IMPACT OF ENERGY STORAGE IN CONJUCTION WITH SOLAR PV ON WHOLESALE ELECTRICITY PRICES

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ABSTRACT: Previous studies have shown that the total electricity demand retreated by PV production is well correlated to the prices, following an exponential curve (R^2 around 69%) and the Merit Order Price is quite dependent on the particular electricity demand profile. Since 2011, the penetration rate of PV is also a significant explanatory variable, suggesting that PV could be replacing base load capacity. Ultimately it has been observed that the negative pressure of PV production on wholesale prices is well reflected in Germany, Austria, France, Switzerland and Italy (GAFSI). The objective of this study is to quantify the impact on the wholesale electricity prices at GAFSI level that would be achieved by adding de-centralized storage capability to the PV capacity and shifting the use of centralized storage (e.g. pump-hydro storage) to benefit from the merit order effect. This study has three main findings: firstly, without storage, the cumulative gain of having PV capacity over the past 10 years is around EUR 31 bn for the whole GAFSI region and the average wholesale prices would have been 4 % higher had there not been any PV; secondly, combining PV with decentralized storage system does not currently contribute positively on the aggregate metrics, though in 2014 and 2015 small increases in the merit order effect were observed suggesting that some optimization may be possible; thirdly, where the centralized storage is used in conjunction with PV, the aggregate gain increases to EUR 33 bn (with a storage capacity of 25 GW).

Keywords: economic analysis, photovoltaic production, electricity prices, merit order effect, energy mix.

1 INTRODUCTION

1.1 General statements on renewable energies

The EU member states have committed to a drastic increase of the share of renewable energy ("RE") sources in their energy mix. PV, like most renewables behaves very differently from conventional generation sources and therefore requires special considerations from a policy, from an electrical system and from an electricity market perspectives:

- Intermittency: PV production is not dispatchable and can only be forecasted with a certain level of uncertainty. As electricity is difficult to store, this leads to require spare peak production capacities to be available and in some cases grids to be upgraded.
- Specialization: PV can be centralized in the case of large ground mounted systems, but is typically decentralized in the case of distributed rooftop applications, which may require grid upgrade works
- Support to transition: Although the cost of photovoltaic (PV) modules has dramatically decreased over the past few years (from approx. 4 €/Wp to approximately 0.5 €/Wp), PV full competitiveness has not yet been reached in all market segments and in all EU Member States, and PV producers will continue temporarily to need monetary support (revenue schemes such as FiT, CfD, ROCs, GC, tax incentives, direct subsidies,..) as well as non-financial support measures (e.g. priority access to the grid, self-consumption provisions,..).

1.2 Observed impacts of RE on electricity markets

The effects of RE generation on electricity markets are still unclear and certainly dependent on each country's energy mix.

A 2013 quarterly report on European electricity markets [1] illustrates this conundrum: *"Intermittent power generation sources, such as wind and solar, played an increasingly important role in the power mixes of many European countries during the second quarter of 2013. In Central Western and Central Eastern Europe, high levels of renewables generation contributed to the lowest wholesale power prices observed in the last few years. Frequent occurrences of negative prices in many European markets signal the need for better integration of renewables into the power grid. On a Sunday afternoon in mid-June, wind and solar assured more than 60% of power generation in Germany, resulting in negative hourly prices in the whole Central Western Europe region."*

1.3 Purpose of this study

The purpose of the study is not to discuss the performance of various policy frameworks in supporting the deployment of RE, but rather to shed light on the gain generated by the downward pressure on market spot prices when renewables produce electricity through the Merit Order Effect, and to quantify the corresponding monetary benefit. This benefit will have to be put in perspective with the costs associated to the deployment of RE, among which the cost of support policies, the impacts on the energy mix (including the possible need for capacity reserves), the grid upgrade costs, and negative prices appearing when overproduction occur as a result of RE generation.

The purpose of this study assesses the impact of adding a storage to the installed PV capacity in terms of cost savings at a national level. To be specific, the impact on the wholesale electricity prices at country level that would be achieved by adding decentralized storage capability to the PV capacity and shifting the use of pump-hydro storage to benefit from the Merit Order Effect.

Additionally, the study measures the benefit generated by the PV production over the past 10 years in Germany, Austria, France, Switzerland and Italy ("GAFSI"). Such analysis will be performed based on historical and statistical methods. The behavior of that benefit with respect to the penetration rate of PV within GAFSI's energy mix and with the correlation between PV production and electricity demand will also be assessed. This study builds on previous work by the authors where similar calculations were carried out for Italy as well as for GAFSI up until 2013 [2][3].

2 THE MERIT ORDER EFFECT

2.1 Preliminary definitions and scope of work

- Cost of electricity
    a. The levelised cost of electricity ("LCOE") is the average cost of a megawatt hour ("MWh") produced by a given plant, including the fuels cost required to produce a MWh, but also the operating expenses (maintenance, taxes, …) as well as the amortization of the investment. The LCOE of PV plants was divided by more than five over the past years,
    b. The marginal cost of electricity represents at a given time, the cost to generate an additional MWh of electricity, e.g. only the cost of gas for a gas fired power plant. By definition, the marginal cost for PV amounts to zero (no fuel cost).
- Price of electricity
    c. Retail prices paid by end consumers are set in long term fixed price contracts and include all costs of generating, transporting and distributing electricity, the margins of the various operators plus applicable taxes;
    d. Wholesale prices (also referred to as wholesale spot market prices) are traded on electricity markets daily and will be the focus of this study, i.e. the authors will not tackle prices observed on other markets (such as the futures market for long term trades, the intraday market or the capacity reserve market),
    e. Price paid to RE electricity producers, which typically includes the revenue of support schemes for RE producers. This study does not focus on this metric.
- Net value for society
    f. It includes a monetary part (i.e. the total energy bill of the country), but also
    g. All sorts of non-monetary externalities (e.g. intermittency of renewable energy, fossil fuels depletion risks, energy security, dependency on unstable foreign countries, pollution, public health, climate change…)
    h. This study only focuses on monetary terms, and attempts to scrutinize if the injection of PV generation capacity into the grid lowers or increases the wholesale prices of electricity at the level of the GAFSI countries.
- Merit order effect ("MOE")
    i. The MOE is the downward pressure on prices exercised by RE sources when they feed electricity into the grid (detailed in section 2)
    j. In order to quantify that phenomenon, one must compare the historical payments for energy of the country/countries over a certain period to what such payments would have been had there been no RE production. This requires to simulate what the prices of electricity would have been then (see section 3)
    k. This study proposes a method based on the fact that for a given country, in a sufficiently short time frame (typically a year), there is a direct relationship between instantaneous demand and electricity price.

2.2 Electricity markets

An electricity market is an exchange platform matching supply and demand for electricity.

- Demand for electricity is a short-term phenomenon and was considered inelastic to price in the study because most consumers are supplied on long-term contracts.
- Supply: Typical energy mix can be split in three categories of energy sources:
    l. Base load, such as nuclear and coal fired power plants, to sustain a constant level of production. It is unable to adapt to short-term variations in electricity demand. It typically has high fixed costs and low marginal costs.
    m. Peak load, such as gas fired turbines, to adapt to high sudden demand. Units are usually smaller with low fixed costs and high marginal costs. These production facilities have a lower utilization rate but charge high prices because of the instantaneous shortage in supply.
    n. Mid load are intermediate generation units, with slower ramp up capabilities than Peak load generators but also lower marginal costs.
- Market coupling: power markets in Europe are currently not integrated with other countries' electricity markets. Their organization at national level can have an impact on the electricity prices since renewables can affect the demand profile generating downward pressure on prices when they feed electricity into the grid. Thanks to a market coupling the energy produced by PV could be counterbalanced between countries in order to be able to manage the electricity prices according to the different country demand profiles. As the study is made at GAFSI level rather than on a per country basis, the authors have opted to focus on the weighted average price ("WAP") of the market prices observed in each country by their respective overall electricity consumption (see section 2.3).

As electricity cannot be easily stockpiled (except to a certain extent when hydro installations are available) there needs to be a perfect clearance at each time between demand for electricity and power injected into the grid. Each supplier estimates its demand profile and purchases electricity accordingly: therefore power plants with the lowest marginal cost will be tapped in first. The system operator is ultimately responsible to guarantee security and adequacy of supply but will settle mismatches between supply and demand on a bilateral basis with balancing costs.

In market environments, prices at a given time are thus determined by the most expensive power producers able to satisfy the demand (i.e. with the highest marginal costs) and are imposed on all other producers (since in a purely competitive market, equilibrium between supply and demand is met when price equals marginal cost). This “uniform pricing” principle is the case in most markets, but there are indeed some markets with “pay-as-bid” clearance.

In a perfectly competitive and transparent market, it is then possible to build the relationship between the electricity demand at a given time and the associated price by sorting energy sources in growing order of marginal cost. This step function is called the merit order curve (“MOC”). The width of each step represents the supply capacity of an energy source while its height is its marginal cost (see figure 1 below).

