Application of a scaling down method to study long term effects of wind and solar on the french tso tariff

Thomas Verderi, RTE/CIRED, + 33670472675, thomas.verderi@rte-france.com
Sandrine Bortolotti, RTE, sandrine.bortolotti@rte-france.com
Laurent Lamy, CIRED, laurent.lamy78@gmail.com

Introduction

Europe and France are engaged in an energy transition in response to the climatic emergency. The French government has set ambitious objectives of renewable electricity production. For instance, solar capacity is set to rise from 10.4 GW in 2020 to 44 GW in 2028. Onshore wind capacities are planned to go from 17.6 GW up to 34.7 GW in 2028 [1].

Several recent works evaluate the consequences of increasing the share of renewables in the electricity mix [2]–[5]. For example, reference [3] studies the impact of several electricity mixes for the European power system on the adequacy between supply and demand, while [2], [4], [5] study the feasibility in terms of adequacy and renewable energies potential of a high level of renewable electricity mix. These studies mainly focus on large-scale national or international consequences of those electricity mixes. However, those scenarios will also have significant consequences at the local scale for the electricity system actors, for example in terms of modifications of land use or in the network dimensioning.

In this article, we will focus on some of those consequences for RTE, the French TSO (Transmission System Operator), of the growth of renewable energy production. Most of this new capacity will be connected to the French DSO grid (Distribution System Operator). In France, DSOs are connected to the TSO through 4000 High Voltage/Mid Voltage [1]substations. However, though these DER (Distributed Energy Resources) will not be directly located on to its grid, the TSO will still be affected. Indeed, TSOs have two major missions. First, they are in charge of the "supply-demand" balance of the entire electricity system. Second, they are responsible for the grid transmission security notably by controlling the flows on their lines and dimensioning network elements. Both missions are impacted by the development of renewables.

Historically, the majority of these High Voltage/Mid Voltage substations were dimensioned based on the local consumption, because the local production was negligible - in comparison. The local consumption (respectively production) of the substation is defined here as the sum of the downstream consumption (respectively production) sites[2] connected to the DSO grid. It was therefore the peak[3] of this local consumption that has consequences on the dimensioning of the substations. In other words, dimensioning costs of the substations were highly dependent on the local consumption peak. The main French DSO, Enedis, published a report saying that only 10% of those substations were dimensioned with the local production in mind[6].

From the TSO point of view, the demand of a DSO at one of these substations is its residual load, defined as local consumption minus local production. By increasing the local productions, the diffusion of DERs will change the shape of the residual loads. Some substations will withdraw less energy and will instead inject energy into the TSO grid. For those substations, the peak of the residual load might become an injection peak rather than a consumption peak. The more DERs are connected to a substation, the more that

[1] The voltage level manage by TSO and DSO vary by country. In France, the TSO manages voltage levels range from 63kV to 400 kV. The voltage levels are separated into three categories: HTB1 for voltage of 63kv and 90kV, HTB2 or voltage levels of 150kV-225kV and HTB3 for 400kV. The DSOs manage the power levels below 63kV.
[2] Those consumption sites can be cities, factories etc.
[3] There is a distinction between the peak power (i.e. the maximum of the load curves) and the subscribed power (i.e. the power contractually asked by the substation). It is possible for a consumer to have an instantaneous need for power that exceeds the subscribed power. However here, for the sake of simplicity we will use interchangeably the two terms.

substation will be affected, leading to heterogeneous impacts (including network dimensioning) given that new DERs are expected to be spread heterogeneously across substations. Consequently, the change of the shape of the load will highly depend on the characteristics of the substation including its demographic density and its geographical location.

In the end, this change of cost will translate into a change in French TSO Tariff. Today, the French TSO grid tariff is designed by the CRE (Commission de Regulation de l'Energie), the French national regulation authority regarding gas and electricity. The main objective of this tariff is set by the French energy law: the revenue of the tariff must cover the costs of the TSO. Those costs are shared nationally and the TSO tariff is under tariff equalization. This tenet is a choice of solidarity: areas that are less costly due to geographical advantages subsidy the most costly area. It means that two consumers connected to the TSO with the same demand will pay the same tariff wherever they are located. Once the tariff revenue is set, the CRE uses the historical demand of the substations to build the tariff. Today, mainly two indicators are used to build the tariff:

- The withdrawn energy: the kWh withdrawn from the TSO grid.
- The subscribed power: the maximum of the demand curves withdrawn from the TSO grid.

In the existing French electricity system, there is an historical strong correlation[4] between the energy withdrawn and the subscribed power. The design of the French grid tariff, which is mainly volumetric (based on the energy withdrawn), has been drawn on this correlation to cover all the costs. As a consequence, if the shape of the load curves change, it may impact the relationship between energy withdrawn and subscribed power, and lead to costs recovery problems. The diffusion of DERs could thus impact the French tariff that would need to be redesigned. A tariff design not suited to the load would be a source of concern because the TSO may not be able to invest suitably in order to adapt the network to the energy transition.

In the literature, the impact of DERs on the DSO grid tariff is often studied. In [7], the authors study the recovery of sunk costs considering the development of prosumers that optimize their consumption and production with solar panels and batteries. Once the load charge of prosumers is modeled, they study the impact of the new shape of load curves on the DSO revenue considering different network tariff structures. The impact on the volumetric charges are more and more important on consumers that are not prosumers as the share of prosumers increase. Under a volumetric tariff structure, their total charges can go up almost 75%.

[8] studies the development of solar panels and the resulting consequences for the current tariff structures. They study the impact of an increasing part of a population that has access to EV (electric vehicles) and rooftop solar panels. The article also notes the fact that the netting of solar production on the energy consumed is a matter of concern for the UK regulator. In addition, the consequences on the tariff structure are increasingly impactful as far as the solar production and EV penetration goes higher. The authors show that the distribution tariff for passive consumers increases with the solar penetration. In some scenarios with a high penetration of EV, the tariff raises up to 10% with almost 50% of solar penetration.

These articles highlight the fact that, in a context of growing DERs capacities, actual DSO grid tariffs can be dramatically impacted or induce important distributive effects. However, there are few articles on the consequences about the diffusion of the DERs on the TSO and the TSO tariff. In this article, we will try to answer the question of how DERs will affect the residual loads of each substation of the French TSO and thus impact the TSO cost and tariff.

The remainder of the paper is organized as follows. Section 2 presents the data and the models of the study. A first model that scales down a nationwide prospective studies is presented. Then the section describes a case study on the French electricity network that evaluate the evolution of local residual loads in several scenarios of renewable development. Finally, a reinforcement cost model is presented. Our results on the shape of residual loads are gathered in Section 3 which is split into three subsections. The first describes the reinforcement difference for each scenario it explains why impacts are so different from one substation

[4] A linear model between the subscribed power and the withdrawn energy gives a R^2 of 0.953

to another. This reinforcement is then translated in term of economic consequences: how much does this impact the reinforcement and the tariff. Then we examine how some indicators of the residual loads are modified by the diffusion of DER. Finally, Section 4 concludes.

