh
CCGT	25.0	52	12.1	47.92	47.2	0.494
Nuclear	7.6	8	33.8	11.17	5.5	0.000
Coal	9.5	26	36.9	28.18	21.5	1.146
Wind	22.9	-	-	0.00	-	0.000
PV	4.4	-	-	0.00	-	0.000
Hydro	20.4	-	>40	4.44	100	0.000
Pumping	3.1	-	>40	36.06	100	0.000
Total	**95.1**					

Values for demand, connection capacity, prices, available wind and PV, available hydropower and pumping, are taken from [8]. The value of required upward reserve capacity is taken from [7]. Data for conventional generators are taken from [9], [10], [11], and [12]. Table I provides a summary of data for utility-scale units. Data for users are taken from [13].

The effect of power injection from residential installations in the Spanish system is assessed through two main results: System operation cost and CO_2 emissions. The value of those results are compared for a number of configurations, some where injection is allowed and others where it is not ("No Inj." in the figures). Sensitivity of results is studied respect to the four parameters that follows:

- $\chi = \frac{N_1}{N}$, where N_1 is the number of customers installing PV and storage, and N is the total number of customers, $D^1_{t,s} = D_{t,s}\cdot\chi$, and $D^0_{t,s} = D_{t,s}\cdot(1-\chi)$.
- $\psi = \frac{\text{PV peak capacity (kWp)}}{\text{Hourly average power consumption (kW)}}$, is the rate between the PV peak capacity installed (kWp) and the hourly average power consumption (kW) for residential customers, $P^{AV}_{t,s} = D^1_{t,s}\cdot\psi$. In the Spanish system $\psi \approx 1$.



(a) (b)

Fig. 1. Effect of (ψ,γ) on system operation cost and CO_2 emissions.

- $\gamma = \frac{\text{storage capacity (kWh)}}{\text{PV peak capacity (kWp)}}$, is the rate between storage capacity and PV peak capacity for the residential installations, $\overline{EB} = P^{AV}_{t,s}\cdot\gamma$.
- $\underline{L}$, is the upper bound for the injection capacity of the residential installations (MW). If the connection capacity is symmetrical (indicated as "Sym." in the figures) then this value equals the upper bound of the connection capacity for residential consumption $\overline{L}$, $\underline{L} = \overline{L}$. If $\underline{L} \neq \overline{L}$ then curves are marked as "Asym." in the figures.

The model is solved using CPLEX under GAMS in a computer with 8GB RAM and processor i5 7400 (4 cores, 3 GHz) with a cost of around 10 seconds per each configuration defined by a particular value of χ, γ, ψ, $\underline{L}$, and $\overline{L}$.

Results for the system with 0% residential PV and 0% storage are referred to as "base values", and are used to normalize values in the figures.

Fig. 1a and 1b shows surfaces for the Relative cost $= 100\cdot\frac{\text{(cost no inject.)}-\text{(cost with inject.)}}{\text{Base cost}}$, and Relative $CO_2 = 100\cdot\frac{(CO_2\text{ no inject.})-(CO_2\text{ with inject.})}{\text{Base }CO_2}$ respectively. Four regions can be observed on these surfaces:

1) For $\psi\in[0.5, 2.5]$ and $\gamma\in[0,5]$, both values for PV and storage are quite small and they have almost no effect on the system.
2) For $\psi\in[2.5,10]$ and $\gamma\in[0,1.5]$, the sensitivity of results respect to storage, γ, is relatively high, details are provided on the discussion for Figs. 6 and 8.
3) For $\psi\in[2.5,8]$ and $\gamma\in[1.5,5]$, the sensitivity of results respect to PV, ψ, is relatively high, details are provided on the discussion for Figs. 7 and 9.
4) For $\psi\in[8,10]$ and $\gamma\in[1.5,5]$, this region contains the maximum values for the results, and it is almost flat, values of γ and ψ have a quite small effect in this region.

Frontiers between region 2 and 3 ($\gamma\approx 1.5$) and between regions 3 and 4 ($\psi\approx 8$) provide threshold values for the effect of γ and ψ on the results, more details are provided on the comments for Figs. 6 to 9.

Fig. 2 and Fig. 4 show the normalized system operation cost, and normalized CO_2 emissions respectively for the same configurations, $\underline{L} = \overline{L}$, (for each single user): ($\gamma = 2, \psi = 3$) $\rightarrow$ (3 kWp PV, 6 kWh storage), ($\gamma = 4, \psi = 3$) $\rightarrow$ (3 kWp PV, 12 kWh sto.), ($\gamma = 2.25, \psi = 6$) $\rightarrow$ (6 kWp PV, 13.5 kWh sto.), ($\gamma = 3, \psi = 6$) $\rightarrow$ (6 kWp PV, 18 kWh sto.). For $\chi = 0.4$, $\gamma = 2.25$, and $\psi = 6$ the total capacity of residential installations is 66.89 GW of PV and 150.50 GWh of storage. In Fig. 2 it can be observed that:

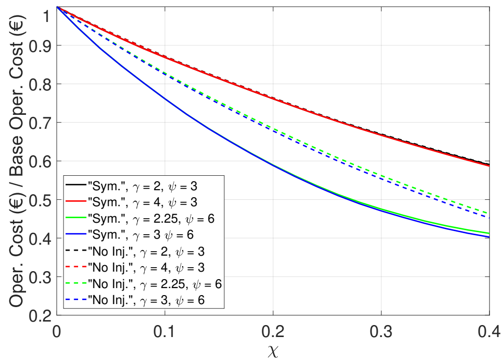


Fig. 2. Effect of χ on system operation cost.

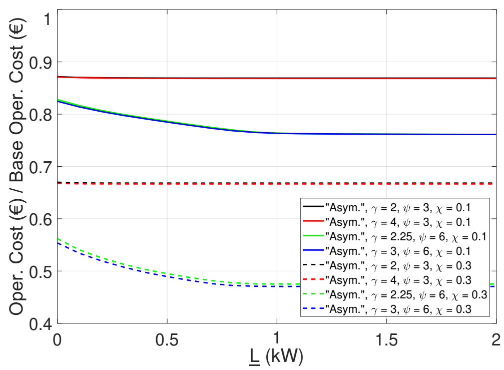


Fig. 3. Effect of $\underline{L}$ on system operation cost.

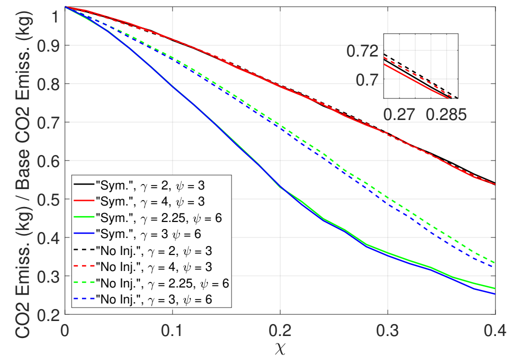


Fig. 4. Effect of χ on system CO_2 emissions.

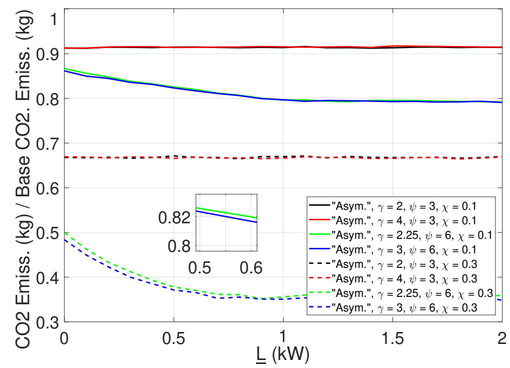


Fig. 5. Effect of $\underline{L}$ on system CO_2 emissions.

- Injection and storage have no value for low values of PV, that is because only the PV generation surplus is used for storage and/or injection.
- Injection has a significant value for high PV, because it allows to integrate more PV generation in the system.
- Value of storage is quite small, this is studied in more detail in Fig. 6.
- Reduction in system operation cost decreases as χ increases, that is because conventional generation, starting from the most expensive, is being replaced by generation from residential installations.

Fig. 4 illustrates how for low values of PV, curves for $\psi = 3$, the reduction in CO_2 emissions is almost linear with χ (fraction of residential users with PV and storage). That is because all the PV generation can be effectively integrated in the system, and there is no difference between injection and not injection because there is not PV surplus to be managed using injection. In the case with high PV ($\psi = 6$) without injection, it is observed an almost linear dependence on χ for the same reasons as in the previous case. For high PV ($\psi = 6$) and with injection, the CO_2 reduction is almost linear on χ, for $\chi \in [0, 0.2]$, and for $\chi > 0.2$ the CO_2 reduction decreases with χ, because not all the PV available for injection can be effectively integrated in the system due to the minimum output power constraints for conventional generators, and the requirement of reserve from dispatchable generators.

In Figs. 3 and 5 the effect of connection capacity for injection on system operation cost and CO_2 emissions is studied for different configurations. The same values for γ and ψ as in Figs. 2 and 4 are taken, but in this case two values of χ are selected to represent a moderate penetration of the residential installations $\chi = 0.1$ (10%), and a high penetration $\chi = 0.3$ (30%). The upper bound for consumption (for each single user) is $\overline{L} = 2$ kW (a fixed value for all figures). The interesting information from Figs. 3 and 5 is the threshold value for the upper connection capacity for injection $\underline{L}$ that is approximately 1 kW, both for operation system cost and CO_2 emissions. For values $\underline{L} > 1$ kW results do not change. For low vales of PV, $\psi = 3$, there is no injection and therefore those curves in Figs. 3 and 5 are horizontal.