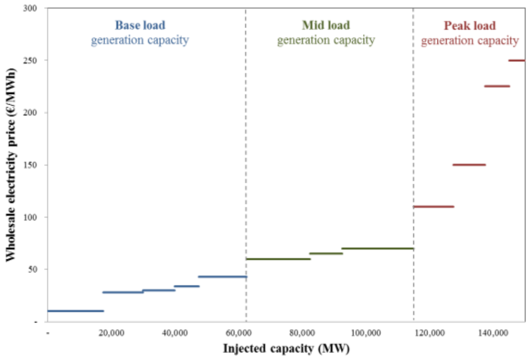

Figure 1: MOC of a fictive electricity market (source: authors)

Therefore, the electricity wholesale prices will be determined as the intersection of the instantaneous demand and the MOC, representing the marginal cost for a given production.

In the MOC context, the case of RE is unusual since they do not behave as a base, mid or peak power plant. As previously mentioned, power suppliers always purchase the renewable power injected in the network (due to the priority of RE production in the grid and because renewables always align to the lowest price) and since electricity demand is inelastic in the short-term, any RE production will decrease demand for other power sources. Since the MOC has a positive slope, this translates into lower wholesale electricity prices. This is defined as the MOE and displayed in figure 2 below.

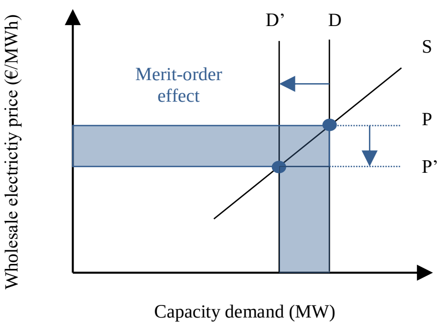

Figure 2: MOE of PV generation (source: authors)

This paper attempts to build the MOC and quantify the MOE for GAFSI between 2006 and 2015.

2.3 Set of assumptions and protocol of the study

The authors based their study on the GAFSI because they estimated it is the set of European countries that fits best with the following necessary criteria for the study.

GAFSI has experienced a massive growth of installed PV capacity over the past years. It is thus possible to measure the MOE behavior with respect to the PV penetration rate. Still, at the GAFSI scale the latter remains moderate (about 5% in 2014), so peak PV production does not lead to important market distortions on a recurrent basis, like negative prices as are observed e.g. in Germany. Intuitively, this underlines the fact that PV production does not replace base load production but rather mid or peak load production (again at the GAFSI level). The results provided in this study are not robust to negative prices (see Section 3) but as stated, fortunately less than 0.5% of negative WAP were observed at the GAFSI level between 2006 and 2014 (less than 1% in Germany alone, and none in Italy).

Up until recently there was little incentive for self-consumption in most GAFSI countries (especially in Germany) and most electricity imports and exports occur within the GAFSI countries: in 2013, exports to and imports (respectively net export) from GAFSI were insignificant compared to the overall internal electricity production, about 6% (respectively 1% in [4]). Taken individually, the countries composing GAFSI show significantly higher shares of imports and exports to production: France alone is the biggest electricity exporter in Europe, mainly to Switzerland (30%) and Italy (21%), and the vast majority of its imports are from Germany (47%) and Switzerland (23%) [7] hence the rationale for studying the GAFSI system and internalize the vast majority of inter-country electricity trades.

The authors thus deemed reasonable to assume that the internal electricity consumption in GAFSI satisfactorily matches the total electricity demand for GAFSI’s electricity (and consequently electricity production).

Only a portion of the total electricity production (and thus consumption) is traded on electricity markets: the relation between electricity spot prices is de facto not obvious. Since only market prices were available the authors had to assume that all the electricity consumed is traded on the day-ahead market. This is a heavy assumption but traded volumes in European day-ahead markets have increased significantly over the last years, fluctuating above 40% since 2010 and reaching 52% of total electricity consumption in Q1 2013 [1]. Such assumption can further be justified by the fact that the mechanics of the day-ahead market are, in the long run, internalised in all the other contracts (long term purchase agreements, futures market...).

Thanks to the conjunction of these assumptions it appears reasonable to assume that all electricity (and therefore solar electricity) produced is fed into the grid and consumed (i.e., there is no self-consumption, no export or import). The GAFSI electricity market is considered as efficient (overall prices reflected through electricity market mechanisms) and shows a diversified energy mix, which leads to a MOC that is easily extractable (contrary to e.g. France alone with a vast majority of nuclear and hydro power) and most importantly invariant. Any injection of PV production in the grid should, under such observations, be reflected into a right shift of the MOC, as displayed in figure 3 below, leading to an overall decrease in prices.

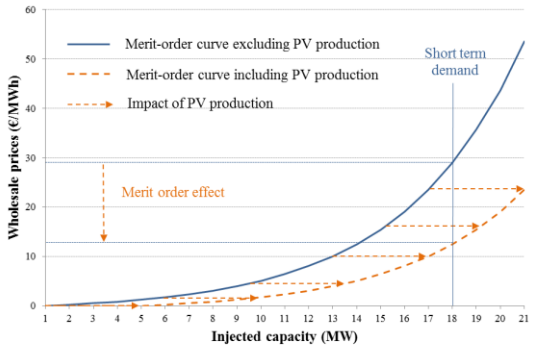

Figure 3: Impact of PV production on the MOC (source: authors)

As mentioned earlier (see definition of the MOE in section 2.1), in order to properly assess the impact of renewable electricity on market prices, the authors simulated what the wholesale price profile over the study period would have been had there been no PV generation. This implied intuiting certain properties of the MOC, i.e. of the relationship between wholesale prices and electricity consumption:

a. To analyse the rightward shift that RE production leads on the MOC, the authors worked on the total consumption of electricity (equal to demand) retreated by the PV production in order to work in a referential with a fixed MOC.
b. If the time period is short enough, the MOC of a country does not vary materially. This assumes that gas and coal prices are not too volatile, and that the country's energy mix does not vary too much (new facilities built or old ones shut down) which is among the set assumptions made above for GAFSI,
c. It is intuitive (and will be further tested) that the MOC has an exponential shape.

3 HISTORICAL ANALYSIS

3.1 MOC and MOE computation methodology

Hourly time series for PV production were reconstructed, between 2006 and 2015, from real solar irradiation data coupled with temperature data as follows:

- The solar irradiation profile was provided by GeoModel solar [6] for 60 regions/cities within GAFSI (regional main cities), using data from the Meteosat Second Generation ("MSG") satellite in the original 15-minute or hourly step time series format for the period from 2006 – 2013.
- In order to achieve a harmonized data set for the whole study period, temperature (with its original time step of 1h/3h) was also resampled to a 15 minute or hourly step time series, and
- The irradiation data set was then transformed into a normalized production of PV plants using a specific performance ratio varying with temperature, and integrated into hourly values (based on the 15 minute or hourly time step profiles).
- The solar irradiation profile for period from 2014-2015 was provided by PV GIS. The basis for the calculation of PV power output is the hourly solar radiation data estimated from satellite images. The method for deriving solar radiation at ground level from satellite data has been described in Mueller et al., 2009 and further validated in Huld et al., 2012. The resulting data consist of hourly maps of global and direct solar irradiance with a spatial resolution of about 4km. The solar radiation data has been supplemented with data on temperature and wind speed from the ECMWF Operational Forecast product (www.ecmwf.int). The temporal resolution is 3-hourly, interpolated to hourly values, while the spatial resolution of 7.5 arc-minutes. These data have been combined with models for inclined-plane irradiance and PV module performance to produce hourly maps of PV power output for each kWp of PV capacity installed. The models take into account the effects of shallow-angle reflectivity, module temperature and low irradiance as well as the cooling effect of wind, see Huld and Gracia Amillo, 2015. The calculation was performed for crystalline silicon modules mounted south-facing with a 20degree inclination. From the maps the average hourly PV production per region was found by area-weighted averaging over each pixel within a given region.

The final GAFSI PV production time series were obtained based on the hourly normalized PV production weighted by the hourly PV capacities in the GAFSI regions.

The GAFSI regions were grouped in 60 zones:

- Germany: 16 regions
- Austria: considered as one region
- France: 22 regions (including Corsica)
- Switzerland: considered as one region
- Italy: 20 regions.

The hourly PV production series obtained are the closest achievable estimation of the real PV production.

The hourly time series for the total electricity consumption [8] and wholesale electricity prices [9] were extracted from public databases.

As mentioned in Section 2 above, it was assumed that the MOC is invariant, and equivalently, that any PV production reduces demand for peak load and mid load generation sources. Based on the sets of values obtained previously, a MOC is obtained through a linear regression of the logarithm of wholesale prices (outliers - negative wholesale prices – are insignificant and have been disregarded) on the total electricity consumption net of PV production for a given period of time. Should the estimates thus derived be statistically significant, the wholesale prices that would have been observed, during such period of time, for a theoretical electricity market without any PV generation capacity, can be simulated with the following formula (with a and b the results of the regression):

$$MOC :: electricity\ consumption\ (c) \rightarrow wholesale\ price\ (p)$$
$$(c) \rightarrow e^{a+b*c}$$

The MOE over a certain period of time is derived from the corresponding MOC as the difference, on the considered period of time, between the total electricity spending of a theoretical electricity market without PV power plants (using the MOC to simulate the theoretical wholesale electricity prices) and the actual spending for electricity consumed. The MOE is the additional amount that would have been spent for the same consumption profile but without PV generated electricity, or equivalently, the MOE represents the monetary gain induced by PV production over a period of time.