Model and data

In this section, the paper describes the data and methodology that is used to scale down the production and the load from a national prospective adequacy study [3] to the substations of the French TSO.

Scaling down of the production

The goal of this paper is to evaluate the impact of DER on the substations for the French TSO. In that respect, DER national capacities must also be downscaled and allocated to each substation. The use of local load factors will then allow us to build the local production curves. Those data comes from the National adequacy from the French TSO [3]. In our study, France is split into 26 areas with consistent climate. In this way the local production curves can be estimated for each substation.

In order to scale down the national production, several assumptions about the DER production have to be made. The location and the development policy of capacity will have a strong impact on the output of our study. Additionally, both are heavily dependent on different politic choices.

First, it is important to distinguish the categories of capacities that will be installed. We choose to study solar and wind production because they are the productions that will develop the most during the French energy transition. For the scope of this study, solely onshore wind production is considered. For solar production, both ground-based production and rooftop panels are considered. The ratio between the installed capacities of these two types of installations is determined by a parameter $\boldsymbol{T}$, referred to as the rooftop vs ground panel parameter. A value of 0% means that all the new solar capacities are ground-based panels.

For both solar ground production and onshore wind, we made a geographical allocation using a formula from the 2016 TSO grid planning report published by RTE [9]. The methodology was designed to simulate the local dynamic of development while accounting for the current network access capacity. Three successive allocation keys split locally the national capacities. A first key translates from national to regional capacities. It distributes installed capacity proportionally to the potential estimated by the producers. A second step goes from regional to departmental: capacities are installed proportional to the dynamic of past years. Finally, a last key goes from departmental to the substation using the available capacity at the substation. Onshore wind and solar ground production are distributed according to the capacity reserved for the implementation of the DER defined by the S3REnR (Schémas Régionaux de Raccordement au Réseaux des Energies Renouvelables)[5].

We make a supplementary distinction between rooftop panels on commercial building and rooftop panels on residential building. The effective repartition of capacities between those two categories rely a lot on regulation and support schemes, that both depend on French governmental and European objectives. Here, we make the assumption that commercial buildings will only develop through auctions made by the government, described in [1].

For the residential rooftop panels, we assume that the capacities will develop with the same trend through collective and individual buildings. Even though today residential panels are mostly individual panels, European Commission try to develop both individual and collective installations through self-consumption [10].

[5] S3RENR are legal documents that are planning tools for the French power grid. For the current and future grid, they evaluate the capacities that are retained for renewable energy and estimate the cost of reinforcement that will be shared between the producers. This document is written by the TSO and the DSO after several public debate with the local authorities and regional and local players. Therefore, it takes into account the social acceptability and the trend of current and expected renewable energy in the area.

This distinction between different categories of rooftop is important because it will affect the geographical location of those panels. We do not have all the information about the available roof spaces for solar panels on the French territory. Here we made a series of assumption and link the capacity of rooftop panels with different socio economics characteristics. The data published by the French national statistical institute is used for this purpose.

Hence, commercial building rooftops capacities are split among the substations according to the number of employees that work in the nearby city. Residential collective capacities are split among the city according to the number of flats whereas individual housing capacities are split according to the number of individual houses.

Then we estimate the local production of each of these capacities (onshore wind and solar) by combining the regionalized load factor curve and those capacities.