The effect of storage (γ) on system operation cost and CO_2 emissions is shown in Figs. 6 and 8. It can be observed that:

- The difference in values between the cases with injection and no injection increases with the value of installed PV (ψ) because injection allows to improve the management of PV surplus generation.
- For all the cases, for both cost and CO_2, there is a threshold for $\gamma = \frac{storage}{PV} \approx 1.6$ above which adding more storage has almost no effect.
- Regarding CO_2 emissions, the combination of storage and injection provides more flexibility (in terms of ramping capability) to the system than only storage without injection. That explains why CO_2 increases with storage in the case with injection for $\psi \leq 6$, because the additional flexibility allows to replace CCGT plants by coal plants, and the overall reduction in CCGT does not compensate for the emissions from the added coal plants.

The effect of ψ (amount of installed PV) on system operation cost and CO_2 emissions is illustrated in Figs. 7 and 9 respectively. These figures show the threshold in the case

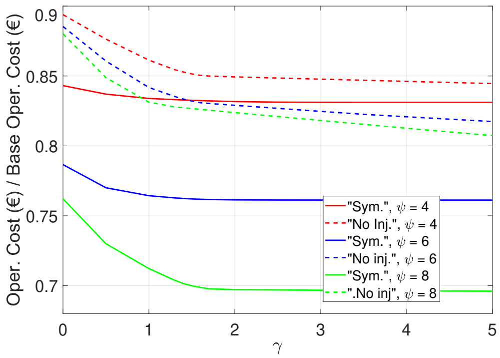


Fig. 6. Effect of γ on system operation cost.

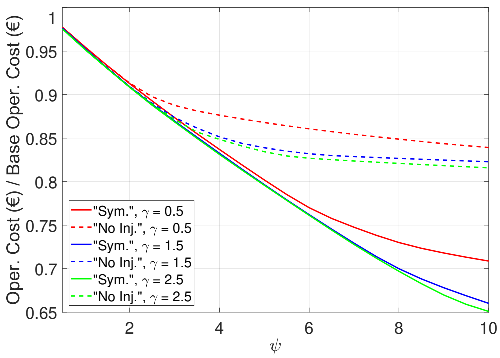


Fig. 7. Effect of ψ on system operation cost.

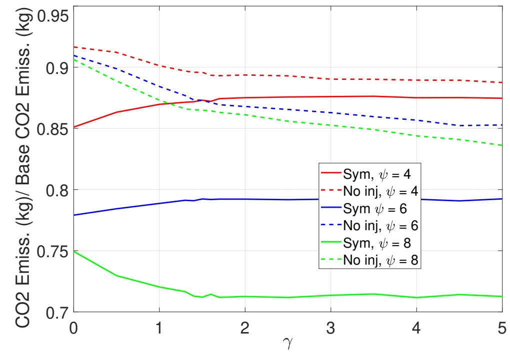


Fig. 8. Effect of γ on system CO_2 emissions.

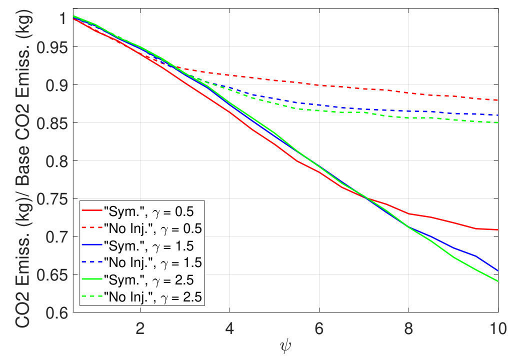


Fig. 9. Effect of ψ on system CO_2 emissions.

without injection is $\psi \approx 4$, (≈ 4 kWp of PV) and in the case with injection is $\psi \approx 7$, (≈ 7 kWp of PV). That is because injection allows to manage a greater amount of PV surplus.

V. Conclusions

A model to assess the potential value of power injection from residential installations with PV generation and storage, posed as a two-stage stochastic economic dispatch from the point of view of a central operator is developed. A case study based on the Spanish power system is presented and discussed.

Results show injection has a value only when there is a surplus of PV generation (considering self-consumption). For this reason, the residential PV generation size that could be efficiently used is approximately 7 kW when injection is allowed and only 4 kW when it is not. On the other hand, the recommended battery size is $\gamma = 1.6$ for both cases (11.2 kWh with injection and 6.4 kWh without injection).

For the recommended values ($\psi = 7$, $\gamma = 1.6$) the system cost, compared to a case without residential installations, moves from 83% (without injection) to 73%, and the CO_2 emissions from 87% to 75%.

For $\psi \leq 6$, $\gamma \leq 1.5$, and injection, CO_2 emissions increase with γ (storage) because the flexibility provided by residential installations allows to replace CCGT plants by less flexible, but cheaper, coal plants. This effect is also observed in the case without injection, but for lower values of ψ.

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