Normalized by the total electricity generated by PV power plants, it provides an order of magnitude of a bonus price that can remunerate the PV asset operators on top of the wholesale price. Such quantity is thereafter defined as the merit-order price (the "MOP").

$$MOE = \sum (p_{no\ pv,simulated} - p_{pv,observed}) * c_{observed}$$

$$MOP = MOE \ / \ Total\ PV\ production$$

3.2 PV production computation methodology

3.2.1 PV production curve without storage system

The hourly PV production series is computed as the result of multiplying hourly irradiation profile with country cumulative PV installation.

$$PV\ production = Irradiation * PV\ installation\ capacities$$

3.2.2 PV production curve with decentralized storage system

When PV panels are attached together with a decentralized storage system. The PV production is calculated taken into accounted pre-set assumptions regarding storage size and the charging and releasing time.

First of all, to simplify the calculation process, it is assumed that the electricity produced by PV system will first be used to charge the de-centralized storage until it is full. Secondly, the moment when the sun sets and PV panel stops to produce electricity, the storage then starts injecting into the grid with equal amount per hour so that at the end of the day the storage is fully discharged and ready for a new round in the following day. It is believed that the assumption is in line with reality since during night time the demand for electricity is higher and production is limited due to reduction in several energy generation sources.

Thirdly, the size of the storage systems chosen for this study are 10GW and 25 GW for the extreme case per nation.

Finally, the study considers 10% as the energy loss ratio for the round trip electricity makes through storage and back to the grid.

3.2.3 PV production curve with pump-hydro storage

In this case, the process of calculating PV prodution curve remains the same as in the case of PV system with decentralized storage.

Due to the difference in the way de-centralized storage and pump-hydro system operate, it is the load curve that is affected in this case. To be clear, using the same assumption that the electricity generated from PV will firstly be stored, during this time of the day, the load curve is increased by the same amount of electricity that is generated by PV for storing while during night time, this accumulated elctricity is injected back to the grid causing decline in the load curve. Therefore, the load curve is decreased linearly from sunset until the end of the day.

Similar to the previous case, the study considers 25% as the energy loss ratio for the round trip electricity makes through storage and back to the grid with pump-hydro system. As for the previous case the size of the storage facilities are 10 GW and 25 GW.

3.3 Results for the historical analysis in simple case where no storage system is added (i.e. PV only).

The MOCs have first been estimated on a country per country basis but the correlation factors proved to be quite poor: Germany alone showed about 57%. Adding Austria, France, Switzerland and Italy, the biggest trading partners of Germany allowed to increase the correlation factor to about 66% as shown below, comforting the assumption that external trades do have a non-negligible impact on the MOE estimation.

The MOCs that were calculated for each year between 2007 and 2015 (dotted curves in Figure 4 and results in table I below) as well as for the whole 2007-2015 period (plain curve in the Figure 4 and results in table II below) display fairly significant correlations between wholesale prices and electricity consumption (R^2 factor above 66%), which validates the set of assumptions listed in section 2.3.

Overall, the above results tend to validate the assumption that the MOC has an exponential shape and does not vary much over time. For each MOC, a MOE and MOP were calculated (see tables below).

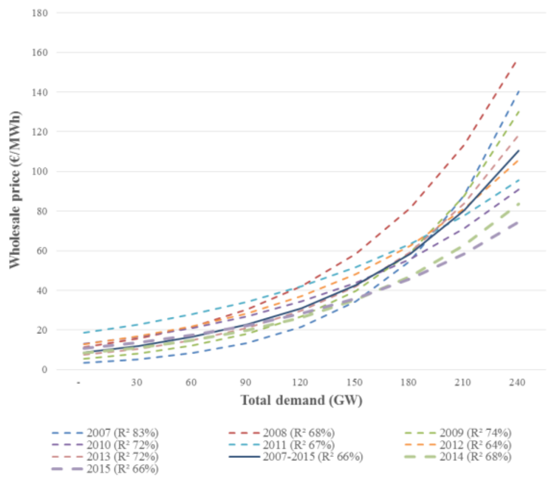

Figure 4: MOC for years from 2007 to 2015 and aggregated for the 2007-2015 period (source: authors' calculation)

Table I: MOC, MOE and MOP results for each year between 2007 and 2015

	MOC			MOE	MOP
Years	a	b	R^2	(€)	(€/MWh)
2007	1.19	$1.56\ 10^{-5}$	83%	$0.6\ 10^{9}$	137
2008	2.42	$1.10\ 10^{-5}$	68%	$0.9\ 10^{9}$	148
2009	1.71	$1.32\ 10^{-5}$	74%	$1.0\ 10^{9}$	108
2010	2.56	$8.12\ 10^{-6}$	72%	$1.2\ 10^{9}$	73
2011	2.92	$6.84\ 10^{-6}$	67%	$2.6\ 10^{9}$	67
2012	2.56	$8.77\ 10^{-6}$	64%	$4.8\ 10^{9}$	83
2013	2.00	$1.15\ 10^{-5}$	72%	$6.2\ 10^{9}$	97
2014	2.12	$9.62\ 10^{-6}$	68%	$4.2\ 10^{9}$	64
2015	2.37	$8.09\ 10^{-6}$	66%	$4.1\ 10^{9}$	57
2007-15	2.17	$1.06\ 10^{-5}$	66%	$30.7\ 10^{9}$	91

Table II: MOC, MOE and MOP results with the 2007-2015 MOC applied to all other years (source: authors' calculation)

	Yearly MOCs		2007-2015 MOC	
	MOE	**MOP**	**MOE**	**MOP**
Years	(€)	(€/MWh)	(€)	(€/MWh)
2007	0.6 10^9	137	0.4 10^9	100
2008	0.9 10^9	148	0.6 10^9	102
2009	1.0 10^9	108	0.8 10^9	88
2010	1.2 10^9	73	1.6 10^9	98
2011	2.6 10^9	67	3.5 10^9	92
2012	4.8 10^9	83	5.3 10^9	92
2013	6.2 10^9	97	5.7 10^9	89
2014	4.2 10^9	64	5.7 10^9	87
2015	4.1 10^9	57	6.7 10^9	92
2007-15	30.7 10^9	91	30.7 10^9	91

It is to be noted that if the MOP were to be paid to PV plants as a bonus on top of the market price for every MWh of PV produced, the total tariff received would be close to 140 €/MWh, as the average WAP is close to 50 €/MWh, which is above the range of the current feed-in-tariffs (and other support mechanisms) offered in EU countries (though in line with amounts offered only 2-3 years ago).

Equivalently, the average market price would have been 4.0% higher (2.0 €/MWh) had there been no PV generation between 2007 and 2015, as shown in table III below.

Table III: Average market price reduction between 2007 and 2015 (based on the 2007-15 MOC)

	Average WAP		Price reduction	
	Excl. PV	**Incl.PV**		
Years	(€/MWh)	(€/MWh)	(€/MWh)	(%)
2007	50.5	50.2	0.3	0.5%
2008	50.8	50.4	0.4	0.8%
2009	47.1	46.6	0.6	1.2%
2010	51.6	50.6	1.0	2.0%
2011	49.5	47.2	2.3	4.7%
2012	49.4	46.0	3.4	7.0%
2013	49.0	45.2	3.7	7.6%
2014	48.8	45.1	3.8	7.7%
2015	50.9	46.6	4.3	8.4%
2007-15	49.8	47.8	2.0	4.0%

Those results are in line with what other research such as Frank Sensfuß, Mario Ragwitz and Massimo Genoese (2008) [10].

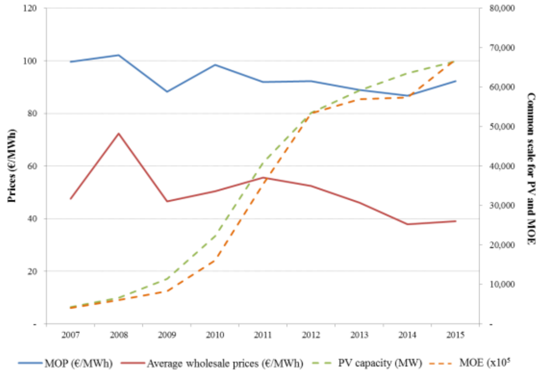

Figure 5: MOP (based on the 2007-15 MOC), average wholesale prices, MOE (based on the 2007-15 MOC) and PV capacities installed between 2007 and 2015 (source: authors' calculation)

The MOPs calculated above shows a downward trend with quite some variability. An intuitive interpretation could be that the MOE is less efficient as the PV penetration increases. In reality, only 10 years of history is rather short to validate any theory on which driver may affect the MOE. Such drivers could be the correlation between the solar irradiation and consumption profiles or the PV penetration rate.