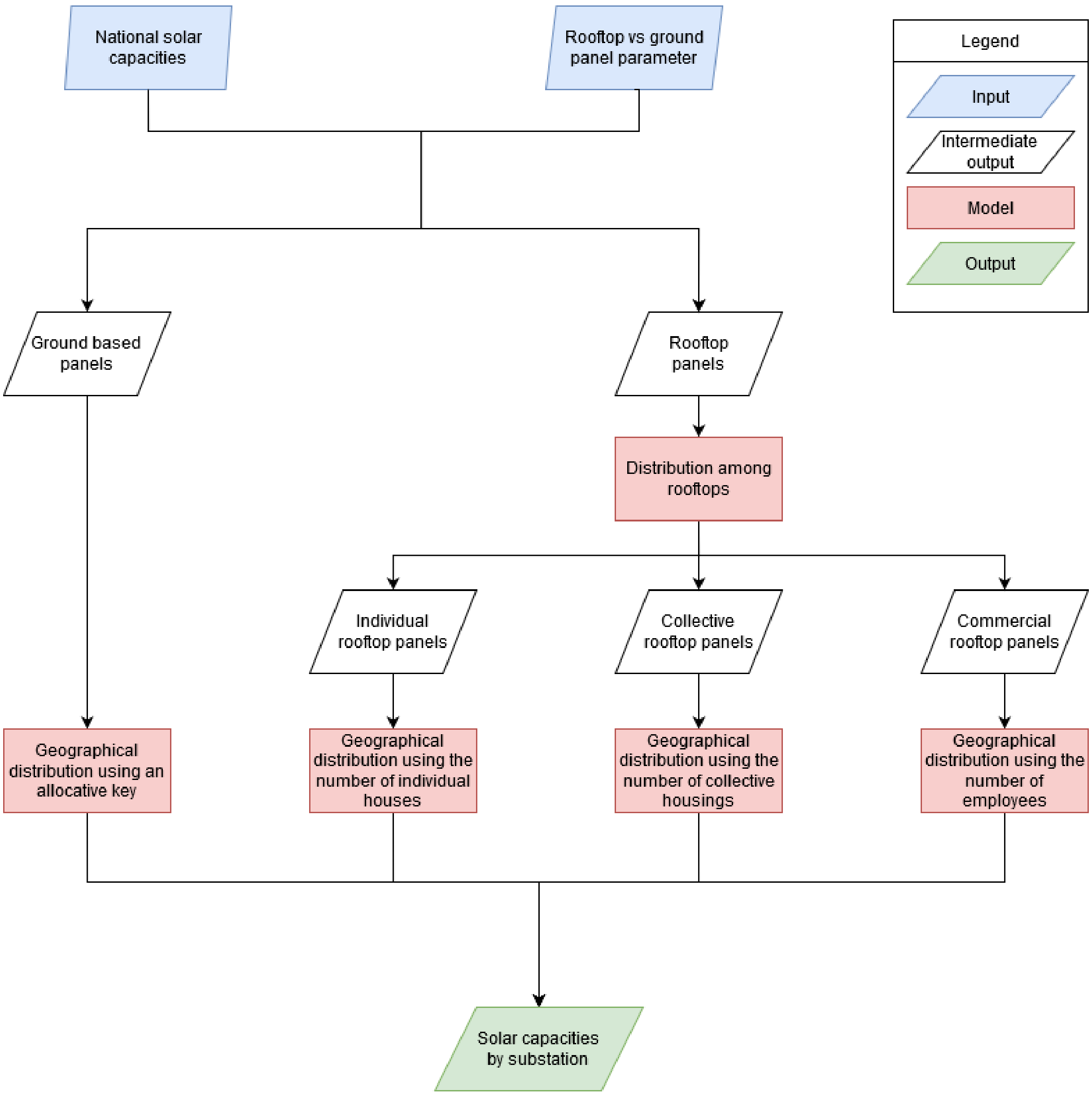

Figure 1: Illustration of the repartition of solar capacities

In the rest of the article, we vary two parameters to evaluate the impact of the development of DERs on residual local load curves. The first parameter to vary is the national installed capacity of wind and solar productions. We chose this parameter because it varies a lot among the different national prospective that may exist. Furthermore, existing studies showed that this parameter will have a tremendous impact on the residual local load curves. In our case study, total installed capacities of wind and solar will vary from the

2018 capacity to 2035 trend governmental objective as defined in [1]. Often, we will refer to the capacity in 2030 if the dynamic follows the current trend capacity as BAU (Business As Usual) capacities and capacities set by the governmental goal as PPE (Programmation Pluriannuelle de l'Energie) capacities.

Table 1: BAU and PPE capacities by 2030

	BAU	PPE
Solar capacity by 2030	18.5 GW	47 GW
Wind capacity by 2030	26.7 GW	36.4 GW

The second parameter to vary is the rooftop vs ground panel parameter, $\boldsymbol{T}$, that we defined in the previous section. This parameter will deeply affect the localization of capacities and it will especially affect the nearness between consumption and production. If the parameter is high, a biggest part of the solar panels will be installed on rooftops which are site of consumptions. In France, it remains unclear how solar production will develop. Its development depends on public objectives and incentives but also on societal acceptances. To explore different options, five variations of the rooftop vs ground panel parameter will be used, going from 0% to 100% by a 25% step[6].

A limit of the study is the lack of interaction between local load and the rooftop vs ground panel parameter. Here, we assume that the local load will not change with the value of the parameter. In reality, a higher rooftop vs ground panel rate would also mean a higher use of consumer flexibility. The article gives a first intuition about the local impacts of those parameters for the TSO and a work on the use of local flexibility could complete the analysis.

Table 2: Parameter and variables of the case study

Parameter and variables	**Value**
Energy yearly consumed	441 TWh
Mean of the subscribed power	85 GW
Number of DSO load curves studied	2200
Data used to down scale the load	Historical data from 2012 to 2016
Installed solar capacity	From 8 GW to 70 GW
rooftop vs ground panel parameter	0% , 25%, 50%, 75%, 100%
Wind capacity	From 8 GW to 65 GW

Scaling down of the load

In this section, the method to downscale the hourly national load from the French TSO long term adequacy report by using hourly data is presented. We choose to develop a scaling down method in order to extend a national prospective analysis by studying the local impacts. The goal is to be able to study the local residual loads at each of the French TSO substation in 2030.

The long term consumption forecast methodology is widely covered by the academic literature. Papers that review the literature [12]–[17] offer a good overview of the diversity of the methodologies. The principal conclusion is that there is not one general methodology; the choice depends on the data available, the temporal and spatial resolution desired.

The majority of the literature focuses on the regional and national levels. At the regional and national levels, statistics and bottom-up models are numerous. The models can work on the consumption value [18] or use the historical link between socioeconomic data and national consumption [19]–[22]. A few also take into consideration a weather normalization methodology [18], [22], [23]. The mathematical methods vary from

[6] We do not have the exact value of the current repartition between solar panels and ground based panels. However, we know that there are around 470 000 [11] installations connected to the main French DSO with a mean power of 0,02MW. This value is low because of the large number of small installation. If we make the assumption that all the capacity connected to the lowest level of voltage are rooftop solar panels, the value of the parameter would be around 20%.

structural time series model [18], [19], genetic algorithms [20], artificial neural networks [21], semi-parametric models [22], and multiple regression [23] among others.

These methods are useful when studying a trend or the impact of a socioeconomic parameter but require the assumption that the observed relation is also true for future consumption pattern. This could be the case for a near future without disruptive technologies or behaviors of consumption but it may not be the case for long term studies in a context of an energy transition. It is notable that this topic is studied by scientists outside the power grid community as the electrical national time series forecast is a mathematical and computational challenge that raises interest beyond the usual community.

Industries and institutions of the power grid sector also realize their own long term consumption forecast. They are used as inputs for various mid and long term adequacy studies [3], [24], [25].

At the scale of the feeder between middle and low voltage (MV/LV) that corresponds to the scale of most cities, the most common methodology in literature is profiling [26]–[29]. Elementary profiles are obtained using consumption data at the feeder level processed with an assortment of mathematical methods, varying from optimization algorithms, heuristics or the k-means method. The load of a new area is then computed as a linear combination of the estimated profiles, assuming a mix of consumers.

None of the previous literature methods allows us to downscale directly a national prospective load at the local level for the French TSO. Because our goal is to study the local consequences of national prospective, we have developed a downscale method. The data used in this article comes from a national prospective long term adequacy study [3]. More specifically, we use the French hourly national prospective load. The load scenario we used is named "intermédiaire 3": it corresponds to a slow decrease of the load by 2035. This load is given for 11 weather realizations that are representative of the current climate.

Clients connected to the TSO network fall into one of the following two categories: industrial consumers and DSOs. The TSO can differentiate between the two based on contractual data. The scaling down method is unique for each category because the evolution of their consumption depends on different factors.

We use a simple method for the industrial consumers: the shape of their load curves is the same as the last known year of historical data. We assume that this load is the most representative of the economic situation of the consumers. Then, we apply the growth rate of industry consumption that is used in [3]. The method is kept simple because the industrial consumers are not the heart of our study.

The load of the DSO connected to the TSO is downscaled differently. We downscaled the national load using hourly consumption data of the substations.

First, in order to compare calendar years together, a standardized calendar is introduced. This calendar is used by Enedis, the main French DSO, to estimate consumption and production of a balancing responsible party [30]. Each hour of the hourly national load curve is identified with a triplet of parameters: week, day[7] and hour.