In order to have a more reliable answer, the authors adopted a statistical analysis to observe the MOE variations with a large number of irradiation profiles, with different electricity demand profiles and different shares of installed PV capacity.

For the sake of consistency, and to allow an adequate comparison between the various metrics detailed section 4, the remainder of the study assumed that the MOC is the one obtained for the 2007 to 2015 period.

3.4 Results for the historical analysis in the case where de-centralized storage is added to the PV capacity

The addition of de-centralized storage does not significantly impact the MOC compared to the MOCs shown in Figure 4, and are thus not included in this paper.

The introduction of de-centralized storage (i.e. storage installed together with PV capacity) appears to reduce the MOE of PV. This can be seen by the decrease in calculated aggregate MOE values compared to the scenario described in Section 3.3 (PV without any additional storage) in the tables below. Similarly, the average electricity market price reduction is lower than if no storage had been added.

Table IV: MOC, MOE and MOP results with the 2007-2015 MOC applied to all other years including 10GW of de-centralized (storage source: authors' calculation).

	Yearly MOCs		2007-2015 MOC	
	MOE	**MOP**	**MOE**	**MOP**
Years	(€)	(€/MWh)	(€)	(€/MWh)
2007	0.4 10^9	111	0.3 10^9	85
2008	0.7 10^9	131	0.5 10^9	91
2009	0.9 10^9	98	0.7 10^9	82
2010	1.1 10^9	69	1.5 10^9	94
2011	2.5 10^9	65	3.4 10^9	91
2012	4.7 10^9	82	5.2 10^9	92
2013	6.1 10^9	96	5.6 10^9	89
2014	4.3 10^9	66	5.8 10^9	88
2015	4.2 10^9	59	6.7 10^9	94
2007-15	29.9$10^9$	90	29.9 10^9	90

Table V: Average market price reduction between 2007 and 2015 (based on the 2007-15 MOC) including 10GW of de-centralized storage.

	Average WAP		**Price reduction**	
	Excl. PV	**Incl.PV**		
Years	(€/MWh)	(€/MWh)	(€/MWh)	(%)
2007	50.5	50.3	0.2	0.4%
2008	50.8	50.5	0.3	0.7%
2009	47.1	46.6	0.5	1.1%
2010	51.6	50.7	1.0	1.9%
2011	49.5	47.3	2.3	4.6%
2012	49.4	46.1	3.4	6.9%
2013	49.0	45.3	3.7	7.5%
2014	48.8	45.1	3.8	7.7%
2015	50.9	46.6	4.3	8.5%
2007-15	49.8	47.8	2.0	4.0%

The negative impact observed on the aggregate MOE is even more pronounced when going from 10 GW to 25 GW of storage (approximately EUR 8 bn decrease in MOE compared to the no additional storage scenario). Similarly, the calculated market price reduction as a result of the combination of PV and storage would be lower with the higher storage capacity. This would suggest that the addition of storage means the MOE is less efficient.

It may be that the approximations made for the calculation of the storage capacity for the purposes of this calculation are perhaps overly simplified. It is, for example possible that not all electricity produced would be fed into the storage units as a priority. In reality the decision on whether to inject electricity into the grid or into storage will be driven by market prices/demand, which the calculations do explicitly account for. Similarly, the re-injection of the electricity into the grid is likely to be linked to demand and price factors and will thus most likely not occur linearly between sunset and midnight. So it would be conceivable, for example, that it is more favorable to inject electricity from storage into the grid during the evening peak demand period rather than in the hour before midnight where market spot prices are likely to be low anyway.

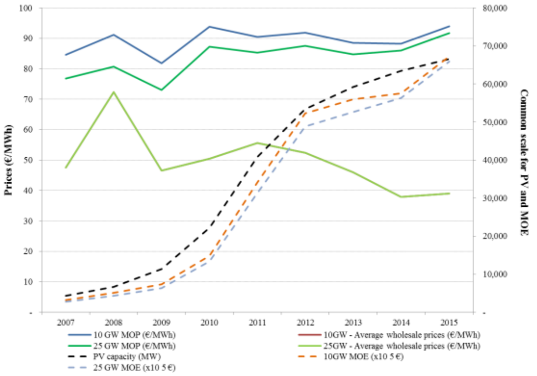

Figure 6: MOP (based on the 2007-15 MOC), average wholesale prices, MOE (based on the 2007-15 MOC) for both cases of de-centralized storage (i.e. 10GW and 25GW installed capacity) and PV capacities installed between 2007 and 2015 (source: authors' calculation)

That being said, the MOE for 2014 and 2015 do actually increase compared to the case without any storage, an effect which is more pronounced when 25GW of storage is included. Therefore, it may be that adding 10/25GW of storage was simply too much for early years were the installed PV capacity was of the order of and sometimes even lower than the storage capacity. This could mean that if all PV electricity generated in the day-time is stored the benefit of re-injecting it during night-time is outweighed by an increase in price during day time (when PV would otherwise produce electricity and thus lower the market spot prices).

Table VI: MOC, MOE and MOP results with the 2007-2015 MOC applied to all other years including 25 GW of de-centralized (storage source: authors' calculation).

	Yearly MOCs		**2007-2015 MOC**	
	MOE	**MOP**	**MOE**	**MOP**
Years	(€)	(€/MWh)	(€)	(€/MWh)
2007	0.4 10^9	99	0.3 10^9	77
2008	0.6 10^9	116	0.4 10^9	81
2009	0.8 10^9	87	0.6 10^9	73
2010	1.0 10^9	65	1.3 10^9	87
2011	2.3 10^9	62	3.1 10^9	85
2012	4.3 10^9	77	4.9 10^9	88
2013	5.6 10^9	90	5.3 10^9	85
2014	4.2 10^9	65	5.6 10^9	86
2015	4.2 10^9	55	5.6 10^9	92
2007-15	28.4 10^9	87	28.4 10^9	87

Table VII: Average market price reduction between 2007 and 2015 (based on the 2007-15 MOC) including 25GW of de-centralized storage.

	Average WAP		**Price reduction**	
	Excl. PV	**Incl.PV**		
Years	(€/MWh)	(€/MWh)	(€/MWh)	(%)
2007	50.3	50.1	0.2	0.4%
2008	50.6	50.3	0.3	0.6%
2009	47.0	46.6	0.5	1.0%
2010	51.4	50.5	0.9	1.8%
2011	49.4	47.3	2.1	4.3%
2012	49.3	46.1	3.2	6.5%
2013	48.8	45.3	3.5	7.2%
2014	48.7	45.0	3.7	7.7%
2015	50.8	46.5	4.3	8.4%
2007-15	49.6	47.7	1.9	3.8%

3.5 Results for the historical analysis in the case where centralized storage (e.g. pump-hydro) is added to the PV capacity.

The addition of centralized storage does not significantly impact the MOC compared to the MOCs shown in Figure 4, and are thus not included in this paper (as was the case for de-centralized storage). Contrary to the observation made for the de-centralized storage, the MOE increases with the addition of centralized storage. This is reflected in an increase of the MOE (of around EUR 1 bn) value over the 10 years studied as well as in higher observed MOPs and a larger reduction in WAP. In the case with 10 GW additional storage capacity the total MOE increases by around EUR 1 bn.

As was the case without the addition of storage capacity the calculated MOPs seem to be trending downwards, though with significant variability. The calculated MOPs broadly follow the trends observed for average wholesale prices over the same time period.

Figure 6 shows that increasing the storage capacity from 10 to 25 GW has a negligible impact on the average market price. Conversely, it is clear that the increase in storage capacity seems to lead to an increase in MOP, especially for the later years. It appear that this effect is amplified with increasing installed solar capacity. In section 4 some statistical analysis is carried out to test this potential correlation.

Table VIII: MOC, MOE and MOP results with the 2007-2015 MOC applied to all other years including 10GW of centralized (storage source: authors' calculation).

	Yearly MOCs		2007-2015 MOC	
Years	**MOE** (€)	**MOP** (€/MWh)	**MOE** (€)	**MOP** (€/MWh)
2007	0.6 10^9	139	0.4 10^9	101
2008	0.9 10^9	149	0.6 10^9	104
2009	1.0 10^9	110	0.8 10^9	90
2010	1.2 10^9	74	1.7 10^9	101
2011	2.6 10^9	68	3.7 10^9	95
2012	4.9 10^9	85	5.5 10^9	95
2013	6.4 10^9	100	5.9 10^9	92
2014	4.5 10^9	67	5.9 10^9	90
2015	4.4 10^9	57	6.9 10^9	96
2007-15	31.7 10^9	94	31.7 10^9	94

Table IX: Average market price reduction between 2007 and 2015 (based on the 2007-15 MOC) including 10 GW of centralized storage.

	Average WAP		Price reduction	
Years	**Excl. PV** (€/MWh)	**Incl.PV** (€/MWh)	(€/MWh)	(%)
2007	50.4	50.2	0.3	0.5%
2008	50.8	50.4	0.4	0.8%
2009	47.1	46.6	0.6	1.2%
2010	51.7	50.6	1.1	2.0%
2011	49.6	47.3	2.4	4.8%
2012	49.5	46.0	3.5	7.1%
2013	49.1	45.3	3.8	7.7%
2014	48.9	45.1	3.9	7.9%
2015	51.0	46.6	4.4	8.6%
2007-15	49.8	47.8	2.0	4.1%

This effect is further amplified when introducing more storage capacity, as seen from the case with 25GW per country, as evidenced by a further increase (with respect to the 10 GW centralized storage case) of EUR 1.2 bn in the calculated MOE. The MOP available for PV producers would be around 98EUR/MWh, making the total tariff payable close to 150EUR/MWh (average market price only decreased minimally), a 10EUR/MWh increase from the PV only case.

The decrease in average market price is more modest (in the range of 0.1%). It is worth noting that, considering the rather simple approximations taken in order to simulate the acquisition and re-injection of electricity by centralized storage facilities such significant impacts were measured. It is, therefore, conceivable that by using a more sophisticated approach (e.g. one that is linked to peak demand and or spot prices) could further improve the MOE as a result of PV installation. Furthermore, it appears to validate the assumptions made for these calculations.

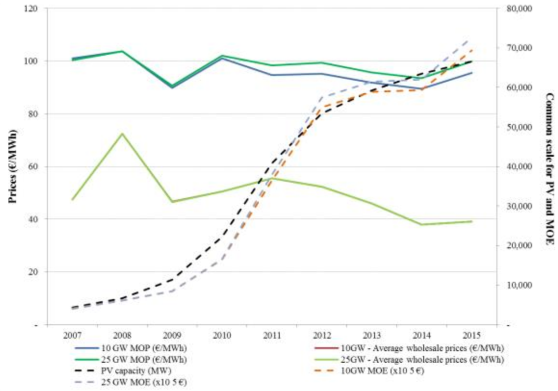

Figure 7: MOP (based on the 2007-15 MOC), average wholesale prices, MOE (based on the 2007-15 MOC) for both cases of centralized storage (i.e. 10GW and 25GW installed capacity) and PV capacities installed between 2007 and 2015 (source: authors' calculation)

Table X: MOC, MOE and MOP results with the 2007-2015 MOC applied to all other years including 25 GW of centralized (storage source: authors' calculation).

	Yearly MOCs		2007-2015 MOC	
Years	**MOE** (€)	**MOP** (€/MWh)	**MOE** (€)	**MOP** (€/MWh)
2007	0.6 10^9	140	0.4 10^9	100
2008	0.9 10^9	151	0.6 10^9	104
2009	1.0 10^9	112	0.8 10^9	91
2010	1.2 10^9	75	1.7 10^9	102
2011	2.7 10^9	70	3.8 10^9	98
2012	5.0 10^9	86	5.7 10^9	99
2013	6.6 10^9	102	6.1 10^9	96
2014	4.7 10^9	70	6.2 10^9	94
2015	4.6 10^9	63	7.3 10^9	100
2007-15	32.9 10^9	98	32.9 10^9	98

Table XI: Average market price reduction between 2007 and 2015 (based on the 2007-15 MOC) including 25GW of centralized storage.

	Average WAP		Price reduction	
Years	**Excl. PV** (€/MWh)	**Incl.PV** (€/MWh)	(€/MWh)	(%)
2007	50.3	50.0	0.3	0.5%
2008	50.7	50.3	0.4	0.8%
2009	47.1	46.5	0.6	1.2%
2010	51.6	50.5	1.1	2.1%
2011	49.7	47.3	2.4	4.8%
2012	49.7	46.1	3.6	7.2%
2013	49.3	45.4	3.9	7.9%
2014	49.0	45.1	3.9	8.0%
2015	51.2	46.7	4.5	8.8%
2007-15	49.8	47.7	2.1	4.2%

4 STATISTICAL ANALYSIS

4.1 Statistical average merit-order effect computation where PV without storage

Ten years of historical data is rather too short to assess with a high level of reliability the MOE at the scale of a country. Policy makers and economic agents may have an interest in predicting its value for the years to come as it will impact the forward prices and may influence their decisions. The MOE is by definition dependant on the PV production profile and how it correlates with the consumptions profile. A statistical approach is thus proposed, in order to observe how the MOE behaves with respect to different PV production profiles.

The data used for this section are the hourly PV production profiles (MWh) and the hourly installed PV capacity (MWp) between 2006 and 2015, to obtain hourly profiles (i.e. the ratio of the PV production by the installed PV capacity (MWh/MWp)). There is one additional year (2006) compared to the previous section, as the authors did not have access to the wholesale prices for that year to run the historical calculations.

A Monte Carlo simulation was run on a central hourly yield profile over a year. Each hourly yield for each of the main 60 regions of GAFSI (see section 3.1) was modelled as an independent random variable following a normal law (there are therefore 8760 Gaussian random yield variable). Each hourly yield has 10 samples (for 2006 to 2015), from which the authors have calculated an average and a standard deviation.

The Monte Carlo simulation was run 100 times (on each of the 8760 random yields just defined) for each of the 60 main GAFSI cities, leading to 6000 random yearly yield profiles. The authors then calculated 100 PV production profiles for each of the 10 years of historical PV installation capacities (2006-2015) around the 60 main GAFSI cities (hence a total of 6000 PV production profiles). The authors could also calculate 100 profiles of demand in GAFSI retreated by PV production for each of the 10 years of historical demand profiles, leading to 81 combinations.

For each of these 100 combinations, 100 values of the MOE and MOP were calculated, using the MOC calculated between 2007 and 2015. The authors used the same MOC throughout the combinations in order to have a common basis for comparison. A statistically meaningful average of the MOE and the MOP were then calculated for each combination.

4.2 Results

The results tables should be read as follows:

- Along columns the amount of installed PV capacities varies (from 2006 to 2015)
- Along rows the profile of total electricity demand varies as observed from 2006 to 2015.

Diagonal values show a more reliable (statistically meaningful) estimate of the MOE and MOP for a given year (note that the MOP are almost identical to the ones on the last column of table II, with a 3% tolerance).

Table XII: MOP and MOE varying with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows)

MONTE-CARLO (100 draws)			PV installed capacities									
			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Consumption profiles	2006	MOP (€/MWh)	99	99	99	99	97	94	92	90	89	89
		MOE (m€)	259	376	571	920	1,660	3,403	5,223	6,181	6,752	7,113
	2007	MOP (€/MWh)	102	102	101	101	100	97	94	92	91	90
		MOE (m€)	265	386	586	944	1,713	3,511	5,352	6,310	6,877	7,245
	2008	MOP (€/MWh)	104	103	103	103	101	98	95	94	93	92
		MOE (m€)	270	392	596	957	1,730	3,549	5,423	6,406	7,001	7,370
	2009	MOP (€/MWh)	90	90	89	89	88	85	83	82	81	80
		MOE (m€)	234	340	517	832	1,509	3,090	4,725	5,577	6,091	6,418
	2010	MOP (€/MWh)	101	101	101	101	99	96	94	92	91	90
		MOE (m€)	263	383	583	941	1,702	3,491	5,337	6,300	6,883	7,247
	2011	MOP (€/MWh)	98	97	97	97	95	92	90	89	88	87
		MOE (m€)	254	370	562	905	1,634	3,348	5,134	6,070	6,627	6,984
	2012	MOP (€/MWh)	100	99	99	99	97	94	92	90	89	89
		MOE (m€)	259	377	574	922	1,664	3,409	5,228	6,183	6,750	7,109
	2013	MOP (€/MWh)	98	98	98	98	96	92	90	89	88	87
		MOE (m€)	255	371	563	908	1,639	3,351	5,144	6,085	6,646	7,003
	2014	MOP (€/MWh)	98	97	97	97	95	92	90	88	87	87
		MOE (m€)	254	369	561	903	1,631	3,337	5,117	6,046	6,602	6,955
	2015	MOP (€/MWh)	105	105	104	104	102	99	96	95	94	93
		MOE (m€)	273	398	602	972	1,752	3,580	5,499	6,502	7,110	7,491

Table XIII: relative variations of the MOP compared to the 2006 value (99 €/MWh) with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows)