Then, we use the same triplets to identify each time step of our historical substation load. For each triplet and for each substation, we use the historical data to build a distribution key. This distribution key is then applied to the national load consumption with a pro-rata based calculation. Thus, the load of a DSO for a given value of the triplet is given by the formula (1).

$$Load_{DSO_i,w,d,h} = Load_{Nat,w,d,h} * \frac{Weight_{DSO_i,w,d,h}}{\sum_j Weight_{DSO_j,w,d,h}} \quad (1)$$

$$Weight_{DSO_i,W,D,H} = Median(Historic\_Load_{DSO_i,w=W,d=D,h=H}) \quad (2)$$

[7] The day of the calendar that are holidays are counted as Sunday to keep more consistency with the value of consumption.

For our case study, we use historical data from 2012 to 2016 to build the weights. The local weights are the median of the substation historical data over the time steps identified by the same triplet as defined in (2). The use of the median[8] has two advantages. First, using several data allow us to deal with the climatic risk. For two same triplet, the value of the historical load can differ because of temperature. Using the median allow to control that effect. Additionally, the use of median allows to deal with outliers. Sometimes the load data can take extreme values because of power outages or of a load transfer. This method has been testing using data from 2012 to 2016 to estimate the local loads of 2017 and 2018. It gives a R^2 mean of 0.86 for 2017 and 0.84 for 2018. It is quite close to others studies in the literature of load estimation as in [27] or in [26]. One way of improving the model would be to investigate other possible weights calculation. Then the method is applied to estimate long term hourly load of the substation. The load curve of the consumers connected to RTE is estimated for 11 weather years simulated for the current climate. Mean of the annual energy consumed by non EV load is 441 TWh (whereas it was 473TWh in 2016).

Description of the variables of interest

The impact of the parameters described above are evaluated through five indicators—aggregated at the national level—that are then used to characterize the load curves. Two of them were already described in the introduction and are currently used to build tariff structure.

- The sum of withdrawn energy: the kWh withdrawn by all the consumers connected to the TSO grid.
- The sum of subscribed power: the maximum of the load curves withdrawn by the consumer across all weather years
- The sum of injected energy: consumers that also produces energy may inject their production on the TSO grid if they produce more than they consume at a given time.
- The sum of injected power: the maximum power injected by the consumer across all weather years.

If the injected power becomes larger than the subscribed power, the power grid must evaluate the most economically suitable solution to adapt to this new constraint. Here, we will use a proxy of the reinforcement the TSO needs to deal with. In these cases, we will study one more indicators:

- The sum of dimensioning power: the maximum between the subscribed power and the injected power.

Description of the cost model

In order to go from physical consequences to economic consequences, we use a reinforcement cost model. We assume that the dimensioning costs only depend on the dimensioning power of the local residual load. In order to evaluate the economic impact of future developments of DER, we will compare the difference of dimensioning power with and without DER for each substation. In other words, we compare the dimensioning power of the local consumption load, which is the subscribed power of the substation, with the dimensioning power of the local residual load with DER. The difference of power gives an additional reinforcement that is monetized. We also assume a linear relation between dimensioning power and cost.

The complete cost of the reinforcement is complex to calculate. Here, we only use data about the cost of a transformer. Given the technical characteristics of transformers, we determine a cost of additional power. The coefficient depends on the level of voltage in which the substation is connected and is shown in Table 3.

Table 3: Coefficient of the cost model

Voltage	Coefficient
HTB 2	7.6 k€/MW
HTB 1	10.6 k€/MW

[8] A way of improving the method would be to study more statistics and find more suited weights.

In this article, the use of this model allows an economic comparison between our different scenarios. What is estimated is only an order of magnitude of the necessary reinforcement of the transformer at the substation. However, the complete cost of reinforcement cannot be estimated from this models because a lot of other costs are missing such as congestion costs, reinforcement costs of lines and on any other material...

In this section, we have presented the data and the models of the study. We are now able to compute local residual loads for different scenarios of renewables development (in terms of capacities and repartition) and to evaluate them regarding five indicators. Finally, a reinforcement cost model is proposed to estimate the variations of costs between scenarios.

Results

The impact of DER on dimensioning power

We first use our model to evaluate the reinforcement induced by the rise of new DER capacity. In the article, the proxy of this reinforcement is the additional dimensioning power. We calculate the delta of dimensioning power between the local consumption load[9] and the local residual load for all the substations. If the value of this delta is negative, it means that the DER help diminish the reinforcement need compared to the consumption. It increases it if is positive.

The Figure 2 and Figure 3 show respectively the repartition function of the delta of dimensioning power for the 2030 PPE and BAU capacities. The curve is shown for three value of the rooftop vs ground panel parameter. The Table 4 gives additional values of the percentile for each of the curves.

The impact of DER on dimensioning power are quite heterogeneous. For the PPE and BAU capacities and all our scenarios, we see that for most of the substations, the dimensioning power slightly decreases. Onshore wind and solar production allow to slightly reduced the value of the subscribed power of the local residual load compared to the value its value for the local consumption.

However, there are some substations with a consequential increase. For the BAU capacities, almost 5% of the substations have a dimensioning increase of more of 20 MW[10]. This share doubles for the PPE capacities. In other words, DER diminish a little the dimensioning power for a large number of substations and largely increase the dimensioning power for a little number of substations.

Rooftop vs ground panel parameter has a slight impact for the PPE capacities and a slighter impact for the BAU capacities. When the parameter rise, the delta of dimensioning power tends to diminish. This is because the parameter has an impact on the nearness between local solar production and local consumption: higher the parameter, higher the share of production that is close to local consumption.

Thus, the proximity between local production and local consumption allows to reduce the dimensioning power. As shown in Figure 4**Erreur ! Source du renvoi introuvable.**, the substations that are the most affected by the increase of dimensioning power are the one with the lowest population density. They are the one with more local production regarding their local consumption.

In this section we have seen that DER may have a consequential impact on dimensioning power. Those impacts seem heterogeneous and more important on the sparsely populated area. According to our cost model, it means that it will also impact the dimensioning cost of the TSO.

[9] For the local consumption, the dimensioning power is the subscribed power.
[10] 20 MW is a consequential raise. The mean of consumption peak power is around 20 MW.