Relative variations to 2006 MOP		PV installed capacity										*Maximum variation*
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	
Consumption profiles	2006	-	-0.3%	-0.6%	-0.6%	-2.5%	-5.6%	-7.8%	-9.2%	-10.1%	-10.7%	*10.7%*
	2007	2.6%	2.4%	2.1%	2.1%	0.6%	-2.6%	-5.6%	-7.3%	-8.4%	-9.0%	*11.6%*
	2008	4.4%	4.1%	3.8%	3.6%	1.6%	-1.7%	-4.3%	-5.8%	-6.8%	-7.5%	*11.8%*
	2009	-9.5%	-9.7%	-10.0%	-10.0%	-11.4%	-14.3%	-16.7%	-17.9%	-18.9%	-19.4%	*9.9%*
	2010	1.9%	1.7%	1.5%	1.7%	0.0%	-3.2%	-5.9%	-7.3%	-8.4%	-9.0%	*10.9%*
	2011	-1.7%	-1.9%	-2.2%	-2.2%	-4.0%	-7.2%	-9.5%	-10.8%	-11.8%	-12.4%	*10.6%*
	2012	0.2%	0.0%	-0.3%	-0.3%	-2.3%	-5.5%	-7.8%	-9.1%	-10.1%	-10.7%	*10.9%*
	2013	-1.3%	-1.6%	-1.9%	-1.9%	-3.8%	-7.0%	-9.2%	-10.5%	-11.5%	-12.1%	*10.8%*
	2014	-1.8%	-2.0%	-2.3%	-2.3%	-4.2%	-7.4%	-9.8%	-11.1%	-12.0%	-12.7%	*10.9%*
	2015	5.6%	5.4%	4.9%	4.9%	2.8%	-0.7%	-3.0%	-4.4%	-5.4%	-6.0%	*11.6%*
Maximum variation		*15.1%*	*15.1%*	*14.9%*	*14.9%*	*14.2%*	*13.6%*	*13.6%*	*13.6%*	*13.5%*	*13.4%*	

As displayed in the tables above, the MOP varies more along columns than along rows. This indicates that the MOP does not depend much on the penetration rate of PV in the country's energy mix (total PV capacity installed), but rather varies significantly with the electricity demand profile, or to be precise, with the correlation between demand and PV production during the year.

This effect seems to ease gradually from 2011 onwards. The variance of the MOP with PV penetration rate (years in the x-axis corresponds to a given capacity profile, i.e. columns in the Table XII) is shown in Figure 8. As more capacity is installed, PV production is ensured to supply a larger portion of the electricity demand from customers. This is in line with what had been observed in the authors' previous study in 2014. Figure 8 below shows the continuation of the trend observed for 2011-2013 into the final two years. Nevertheless, the observed effect seems to have plateaued since circa 2011, perhaps suggesting that a 'critical mass' in terms of PV capacity was reached meaning that further increases do not impact the variance of MOPs as significantly.

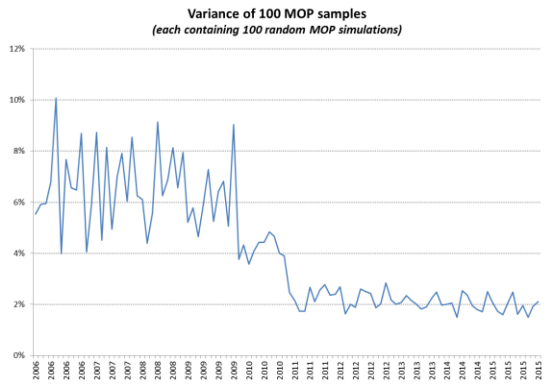

Figure 8: Variance of the 100 random MOPs of each of the 100 combinations (source: authors' calculation). On the x-axis the years are ordered between 2006 and 2015 and each year has 10 combinations (one per electricity

demand profile).

4.2.1 Statistical average merit-order effect computation in the case where de-centralized storage is added to the PV capacity.

The results are to be read as for Section 4.2. As for the PV only case, the diagonals should indicate a more reliable and statistically meaningful estimate of the MOE/MOP for each year.

Table XIV: MOP and MOE varying with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows) for the case with 10 GW of de-centralized storage.

MONTE-CARLO (100 draws)			PV installed capacities									
			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Consumption profiles	2006	MOP (€/MWh)	94	93	93	93	91	87	86	85	84	83
		MOE (m€)	251	364	552	885	1,594	3,242	4,999	5,923	6,474	6,802
	2007	MOP (€/MWh)	96	96	95	95	94	90	88	86	86	85
		MOE (m€)	257	374	567	908	1,642	3,341	5,117	6,028	6,588	6,920
	2008	MOP (€/MWh)	98	98	98	97	95	91	90	89	88	87
		MOE (m€)	263	382	580	930	1,669	3,392	5,214	6,168	6,749	7,092
	2009	MOP (€/MWh)	85	85	85	85	83	80	78	77	77	76
		MOE (m€)	229	332	504	808	1,458	2,967	4,559	5,398	5,895	6,201
	2010	MOP (€/MWh)	97	96	96	96	94	91	89	88	87	87
		MOE (m€)	259	376	570	917	1,660	3,381	5,191	6,148	6,715	7,071
	2011	MOP (€/MWh)	93	93	92	92	90	87	85	85	84	83
		MOE (m€)	249	362	548	880	1,585	3,233	4,978	5,898	6,450	6,777
	2012	MOP (€/MWh)	94	94	93	93	91	87	86	85	84	84
		MOE (m€)	252	366	554	888	1,595	3,244	5,004	5,930	6,484	6,801
	2013	MOP (€/MWh)	93	92	92	92	90	86	84	84	83	82
		MOE (m€)	248	360	545	874	1,571	3,188	4,917	5,822	6,364	6,689
	2014	MOP (€/MWh)	95	94	94	94	92	88	87	86	85	84
		MOE (m€)	254	368	558	894	1,607	3,275	5,037	5,965	6,518	6,855
	2015	MOP (€/MWh)	102	101	101	100	98	95	93	92	91	91
		MOE (m€)	272	396	599	958	1,726	3,511	5,414	6,414	7,012	7,373

However, in this case the MOP values are not as well aligned with some discrepancies of over 10% with respect to the historical MOP calculations described in Section 3. This is not entirely surprising as changing the PV production profile is similar to changing the energy mix of a country/region. This could create higher variance leading to a poorer match between statistical and historical data.

Table XV: relative variations of the MOP compared to the 2006 value (94 €/MWh) with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows) for the case with 10 GW of de-centralized storage.

Relative variations to 2006 MOP		PV installed capacity										*Maximum variation*
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	
Consumption profiles	2006	-	-0.4%	-0.9%	-1.2%	-3.2%	-6.9%	-8.6%	-9.4%	-10.3%	-11.0%	*11.0%*
	2007	2.5%	2.2%	1.8%	1.4%	-0.1%	-4.0%	-6.4%	-7.8%	-8.8%	-9.4%	*11.9%*
	2008	5.0%	4.6%	4.0%	3.6%	1.5%	-2.5%	-4.6%	-5.6%	-6.5%	-7.2%	*12.2%*
	2009	-8.9%	-9.2%	-9.7%	-9.8%	-11.5%	-14.8%	-16.5%	-17.5%	-18.3%	-18.9%	*10.0%*
	2010	3.1%	2.8%	2.5%	2.5%	0.7%	-2.9%	-4.9%	-6.0%	-7.0%	-7.5%	*10.6%*
	2011	-0.8%	-1.0%	-1.6%	-1.7%	-3.7%	-7.1%	-8.9%	-9.8%	-10.7%	-11.3%	*10.5%*
	2012	0.4%	0.0%	-0.6%	-0.8%	-3.0%	-6.8%	-8.4%	-9.4%	-10.3%	-10.9%	*11.3%*
	2013	-1.2%	-1.6%	-2.1%	-2.4%	-4.5%	-8.3%	-10.0%	-10.9%	-11.7%	-12.3%	*11.1%*
	2014	0.8%	0.5%	-0.1%	-0.3%	-2.2%	-5.8%	-7.7%	-8.8%	-9.6%	-10.2%	*11.1%*
	2015	8.4%	8.0%	7.4%	7.0%	4.9%	1.0%	-0.9%	-1.9%	-2.9%	-3.5%	*11.8%*
Maximum variation		*17.3%*	*17.3%*	*17.1%*	*16.8%*	*16.4%*	*15.7%*	*15.6%*	*15.6%*	*15.5%*	*15.4%*	

As was the case for the PV only case, the MOP varies more strongly as a function of consumption profile (i.e. along columns) than PV penetration (along rows). Although this observation is slightly less pronounced for the more recent years (as for the PV only case). The reasoning must be different, even if numerically, the maximum variations along columns are much higher for both of the de-centralized storage cases compared to the PV only case.

Table XVI: MOP and MOE varying with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows) for the case with 25 GW of de-centralized storage.