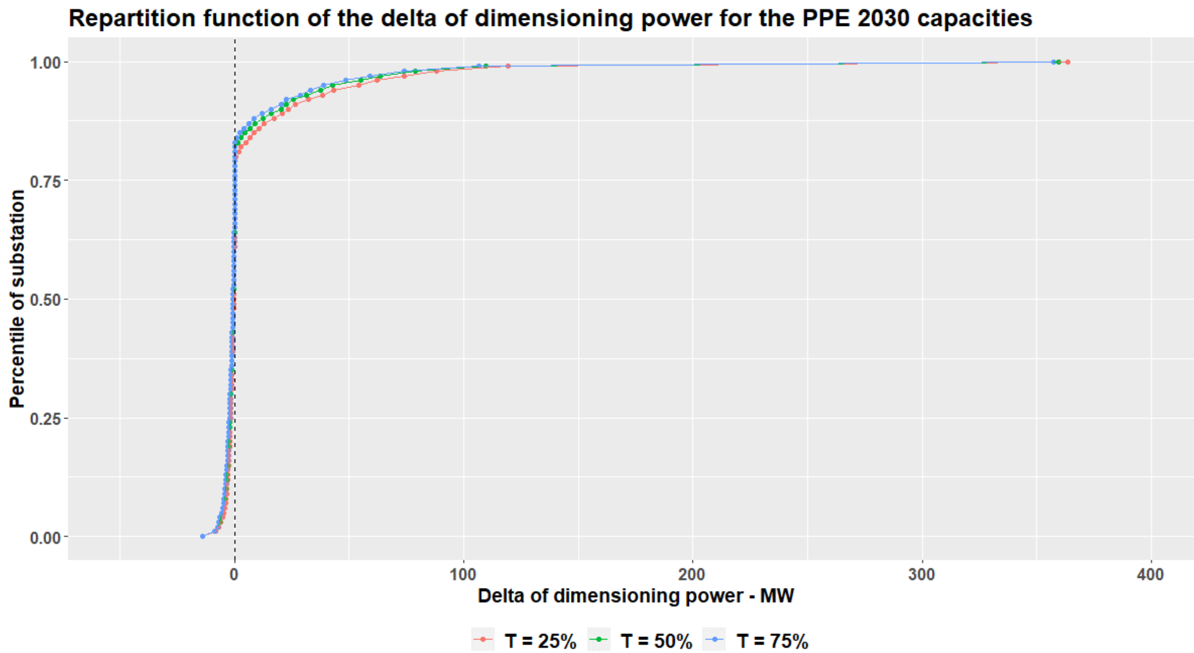

Figure 2 : Repartition function of the delta of dimensioning power for the PPE 2030 capacities

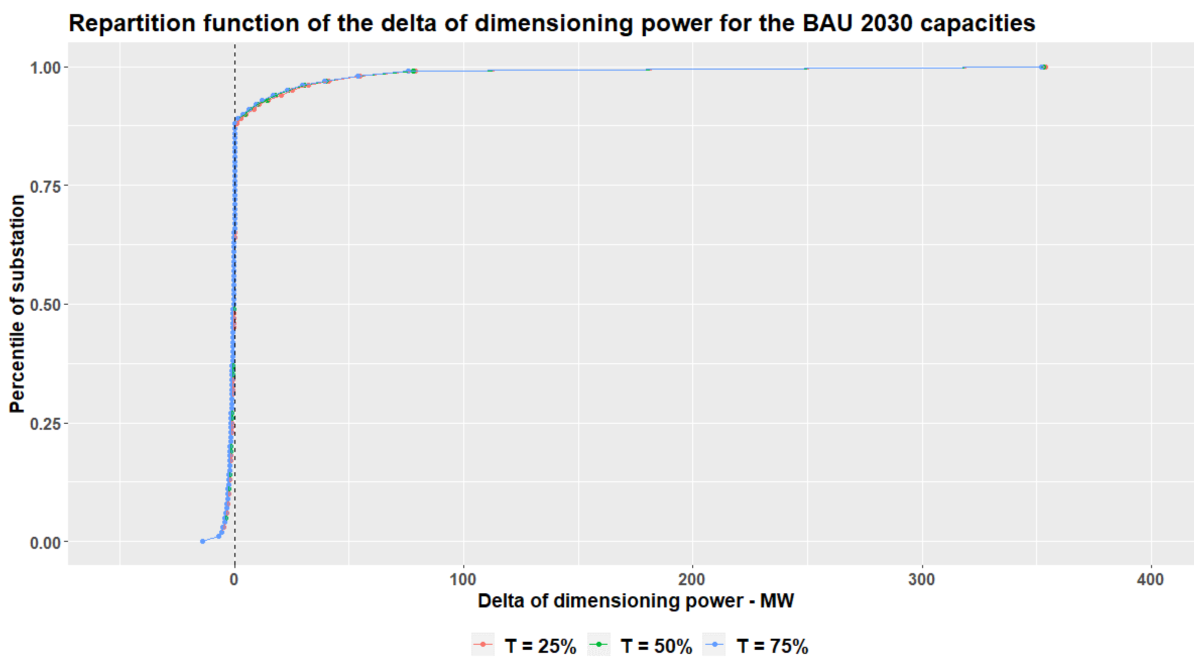

Figure 3: Repartition function of the delta of dimensioning power for the BAU 2030 capacities

Table 4 : Value for several percentile of the dimensioning power

Capacity	2030 - BAU			2030 - PPE		
Rooftop vs ground panel parameter	25%	50%	75%	25%	50%	75%
Max	315.24	314.78	314.52	335.84	335.83	335.80
Percentile 0.95	21.47	20.43	19.70	48.62	40.16	35.59
Percentile 0.90	4.01	2.76	2.32	21.33	17.37	13.47
Percentile 0.80	-0.01	-0.02	-0.03	0.28	0.00	0.00
Percentile 0.75	-0.06	-0.11	-0.13	0.00	-0.04	-0.09
Percentile 0.5 / Median	-0.48	-0.57	-0.63	-0.65	-0.79	-0.88
Percentile 0.25	-1.28	-1.35	-1.42	-1.58	-1.81	-1.97

Percentile 0.20	-1.56	-1.62	-1.65	-1.91	-2.16	-2.30
Percentile 0.10	-2.44	-2.48	-2.54	-2.87	-3.15	-3.32
Percentile 0.05	-3.50	-3.48	-3.46	-4.01	-4.25	-4.39
Min	-23.48	-22.97	-22.75	-17.04	-17.00	-16.97

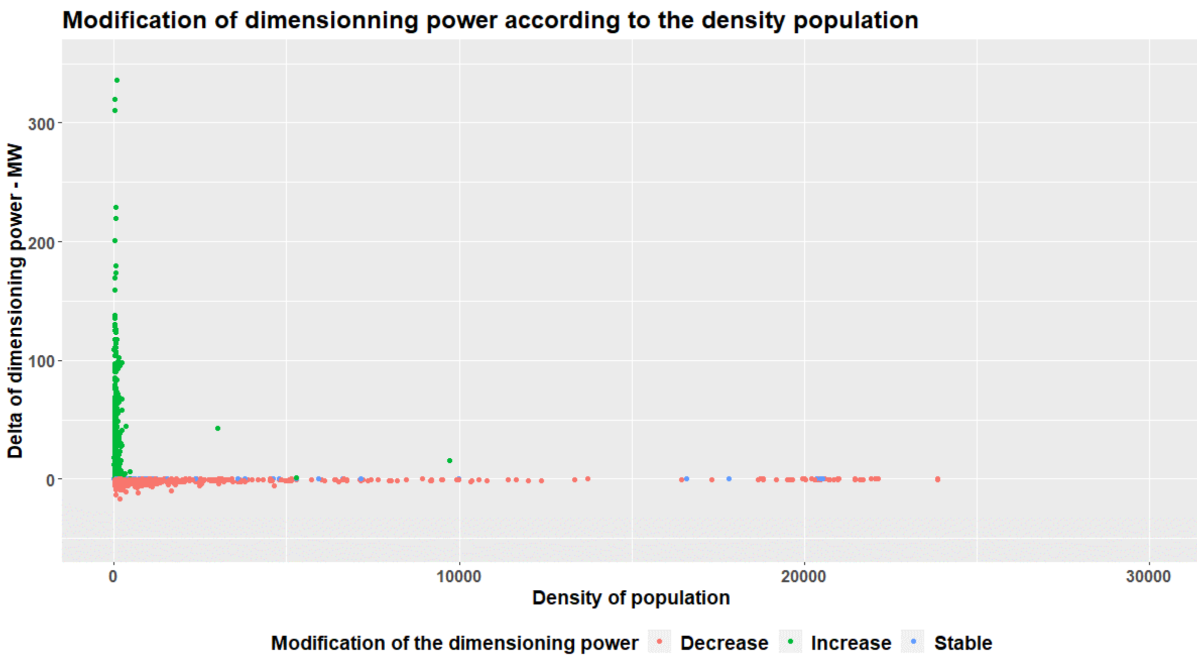

Figure 4: Increase and decrease of dimensioning power according to the density of population in the T = 75 % scenario for the PPE 2030 capacities.

The impact on the cost and tariff revenue

In order to estimate the economic impact, the delta of cost induced by DER has been calculated for all of the substations connected to the TSO. Reinforcement costs are calculated for solar and wind capacities in the BAU and PPE 2030 scenarios as well as for the three values of the rooftop vs ground panel parameter (25%, 50% and 75%).

Table 5: Cost estimations on the transformer of substations in our scenarios

Capacities		rooftop vs ground panel parameter		
		25%	50%	75%
2030 - PPE	Increase	181.25 M€	153.54 M€	139.24 M€
	Decrease	- 26.79 M€	- 30.32 M€	- 32.15 M€
	Total	154.46 M€	123.23 M€	107.09 M€
2030 - BAU	Increase	90.47 M€	87.24 M€	85.64 M€
	Decrease	- 23.10 M€	- 24.33 M€	- 25.07 M€
	Total	67.37 M€	62.92 M€	60.58 M€

Results are shown in the Table 5. First, we see the cost of reinforcement mostly depends on the installed capacities. Costs vary from almost 50% between BAU and PPE reference scenarios. In BAU scenarios, total cost does not depend on the rooftop vs ground panel parameter. Solar capacities are too low to see an effect. However, choice of rooftop vs ground panel parameter make a huge difference in the PPE scenarios. Costs vary from 154.46 M€ to 107.09 M€ which represents almost 50% of variation. This scarce analysis is not an advocacy in favor for more rooftop panels against ground based panels. The cost model is really simple and only calculates an order of magnitude of the cost for new transformers at the substation between DSO and TSO. Line reinforcing and topology changes are not taken into account. Furthermore, grid costs are only a part on the cost of electricity system. For example, rooftop and ground based panels also differ by operating and capital expenses and support schemes. It however advocates in favor of a systemic vision of the energy transition: developing solar through plant of self-consumption changes the total cost of development and the repartition of this reinforcement cost.

To complete our analysis, we also calculated the bill for each substations connected to the TSO for all our scenarios in the PPE and BAU capacities. We compare the amount of money a substation would pay with and without DER. We apply the current tariff structure of 2021 to calculate the revenue each substation would pay to the TSO. Either way, the tariff revenue decrease for most of the substations. With the current structure, the DER will decrease the tariff of around 660 M€ for the PPE capacities and 430 M€ for the BAU capacities. It represents respectively 16,1% and 10,5% of the French TSO revenue for the year 2019. Even though it is a consequential amount, the inadequacy of revenue can be easily solved by the regulation authority by raising the level of the current tariff structure.

We calculate the tariff for each substation in the case where the regulator tries to correct the revenue by increasing the tariff without modifying its structure. Then, we compare the delta of tariff with the delta of cost and we display the results in **Erreur ! Source du renvoi introuvable.**. The figure shows two things. First, the raise of tariff mostly impact the substations with a decrease of cost. Given the current tariff structure, it means that the dimensioning power of those substations does not increase while the energy withdrawn and the subscribed power remain steady. Second most of the substations with a raise of reinforcement cost also sees their tariff decrease. It means that an increase of dimensioning power also goes with at least a reduction of or energy withdrawn or subscribed power. Those individual impacts on costs and tariffs shed the light on the fact that DER will impact the variables of interest, which will affect the future tariff design.