MONTE-CARLO (100 draws)			PV installed capacities									
			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Consumption profiles	2006	MOP (€/MWh)	88	87	87	87	85	82	81	80	79	78
		MOE (m€)	233	338	512	821	1,482	3,020	4,651	5,502	6,025	6,337
	2007	MOP (€/MWh)	90	90	89	89	88	85	82	81	80	80
		MOE (m€)	239	346	526	842	1,530	3,110	4,763	5,609	6,125	6,440
	2008	MOP (€/MWh)	92	92	91	91	89	86	84	83	82	82
		MOE (m€)	245	355	538	862	1,554	3,165	4,859	5,760	6,286	6,615
	2009	MOP (€/MWh)	80	80	80	80	78	76	74	73	72	71
		MOE (m€)	212	309	468	753	1,360	2,773	4,257	5,035	5,499	5,797
	2010	MOP (€/MWh)	91	91	90	91	89	86	84	83	82	82
		MOE (m€)	241	350	531	856	1,551	3,164	4,862	5,758	6,291	6,621
	2011	MOP (€/MWh)	87	87	87	87	85	82	81	80	79	78
		MOE (m€)	232	337	511	821	1,483	3,024	4,655	5,514	6,021	6,340
	2012	MOP (€/MWh)	88	88	87	87	85	82	81	80	79	78
		MOE (m€)	233	339	515	823	1,484	3,025	4,659	5,517	6,032	6,346
	2013	MOP (€/MWh)	86	86	86	86	84	81	79	78	78	77
		MOE (m€)	230	333	504	812	1,457	2,970	4,580	5,419	5,923	6,234
	2014	MOP (€/MWh)	90	89	89	89	87	84	82	81	80	80
		MOE (m€)	237	345	523	837	1,515	3,094	4,745	5,606	6,135	6,454
	2015	MOP (€/MWh)	96	96	95	95	93	90	88	87	86	86
		MOE (m€)	255	370	560	899	1,623	3,310	5,092	6,021	6,584	6,927

Table XVII: relative variations of the MOP compared to the 2006 value (88 €/MWh) with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows) for the case with 10 GW of de-centralized storage.

Relative variations to 2006 MOP		PV installed capacity										*Maximum variation*
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	
Consumption profiles	2006	-	-0.4%	-0.8%	-0.8%	-3.0%	-6.1%	-8.0%	-9.1%	-10.0%	-10.7%	*10.7%*
	2007	2.5%	2.2%	1.9%	1.7%	0.1%	-3.3%	-6.0%	-7.4%	-8.5%	-9.3%	*11.8%*
	2008	5.1%	4.7%	4.3%	4.0%	1.9%	-1.6%	-3.9%	-5.1%	-6.2%	-6.9%	*12.0%*
	2009	-8.5%	-8.8%	-9.1%	-9.2%	-10.8%	-13.8%	-15.7%	-16.8%	-17.8%	-18.4%	*9.9%*
	2010	3.8%	3.5%	3.2%	3.3%	1.7%	-1.6%	-3.8%	-5.1%	-6.1%	-6.9%	*10.7%*
	2011	-0.2%	-0.5%	-0.8%	-0.9%	-2.9%	-5.9%	-8.0%	-9.0%	-10.0%	-10.6%	*10.5%*
	2012	0.4%	0.0%	-0.4%	-0.5%	-2.6%	-6.0%	-7.9%	-8.9%	-10.0%	-10.6%	*11.1%*
	2013	-1.3%	-1.7%	-2.1%	-2.1%	-4.3%	-7.6%	-9.5%	-10.5%	-11.5%	-12.2%	*10.9%*
	2014	2.2%	1.8%	1.5%	1.2%	-0.7%	-3.9%	-6.2%	-7.4%	-8.4%	-9.2%	*11.4%*
	2015	9.7%	9.3%	8.8%	8.6%	6.5%	2.9%	0.7%	-0.5%	-1.7%	-2.4%	*12.1%*
Maximum variation		*18.2%*	*18.1%*	*17.9%*	*17.8%*	*17.3%*	*16.7%*	*16.4%*	*16.3%*	*16.1%*	*16.0%*	

4.2.2 Statistical average merit-order effect computation in the case where centralized storage (e.g. pump-hydro) is added to the PV capacity.

The results are to be read as for Section 4.2. Similar to the PV only case, the diagonal values show a more reliable (statistically significant) estimate of the MOE and MOP for a given year. For the 10 GW storage case, note that the MOP values in the diagonal are almost identical to those in the last column of table IX (within a 3% tolerance).

Table XVIII: MOP and MOE varying with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows) for the case with 10 GW of centralized storage.

MONTE-CARLO (100 draws)			PV installed capacities									
			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Consumption profiles	2006	MOP (€/MWh)	100	100	100	100	98	95	93	91	90	90
		MOE (m€)	261	380	578	930	1,679	3,440	5,281	6,247	6,820	7,188
	2007	MOP (€/MWh)	103	103	103	103	101	98	95	93	92	92
		MOE (m€)	269	391	594	956	1,736	3,555	5,421	6,385	6,973	7,342
	2008	MOP (€/MWh)	106	105	105	105	103	99	97	95	94	93
		MOE (m€)	275	399	607	975	1,762	3,605	5,514	6,514	7,115	7,491
	2009	MOP (€/MWh)	92	91	91	91	90	87	84	83	82	82
		MOE (m€)	238	347	527	847	1,535	3,145	4,812	5,683	6,203	6,534
	2010	MOP (€/MWh)	104	104	103	104	102	99	96	94	93	93
		MOE (m€)	270	393	598	964	1,747	3,583	5,472	6,467	7,058	7,435
	2011	MOP (€/MWh)	101	101	100	100	98	95	93	91	90	90
		MOE (m€)	262	381	580	933	1,686	3,454	5,298	6,259	6,843	7,203
	2012	MOP (€/MWh)	103	103	102	102	100	97	95	93	92	92
		MOE (m€)	268	389	591	951	1,718	3,521	5,399	6,392	6,981	7,351
	2013	MOP (€/MWh)	98	98	97	97	95	92	90	89	88	87
		MOE (m€)	254	371	563	906	1,635	3,350	5,138	6,080	6,636	6,991
	2014	MOP (€/MWh)	101	100	100	100	98	95	92	91	90	89
		MOE (m€)	262	380	578	930	1,681	3,440	5,274	6,229	6,807	7,173
	2015	MOP (€/MWh)	108	108	108	108	105	102	99	98	97	96
		MOE (m€)	282	409	622	#####	1,806	3,695	5,677	6,713	7,334	7,734

Table XIX: relative variations of the MOP compared to the 2006 value (100 €/MWh) with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows) for the case with 10 GW of centralized storage.

Relative variations to 2006 MOP		PV installed capacity										*Maximum variation*
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	
Consumption profiles	2006	-	-0.2%	-0.5%	-0.5%	-2.5%	-5.6%	-7.8%	-9.1%	-10.1%	-10.7%	*10.7%*
	2007	2.8%	2.7%	2.4%	2.3%	0.9%	-2.4%	-5.5%	-7.1%	-8.2%	-8.8%	*11.7%*
	2008	5.1%	4.9%	4.5%	4.3%	2.3%	-1.1%	-3.7%	-5.3%	-6.3%	-7.0%	*12.1%*
	2009	-8.9%	-9.1%	-9.3%	-9.3%	-10.8%	-13.7%	-16.0%	-17.4%	-18.3%	-18.8%	*9.9%*
	2010	3.4%	3.2%	3.0%	3.2%	1.6%	-1.7%	-4.4%	-5.9%	-7.0%	-7.7%	*11.1%*
	2011	0.3%	0.1%	-0.2%	-0.2%	-2.1%	-5.2%	-7.6%	-8.9%	-9.9%	-10.5%	*10.9%*
	2012	2.3%	2.1%	1.9%	1.8%	-0.2%	-3.4%	-5.7%	-7.1%	-8.0%	-8.7%	*11.0%*
	2013	-2.6%	-2.7%	-3.0%	-3.1%	-5.0%	-8.1%	-10.3%	-11.6%	-12.6%	-13.1%	*10.6%*
	2014	0.1%	-0.2%	-0.5%	-0.5%	-2.4%	-5.6%	-8.0%	-9.4%	-10.3%	-11.0%	*11.1%*
	2015	7.8%	7.6%	7.2%	7.1%	4.9%	1.4%	-1.0%	-2.3%	-3.4%	-4.0%	*11.8%*
Maximum variation		*16.7%*	*16.6%*	*16.5%*	*16.5%*	*15.7%*	*15.1%*	*15.1%*	*15.1%*	*14.9%*	*14.8%*	

This observation is no longer valid for the 25 GW storage case. One reason for this is that with 10 GW, the changes made to the consumption/load curve were not significant enough to impact the variance of the Monte Carlo calculations. Conversely, once we introduce 25 GW it has a much more significant impact.

Table XX: MOP and MOE varying with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows) for the case with 25 GW of centralized storage.