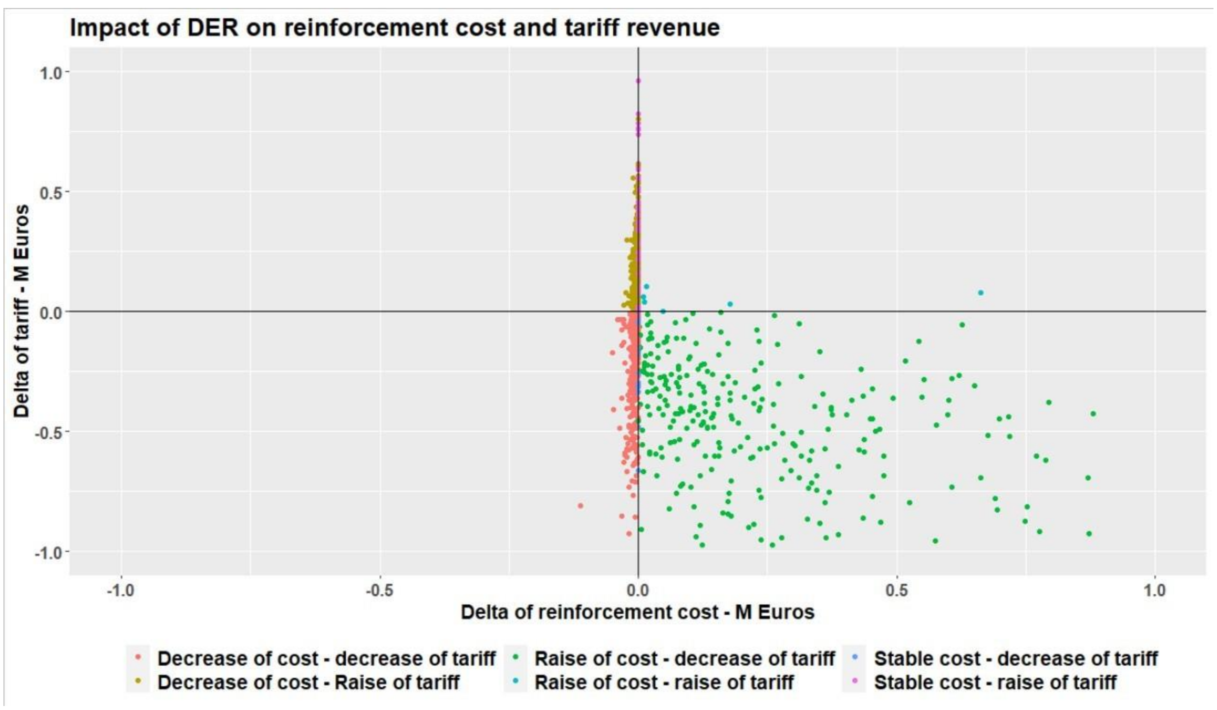

Figure 5: Impact of DER on reinforcement cost and tariff revenue. Substations with decrease of cost and tariff represent 9% of the substations. Substations with decrease of cost and raise of tariff represent 28 % of the substations. Substations with a raise of cost and decrease of tariff represent 9 % of the substations. Substations with a raise of cost and tariff represents less than 1% of the substations. Substations with stable cost and decrease of tariff represent 2 % of the substations. Substations with stable cost and raise of tariff represent 45 % of the substations.

National aggregated impact of DER on the variables of interest

In order to estimate how the current tariff structure will be affected by the new shape of the residual load we have evaluated, the impact of capacities and rooftop vs ground panel parameter on the variables of interest. First, we quantify the effect of solar production on the indicators. We vary the installed capacity from 8 GW to 70 GW. In addition, we simulate and aggregate the local residual load curves for 5 values of rooftop vs ground panel parameter from 0% to 100% by 25% step. For all the rooftop vs ground panel parameters values, the energy withdrawn decreases with the installed solar capacity.

In our median scenario, a rise of +15 GW of capacity induces a decrease of around 10 TWh of the energy withdrawn whereas the energy injected rises of 3 TWh. Most surprisingly, we do not see a saturation effect: even with quite high installed capacity, the energy withdrawn continues decreasing with new capacities. There is still a netting of local solar production on the energy consumed.

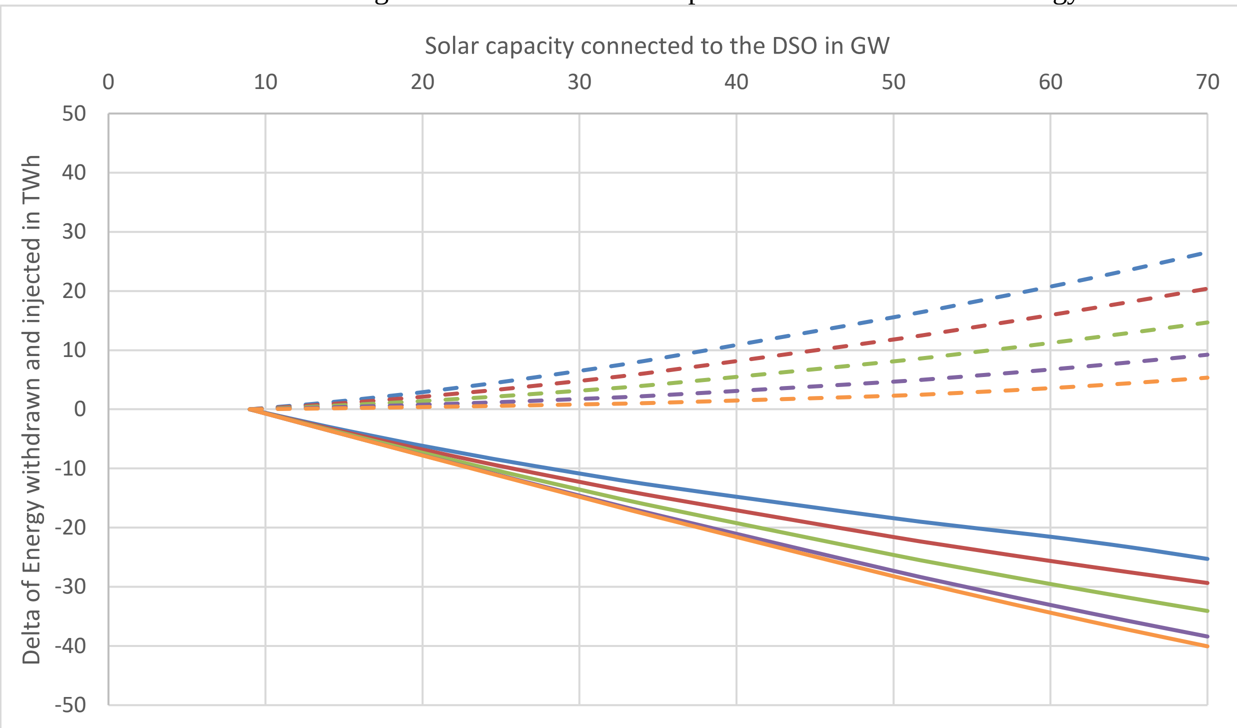

Figure 6: Delta of Energy withdrawn given the installed capacities of solar panels. The curves start at the 2018 solar capacity. Straight lines correspond to the variation of Energy withdrawn. Dotted lines corresponds to variation of Energy injected into the TSO. Each color corresponds to a value of parameter of rooftop vs ground panel. Blue = 0 % / Orange = 25% / Grey = 50 % / Yellow = 75 % / Green = 100%.

The impact of the parameter of rooftop vs ground panel is more significant as the capacity rises. In 2030, decentralizing 10% more of the solar capacity diminishes the energy withdrawn three times more in the PPE scenario than in the BAU scenario. The more the capacity are decentralized, the more the solar production is closer to the consumption site. From the TSO point of view, both production and consumption occur at the same place, inducing a netting of the two local curves.

The effect of solar energy on the subscribed power is less significant: solar production does not allow for a reduction in the sum of subscribed power in any of our rooftop vs ground panel scenarios as shown in Figure 7. This is because only a few of the local peaks occurs at midday. 15 more GW of PV reduce the sum of subscribed power by 0.3 GW. However, it has a tremendous effect on the injected power. In the most centralized scenario, 15 GW more of PV provoke 7 GW of injected power. More notably, the rooftop vs ground panel effect has a huge impact on the sum of injected power, shown in in Figure 7.

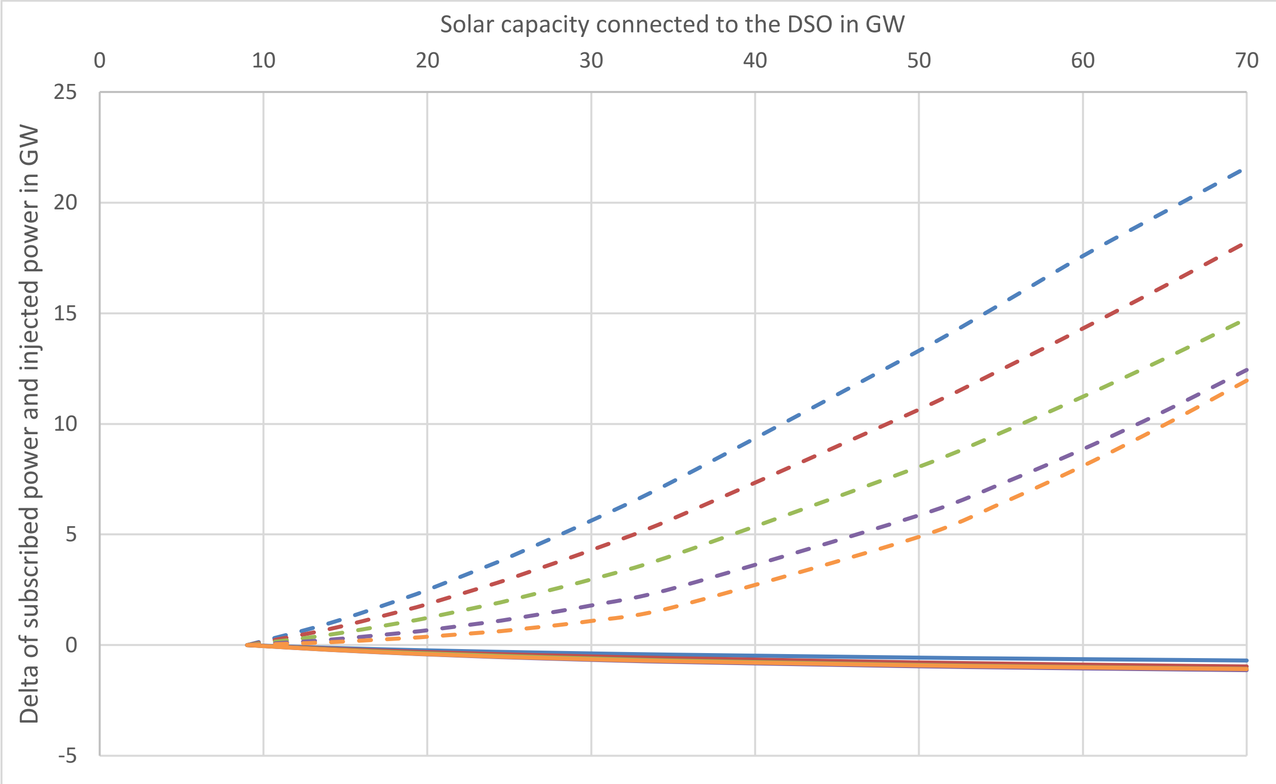

Figure 7: Delta of subscribed power and injected power given the installed capacities of solar panels. Straight lines correspond to the variation of subscribed power. Dotted lines corresponds to variation of injected power into the TSO. Each color corresponds to a value of parameter of rooftop vs ground panel. Blue = 0 % / Orange = 25% / Grey = 50 % / Yellow = 75 % / Green = 100%.

We show that the installed capacity and the rooftop vs ground panel parameter have a tremendous impact on our indicators. They mostly impact the energy withdrawn, the energy injected and the dimensioning power. Both those parameters depend on the political objective and the societal will.

Then, we estimate the effect of wind production on our indicators. Here, the installed capacities vary from 15 GW to 50 GW. Wind production has an important effect on the energy withdrawn. A rise of +15 GW of capacity induces a reduction of around +10 TWh. This reflects the same effect as the increase in solar capacities seen in the previous section. Once more, we do not observe any asymptote in the decrease of the energy withdrawn for our interval of study. Wind capacity has more effect on injected capacities increase as solar because 15 GW of additional capacity provokes an increase of the injected energy of almost 17 TWh. Wind power plants have also more impact on the injection peak. 15 GW more of wind capacity leads to a 10 more GW of injected power**Erreur ! Source du renvoi introuvable.**. It is more than the most centralized solar scenario. This rise leads to a bigger impact on the dimensioning power.

Solar and wind productions impact mostly three of our indicators: energy withdrawn, energy injected and injected power. If the tariff structure (that mostly depends on the energy a DSO withdraws from the grid in France) remains the same, we can expect less tariff revenue for the TSO while the need for reinforcement may increase.

Both DER have almost the same effect: the order of magnitude of reduction on the energy withdrawn and the subscribed power are similar. This result can be surprising because their hourly load factors are very different. Solar production peaks around midday while wind production is steadier among the day. The similitude of impacts is explained by the location of the capacity production. Wind production is only developed through important farms which are located away from the site of consumption (on the contrary of self-production solar panels). Plus, good solar irradiation and wind profile may not be located at the same place. The fact that location matters means that effect may be heavily different from one consumer to another.

Conclusions

The article described a method for down scaling the national production and load of a national prospective study at the substation of a TSO. This method allows to evaluate some local impacts of such study and hence to complete the analysis.

Here, the down scaling method is used to study various distinct scenarios of French electricity mix. We use the method to assess the impact of DER on the French TSO tariff revenue. We show that DER will have heterogeneous impact on the dimensioning need of the different substations. The total installed capacity and their location that also depend on social and political factors highly impact the result. DER diminish a little the dimensioning power for a large number of substations and largely increase the dimensioning power for a little number of substations. In the end, according to our cost model, the cost are most likely to rise. We also show that the installed capacity and the rooftop vs ground panel parameter have a tremendous impact on three indicators: energy withdrawn, energy injected and the dimensioning power that are key to the structure of electricity tariff and the dimensioning cost. If the tariff structure remains the same, we can expect less tariff revenue for the TSO while the need for reinforcement will likely increase.

Our study has several limits. First the local load is not linked with local production. One could expect that local load flexibility would rise with more rooftop panels. The location of DER highly rely on our assumptions. The data we used to down scale the production will have to be updated with the current development in order to be more precise. Finally, the cost model we use only represent a small fraction of the TSO costs; that also represents a small fraction of the electrical system.

In the article, we have focused on a fraction of TSO cost and we have not spoken into details about the distributive impact of the diffusion of DER. We show that, with the current tariff structure, the raise of cost at a substation induced by DER will not necessary induced a raise of tariff for this substation. The heterogeneous effect on the different substations shows that cost are most likely to be more and more different from one region to another. This difference feeds the French political debate about tariff equalization. Further works will investigate the distributive impact and specially the geographically differentiated impact.

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