MONTE-CARLO (100 draws)			PV installed capacities									
			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Consumption profiles	2006	MOP (€/MWh)	99	99	99	99	97	94	92	90	102	102
		MOE (€)	259	376	571	920	1,660	3,403	5,223	6,181	265	386
	2007	MOP (€/MWh)	102	101	100	97	94	92	104	103	103	103
		MOE (€)	587	944	1,715	3,512	5,350	6,302	270	392	596	958
	2008	MOP (€/MWh)	101	98	95	94	90	90	89	89	88	85
		MOE (€)	1,732	3,542	5,429	6,408	234	340	517	832	1,508	3,087
	2009	MOP (€/MWh)	83	82	101	101	101	101	99	96	94	92
		MOE (€)	4,724	5,579	264	384	582	939	1,704	3,488	5,336	6,301
	2010	MOP (€/MWh)	98	97	97	97	95	92	90	89	100	99
		MOE (€)	254	370	562	905	1,635	3,349	5,132	6,067	259	377
	2011	MOP (€/MWh)	99	99	97	94	92	90	98	98	97	98
		MOE (€)	573	923	1,664	3,408	5,230	6,186	256	371	564	908
	2012	MOP (€/MWh)	96	92	90	89	98	97	97	97	95	92
		MOE (€)	1,637	3,353	5,145	6,087	254	369	561	903	1,630	3,339
	2013	MOP (€/MWh)	90	88	103	103	104	104	102	99	96	95
		MOE (€)	5,112	6,049	907	1,054	603	970	1,751	3,578	5,501	6,506
	2014	MOP (€/MWh)	94	94	97	97	95	92	90	88	87	87
		MOE (€)	6,423	6,779	559	901	1,626	3,340	5,114	6,046	6,603	6,942
	2015	MOP (€/MWh)	105	105	104	104	102	99	96	95	94	93
		MOE (€)	274	397	606	969	1,750	3,581	5,487	6,498	7,109	7,482

Table XXI: relative variations of the MOP compared to the 2006 value (99 €/MWh) with the PV penetration rate (installed capacity, in columns) and with electricity demand profiles (i.e. with the PV irradiation profiles, in rows) for the case with 25 GW of centralized storage.

Relative variations to 2006 MOP		PV installed capacity										Maximum variation
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	
Consumption profiles	2006	-	-0.3%	-0.6%	-0.5%	-2.5%	-5.6%	-7.9%	-9.1%	2.6%	2.4%	*11.8%*
	2007	2.2%	2.0%	0.7%	-2.6%	-5.6%	-7.2%	4.4%	4.1%	3.8%	3.6%	*11.7%*
	2008	1.7%	-1.7%	-4.3%	-5.8%	-9.5%	-9.7%	-10.0%	-10.0%	-11.4%	-14.4%	*16.0%*
	2009	-16.6%	-17.9%	1.9%	1.7%	1.5%	1.6%	0.0%	-3.2%	-5.9%	-7.3%	*19.8%*
	2010	-1.7%	-1.9%	-2.2%	-2.2%	-4.1%	-7.1%	-9.5%	-10.8%	0.2%	0.0%	*11.0%*
	2011	-0.3%	-0.3%	-2.3%	-5.5%	-7.8%	-9.1%	-1.3%	-1.5%	-1.9%	-1.8%	*8.8%*
	2012	-3.8%	-7.0%	-9.3%	-10.5%	-1.8%	-2.0%	-2.3%	-2.3%	-4.3%	-7.3%	*8.7%*
	2013	-9.8%	-11.1%	3.9%	3.6%	5.0%	4.9%	2.8%	-0.7%	-3.0%	-4.3%	*16.0%*
	2014	-5.0%	-5.6%	-2.3%	-2.4%	-4.2%	-7.4%	-9.8%	-11.1%	-12.0%	-12.6%	*10.3%*
	2015	5.6%	5.4%	4.9%	4.8%	2.8%	-0.6%	-3.1%	-4.4%	-5.3%	-6.1%	*11.8%*
Maximum variation		*22.3%*	*23.3%*	*14.2%*	*15.4%*	*14.5%*	*14.7%*	*14.4%*	*15.2%*	*15.8%*	*18.0%*	

In the 10 GW storage case the variation along columns is larger than the variation along rows, in line with all the previous analysis in this study. However, when looking at the variations as a function of PV penetration vs consumption profile for the 25 GW storage capacity case this is clearly no longer applicable. There are some years where the variation as a function of PV penetration is larger than for the consumption profile. This could be because some of the GAFSI countries might have reached large enough amounts of PV production so that the full amount of storage is used over a period of only a few hours (e.g. PV capacity from one of the later years with the consumption of one of the earlier years). If 26 GW represents a large portion of the total consumption during that time period (or even if that is similar to the total consumption) it could create some unusual scenarios. This would be reflected in the in higher variability of MOPs.

5 SOCIAL BENEFITS: ARE WHOLESALE PRICES ACTUALLY DECREASING?

It has been estimated in sections 3 and 4 that (i) the MOP is close to 90 €/MWh and could be paid to PV plants as a bonus on top of the market price for every MWh of PV produced, and (ii) that the average market price would have been 4.0% higher (2.0 €/MWh) had there been no PV generation between 2007 and 2015.

In order to estimate the net social gains for society, several factors must be also taken into account such as the costs of the various support schemes to PV (tax incentives, feed-in tariffs), additional reserve capacity, grid upgrades on the one hand, and, indirect gains through taxes, job creations and reduction of negative externalities (pollution, energy dependent on Russian gas), hedging against fuel price volatility on the other hand. As stated before, this is not the purpose of this paper.

6 CONCLUSION

This study aimed at quantifying the savings incurred in Germany, Austria, France, Switzerland and Italy as a whole over the past 10 years as a result of the decrease in electricity spot market prices observed when PV plants feed electricity into the grid. It assessed the effect in two additional cases where PV has a decentralized storage system as well as a centralised storage system (e.g. pump-hydro).

For the case where there is no storage involved, the authors showed that the total electricity demand retreated by PV production is well correlated to the prices, following an exponential curve (R^2 around 66%). That good correlation proves that the strong set of assumptions was acceptable (low share of electricity export or import to production, no self-consumption, all electricity demand traded on the spot market, stable energy mix and price behaviour). The MOE, i.e. the aggregated energy bill saving in a year, has of course increased as more PV plants were installed, reaching a circa € 31 Bn cumulative amount by end 2015. If such benefit could be monetised by the public authorities, it could be invested in the infrastructure necessary as a result of the introduction of renewables into the energy mix such as grid reinforcement works or to allow spare peak producers to remain profitable. Over the 10 year period, the MOP (MOE expressed per MWh of PV production) is close to 91 €/MWh, which could be paid as a bonus to PV producers on top of their sale on the spot market. Also, market prices would have been 4.0% higher (2.0 €/MWh) had there been no PV production.

In order to test what the impact could be on the MOE (and related metrics) if significant amounts of energy storage facilities were installed, two types of storage were identified: centralized and de-centralized. In the former case it was found that the MOE amount decreased by EUR 800 M after the introduction of 10 GW of storage and a by a further EUR 1.5 bn when considering 25 GW of storage. The MOP decreased and the average market price decrease due to PV was lower than in the PV only case. Though the impact on those is relatively minor (in the order of 3-4 EUR/MWh for the MOP and around 0.1 EUR/MWh for the average market price decrease). Nevertheless, the MOP/MOEs increased year-on-year for 2014 and 2015 compared to the PV only case. This could be an indication that the amount of storage introduced were too high in the early years. To confirm these results/hypotheses additional calculations would be needed amongst others, to test the impact of gradually scaling up the storage systems over the years along with PV capacity; test the impact of more sophisticated re-injection methodologies (to better correlate the injection to the demand curve) and simply use smaller amounts of storage capacity, particularly in the early years when PV capacities are still relatively low.

For the centralised storage the results are quite different. In this case the MOE amount increases by EUR 1 bn for 10 GW of centralized storage and by an additional EUR 1.2 bn for 25 GW of storage. This leads to an increase of MOP by up to 8 EUR/MWh (25 GWh of storage). This would mean that PV plants could be paid almost 150 EUR/MWh including the WAP (around 50 EUR/MWh).

A statistical approach enabled the authors to simulate a large number of PV production profiles, and calculate the MOP with 10 different electricity demand profiles (those observed between 2006 - 2015) and 10 penetration rates (PV capacity installed between 2006-2015). The statistical analysis revealed that the MOP is generally quite dependant on the particular electricity demand profile, and therefore on how well it is correlated to the PV production profile. Introducing a storage element allowed the authors to test if this would be an efficient way of optimising the MOE for PV (by improving the correlation between injection of electricity produced by PV and demand profile). With a relatively simple approach it was possible to significantly improve the MOE and MOP using a form of centralized storage. This suggests that there is room for further optimisation and, thus, improvement of the MOE. Since 2011, the penetration rate of PV is also a significant explanatory variable, suggesting that PV could be increasingly replacing mid load capacity.

Ultimately it has been observed that the negative pressure of PV production on wholesale prices is well reflected in Germany, Austria, France and Switzerland.

Another contribution of this analysis is the quantitative assessment of the market coupling effect on PV impact on the electricity markets (through WAP). The same methodology could be applied to wind energy. In fact, as PV, it also represents a good share of the power generation of the countries analysed here. Further studies could sign the pathway to an integrated electricity market which will not only exploit the negative pressure of PV on electricity market but also what are at the moment known as weaknesses of the RE (i.e. intermittency).

This paper opens the route for other improvements:

- take account of export/import and self-consumption;
- run the Monte Carlo on irradiation (which is expected to follow more closely a Gaussian behaviour) rather than yield.
- Analyse the combined effect of Wind and PV electricity fed into the grid on wholesale prices.
- Use more sophisticated approaches in the simulation of storage capacities to improve the correlation between electricity injection from PV production and electricity demand.

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